
# 2016-2020 Rate Application

Hydro Ottawa

# MANAGEMENT, DISCUSSION AND ANALYSIS

Please see A2 – Executive Summary.

# MANAGEMENT DISCUSSION & EXECUTIVE SUMMARY

## 1.0 INTRODUCTION

This schedule provides a summary of Hydro Ottawa Limited (" Hydro Ottawa or HOL or the Company", "the utility")'s Custom Incentive Regulation ("Custom IR") rate application for the five year period beginning 2016 and ending in 2020. This schedule describes Hydro Ottawa's business plan and identifies the funding the company requires in order to continue to serve its current and future customers in a manner that allows it to fulfil its mission to deliver safe, reliable, affordable and sustainable electricity to the homes and businesses in the City of Ottawa and the Village of Casselman and to meet the demands of a growing, expansive and complex urban/rural environment while pursuing productivity improvements to benefit the company's ratepayers and an appropriate rate of return for its shareholders. This Executive Summary is guided by the requirements set out in Sections 2.4.1 and 2.4.2 of Chapter 2 of the Ontario Energy Board ("the OEB" or "the Board")'s Filing Requirements for Electricity Distributors Companies' Cost of Service Rate Applications, based on the forward Test Years (the 'Chapter 2 Requirements').

This application represents Hydro Ottawa's assessment of its capital and operational needs and of its commitment to its customers over the next five years. The investments set out in this application are required in order to address the pressures of aging infrastructure, a continuously growing customer base, challenging weather, increasing urban and rural development and modernization, an aging workforce, and a growing customer appetite for innovative leading-edge and technology-based services. Hydro Ottawa's challenge is to finance its operations so that it may continue to provide its customers with a safe and reliable source of electricity, as well as, acceptable customer service levels at reasonable rates.

By way of this application, Hydro Ottawa seeks approval for its five year Custom IR rate application which is based on a rate-setting model wherein Hydro Ottawa's capital requirements are recovered on a five year forecasted cost of service basis and its operations, maintenance and administrative ("OM&A") requirements are recovered pursuant to an "I-X" formula. Hydro Ottawa seeks approval for final rates for a three year period beginning 2016 and ending 2018 and for its five year forecasted capital requirements. Hydro Ottawa proposes to apply to the Board to adjust its 2019 and 2020 rates to incorporate a revised inflation factor and updated cost of capital parameters. Finally, Hydro Ottawa reserves the right to file Y and Z factor applications during the course of its Custom IR period and proposes to share earnings with its customers based on increasing proportionality scale for earnings that rise above certain thresholds.

Recognizing its significant multi-year capital needs Hydro Ottawa has exercised the option provided to it pursuant to the Report of the Board entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (the "RRFE") to account for its unique capital funding requirements that cannot be accommodated for under the OEB's 4$^{th}$ Generation Incentive Regulation model. In filing a Custom IR application, Hydro Ottawa has applied the key tenants of the RRFE including, but not limited to;

a) By applying for an initial rebasing (financial viability) then applying for a rate setting approach to recover forecasted capital needs but recovers OM&A needs pursuant to an I-X formula (operational effectiveness);
b) By identifying historical and future productivity initiatives to achieve continuous improvement (operational effectiveness);
c) By providing a total cost and reliability econometric benchmarking, as authored by Power System Engineering and based on the OEB's benchmarking approach;
d) By providing a customer engagement strategy to ensure responsiveness to identified customer preferences (customer focus);
e) By providing a comprehensive asset management and infrastructure investment plan that is linked to the capital budget, prioritizes for total bill

impact, is informed by customer consultation and been subject to an independent assessment;

f) By providing an annual reporting mechanism through which Hydro Ottawa can inform the Board of its progress on implementing its capital plan as well as its continuous improvement initiatives.

This application has been prepared and guided by the OEB's requirements set out in the OEB's Filing Requirements for Electricity Distributors Companies' Cost of Service Rate Applications and seeks to align with the OEB's guidance to electricity distributors in its' Renewed Regulatory Framework for Electricity Distributors report ("RRFE"). For further details illustrating how the evidence comprising Hydro Ottawa's application aligns with the Board's RRFE expectations please see section 3.0 below and refer to Exhibit A-2-2.

## 2.0 ABOUT HYDRO OTTAWA

### 2.1 General Facts

Hydro Ottawa serves Canada's capital Ottawa and the Village of Cassleman. Ottawa is home to the Parliament of Canada and key departments within the federal public service, is the second largest city in Ontario and the 6th largest city in Canada. Hydro Ottawa is the fourth largest electricity distributor in Ontario serving over 315,000[1] customers and has a service territory of 1,104 square kilometers that includes a complex dense urban core, large areas of suburban development and a vast rural area representing approximately 60%[2] of the company's territory. Hydro Ottawa is the amalgamation of five predecessor utilities: Ottawa Hydro, Kanata Hydro, Gloucester Hydro, Nepean Hydro and Goulbourn Hydro. In 2002, Hydro Ottawa acquired the service territory of Casselman Hydro.

[1] New customer growth is occurring at a rate of approximately 1% per annum.
[2] According to the latest Ontario Energy Board ("OEB" or "Board") Electricity Distributor Yearbook results (2013), Hydro Ottawa has a total service area of 1,104 square kilometers with approximately 60% of the service territory being classified as rural.

## 2.2 Challenges faced by Hydro Ottawa

Hydro Ottawa operates in a unique market with unique challenges. Among the challenges unique to Hydro Ottawa is its weather. Ottawa winters are cold and they are long. Relative to other large local distribution companies ("LDCs") in Ontario, Hydro Ottawa must contend with longer periods of ground freeze and more significant snow cover. This impacts Hydro Ottawa's operations and its costs in a number of significant ways. First, extended periods of ground freeze and snow cover shortens the infrastructure construction period and lengthens the moratorium period by approximately 4-6 weeks which can reduce the construction seasons by as much as 20%. In addition, snow and ice impedes normal work flow because it increases time to access sites, access equipment safely, and impacts the set-up/take down of a work area. The increase to time spent at each worksite reduces the number of worksites that can be scheduled in a day consequently increasing overall costs from a unit of work perspective. On the capital side, Ottawa's long winters require the municipality to use significant quantities of road salt which has a corrosive effect on ductwork, wires and insulators shortening the effective asset life of Hydro Ottawa assets.

Another challenge that Hydro Ottawa faces stems from the approximately 43% of its workforce that is eligible to retire by 2020 or during the course of Hydro Ottawa's Custom IR rate period. The preponderance of employees eligible to retire are technical and operational staff that require multi-year training and apprenticeship. Details on the measures Hydro Ottawa is undertaking to address the challenges of managing the utility with an aging workforce are set out in its Workforce Planning Strategy available in Exhibit D-1-7.

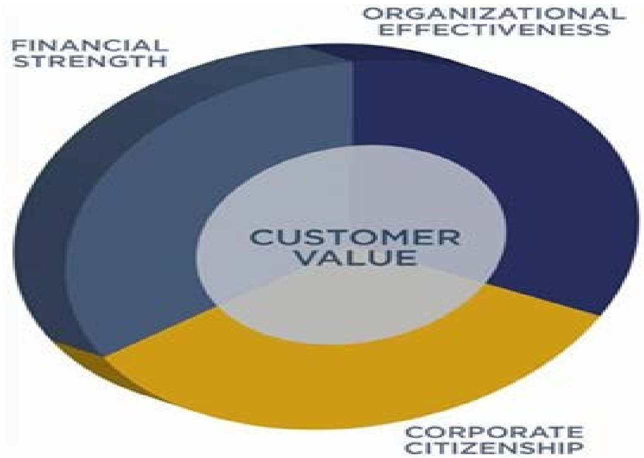
Like other LDCs, Hydro Ottawa also faces challenges presented by aging infrastructure. Hydro Ottawa estimates that approximately 30% of its assets have reached or exceeded their expected useful life. This is creating increasing pressure on the company to replace aging assets before they fail. See Exhibit B-1-2(A)-(C) for further details. Also, though serving a major urban centre, Hydro Ottawa must contend with intensification of development within its urban core as well as continued suburban growth in the east, west and southern regions of its service territory. One of the challenges that is unique to Hydro Ottawa to execute its capital construction plans arises from constraints on contractor availability. Despite the City of Ottawa being the second largest city in Ontario, there are an insufficient number of qualified contractors to support Hydro Ottawa's capital plans requiring Hydro Ottawa to pay a premium in order to attract contractors from the Toronto region.

Finally, with raising electricity rates comes rising customer expectations. Hydro Ottawa's customers are expecting new and/or improve services allowing the customer to interface with Hydro Ottawa and obtain information (i.e., billing, time-of-use consumption, appliance consumption, outage alerts, etc.,) on the device or medium of the customers' choice and at a time of the customers' choice. The challenge moving forward is to meet these expectations in an innovative, agile and timely manner within the funding resources provided for and approved by the Board in this application. Hydro Ottawa's ability to be innovative and agile and its ability to respond to industry market changes and customer expectations will become an increasingly important strength over the next five years with the introduction of new technologies, and as legislative and policy modernization take a foothold within the industry to incentivize distributor consolidation.

### 2.3 Hydro Ottawa Four Strategic Objectives

Hydro Ottawa's four strategic objectives are: a) to deliver customer value; b) to create sustainable growth; c) to achieve performance excellence; d) to contribute to the well-being of the community. As denoted in Figure 1 below, Hydro Ottawa fundamentally believes that delivering customer value is at the core of its mission and that if it can create sustainable growth, achieve performance and contribute to our community, the customer will derive long term value from the company and the activities and initiatives it proposes undertake over the next several years.

**Figure 1**:




These corporate objectives are consistent with the four performance outcomes set out in the RRFE namely that a) Customer Focus – that services are provided in a manner that responds to identified customer preferences; b) Operational Effectiveness – continuous improvement in productivity and cost performance is achieved and utilities deliver on system reliability and quality objectives; c) Public Policy Responsiveness – that utilities deliver on obligations mandated by government and d) Financial Performance – financial viability is maintained and savings from operational efficiencies are sustainable.

## 3.0 ALIGNMENT WITH THE RRFE

The design of Hydro Ottawa's Custom IR application and the evidence filed in support of its capital and operational funding requirements seeks to respond to the Board's expectations for Custom IR applications as set out in the RRFE. These expectations and the evidence that Hydro Ottawa relies on to illustrate its compliance are summarized in Exhibit A-2-2 as well as in Table 1 below.

**Table 1.**

| **OEB's RRFE Performance Outcomes** | | **Hydro Ottawa's Corporate Objectives** | | **HOL Evidentiary Alignment with RRFE** |
|---|---|---|---|---|
| **Focus** | **Objective** | **Focus** | **Objective** | |
| **Customer Focus** | Services are provided in a manner that responds to identified customer preferences | **Customer Value** | We will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates | Exhibit D-1-6 Customer Service Strategy<br><br>Exhibit A-3-1 – Customer Engagement Plan<br><br>See Exhibit B-1-2 for HOL's Distribution System Plan. |
| **Operational Effectiveness** | continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives; | **Organizational Effectiveness** | We will achieve performance excellence by cultivating a culture of innovation and continuous improvement | See Exhibit D-1-5 for an overview of productivity & benchmarking<br><br>See Exhibit D-1-4 for a discussion of HOL's historical and forward looking productivity initiatives<br><br>See Exhibit D-1-7 for Hydro Ottawa's Workforce Planning strategy<br><br>See Exhibit B-1-2 for HOL's Distribution System Plan. |
| **Financial Performance** | Financial viability is maintained; and savings from operational effectiveness are sustainable. | **Financial Strength** | We will create sustainable growth in our business and our earnings by improving productivity and pursuing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people | See Exhibit D-1-5 for an overview of Hydro Ottawa's productivity & benchmarking<br><br>See Exhibit D-1-4 for a copy of Hydro Ottawa's OEB Scorecard.<br><br>See Exhibit E for details of Hydro Ottawa Cost of Capital and Capital Structure.<br><br>See Exhibit B-1-2 for HOL's Distribution System Plan. |
| **Public Policy Responsiveness** | utilities deliver on obligations mandated by government | **Corporate Citizenship** | We will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen | See Exhibit D-1-9 for details of Hydro Ottawa's Health, Safety & Environment Plan<br><br>Hydro Ottawa will file at a later date its approved 2015-2020 CDM Plan<br><br>See Exhibit B-1-2 for HOL's Distribution System Plan. |

# 4.0 HYDRO OTTAWA'S CUSTOM IR APPLICATION

## 4.1 Hydro Ottawa Guiding Principles

Hydro Ottawa proposes a Custom IR rate-setting framework that constrains operational funding increases after rebasing and provides the ability to recover its multi-year capital investments. To facilitate the development of the 2016 to 2020 Custom IR application Hydro Ottawa developed the following guiding principles:

- ✓ Ensure rate increases are as minimal as possible and that rates are timely and commensurate with the cost to provide service.
- ✓ Ensure new customer services can be introduced throughout the term of the plan so that customer expectations are met.
- ✓ Invest in assets which ensure that the distribution system is efficient and reliable in order to meet expectations of both existing customers and new customers during the five-year term.
- ✓ Demonstrate cost containment and control, encourage productivity initiatives, while still providing customers with appropriate service levels.
- ✓ Ensure that capital expenditures earn an appropriate rate of return in a timely manner so that continued investment in capital assets can be afforded and, therefore, meet customer expectation's regarding reliability.

## 4.2 Principle Drivers Justifying Custom IR

Hydro Ottawa's decision to adopt a Custom IR rate-setting model is justified in light of the significantly large multi-year capital investments needed by Hydro Ottawa to continue to provide a safe and reliable electricity distribution service so that it may continue to meet the needs and expectations of its customers. Hydro Ottawa's capital requirements are the result of investments identified through the Company's asset management planning and network investment planning processes and in particular through its Heath Indexing method used to assess the condition of its assets. A copy of Hydro Ottawa's Asset Management Planning process, its Distribution System Plan and its Grid Transformation Plan can all be found in Exhibit B-1-2.

### 4.3 Hydro Ottawa's Financial Planning and Budgeting Approach

Hydro Ottawa's approach to its 2016 Custom IR rate application and the financial planning considerations and budgeting were informed by and reflect the guiding principles enunciated above. Hydro Ottawa's financial planning and budgeting approach included a number of interrelated steps which started with the development of a detailed forecast of capital and operations, maintenance and administrative (OM&A) expenditures, for the years 2016 through 2020.

#### 4.3.1 Capital Budget Forecasts

The final detailed forecast of capital expenditures for each year of 2016 through 2020 presented in this application is the result of a number of refinements and several iterations. Initial forecasts included funding requests that were greater than the final forecast, as there was opinion that a higher funding level was required from an asset-needs perspective. That higher funding level was measured against a number of other key factors including rate impacts and resources available and/or required for execution of Hydro Ottawa's capital plans and the company's financial capability to fund investments.

The final, detailed forecast of capital expenditures resulted in a calculation of rate base for each year of 2016 through 2020. With the calculation of rate base for each year, Hydro Ottawa proposes to determine, for rate making purposes, the return on investment on the annual rate base and adjust rates each year to recover this return on investment. This step of the approach addresses a number of the guiding principles above.

1) The final detailed forecast of capital expenditures ensures that a safe and reliable electrical service is provided to the customers of Hydro Ottawa.
2) The final detailed forecast and subsequent budget provides incentives to prioritize pace and effectively manage the annual budgets.
3) The recovery of return on investment for large capital expenditures, on an annual basis, provides customers with timely and appropriate rates for the cost of providing service. This eliminates potential intergenerational rate

increases that arise when the return on large capital expenditures is not incorporated into rates until a subsequent re-basing application.

4) The recovery of return on investment for large capital expenditures, on an annual basis, ensures that those customers who benefit from the service associated with the expenditures are, in fact, the customers paying for the service.
5) The timely recovery of return on investment of the large capital expenditure from 2016 – 2020 ensures Hydro Ottawa is financially capable of continuing to fund large capital expenditures into the future, so safe and reliable electrical service may continue to be provided to the customers of Hydro Ottawa.

Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Hydro Ottawa fully expects this level of annual capital expenditure will be sustained, if not increased through the decade from 2020-2030.

The proposed annual expenditure level is significantly greater than annual expenditure levels set out in previous Hydro Ottawa rate applications but is consistent with the 2013-2015 capital spend levels for distribution plant. What's more the annual expenditure levels are necessary to effectively address all the key areas outlined above in order to continue to provide customers with safe, reliable service at a reasonable rate. By comparison, between 2006 and 2009, Hydro Ottawa's average annual net expenditure level was approximately $60 million per year (gross expenditure average was $75 million per year).

To support this level of annual capital expenditure over the five year period, Hydro Ottawa requires a financial sustainability model which provides timely return on invested capital. The financial model under the OEB's 4th generation IRM model does not provide appropriate timing of return on capital expenditures for Hydro Ottawa due to the significant percentage differential between net capital expenditures per year and annual depreciation expense. In Hydro Ottawa's case, the differential for the years 2016 to 2020 is approximately 245% or approximately $60 million per year. Table 2 below compares Hydro Ottawa's forecasted annual capital expenditure requirements to its annual forecasted depreciation expense to illustrate that Hydro Ottawa's capital requirements are over two times and as much as three and a half times the level of forecasted depreciation. Hydro Ottawa's annual increases in capital expenditures and depreciation outpaces inflationary increases to revenue available under the IRM regime rendering the latter an inappropriate mechanism for recovering Hydro Ottawa's capital needs.

**Table 2 – Capital Expenditure vs. Depreciation**

| ($000s) | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **Capital Expenditures** | $145,430 | $149,073 | $119,418 | $120,982 | $119,538 |
| **Depreciation** | $40,826 | $44,145 | $47,047 | $48,949 | $50,295 |
| **Multiple** | 3.5 | 3.3 | 2.5 | 2.4 | 2.3 |

### 4.3.2 OM&A Budget Forecasts

To support Hydro Ottawa's operation, maintenance and administrative proposed expenditures ("OM&A), Hydro Ottawa has put forth a detailed budget and analysis of its OM&A costs for 2016. For the 2016 test year, a budget process was completed in 2014 to identify the OM&A needs of Hydro Ottawa. The budget memo directed division leaders to develop the 2016 OM&A budget under certain parameters for ongoing programs and projects and sought identification by individual divisions of extraordinary or unique programs and projects.

For 2017 through 2020 OM&A costs are calculated based upon a formulaic adjustment mechanism. This formulaic adjustment would result in the costs for OM&A included for rate making purposes being delinked from the actual costs incurred by the Company for OM&A expenses for the same period. Following the establishment of a baseline budget for 2016, Hydro Ottawa has chosen to adjust the 2016 test year OM&A by "I" – "X" formula for the each year of 2017 through 2020 where "I" refers to inflation and "X" refers to productivity. This formulaic adjustment is consistent with the OEB's policy framework under the RRFE where rates charged to customers are de-linked from the costs of operating the utility.

This approach creates an incentive for the Company to seek out productivity initiatives during this period in order to meet ever growing OM&A costs and pass those benefits of the productivity initiatives on the customer during the Custom IR period and in the subsequent 2021 – 2025 rate timeframe. See below for a discussion of how Hydro Ottawa proposes to define the I-X.

#### 4.3.3 Proposed Rate Adjustments

Hydro Ottawa proposes to establish final rates for 2016, 2017 and 2018, as part of this application and to establish final rates for 2019 and 2020 based on capital requirements plus updated inflation and cost of capital parameters. The proposal is to establish the forecast capital expenditures and resulting rate base for 2016, 2017 and 2018. In addition OM&A costs would be established for 2016 and adjusted by formula for 2017 and 2018, based upon a forecast for inflation and a fixed productivity adjustment. The cost of capital parameters will be updated based upon the OEB's prescribed 2016 rates for deemed short term debt and return on equity ("ROE") with long term debt being a weighted average of embedded and forecast deemed rates calculated as discussed in E-1-1. The cost of capital parameters would not be updated annually for 2017 and 2018.

Hydro Ottawa also proposes to establish final rates for 2019 and 2020 in the fall of 2018, based upon the following parameters:

a) Capital expenditures and rate base – 2019 and 2020 capital expenditures and corresponding rate base will be calculated based upon the capital expenditure forecast and rate base forecast contained in this application.
b) OM&A – OM&A expense will be calculated based upon the updated inflation forecast of the Conference Board of Canada ("CBofC"), released in fall 2018 for 2019 and 2020.

c) Cost of Capital parameters – any adjustment to the cost of capital parameters will be based upon the OEB's prescribed rates for 2019 (short term debt, and ROE) released in the fall of 2018. The OEB prescribed rates for 2019 will also apply to 2020 rates for Hydro Ottawa. Long term debt will be a weighted average of embedded and forecast deemed rate at that time as outlined in E-1-1.

Hydro Ottawa's proposal to fix final rates for three years (2016-2018) then adjust the rates only to update for inflation and cost of capital variables. This is intended to build in rate protection for Hydro Ottawa's customers and to provide operating and business certainty to Hydro Ottawa and its shareholder. Hydro Ottawa recognizes that this is a departure from other Custom IR proposals such as those filed by Horizon and Oshawa that have a built in mechanism through which rates can be adjusted annually but the Company stands by the merits of proposing fixed and final rates for the first three years of its five year Custom IR plan.

### 4.4 Custom IR Rate-Setting Framework

Consistent with Hydro Ottawa's letter to the Board dated December 22, 2014, Hydro Ottawa has opted to apply for rates based on a Custom IR framework. Hydro Ottawa propose a custom IR framework on the grounds that it must undertake unprecedented infrastructure investments in the near to medium term to avoid risks to system and service reliability.

The Custom IR option is the best option for Hydro Ottawa and its customers to ensure the Company has the financial capacity to increase its investments to replace system assets that have reached the end of their useful life. The other rate making approaches identified by the OEB in the RRFE are deficient insofar as they would not result in sufficient capital funding to support Hydro Ottawa's increasing investment requirements.

### 4.4.1 Capital Expenditures

For all these reasons, Hydro Ottawa's application proposes to have its capital investment requirements fully funded on a five year forecasted cost of service basis. Refer to Exhibit B-1-2(A)-(C) for details on Hydro Ottawa's capital requirements.

### 4.4.2 Operations, Maintenance & Administrative (OM&A)

For OM&A, Hydro Ottawa proposes a budget for 2016 and thereafter to adjust the 2016 test year OM&A by "I" – "X" (inflation minus productivity) formula for the each year of 2017 through 2020. This formulaic adjustment is consistent with the OEB's policy framework under the RRFE where rates charged to customers are de-linked from the costs of operating the utility.

For the inflation factor, Hydro Ottawa proposes to use the GDP-IPI forecast from the Conference Board of Canada ("CBofC") for the period of 2017 and 2018. The CBofC only provides a three-year forward forecast for GDP-IPPI or CPI. The CBofC has forecast GDP-IPPI at 2.1% for each of 2017 and 2018. For application purposes, Hydro Ottawa has used the CBofC's 2018 forecast of GDP-IPPI as a placeholder for both 2019 and 2020. Hydro Ottawa will update the forecast for GDP-IPPI for 2017 and 2018 using the CBofC's 2015 fall forecast.

Hydro Ottawa will use the 2017 fall forecast of the CBofC to establish the final inflation adjustment for OM&A for 2019 and 2020.

To derive the productivity factor Hydro Ottawa has relied upon the empirical evidence submitted by expert witnesses in the OEB's Report of the Board entitled *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379). In that proceeding, four experts put forth reports on an appropriate X factor to be used by electricity distributors in Ontario. Table 3 provides a summary of final results of each expert.

**Table 3 – Summary of X Factor Results**

| Expert | X Factor |
|---|---|
| L. Kaufmann, Pacific Economics Group Research, LLC | -0.33 % |
| S. Fenrick, Power Systems Engineering | -1-10 % |
| A. Yatchew, University of Toronto | - 0.75 % |
| F. Cronin, | -2.40 % |
| Average | -1.145 |

Hydro Ottawa contends that this is the only empirical evidence of Ontario electricity distributors' productivity trends over the last 10 years that is available to Hydro Ottawa. Hydro Ottawa has chosen to use the average productivity trend number from all of the studies. In this way, Hydro Ottawa has not endorsed any of the recommendations and has given each recommendation equal weight. The productivity adjustment chosen would apply to each year for the period of 2016 to 2020. Please see Exhibit D-1-4 for details on the productivity initiatives of Hydro Ottawa.

Therefore, to determine the annual increase in OM&A for the 2017 through 2020 period, the following Table summarizes Hydro Ottawa's recommendations:

**Table 4 – Proposed OM&A Increase for 2017 to 2020**

| | 2017 | 2018 | 2019* | 2020* |
|---|---|---|---|---|
| Inflation (GDP-IPPI) (%) | 2.1 | 2.1 | 2.1 | 2.1 |
| Productivity (%) | -1.145 | -1.145 | -1.145 | -1.145 |
| Annual OM&A Adjustment (%) | 3.245 | 3.245 | 3.245 | 3.245 |

* Values for 2019 and 2020 are for illustrative purposes

### 4.4.3 Y Factor

Hydro Ottawa further proposes to introduce a Y factor to recover the costs associated with the construction of its new facilities. The Y factor recovers routine or expected cost changes outside the scope of the annual adjustment mechanism; these are considered to be a cost pass-through. Hydro Ottawa proposes to use a Y factor to pass along to ratepayers the costs associated with the construction of the administrative and operational buildings as outlined in section 3.4.5.3 of the DSP. For further details on Hydro Ottawa's Y Factor proposal refer to Exhibit I, Tab 1, Schedule 2.

#### 4.4.4 Z Factor

Pursuant to the OEB's policies related to the treatment of unforeseen events as set out in *The Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*[3] as may be revised, Hydro Ottawa reserves the right to file a Z factor application to recover costs resulting from events or initiatives having a material impact to Hydro Ottawa's cost or revenue structure.

#### 4.4.5 Earning Sharing Mechanism

Hydro Ottawa proposes to include an earning sharing mechanism as a key feature of its Custom IR Application. Earnings sharing mechanisms are features of incentive regulation frameworks that permit the sharing of utility earnings between its shareholder and/or its customers when earnings rise above or fall below a certain threshold. Earnings sharing is a mechanism through which earnings may be passed along to the customer in the form of rate reductions or rate offsets. Hydro Ottawa is proposing an asymmetrical earning sharing mechanism such that it is only proposing to share earnings that are above a basis point threshold above Hydro Ottawa's return on equity but the company will not impose a corresponding rate adjustment if its earnings fall below a basis point threshold of its return on equity.

Hydro Ottawa proposes the following formula for its earnings sharing mechanism.

**Table 5 – Hydro Ottawa's Earnings Sharing Proposal**

| # | Threshold | Treatment |
|---|---|---|
| 1 | Under Earning | borne entirely by shareholder |
| 2 | 0 – 150 basis points | fully retained by shareholder |
| 3 | 151- 250 basis points | 50:50 sharing of ratepayer/shareholder |
| 4 | 251 and above | 90:10 sharing of ratepayer/shareholder |

[3] Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf

### 4.4.6 Monitoring and Outcome Measurement

Hydro Ottawa proposes to provide the following information as part of the annual written reporting process to be filed with the OEB:

a) Hydro Ottawa's OEB Scorecard results
b) Annual update on actual capital expenditures by program type, versus, budgeted capital expenditures by program type and appropriate variance analysis;

For further details on Hydro Ottawa's proposed written annual reporting proposals refer to Exhibit A-2-2.

### 4.4.7 Off Ramps

Hydro Ottawa proposes to apply the OEB's existing policy with respect to off-ramps. The RRFE Report sets out the off ramp trigger which is equal to the annual return on equity review where the dead band equals plus or minus 300 basis points. In the event the 300 basis point dead band is triggered a regulatory review may be initiated.

## 5.0 SUMMARY OF APPLICATION KEY COMPONENTS

### 5.1 Capital Expenditures

Hydro Ottawa developed the forecasted capital expenditures for the years 2016 – 2020, based upon a process of identification and analysis of distribution system needs, customer expectations and requirements for general plant capital.

The total capital expenditure forecast underwent a number of iterations to address issues of pace, priority, rate impact, resource capacity and financing capability. For example, a new capital expenditure area relating to Hydro One transmission costs was accommodated to a certain level by reducing other areas of capital expenditure. As well, pacing and prioritization of other capital projects (typically IT expenditures) were adjusted through a number of iterations so that the resource capacity of company could complete the projects in a timely manner and to pace the total expenditures of other capital projects more evenly throughout the 2016 – 2020 timeframe. Please see Exhibits B1-1 and B-1-2 for details.

A detailed capital expenditure for each year from 2016 – 2020 provides the basis of the calculation for rate base. The capital expenditure is detailed by asset type and the corresponding amortization is calculated. Hydro Ottawa has used the half year rule in the calculation of rate base for each year of 2016 -2020. Please see Exhibit B-1-1 for details.

Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Forecasted gross capital expenditures for the 2016 test year are approximately $145.4 million which represents an increase of approximately $109 million or 26 % from Hydro Ottawa's last rebasing application in 2012. For the 2016-2020 period, Hydro Ottawa's proposed capital expenditures are as follows:

**Table 6 – Summary of Capital Expenditures for Test Years**

| ($000s) | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **Capital Expenditures** | 145,430 | 149,073 | 119,418 | 120,982 | 119,538 |

Source: table 1.1.1 DSP Exhibit B-1

For greater detail on Hydro Ottawa's 2016-2020 capital funding requirements please refer to Hydro Ottawa's Distribution System plan and associated schedules and appendices in Exhibit B-1-2. The DSP outlines Hydro Ottawa's Asset Management Process and Capital Expenditure Plan, in line with the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements, providing evidence for good distributor planning.

## 5.2 Rate Base

Hydro Ottawa's requested rate base for the 2016 test year is $923,306,000 which represents an increase of approximately $254,244,000 or 28% from the total rate base amount approved by the OEB in Hydro Ottawa's last rebasing application in 2012 (EB2011-0054). Table 7 sets out the rate base requested for each of the test years 2016-2020.

**Table 7 – Summary of Rate Base for Test Years**

| ($000s) | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **Rate Base** | 923,306 | 970,582 | 1,020,297 | 1,050,724 | 1,094,270 |

With respect to costs for renewable energy connections, Hydro Ottawa has provided a historical and forwarding looking forecast of system access costs arising from embedded generations as captured in section 3.4 of the Distribution System Plan available in Exhibit B-1-2.

## 5.3 Operations, Maintenance and Administrative (OM&A)

Hydro Ottawa's OM&A costs are significantly influenced by its requirement to operate and maintain a safe and reliable distribution grid, provide service levels that are satisfactory to customers while ensuring its continued compliance with all legislative and regulatory obligations. Among other things, this requires that Hydro Ottawa strategically manage its workforce in a manner that allows it to replace retiring workers with new tradespeople and respond to the changing dynamics of the market and operating environment within which it is tasked with distributing electricity to customers.

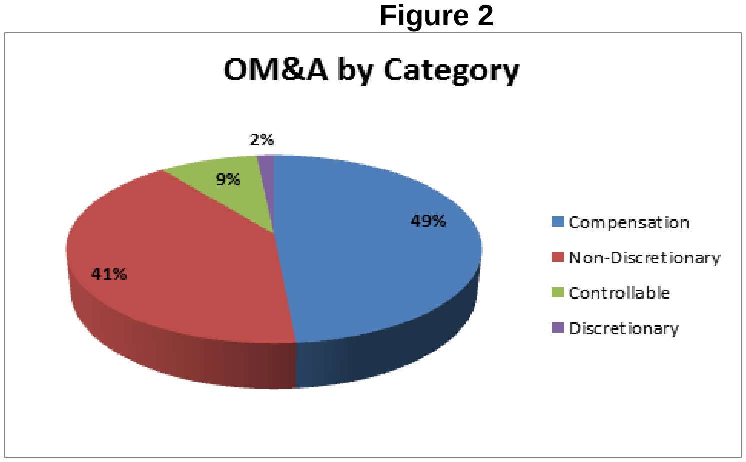
The proposed OM&A costs for the test years range from $87.1 million in the 2016 test year to $99.0 million in the 2020 test year.

**Table 8 – Hydro Ottawa's Proposed OM&A Expenditures**

| ($000s) | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|
| **OM&A Expenditures** | $87,106 | $89,932 | $92,850 | $95,863 | $98,974 |

Hydro Ottawa's OM&A costs arise from four distinct sources, namely compensation, non-discretionary, controllable and discretionary costs. Figure 2 below denotes that compensation costs represent 49% of Hydro Ottawa's OM&A costs while 41% are non-discretionary costs, 9% are controllable and only 2% are discretionary.

**Figure 2**




Source: Hydro Ottawa 2014 OM&A

For a discussion of the costs captured in each of the categories contained in Figure 2 and for a description of Hydro Ottawa's proposed OM&A costs for each of the 2016-2020 test years and for a discussion of the year over year variances by major category, please refer to Exhibit D-1-2.

Table 9 below provides a summary of the overall OM&A cost drivers and cost trends.

**Table 9 – OM&A by Cost Driver**

| **OM&A ($M)** | **Last Rebasing Year (2012 Actuals)** | **2013 Actuals** | **2014 Q2 Forecast** | **2015 Bridge Year** | **2016 Test Year** |
|---|---|---|---|---|---|
| ***Reporting Basis*** | | | | | |
| **Opening Balance** | 73.1 | 73.1 | 75.8 | 80.8 | 83.7 |
| Workforce Planning | | - | 0.2 | 0.3 | 0.4 |
| Collective Agreement/Annual progressions | | 1.1 | 1.2 | 1.3 | 1.4 |
| Vacancy and Vacancy Allowance | | - | (1.6) | (0.5) | (0.1) |
| Benefits & Pensions | | 0.1 | 1.7 | (0.3) | 1.0 |
| Vegetation Management | | 0.4 | 0.3 | 0.9 | (0.4) |
| Underground Locates | | 0.2 | 0.1 | 0.3 | 0.3 |
| Changes in Capital and Allocations | | (0.6) | 0.2 | 0.1 | (0.2) |
| Postage | | (0.1) | 0.7 | 0.2 | - |
| IT Maintenance | | 0.5 | 1.2 | 0.4 | 0.5 |
| Bad Debts | | 0.8 | (0.4) | (0.3) | 0.4 |
| Inventory Scrap recovery reclass out of OMA | | - | 0.8 | $ - | $ - |
| Inflation | | - | | 0.8 | 0.8 |
| Other Costs/(Cost reductions) | $ - | 0.3 | 0.6 | (0.3) | (0.7) |
| **Closing Balance** | 73.1 | 75.8 | 80.8 | 83.7 | 87.1 |

For a full discussion of Hydro Ottawa's OM&A programs, the costs drivers and year over year variances to the company's OM&A costs, please refer to Exhibit D-1-3.

### 5.3.1 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an inflation factor of 2.1% is applied to OM&A expenditures consistent with the Conference Board of Canada's GDP IPI.

#### 5.3.2 Compensation Costs

Hydro Ottawa's forecasted total compensation costs for the 2016 test year are $71,944,283. This represents an $11,038,541 increase or an approximate 15% increase over the 2012 Board approved. Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees. For more information regarding Hydro Ottawa's compensation strategy please refer to Exhibit D, Tab 1, Schedule 8.

For further details on Hydro Ottawa's OM&A proposals see Exhibits D-1-1, D-1-2 and D-1-3.

### 5.4 Revenue Requirement

Hydro Ottawa requests approval for service revenue requirement for each of its 2016-2020 Test Years, base revenue requirements for each of its 2016-2020 Test Years and resulting rates and riders based on Hydro Ottawa's forecast capital expenditures, OM&A, depreciation expense, cost of capital, payment in lieu of taxes ("PILS") and revenue from other sources. For the 2016 Test Year, Hydro Ottawa requests a service revenue requirement of $187,269,000 which represents an increase of $18,968,000 or 11% from the service revenue requirement previously approved by the Board in 2012 during Hydro Ottawa's last rebasing.

The main cost drivers underlying Hydro Ottawa's test year revenue requirements are the result of increases to Hydro Ottawa's rate base due to the significant capital investments that Hydro Ottawa must undertake so that it may continue to provide a safe and reliable electricity service to the residents and businesses in the City of Ottawa and Village of Casselman. Other cost drivers impacting Hydro Ottawa's revenue requirement include increases to amortization expense, increase to OM&A expenses, increases in interest and return on equity. For further details regarding Hydro Ottawa's revenue requirement and related cost drivers please refer to Exhibit F-1-1

**Table 10 – Hydro Ottawa's Revenue Requirement**

| | $000 | $000 | $000 | $000 | $000 |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| Return on Rate Base | 54,379 | 58,359 | 62,148 | 64,531 | 67,573 |
| Distribution Expenses (not including amortization) | 87,106 | 89,932 | 92,850 | 95,863 | 98,974 |
| Amortization | 40,826 | 44,145 | 47,047 | 48,949 | 50,295 |
| Payment in Lieu of Taxes | 4,958 | 4,799 | 6,074 | 8,473 | 7,587 |
| Service Revenue Requirement | 187,269 | 197,235 | 208,120 | 217,816 | 224,430 |
| Less Revenue Offsets | 11,700 | 11,565 | 11,722 | 11,802 | 11,898 |
| 2012 Base Revenue Requirement | 175,570 | 185,670 | 196,398 | 206,014 | 212,532 |
| Transformer Ownership Allowance | 1,125 | 1,114 | 1,109 | 1,106 | 1,105 |
| Revenue Requirement from Rates | 176,694 | 186,784 | 197,507 | 207,120 | 213,637 |
| Forecasted Load at 2015 Rates | 159,358 | 158,984 | 159,419 | 159,975 | 160,461 |
| **Cumulative Revenue Deficiency (over 2015)** | **(17,337)** | **(27,800)** | **(38,088)** | **(47,146)** | **(53,176)** |
| **Yearly Revenue Deficiency over 2015** | **(17,337)** | **(10,464)** | **(10,288)** | **(9,057)** | **(6,030)** |

Amortization expense has been calculated each year based upon the assets in rate base. Each year new assets are incorporated in rate base with their corresponding amortization rate while older assets are retired with their corresponding amortization rate. A new, weighted average amortization rate is calculated for each year. Please see Exhibit D-3-1 for details. Finally, a detailed Payment in Lieu of Taxes ("PILS") calculation has been completed for each year to determine the appropriate cost for PILS to be included in revenue requirement for each year. Please see Exhibit D-4-1 for details.

### 5.5 Bill Impacts

In developing its initial and test year capital and OM&A budgets Hydro Ottawa was careful to have due regard to the impacts bill increases may have on its customers. Hydro Ottawa's objective was to keep the total bill impacts for each of its customers as minimal as possible.

Hydro Ottawa anticipates that, on average for each of the next five years, the bill impacts resulting from Hydro Ottawa's application as filed (including rate riders associated with Hydro Ottawa's proposed new facilities) will be on average approximately $1.35 per month for residential customers and $4.57 per month for General Service customers.

Table 11 below provides a summary of the total bill impacts for typical customers in all classes. Further details regarding Hydro Ottawa's proposed bill impacts are available in Exhibit H-12-1.

**Table 11 – Hydro Ottawa Estimated Bill Impacts**

| Rate Class | | 2015 Approved | 2016 Proposed | 2017 Proposed | 2018 Proposed | 2019 Proposed | 2020 Proposed |
|---|---|---|---|---|---|---|---|
| Residential (800 kWh) | Distribution Charge | $ 28.39 | $ 31.05 | $ 32.49 | $ 33.78 | $ 34.68 | $ 35.15 |
| | Change in Distribution Charge | | $ 2.66 | $ 1.44 | $ 1.29 | $ 0.90 | $ 0.47 |
| | % Distribution Increase | | 9.37% | 4.64% | 3.97% | 2.66% | 1.36% |
| | % Increase of Total Bill | | 1.84% | 1.06% | 0.93% | 0.65% | 0.34% |
| General Service <50kW (2000 kWh) | Distribution Charge | $ 58.72 | $ 65.95 | $ 70.55 | $ 74.85 | $ 78.95 | $ 81.60 |
| | Change in Distribution Charge | | $ 7.23 | $ 4.60 | $ 4.30 | $ 4.10 | $ 2.65 |
| | % Distribution Increase | | 12.31% | 6.97% | 6.09% | 5.48% | 3.36% |
| | % Increase of Total Bill | | 2.11% | 1.41% | 1.30% | 1.22% | 0.78% |
| General Service 50-1,499 kWh (250 KW) | Distribution Charge | $ 1,153.10 | $ 1,276.35 | $ 1,329.05 | $ 1,377.48 | $ 1,411.05 | $ 1,423.25 |
| | Change in Distribution Charge | | $ 123.26 | $ 52.70 | $ 48.43 | $ 33.58 | $ 12.20 |
| | % Distribution Increase | | 10.69% | 4.13% | 3.64% | 2.44% | 0.86% |
| | % Increase of Total Bill | | 0.55% | 0.30% | 0.28% | 0.19% | 0.07% |
| General Service 1,500-4,999 kWh (2500 KW) | Distribution Charge | $12,915.68 | $14,300.50 | $15,118.75 | $15,850.50 | $16,401.75 | $16,707.75 |
| | Change in Distribution Charge | | $ 1,384.82 | $ 818.25 | $ 731.75 | $ 551.25 | $ 306.00 |
| | % Distribution Increase | | 10.72% | 5.72% | 4.84% | 3.48% | 1.87% |
| | % Increase of Total Bill | | 0.49% | 0.46% | 0.41% | 0.31% | 0.17% |
| Large Use (7500KW) | Distribution Charge | $40,078.07 | $44,383.00 | $46,959.50 | $49,690.50 | $52,139.25 | $53,806.00 |
| | Change in Distribution Charge | | $ 4,304.93 | $ 2,576.50 | $ 2,731.00 | $ 2,448.75 | $ 1,666.75 |
| | % Distribution Increase | | 10.74% | 5.81% | 5.82% | 4.93% | 3.20% |
| | % Increase of Total Bill | | 0.74% | 0.47% | 0.50% | 0.44% | 0.30% |
| Sentinel Lighting (0.4 KW) | Distribution Charge | $ 6.63 | $ 8.08 | $ 8.58 | $ 9.02 | $ 9.42 | $ 9.72 |
| | Change in Distribution Charge | | $ 1.44 | $ 0.50 | $ 0.44 | $ 0.40 | $ 0.30 |
| | % Distribution Increase | | 21.73% | 6.24% | 5.09% | 4.43% | 3.21% |
| | % Increase of Total Bill | | 7.34% | 2.41% | 2.05% | 1.86% | 1.34% |
| Street Lighting (1 KW) | Distribution Charge | $ 4.57 | $ 4.99 | $ 5.24 | $ 5.47 | $ 5.63 | $ 5.88 |
| | Change in Distribution Charge | | $ 0.42 | $ 0.24 | $ 0.23 | $ 0.17 | $ 0.24 |
| | % Distribution Increase | | 9.29% | 4.90% | 4.36% | 3.02% | 4.32% |
| | % Increase of Total Bill | | 1.53% | 0.92% | 0.84% | 0.61% | 0.93% |
| Unmetered Scattered Load (470 kWh) | Distribution Charge | $ 14.72 | $ 16.12 | $ 16.89 | $ 17.58 | $ 18.26 | $ 18.69 |
| | Change in Distribution Charge | | $ 1.40 | $ 0.77 | $ 0.69 | $ 0.69 | $ 0.42 |
| | % Distribution Increase | | 9.52% | 4.74% | 4.06% | 3.91% | 2.32% |
| | % Increase of Total Bill | | 1.69% | 1.00% | 0.87% | 0.87% | 0.53% |

## 5.6 Budgeting and Accounting Assumptions

See sections 4.2 above for a description of the financial planning and budgeting process used to derive Hydro Ottawa's capital and operational budgets and all the accounting and inflationary assumptions used.

## 5.7 Load Forecast Summary

Hydro Ottawa's forecasted energy consumption for the 2016 Test year is 7,440,624 kWh. This is 233,334kWh or 3% lower than the 2012 Board Approved kWh forecast. Hydro Ottawa's forecasted number of customers for the 2016 test year is 325,238 representing an increase of 5.6% over the 2012 Board Approved. Table 12 below provides a high level summary of Hydro Ottawa's forecasted load forecast.

**Table 21 – Hydro Ottawa's Estimated Load Forecast**

| Year | Total Sales (GWh) | Total Customers |
|---|---|---|
| 2016 | 7,441 | 325,238 |
| 2017 | 7,380 | 329,294 |
| 2018 | 7,366 | 333,321 |
| 2019 | 7,364 | 337,306 |
| 2020 | 7,364 | 341,241 |

Note: Customer number do not include Streetlighling, Sentinel Lights, Unmetered and Standby

Hydro Ottawa has provided a five year detailed class specific weather normalized load forecast and customer connection forecast for each rate class in Exhibit C-1-1. The load forecast incorporates the commitments of Hydro Ottawa for conservation to the Ontario government.

## 5.8 Cost of Capital

The components of the cost of capital have been determined for each year. Hydro Ottawa has used the following debt/equity ratio for all years – 4% short term debt, 56% long term debt and 40% equity. As part of this application, Hydro Ottawa has used as a placeholder for determination of the deemed short term debt rate, deemed long term debt rate and the return on equity. The placeholder Hydro Ottawa has used for both of these components is the prescribed rates of the OEB issued on November 20, 2014.

Hydro Ottawa proposes to update short term debt and ROE with the effective OEB-prescribed rates for 2016 which will be announced in fall 2015. The long term debt is a weighted average of embedded and forecast deemed rates calculated as outlined in E-1-1. Hydro Ottawa has incorporated the embedded cost of long term debt in its calculation of cost of capital for that portion of the long term debt that has been issued to third party bondholders.

### 5.9 Cost Allocation and Rate Design

Hydro Ottawa has prepared a cost allocation model for each of the five Test Years using the Board's cost allocation methodologies and the Board's V3.2 Cost Allocation Model Hydro Ottawa's 2016 base revenue requirement has been allocated to the company's nine rate classes. The resulting revenues-to-cost ratios for each rate class were determined using the total revenues over costs for each test year pursuant to the OEB's guidelines set out in EB-2010-0219.

Hydro Ottawa engaged Elenchus to undertake a Cost Allocation Model study to determine whether refinements were necessary to better reflect the OEB's principle of cost causality in its cost allocation to customers. The result of the consultant's study indicated that some classes of customers fell outside the acceptable revenue to cost range as established by the Board. Hydro Ottawa adjusted two classes that fell outside the acceptable revenue to cost range, namely Sentinel lights and unmetered scattered load. The study also indicated that the Small Commercial classes fixed charge could be increased.

Consistent with the Board policy entitled "A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) that seeks to gradually adjust the fixed/variable portions of customer bills, Hydro Ottawa proposes by way of this application increases to the fixed elements of its rates.

## 5.10 Deferral and Variance Accounts

The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046) ("EDDVAR") classifies variance and deferral accounts into two groups, namely Group 1 and Group 2. In this application, Hydro Ottawa proposes to clear both Group 1 and Group 2 deferral accounts. The total net DVA balances proposed for disposition are $8.2 million. The proposed disposition period is one year. Disposition for RPP customers is approximately $7.0 million and $1.2 million for non-RPP customers.

Hydro Ottawa Limited ("Hydro Ottawa") is proposing new rate riders to clear a number of Deferral and Variance ("DVAs") balances, including the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA").

The total net DVA balances proposed for disposition are $8.2 million. The proposed disposition period is one year.

1) Y Factor Deferral and Variance account to record costs to be recovered from the construction of Hydro Ottawa's new head office and operations buildings;
2) Proceeds of Sale of Existing Facilities to capture the after tax gain/loss from the sale of Hydro Ottawa current facilities;
3) Energy East – Trans Canada Pipeline – Hydro Ottawa requests a sub-account be added to US ofA 1508 Other Regulatory Assets deferral account to capture costs associated with consultations regarding the TransCanada Pipeline Limited's Proposed Energy East Pipeline Project;
4) Monthly Billing – Hydro Ottawa requests a deferral account to record costs associated with the transition to monthly billing per EB-2014-0198;
5) Loss on Disposal of Fixed Assets
6) Earnings Sharing Mechanisms to record earnings to be shared above prescribed threshold.

For further information regarding the DVA accounts, the amounts proposed for clearance, proposals for new deferral and variance accounts and other DVA information please refer to Exhibit I, specifically I-1-1, I-1-2 and I-8-1.

## 6.0 CONCLUSION

Over the next five years, the electricity industry in Ontario will undergo transformative change not only to how the market is structured but predictably to how the market is regulated. The government will continue to implement changes foreseen and unforeseen in the Long Term Energy Plan and new technology and new players in the market risk disrupting the fundamental business models upon which the industry is constructed potentially triggering a review of how distributors are regulated. During the five years of Hydro Ottawa's Custom IR application, it fully expects to see increases to growth of distributed generation and further electrification of transportation such as via the City of Ottawa's light rail initiatives and electric vehicles. Hydro Ottawa further anticipates increased customer and third party demand for system monitoring technologies and more "cloud" based solutions. Against this backdrop is an economy that still recovering from a prolonged economic downturn and governments that are introducing new forward energy related or impacting policies.

It is for these reasons that Hydro Ottawa has structured its Custom IR in a manner that ensures it has the funding necessary to build and harden a safe reliable electricity distribution system and has enough operational funding to manage the known and anticipated requirements leaving the balance to be met through productivity and innovative initiatives and solutions. Table 13 below denotes all the components of its rate application and the treatment of each component for each year before Hydro Ottawa returns in 2017 to have certain components of its rate framework adjusted for 2019 and 2020.

**Table 13 – Revenue Requirement Components for 2016 to 2018**

| | 2016 | 2017 | 2018 |
|---|---|---|---|
| Load forecast | Annual forecast | Annual forecast | Annual forecast |
| Capital expenditure | Annual forecast | Annual forecast | Annual forecast |
| Rate base | Annual forecast | Annual forecast | Annual forecast |
| Amortization | Annual forecast | Annual forecast | Annual forecast |
| PILS | Annual forecast | Annual forecast | Annual forecast |
| Inflation factor | CBoC forecast | CBoC forecast | CBoC forecast |
| Productivity factor | Fixed | Fixed | Fixed |
| OM&A | Annual forecast | Formulaic | Formulaic |
| Short Term Debt | Fixed | Fixed | Fixed |
| Long Term Debt (embedded) | Actual | Actual | Actual |
| Long Term Debt (deemed) | Annual Forecast | Annual Forecast | Annual Forecast |
| Return on Equity | Fixed | Fixed | Fixed |

By way of this, its Custom IR application, Hydro Ottawa both undertakes certain manageable risks and is incentivized to seek out additional rewards. For these reasons, Hydro Ottawa respectfully requests that the OEB approve this Custom IR application.

# ALIGNMENT WITH RRFE

This Schedule sets out how Hydro Ottawa Limited ("Hydro Ottawa" or "the Company")'s Custom IR rate setting application and its supporting evidence aligns with the Ontario Energy Board ("OEB")'s expectations as set out in the Renewed Regulatory Framework for Electricity ("RRFE") as well as the key policies and principles enunciated in the RRFE that are intended to apply to Custom IR rate applications.

## 1.0 OEB's Principle-Based Rate Setting

The RRFE sets out the Board's vision for evolving the rate setting approaches available to electricity distributors to incorporate balanced incentives and an outcome-based focus consistent with performance based incentive regulation. With respect to the outcomes-based focus, the Board determined that four categories of outcomes were appropriate for distributors namely a) customer focus; b) operational efficiency; c) public policy responsiveness; and d) financial performance. With respect to balanced incentives, the Board determined that distributors could have the flexibility to choose their rate-setting method based on their unique needs and circumstances. Regardless of the rate-setting method adopted, the Board was clear in the RRFE that each rate method should be supported by a) the fundamental principles of good asset management; b) coordinated longer-term optimized planning; c) a common set of performance expectations and benchmarking.[1]

In what follows, Hydro Ottawa demonstrates that it has embraced both the spirit and intent of the RRFE in crafting its Custom IR application and points to numerous Exhibits contained within its supporting evidence that illustrate its alignment with the many requirements set out in the RRFE.

[1] Page 10, RRFE.

## 2.0 Operational Effectiveness - Asset Management & Network Investment Planning

One of the centerpieces of the RRFE is the symbiotic relationship between asset management planning and network investment planning and the impact that an integrated approach to infrastructure planning has on optimizing investments and prioritizing said investments to manage rate impacts. The Board signaled that a planning horizon of five years is necessary to support integrated planning, to align distributor planning cycles with rate setting cycles and allow distributors to pace and prioritize projects to have regard for total cost impacts and to enhance cost predictability for customer. In the words of the Board:

> [a]n integrated approach to planning will provide a foundation for the setting of distribution rates and lead to optimized investments that support the achievement of the outcomes identified by the Board.[2]

With respect to the relationship between asset management planning and distributor's capital budget, the Board was clear in its direction when it noted:

> The Board needs evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget. Distributor plans must therefore demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation with customers, municipalities and neighbouring distributors and transmitters where applicable.[3] and

> The Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor).[4]

[2] Page 31, RRFE.
[3] Ibid.
[4] Page 37, RRFE.

To fulfill the Board's evidentiary expectations set out in the RRFE as it relates to asset management planning and network investment planning, Hydro Ottawa has provided a five year Distribution System Plan as well as a copy of the Company's 2014 Asset Planning Report in Exhibit B-1. The Asset Planning Report sets out Hydro Ottawa's Asset Management planning process which is updated annually and covers a twenty year period. The Asset Planning Report is designed to identify resource requirements necessary to meet the demands of growth and aging infrastructure as well as any risks or challenges that will adversely affect Hydro Ottawa's ability to deliver on the company's strategic directives.

Hydro Ottawa's Distribution System Plan provides a consolidated view of the company's planning processes used to identify resource requirements and forecast capital expenditure requirements for System Access, System Renewal, System Service and General Plant investments. The DSP translates the system demographics and needs into specific projects with forecasted expenditure plans. Hydro Ottawa's Distribution System Plan and Asset Planning Report were reviewed by Kinetrics for alignment with the Chapter 5 filing requirements as well as to assess Hydro Ottawa's overall Asset Management process for areas of improvement. Kinetrics third party review letter is provided in Exhibit B-1(D).

For full details of Hydro Ottawa's Distribution System Plan and Annual Planning report refer to Exhibit B-1.

## 3.0 Operational Effectiveness – Productivity, Benchmarking & Performance Measurement

The RRFE stipulates that one of the principle outcomes sought by the Board is operational effectiveness including the delivery of continuous improvement in productivity and cost performance and achievement of system reliability and quality objectives.[5] According to the RRFE, a Custom IR application should facilitate the OEB's assessment of "the adequacy of the past and future productivity levels"[6] and the "reasonableness of the distributor's forecasts."[7]

### 3.1 Productivity

To facilitate the OEB's assessment of the reasonableness of Hydro Ottawa past and future productivity levels and to illustrate Hydro Ottawa's adherence to the three policies comprising the OEB's productivity and benchmarking expectations namely as it relates to rate setting; capital planning and measured performance, Hydro Ottawa provides an overview of its productivity and benchmarking evidence in D-1-5. This overview describes how Hydro Ottawa fulfills the OEB's productivity expectations within its Custom IR rate setting approach, within its asset management planning and capital investment planning processes and finally through measurement of performance outcomes and through benchmarking.

In addition to the productivity specific evidence, Hydro Ottawa's evidence of continuous improvement is embedded throughout its application including in the following Exhibits:

a) Exhibit D-1-4 which provides a detailed discussion of its historical and forward looking productivity initiatives that were, are, or will be implemented as illustration of Hydro Ottawa's continuing commitment to efficiency and long run net efficiency savings for the company's customers;
b) Exhibit D-1-2 Hydro Ottawa's Operating, Maintenance and Administrative ("OM&A") evidence;
c) Exhibit D-1-6 Hydro Ottawa's Customer Service Strategy;
d) Exhibit B-1 Hydro Ottawa's Distribution System Plan for continuous improvement metrics and Annual Planning Report illustrating compliance with system reliability and quality requirements;
e) Exhibit D-1-7 Hydro Ottawa's Workforce Planning Strategy;
f) Exhibit A-3-1 Hydro Ottawa's Customer Engagement Plan.

[5] Page 2, RRFE
[6] Ibid, Page 70.
[7] Ibid, Page 13, Table 1.

### 3.2 Benchmarking

To fulfill the Board's benchmarking expectations, Hydro Ottawa has provided a total cost and reliability econometric benchmarking, as authored by Power System Engineering which is available in Attachment C to Exhibit D-1-5.

### 3.3 Performance Measurement

Finally, the RRFE indicates the Board's intent to use a rigorous performance reporting and monitoring process to ensure distributors are responding to performance incentives and customer interests are protected. Among the performance outcomes to be measured and reported annually are the OEB scorecard results and the progress on implementing the Distribution System Plan.

To fulfill the OEB's RRFE expectations, Hydro Ottawa proposes to provide the following information as part of the annual written reporting process to be filed with the OEB:

a) Hydro Ottawa's OEB Scorecard results;
b) Annual update on actual capital expenditures by program type, versus, budgeted capital expenditures by program type and appropriate variance analysis.

## 4.0 Customer Focus - Customer Engagement on Proposed Capital Investments

A second key focus of the RRFE emerges from the customer focus outcome and the need to provide value for money and respond to identified customer needs. At page 31 of the RRFE the Board is specific in its direction that distributor plans must "demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation with customers, municipalities and neighbouring distributors and transmitters where applicable.[8]

[8] Page 31, RRFE

To fulfill this requirement, Hydro Ottawa held a customer engagement process to collect its customers' opinions on planned expenditures and outcomes identified in the proposed 2016 rate application. Detailed results of Hydro Ottawa's Custom IR Application consultation and the five engagement options, through which the company gathered feedback, are provided in the *Customer Consultation Report* produced by Innovative Research Group Inc. which is provided in Exhibit A, Tab 3, Schedule 1, Attachment (A).

In addition to the customer consultation conducted specifically in relation to Hydro Ottawa's planned capital expenditures and distribution system plan, the Company engages in ongoing customer engagement through a variety of feedback vehicles from a number of sources. Each of these is specified in detail in Exhibit A-3-1.

## 5.0 Financial Performance – Custom IR Rate Setting Framework

Table 1 on page 13 of the RRFE provides an overview of the rate setting elements expected for each of the three rate setting methods. Among other things the rate setting framework for Custom IR applications stipulates that the coverage be comprehensive of capital and OM&A requirements and that there is one or more mechanisms for sharing benefits with customers. As discussed in Exhibit A-2-1, Hydro Ottawa opted to structure its five year rate application using the Custom IR approach in order to recover its significant capital needs. Like many other electricity distributors in Ontario whose infrastructure was built in the 60s, 70s and 80s large parts of Hydro Ottawa's distribution system are approaching or exceeding anticipated end of life. Hydro Ottawa's Custom IR application seeks to generate necessary levels of cash flow to finance its capital and operational investment requirements. For further details on Hydro Ottawa capital requirements, rate base, and revenue requirements please refer to Exhibit B-1-2, B-1-1 and F-1-1 and to E-1-1 for details on working capital requirements.

According to the RRFE, the rate setting framework is intended to incorporate balanced incentives including benefits sharing mechanisms. For Custom IR applicants, the rate setting framework is expected to include a productivity factor and, as determined on a case by case basis, a stretch factor or other benefits sharing construct.

To fulfill the Board's requirements to build in a benefits sharing mechanism, Hydro Ottawa has proposed a Custom IR rate setting framework that treats capital separate from its OM&A expense where the capital requirements are recovered on a five year forecasted cost of service basis and its operations, maintenance and administrative ("OM&A") requirements are recovered pursuant to an "I-X" formula. An explicit productivity factor is built into the forecast that adjusts OM&A expenses and in so doing provides a year over year obligation on the company to find efficiency savings the results of which is a guaranteed consumer benefit. In addition to the explicit productivity factor, Hydro Ottawa proposes to introduce an earnings sharing mechanism to share benefits with its customers. Details of Hydro Ottawa's proposed Custom IR rate setting framework is available in Exhibit A-2-1.

Hydro Ottawa notes that generally within incentive regulation regimes benefits sharing is generally not limited to that captured within the rate setting mechanism such as the productivity factor, the stretch factor or via an earnings sharing mechanism. Hydro Ottawa believes that there are productivity and efficiency benefits that can be derived from long term budget forecasting that are not readily quantifiable. Similarly, Hydro Ottawa believes that the benefits that some productivity initiatives produce may be qualitative and intangible and consequently may not produce results that are monetarily quantifiable.

Hydro Ottawa's Custom IR rate setting framework is designed to achieve the Board's stated focus on balancing incentives within the outcomes based incentive regulation model and, most importantly, to ensure that Hydro Ottawa maintains financial viability throughout the course of the five year rate plan. This means that any operational efficiency built in to Hydro Ottawa's plan are sustainable and do not result in the company funding significant capital requirements towards the end of its rate plan and cause rate shock to its customers.

Financial viability is one of the key outcomes of the RRFE and as the business environment within which distributors operate becomes more complex and demanding this is not an outcome that should take a back seat to all other RRFE outcomes. It is for these reasons that Hydro Ottawa's Custom IR rate setting framework is designed to balance the interests and incentives for both Hydro Ottawa ratepayers and Hydro Ottawa's shareholder to ensure the company's financial viability is to the benefit of all.

## 6.0 Public Policy Responsiveness

Finally, the RRFE requires that as an outcome-based focus of the electricity distributors is to "deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)."[9]

To fulfill the Board's RRFE requirements for public policy responsiveness, Hydro Ottawa complies with regulations and directives emanating from the federal, provincial and municipal levels of government. Recent examples of important public policy initiatives include the Ministry of Energy's conservation first program, recent health and safety obligations as well as the Board's Low Income Energy Assistance (LEAP) program. Looking to the future, Hydro Ottawa is not in a position to reasonably anticipate new legislative or regulatory requirements that may be implemented nationally, provincially or municipally. It is for these reasons that Hydro Ottawa has built in to its Custom IR rate setting framework a Z factor allowing it to recover the costs imposed by new legislative or regulatory obligations of which the Company cannot reasonably be expected to anticipate over the five year period of its Custom IR term. If and when such events should occur, Hydro Ottawa will evaluate its costs against the Board's criteria for causation, materiality and prudence as set out in *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. See Exhibit A-2-1 for details.

[9] Page 2 & 57, RRFE Report

## 7.0 Conclusion

In crafting its Custom IR application Hydro Ottawa was mindful to address in its evidence the expectations set out in the Board's RRFE. Particular attention was paid to not only the four stipulated outcomes but also to how these outcomes were further defined within the RRFE and the interrelatedness between some of the objectives. Hydro Ottawa also ensured that its application captured the balanced incentives inherent to incentive regulation regimes. While Hydro Ottawa recognizes that there remains no set filing requirements for Custom IR applications, the RRFE stipulates that the material in the cost of service filing requirements will be relevant for Custom IR filers. As is discernible from Hydro Ottawa's evidence the Board's Cost of Service filing requirements formed the foundation upon which it supplemented evidence prescribed in the RRFE as captured above.

# CUSTOMER ENGAGEMENT

## 1.0 INTRODUCTION

Hydro Ottawa recognizes customer engagement as an essential part of doing business and, as a result, has placed the customer at the centre of everything Hydro Ottawa does by weighing customer impacts in every decision. As reflected in Hydro Ottawa's "*2012 – 2016 Strategic Direction: Creating Long-Term Value",* stakeholder engagement is a guiding principle of Hydro Ottawa's strategic direction. Hydro Ottawa "is committed to taking into account the concerns and interests of all stakeholders including employees, customers, suppliers, our shareholder and the communities and environment in which Hydro Ottawa operates. Hydro Ottawa will continue to operate with the interests of these groups in mind and will actively encourage their participation in shaping the future of the company[1]."

The key Divisions within Hydro Ottawa that are primarily responsible for customer outreach are Customer Service, Distribution Operations, Asset Management, Conservation and Demand Management ("CDM") and Corporate Communications. Customer needs and expectations are diverse and dynamic. To ensure Hydro Ottawa aligns its services to effectively meet evolving customer expectations Hydro Ottawa has undertaken many customer engagement activities related to all areas of the distribution company. Customers also have the option to proactively engage with Hydro Ottawa, through a variety of social media platforms. These activities and their findings are detailed within.

As of December 31st, 2014, Hydro Ottawa serviced 319,736 customers over a 1,104km$^2$ service territory, within the City of Ottawa and Village of Casselman. Of those customers 291,816 were residential; 24,149 were General Service <50kW; 3,617 were General

[1] Strategic Direction 2012-2016: Creating Long-Term Value, Page 40.

Service >50kW and 11 were Large Users. Further, as the nation's capital, Hydro Ottawa provides service in both official languages.

According to more recent demographic trends, the City of Ottawa's population is expected to grow by 36.5 % over the next 25 years, from 962,088 in 2014 to over 1.3M in 2039. The most significant demographic force will be an aging population. Diversity will continue to be a predominant feature of Ottawa's population.[2] The need for and value in engaging customers ensures that Hydro Ottawa's business initiatives continue to align with the needs and expectations of its rapidly growing and diverse rural and urban customer base.

## 2.0 ONGOING CUSTOMER ENGAGEMENT

### 2.1 Distribution Operations and Asset Management Divisions

#### 2.1.1 System Planning Activities

With respect to distribution operations and management of the physical system, Hydro Ottawa strives to understand the customer's needs, ranging from reliability and servicing needs, to meeting expectations during construction activities. As discussed in Section 2.2.1, the annual customer satisfaction survey provides customer feedback and insight regarding reliability, duration of outages and willingness to spend more for increased service levels. The related survey measures and results are outlined in the Distribution System Plan, Exhibit B-1-2, Sections 3.1.10 and 3.2.4 of the Distribution System Plan, insights gained from customer feedback have informed the development of Hydro Ottawa's system planning and servicing activities.

#### 2.1.2 Major Project Customer Consultations

As an example of ongoing customer engagement, Hydro Ottawa hosts major project customer consultations when large distribution system renewal projects have the

[2] The Strategic Council, Customer Persona Presentation, May 2013.

potential to physically impact customers, such as, cable replacement projects or transformer replacement projects. For example, there were four open houses relating to cable replacement projects in 2014. This process involves, first, informing the impacted customers of the pending work, well in advance, which is then followed by a customer open house aimed at creating an open dialogue between Hydro Ottawa and the impacted customers. During these open house sessions, Hydro Ottawa staff informs customers of the scope of work, the tentative schedule and the equipment and processes involved in performing the work, as well as, the site restoration plans once the work is completed. It is also a venue for customers to provide their feedback and voice their concerns, which staff attempt to immediately address. By engaging customers early in the process, they have opportunity to positively influence the project. In some instances, these dialogues have led to design and scheduling improvements. Further, customer inquiries and escalations have been reduced. These open houses originated from positive feedback received by customers of similar projects in the past and have proven to be productive and positive undertakings, leading to successful outcomes from the perspective of both customers and Hydro Ottawa.

#### 2.1.3 Participation with Electrical Contractors Association

Hydro Ottawa actively engages with the Electricity Contractor Association ("ECA") of Ottawa to ensure timely and effective communications are maintained between Hydro Ottawa and the numerous contractors that work in Ottawa. This need was identified by the ECA as part of the customer persona research program which Hydro Ottawa initiated in 2013 and is referred to in section 2.2.1 of this Exhibit. As a result, Hydro Ottawa ensures all ECA concerns or inquiries are responded to in a timely manner and new information is actively communicated. For example, matters of mutual interest, such as revisions to Hydro Ottawa's Conditions of Service are outlined and discussed to ensure related requirements and processes are clearly understood.

#### 2.1.4 Conditions of Service Stakeholder Outreach

Hydro Ottawa revises its Conditions of Service (“COS”) approximately every two (2) years. Version updates are facilitated by an internal, cross-functional team, or, working group (“COSWG”). In addition to updating COS content and in keeping with Hydro Ottawa’s strategic priorities, the COSWG recognized the need to make COS Version 5 more customer-centric. In order to move forward, the COSWG first needed to understand how both internal and external stakeholders utilized the document and to what extent it satisfied their needs. And most importantly, what enhancements were desired. Hydro Ottawa recognizes the important role of the Conditions of Service with respect to delivering services and meeting customer expectations.

In order to engage both internal and external stakeholders, surveys were developed and posted on both Hydro Ottawa’s corporate website and intranet. Responses to the surveys were followed up with professionally-led focus groups and one-on-one interviews with key staff, stakeholders and customers.

While the participation rate from internal and external stakeholders (i.e., Hydro Ottawa customers, developers, retailers and contractors) was limited, insight was gained from this initiative as reflected in the follow-up report “Improving the Reader Experience, Hydro Ottawa – Conditions of Service, Janet Leblanc & Associates Inc.“ Specifically, customers and staff shared their impressions of the COS document, identifying both its’ strengths and weaknesses[3], as well as, its effectiveness in reaching intended audiences[4]. In follow-up, focus groups consisting of survey and interview respondents were established to brainstorm COS design improvements. A number of stakeholder recommendations, as outlined in the report[5], have been incorporated into COS V5 and/or will be embodied in future COS revisions. Further information on COS V5 is provided in Exhibit A-6-6.

[3] Janet Leblanc & Associates, “Improving the Reader Experience: Hydro Ottawa - Conditions of Service,” October 2014, pages 8-9.
[4] Ibid, Page 15.
[5] Ibid, Page 23.

In addition to the recommended COS document enhancements, the COSWG gained valuable insight with respect to increasing the profile and utilization of the COS, as well as, recommended approaches to promote the engagement of internal and external stakeholders in the ongoing change management process.[6]

The results of this initiative highlight the immediate and long-term value of stakeholder engagement for both the distributor and customer(s).

## 2.2 Customer Service

### 2.2.1 Customer Persona Research

In September, 2012, Hydro Ottawa embarked on a major, leading edge Customer Persona Research Program to complement the customer feedback obtained through annual and monthly customer satisfaction surveys, as outlined in Section 2.2.2. Detailed results from the Customer Persona Research Program are provided in Attachment D-1(D).

The key objectives of the Customer Persona Research Program were to identify:

- Who are Hydro Ottawa's customers?
- How do they segment?
- How do they want to interact with Hydro Ottawa?
- What messages resonate with them?

Over a six-month period, Hydro Ottawa engaged over 2,500 customers and stakeholders in surveys, focus groups and one-on-one interviews in order to establish customer segments. Segments were based upon customer demographics, lifestyles, general attitudes, technological use, perceptions of Hydro Ottawa, cost sensitivities and environmental and energy conservation views.

[6] Ibid, Page 24 and 25

Once identified, customer segments were further classified as either primary or secondary targets, based upon the following criteria:

- Level of trust in Hydro Ottawa;
- Willingness to engage;
- Openness to information and communications;
- Extent to which customers view Hydro Ottawa as a credible source for information;
- Potential for Hydro Ottawa to shape future behaviours (e.g., conservation interest; interest in saving money and stage-of-life/point of entry marketing;
- How the segment might change over time (e.g., trend data).

The segmentation exercise identified the following customer segments, within each customer classification and key stakeholder group:

Within the residential classification, six (6) key segments emerged which were categorized as:

- Penny Pinched
- Greg Greene Sam Simplify
- Salwa Swamped
- Chris Critical
- Rick Frugal

Based upon the highest percentages within these residential segments, Penny Pinched, Greg Greene and Sam Simplify were chosen as primary targets, whereas, Salwa Swamped, Chris Critical and Rick Frugal were considered secondary targets.

Within the commercial classifications, the following six (6) themes emerged:

- Motivated to partner with Hydro Ottawa to strengthen business goals;
- Need direction to understand and pursue mutual business opportunities;
- All about cost and feeling valued by Hydro Ottawa;
- Disengaged; don’t interact with Hydro Ottawa;

- Off the radar; not knowledgeable about hydro and would like face-to-face advice ;
- Show me; conserving but bills are increasing – would be open to face-to-face advice.

Of the commercial segments, Motivated, Need Direction and All About Cost were chosen as primary targets; whereas, Disengaged, Off the Radar and Show Me were deemed secondary targets. The primary targets were based upon the highest percentages.

Within the key account group (e.g., large users and major accounts), the customer feedback received was dependent upon the level of interaction the customer had with Hydro Ottawa's key account team. The following themes were derived from this unique customer group:

- Conservation is an important priority for all key accounts, driven mostly by reducing costs;
- All are highly receptive to ideas and programs for reducing energy consumption;
- Capital costs are the largest barrier to conservation; incentive programs are valued.

Hydro Ottawa's business interactions with contractors and developers have a direct impact on customer service delivery outcomes, costs and satisfaction levels. These key stakeholders offered the following recommendations:

- Communicate, more effectively, changes that could impact a project (i.e., technical specifications, etc.);
- Provide more details about pricing and related costs;
- Offer pricing guarantees (i.e., fixed cost quotes);
- Extend working hours in the field;
- Increase capability to support peak demands for service (i.e., engineering, field inspectors, etc.);
- Be accountable for unplanned work plan changes;
- Improve scheduling practices and develop strategies to decrease lag times (i.e., waiting for equipment);

- Simplify easement registration process;
- Dedicate a section on the corporate website for developers and contractors.

The Customer Persona Research Program is one of the most comprehensive customer engagement programs ever undertaken by Hydro Ottawa. The insight obtained from this initiative has been and will continue to be utilized to guide business planning and investment priorities across the organization. Specifically, the customer personas enable staff to increase their awareness of Hydro Ottawa's customer base, their diversity, what's important to them and what's unacceptable to them. This is critical towards becoming a customer-centric organization. The personas also act as a filter in the design of new products, services and programs. One size does not fit all; therefore, the intended customer value may be targeted to the appropriate end user(s) for maximum effectiveness.

The Customer Persona Research Program further informed the development of Hydro Ottawa's Customer Experience Strategy. Over a two-day planning session with members of Hydro Ottawa's management team, a strategy was developed to engrain a customer-centric focus throughout the organization. The Customer Experience Vision that emerged was for Hydro Ottawa to be viewed as:

- Easy to do business with;
- Caring;
- Knowledgeable;
- Efficient.

To achieve this vision, a five-year customer experience strategy and action plan was developed in Q4, 2013 and anchored by the following strategic imperatives:

- Establish and commit to a clear Customer Experience vision;
- Understand, measure and improve customer value;
- Engage and enable employees;
- Interact and enhance our ability to communicate with customers.

At outlined in the 2016-2020 Customer Service Strategy (ref: Exhibit B-1-12) Hydro Ottawa's customers are becoming more engaged and centric in the business priorities of Hydro Ottawa. Customers have increasingly more options available in which to interact with Hydro Ottawa, as well as, offer comments on the services that they value and those they do not.

### 2.2.2 Customer Service Surveys

Since 2004, Hydro Ottawa has been continuously surveying its customers to measure customer service satisfaction levels, as well as, to compare results across the Ontario and external markets.

A random sample of Hydro Ottawa customers participate in an "in-depth" Customer Satisfaction Telephone Survey each year, referred to as the Simul survey. This random sample approach encompasses two customer segments – 85% Residential and 15% Commercial and is conducted through telephone interviews with respondents who pay or manage their electricity bills from Hydro Ottawa. The Annual Simul / Utility Pulse Electric Utility Customer Satisfaction Survey results provide Hydro Ottawa with insight of common universal and provincial trends and benchmarks. These results are computed by formulas which map the attributes of corporate image to customer satisfaction and loyalty.

Results of the 2014 Annual Electric Utility Customer Satisfaction Survey indicated the national and Ontario benchmark has been impacted negatively, but, that a customer can "dislike" the industry and still respect their LDC. Customers regard Hydro Ottawa as a trustworthy company that deals professionally and quickly to resolve customer issues.

Hydro Ottawa also surveys a sampling of customers each month through a Touch Logic survey. For two days each month, each customer that telephones Hydro Ottawa is contacted and prompted to rate their experience with Hydro Ottawa's Customer Service. The first question asks the purpose of the call (Billing, Collections, Disconnection Notice, or Other) while the subsequent questions request a rating of one through five, with five being the highest level of satisfaction. These questions are related to satisfaction with:

- Speed of Call Answer;
- Courtesy;
- Knowledge;
- First Call Resolution; and
- Overall Satisfaction.

Through analysis and monitoring of these results, Hydro Ottawa is able to focus on the identified areas, seeking ways to improve and enhance the customer experience when they contact Customer Service. The targeted nature of this survey enables Hydro Ottawa to adapt processes and procedures in a timely manner in response to changing customer needs and expectations.

**2.2.3 Customer Service Strategy**

The 2016-2020 Customer Service Strategy is a continuation and evolution of the Customer Service Strategy introduced in 2009[7] and the Customer Experience Strategy developed in Q4, 2013. Between the years 2009 and 2014, a dedicated team of experienced customer service staff have actioned customer-centric strategies, first, by establishing a project management team and, subsequently, by forming a cross-functional Customer Experience function within the Customer Service Division.

The 2016-2020 Customer Service Strategy identifies six (6) foundational components for customer experience management, of which three (3) relate specifically to customer engagement, as follows:

- Measuring customer value utilizing an online survey of residential and commercial customers to rate Hydro Ottawa's performance across the end-to-end experience and to identify what customers <u>value</u> most;

[7] Customer Service Strategy, Presentation to Enterprise Executive Team, September 15, 2010,

- Customer Experience Journey Mapping which identifies the steps our customers go through to engage with Hydro Ottawa (e.g., all the touch points, actions, pain and pleasure points);
- Transactional surveys using a short online survey (5-8 questions) after a customer interacts with one of Hydro Ottawa's touch points (e.g., service desk, outage management, website, etc.).

Delivering excellent customer service and value relies upon flawless service delivery, throughout the entire process. The above measures are intended to illuminate unintended and, potentially, undetected weaknesses in service delivery processes. This innovative approach to measuring outcomes will enable Hydro Ottawa to view itself from the customer's perspective. This unique insight will ensure that follow-up solutions effectively align with customer needs and expectations.

On several occasions, Hydro Ottawa has been awarded for its customer service and customer communications initiatives. Hydro Ottawa is considered an industry leader in Customer Service, within and beyond the Ontario market.

### 2.2.4 Key Accounts Program

As outlined in Section 2.2.1, page 7, through the customer persona research initiative, key account customers, developers and contractors offered a number of recommendations and insights.

This stakeholder feedback subsequently informed the work of an internal team ("the team") tasked with the development of a Key Accounts Program focused on the needs of major accounts, as well as, developers and contractors.

In April, 2014, the team proposed a Key Accounts, Developer and Contractor Strategy, which reflected many of the recommendations provided from customers and stakeholders.

The research undertaken identified ten (10) common attributes of leading account management organizations as:

- Being proactive;
- Having segmented customer groups;
- Utilizing account plans;
- Being disciplined;
- Having measurements;
- Striving to be centers of excellence;
- Providing services;
- Utilizing customer relationship management tools ("CRM");
- Being visible;
- Having robust selection and training programs.

Consultations were also undertaken with internal and external stakeholders/agencies, as well as, through an online survey to guide priorities, from the perspective of stakeholders.

As a result of the aforementioned consultation work, Hydro Ottawa embarked on the development of five (5) account management best practices, namely:

- Enhance Service Offerings
- Provide Personal Contact
- Improve Communications
- Provide an Added Value
- Be Accessible.

As a result of the aforementioned effort, a Key Account Program emerged. As a recent example of Hydro Ottawa's new Key Account Program in action, staff delivered a presentation to a business development team at Invest Ottawa. Invest Ottawa is an arms-length organization primarily supported by the City of Ottawa. The goal of this presentation was to update business development staff on the services and benefits Hydro Ottawa can offer prospective companies considering operations in Ottawa. As a result of this opportunity, Hydro Ottawa has established itself as a credible and reliable ally to businesses promoting economic development.

To enable Hydro Ottawa to meet the diverse needs of key accounts, developers and contractor, often within tight timelines, staffing within the Customer Service Group increased from one (1) to two (2) full-time key account coordinators in 2014.

As outlined in the 2016-2020 Customer Service Strategy (ref: Exhibit D, Tab 1, Schedule 6), Hydro Ottawa is transitioning from a reactive form of account management to a proactive one, through its plans to implement a robust customer relationship management system ("CRM"). While not yet a fully, technically-integrated solution, key internal Divisions utilize a shared folder in which key account contacts are maintained and shared for Hydro Ottawa's key account portfolio.

The Key Accounts Program focuses on segmenting the Key Account customers by like characteristics and needs, supported by a dedicated Key Account coordinator for each of the customers designated as a Key Account customer, as identified in the Account Management Strategy, dated November 13, 2013. This enables the coordinator to ensure the account plan for each Key Account customer is tailored and executed to the customer's satisfaction. Key Account coordinators also deliver presentations and participate in customer site meetings, which are collaborative and constructive. Further, Hydro Ottawa's key account coordinators now sit on the Builder Trade Council, which meets monthly and represents 85 percent of new developments in Ottawa.

In 2015 a Key Account customer symposium is planned. This initiative will focus on the further evolution of Hydro Ottawa's Key Account Program, by collaborating with Key Account customers to determine Hydro Ottawa's key account priorities, from the perspective of key account customers.

### 2.3 Communications and Public Affairs Group

Hydro Ottawa Limited's Communications and Public Affairs Group deploys a variety of communication tools to inform, raise levels of understanding and encourage customer feedback. This includes communicating across a variety of platforms, both online and traditional, and in both official languages to suit our customer needs.

Customer input provides the organization with insight into our customers' needs, pain-points, level of understanding and expectations. This, ultimately, establishes communications priorities and informs planning and key decision making in order to successfully engage with customers in a way that is both timely and relevant.

#### 2.3.1 Social Media

Overseen by the Communications and Public Affairs Group, Hydro Ottawa has a cross-functional Social Media Team that contributes social media content from their respective groups. The content is tailored specifically for our customers, with the goal of satisfying common customer inquiries, gaps in understanding and to encourage engagement.

Hydro Ottawa regularly seeks to engage with customers on its social media channels, values both positive and negative feedback equally in order to understand what is working and what improvements need to be made. Customer feedback indicates users appreciate the real-time replies to their inquiries, particularly during power outages, storms and in times of crisis. The result has seen significant uptake in the company's relatively young social media channels, specifically Twitter thanks to its real-time urgency.

Social media platforms also provide self-help options to customers, such as Hydro Ottawa's YouTube channel. Videos inform and educate customers on various facets of Hydro Ottawa's business, including power outages, infrastructure and investment requirements, rates, careers, residential and commercial conservation programs, community involvement initiatives focused on youth and partner agencies working to help those that are homeless or at risk of homelessness. A CDM Program Officer at Hydro Ottawa hosts a series of "*Ask the Energy Coach*" videos, which have resulted from customer inquiries on a wide-range of conservation topics. Through YouTube, customers can also provide input and feedback in the comments section of the video sharing site. This helps Hydro Ottawa understand customer sentiment and identify gaps in awareness or content. Hydro Ottawa recognizes the value digital media content provides its customers and is working to develop more video content in its communications plans.

2014 highlights from Hydro Ottawa's Social Media channels:

- 2,746 new Twitter Followers in 2014, bringing Hydro Ottawa's total Follower count to 7,547.
- Hydro Ottawa received 3,306 mentions on Twitter in 2014.
- Links included in Hydro Ottawa's tweets were accessed a total 6,851 times by customers in 2014.
- In February 2014, Hydro Ottawa launched its Facebook account to connect with customers. Currently Hydro Ottawa has 349 Followers.
- LinkedIn helps Hydro Ottawa stay connected to area businesses and professionals in terms of our corporate culture, initiatives, careers and our suite of business programs that are of relevance to them. Since April, Hydro Ottawa's LinkedIn has grown to 1,373 Followers.
- Since 2010, 114 videos have been viewed nearly 27,000 times on Hydro Ottawa's corporate YouTube channel.

### 2.3.2 Website

Hydro Ottawa's website is a key forum for communicating with our customers and capturing customer feedback through the use of a comment box on each page. For quick, general impressions, clickable 'thumbs up' and 'thumbs down' icons are available. This provides an easy way to gather general sentiment about the design and content of Hydro Ottawa's web pages so improvements can be made.

In correlation with Google analytics data and based upon feedback received from customers, there were a number of enhancements made to our website in 2014, such as making Hydro Ottawa's Outage Map more accessible and customer friendly. Visitors can now type in their address or click on the new "Current Location" button to zoom in on their GPS position. This helps customers quickly discover if their neighbourhood is being affected by an ongoing outage and may conveniently retrieve details about it. Clicking on an outage will then display a pop-up box with information that includes the area or City Councillor ward, number of affected customers, status of Hydro Ottawa's crew and estimated restoration time.

Understanding what devices our customers are utilizing to reach our website enhanced our website initiative by ensuring the design was compatible for multiple screen sizes and the information architecture was simplified to reduce clicks to get to the desired information.

Recognizing that all feedback is valuable to improving the customer experience, there are often minor comments on a daily basis with suggestions to improve the design or revise content for clarity, if unclear. This feedback also gives Hydro Ottawa an indication of what pages customers care about. This combined with usage analytics helps Hydro Ottawa focus on those customer priorities.

As a key customer interface, Hydro Ottawa performs regular audits of its website to ensure the information presented remains up-to-date, secure, user friendly, performs robustly and is fully accessible to a diverse range of customer needs. For example, the website is accessible to visually-impaired customers with screen readers, as part of a major website upgrade undertaken in 2014, which incorporated the compliance requirements of the "Accessibility for Ontarians with Disabilities Act" Regulation in advance of the 2021 deadline

### 2.3.3 Media and Stakeholder Relations

Hydro Ottawa engages with its shareholder, the City of Ottawa, in numerous ways. Regular communications keep the Mayor and City Council updated with news, plus invite feedback and questions. The company's monthly shareholder update newsletter was recently revised from a PDF format to a shareable, HTML format based on feedback we received from City Councillors asking how they prefer to be communicated with. This online format enables the organization to track what stories are most often read, and to tailor content in future issues, accordingly, to ensure we provide value.

In response to feedback provided by City Council, a direct email was developed to fast-track customer inquiries received by City Councillors. The process ensures a timely response to customers.

With regards to timely notification of power outages, Councillors and local media are invited to sign-up to receive power outage email alerts. These emails provide details such as the area and ward where the outage is occurring, restoration time and cause, if known. This enables us to leverage their channels and audiences to help assist in spreading the word in real-time.

### 2.4 Conservation & Demand Management ("CDM")

Hydro Ottawa has been engaging customers in both the development, implementation and assessment phases of its CDM programs, since 2005. Customer engagement enables Hydro Ottawa to tailor local CDM programs to meet the expressed needs of its customers. In fact, customer outreach activities have also been successful in identifying projects customers are independently pursuing (primarily the commercial class), which may be incorporated into Hydro Ottawa's CDM program offerings and leveraged to other customers. Hydro Ottawa further engages customers in post-implementation program evaluation activities, which has often led to further program refinements and improvements. The customer experience offers a unique and invaluable perspective of program effectiveness.

Customers influence Hydro Ottawa's CDM programs in a number of ways. For example:

As a result of Hydro Ottawa's Fridge Bounty program promotions, residential customers started asking how they could measure the amount of electricity their appliances were using. In response, Hydro Ottawa sourced a Kill-A-Watt meter that could be placed between the appliance and the outlet to record the electricity being consumed by the appliance. Hydro Ottawa approached the Ottawa Public Library and made 150 Kill-A-Watt meters available for loan to anyone with a library card. Customers were able to use the meters to identify where they were using a lot of electricity in their homes. When Hydro Ottawa added freezers to the program, a note was received from a customer wishing to get rid of his very large, old freezer, when he discovered it was costing him a fortune to operate. Hydro Ottawa also ran a feature in its Currents newsletter on this customer experience. The Kill-A-Watt meters continue to be in demand and available from the Ottawa Public Library.

As one example of proactive customer engagement, Hydro Ottawa hosted a breakfast event on November 25, 2014 for business customers entitled "Doing More with Less". The event, attended by 200 people, included a presentation from an engineer focused on identifying and implementing greater savings when undertaking conservation retrofit projects. Those in attendance appreciated the opportunity to network with colleagues and speak with the Hydro Ottawa sales team about their projects and opportunities. During all engagement events, business customers are encouraged to reach out to the Hydro Ottawa sales team about their projects and ideas. Hydro Ottawa makes every effort to include viable projects in its programming. An example of this is the 'Free Air' project that was brought to our attention by Quickie Convenience Stores ("Quickie"). Quickie approached Hydro Ottawa with the concept and new product that made use of the cold outside air in the winter to refrigerate walk-in coolers. We were able to assist Quickie with retrofit incentives to implement 'Free Air'. Quickie experienced a drop in energy use for their cold air refrigeration systems for their walk-in coolers by 80%. Now other customers are taking advantage of this product.

As another example, Hydro Ottawa recently participated in "*Idea Jam*" hosted by HUB Ottawa ("The HUB"). The HUB is about the power of innovation through collaboration. HUB Ottawa is a community-based collaboration network comprised of innovators, artists, professionals and entrepreneurs, whom collectively strive to create and promote innovations that create a positive social impact. The HUB is a local and global collaboration platform that provides access to a vibrant global community of 7,000 individuals leading social innovation in over 45 cities worldwide. "*Idea Jam*" brought together a group of people from the community with a wide variety of skill sets from data programmers and developers, interaction designers, customer service professionals, sustainability leaders, communicators and marketers - with an interest in energy conservation. It was the first time this type of event collaboration had taken place at the HUB Ottawa. The participants spent a day developing and presenting ideas to promote customer engagement in the development of conservation programs within our community. Many of the ideas generated were not new to Hydro Ottawa, however, there were a few new elements identified that may be considered for future CDM program plans. Hydro Ottawa's participation in this event was received positively by stakeholders.

Finally, in terms of ongoing, normal-course customer engagement, Hydro Ottawa's Conservation Event Team participates at over 100 community and customer events annually. This allows for interactions that assist customers improve their understanding of the conservation programs by addressing any misconceptions or misinformation that they may have. It is a great platform to start talking about trends, such as the transition from CFL to LED lighting. During these face-to-face opportunities, Hydro Ottawa also promotes service offerings, such as e-billing, MyHydroLink, power outage notifications, etc. As a result, further insight is gained into the evolving needs of customers, which inform future service offerings and delivery.

Customer engagement has been integral in the successful development and deployment of CDM programs at Hydro Ottawa and will continue to be, as new CDM programs are developed and implemented.

## 3.0 CUSTOM IR APPLICATION CONSULTATION

In accordance with the customer focus outcome identified in the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach ("RRFE")*[8], Hydro Ottawa initiated a customer engagement process to gather customer opinion on planned expenditures and outcomes identified in the proposed 2016 rate application. Detailed results of Hydro Ottawa's Customer IR Application consultation are provided in the *Customer Consultation Report* ("Report") produced by Innovative Research Group Inc. ("Innovative"), which is referred to as Attachment A-3(A).

In collaboration with Innovative, Hydro Ottawa designed, tested and implemented a customer engagement strategy in Fall 2014 and Winter 2015. In order to maximize the effectiveness of the customer engagement process, five key principles were adopted:

1. Ensure all Hydro Ottawa customers have an opportunity to be heard;
2. Ensure a representative sample of customers engage;
3. Create an open, voluntary process to allow any customer the opportunity to provide comment;
4. Focus on the key outcomes and customer preferences;
5. Inform customers about the distribution system and electricity industry.

Prior to implementation, a customer focus group was invited to provide feedback. A majority of participants supported the proposed customer engagement strategy and offered valuable suggestions.

Hydro Ottawa's consultation focused on three key stages:

1. Think: Develop key supporting material and questions

[8] A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, Pg. 2.

2. Identify: Maximize customer engagement opportunities
3. Quantify: Draw conclusions from customer feedback

Hydro Ottawa deployed five customer engagement options, which included:

1. An online workbook available to all customers;
2. General service and residential consultation focus groups;
3. Mid-market workshops (e.g., general service customers over 50 kW);
4. Key account validation interviews; and
5. Random telephone surveys.

## 3.1 Summary of Results

### 3.1.1 Customer Needs and Preferences

Overall, customers were generally satisfied with the service provided by Hydro Ottawa, that being *very* or *somewhat* satisfied. Suggestions for improvement primarily focused upon reducing rates and, to a lesser degree, reducing power outages.

With respect to reliability of service, a majority of customers supported maintaining system reliability, even if doing so increased their monthly electricity bill by a few dollars over the next few years. Customers also indicated that new technology and infrastructure were important priorities, as was ensuring employees have the equipment and tools necessary to manage the distribution system efficiently and effectively.

In terms of affordability, while a majority of customers indicated that electricity costs have a major impact on their finances, a larger majority stated that they were willing to pay a bit more because investing in the system is money well spent.

### 3.1.2 Customer Reaction to Proposed Rate Increase

When customers were asked about the extent to which they felt the proposed rate increase was reasonable (referred to as social permission), there were variations among the consultation mediums. The focus groups and telephone surveys rendered the highest levels of social permission, while the mid-market workshops and online survey resulted in lower levels of social permission. Mid-market workshop participants expressed frustration that some of their questions had not been answered to their satisfaction. The telephone surveys garnered the most support (66 to 70 percent across customer classes) for the proposed rate increase, although somewhat reluctantly. As the Report indicates, reluctant acceptance highlights the challenges customers can face when choosing between reliability and price. That said Hydro Ottawa customers favour a proactive approach to system reliability.

It is worth noting that during the consultation period, there was significant local media coverage, including callers on a “talk radio” program that was primarily negative in tone. Results indicate that lower levels of social permission were received after the media coverage began. Hydro Ottawa was also active in the media, as CEO, Bryce Conrad participated in a related radio interview during this period. Survey participation by Hydro Ottawa customers exceeded that of participation rates of similar surveys in other jurisdictions.

### 3.1.3 Online Workbook

Hydro Ottawa’s online workbook and survey was available in both official languages between February 23 and March 20, 2015. The online workbook was promoted through print and online advertising with local media outlets, social media, bill inserts and e-bills, as well as, Hydro Ottawa’s website. There were 4,745 residential and 55 commercial customer respondents. Respondent profiles and sample comments are provided on pages 15 to 17 of the Report. Customer feedback on their familiarity and satisfaction with Hydro Ottawa; system reliability; investment planning and cost drivers, Hydro Ottawa’s plan, acceptance of the proposed rate increase and the workbook itself are provided on pages 18 to 36 of the Report. A copy of Hydro Ottawa’s workbook is also appended to the Report.

### 3.1.4 General Service and Residential Customer Consultation

Hydro Ottawa held consultation sessions in Ottawa on March 17 and 18, 2015. A total of 34 general service and residential customers participated, who were recruited from a randomly generated list provided by Hydro Ottawa. Eligible customers were those who either managed or oversaw their business' electricity bill. All consultation sessions were video recorded and ran for approximately two hours.

The consultation sessions were structured around the themes of the workbook noted in Section 3.1.3. With a facilitator, the participants were led through the workbook and asked to independently respond to the questions therein.

The outcomes of this consultation activity are provided in pages 41 to 52 of the Report.

### 3.1.5 Mid-Market Workshop

A workshop was held with the mid-market, general service *greater than* 50 kW customers in Ottawa on March 18, 2015. A total of 16 mid-market customers participated in this session. Again, customers were randomly selected and screened. The workshop began with a two-hour presentation and Q&A from Hydro Ottawa explaining the operational and financial impacts of the proposed rate application. As noted previously, this consultation session was video recorded.

After the presentation, customers were divided into equal-size groups and taken to breakout rooms to begin moderator-led focus group discussions, for approximately one hour. Similarly, an information workbook was provided to the participants as an educational tool. Participants were then asked to independently respond to the questions therein.

The outcomes of this consultation activity are provided in pages 57 to 67of the Report.

### 3.1.6 Key Account Validation Interviews

In follow-up to nine, one-on-one key account consultation sessions with Hydro Ottawa staff, Innovative conducted six follow-up interviews in order to verify that the customer had the information they needed in order to provide informed feedback on Hydro Ottawa's proposed Distribution System Plan. The key account customers represented a diverse range of interests from a cross-section of manufacturing, public works and property management. These sessions were held the last three weeks of March, 2015.

The outcomes of this consultation activity are provided in pages 72 to 74 of the Report.

### 3.1.7 Customer Telephone Surveys

In order to validate the statistical significance of the previous research phases, randomly selected telephone surveys were conducted among 1,036 residential and 200 general service customers between April 1 and April 12, 2015. The ten-minute questionnaire simulated the workbook by including elements of customer education, customer knowledge of the distribution system and their values, in terms of system reliability and bill impacts.

The outcomes of this final consultation activity are provided in pages 77 and 117 of the Report.

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| **File Number:** | EB-2015-0004 |
| **Exhibit:** | A |
| **Tab:** | 3 |
| **Schedule:** | 1 |
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| **Date:** | ORIGINAL |

# Appendix 2-AC
## Customer Engagement Activities Summary

| Provide a list of customer engagement activities | Provide a list of customer needs and preferences identified through each engagement activity | Actions taken to respond to identified needs and preferences. If no action was taken, explain why. |
|---|---|---|
| REFER TO EXHIBIT A-3-1 | REFER TO EXHIBIT A-3-1 | REFER TO EXHIBIT A-3-1 |

**Note: Use "ALT-ENTER" to go to the next line within a cell**

**Innovative Research Group, Inc.**
Toronto • Vancouver

# Customer Consultation Report

## 2016 Rate Application Review

April 2015

Prepared for:

**Hydro Ottawa Limited**
3025 Albion Rd. N., Box 8700
Ottawa, Ontario
K1G 3S4

# Customer Consultation Report

## 2016 Rate Application Review

April 2015

This report has been prepared by Innovative Research Group Inc. for Hydro Ottawa Limited.

The conclusions drawn and opinions expressed are those of the authors.

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# Introduction

## About this Consultation

Innovative Research Group Inc. (INNOVATIVE) was commissioned by Hydro Ottawa Limited (Hydro Ottawa) to help the utility design, collect feedback and document its customer engagement and consultation process as part of its 2016 Custom Incentive Rate-setting (CIR) application.

Hydro Ottawa's customer consultation is a key element of its distribution cost of service rate application. The outcome of this application will determine Hydro Ottawa's electricity distribution rates for a five year period– beginning January 1, 2016 and ending December 31, 2020.

The Ontario Energy Board's (OEB) new "consumer-centric" approach to rate applications as detailed in the *Renewed Regulatory Framework for Electricity Distributors (RRFE)* requires distributors to demonstrate that services are provided in a manner that responds to identified customer needs and preferences[1]. Distributors are required to provide an overview of customer engagement activities that they have undertaken with respect to its plans and how customer needs and preferences have been reflected in the distributor's application. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in Hydro Ottawa's 2016 rate application with the OEB.

This process of identifying and reacting to customer needs and preferences towards Hydro Ottawa's system plan development and execution, as it relates to rate applications, is relatively new to Ontario's distributors. Aside from a few distributors who have had their rates approved under the RRFE, there are few established practices of engaging customers to identify their needs and preferences. That said, there are a number of options available to distributors to engage with their customers. The following section explains Hydro Ottawa's approach to its customer engagement related specifically to its rate application.

### Effective and Meaningful Customer Engagement

INNOVATIVE's past experience with engaging customers in meaningful consultation has documented a number of challenges. The reality of most consultation processes is that they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they do not know enough to contribute to the consultation process. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had have been aware.

Facilitating a customer consultation for distributors has an additional challenge – the lack of familiarity with the distribution system; including how it is funded, regulated and the nature of its

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

challenges. This is well documented in the OEB's publicly available consumer research and in INNOVATIVE's own experience.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, we developed a process built on five key principles:

1. Ensure all Hydro Ottawa customers have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.
3. Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.

Since this was the first time Hydro Ottawa so explicitly engaged customers in the development of their distribution system planning, a specific effort was made to collect participant comments on the process itself. Most customers felt this approach to engagement was effective at soliciting their feedback on Hydro Ottawa's investment and spending plan.

# Customer Consultation Overview

Based on the principles outlined above, INNOVATIVE worked with Hydro Ottawa staff to design a multifaceted customer engagement program which included a combination of qualitative and quantitative research elements. This consultation was designed to engage various rate classes and collect feedback on needs and preferences as they relate Hydro Ottawa 2016 Rate Application Review.

There were three stages in the development and implementation of Hydro Ottawa's consultation:

- **Think**: The first stage was to develop the core background material and key questions for the workbook. INNOVATIVE and Hydro Ottawa worked together to review the utilities system plan, capital investments and OM&A spending. Potential questions were identified that would allow customers to share their needs and preferences. Then a workbook was developed that would provide the information needed to allow customers with varying levels of knowledge to find answers to those questions.

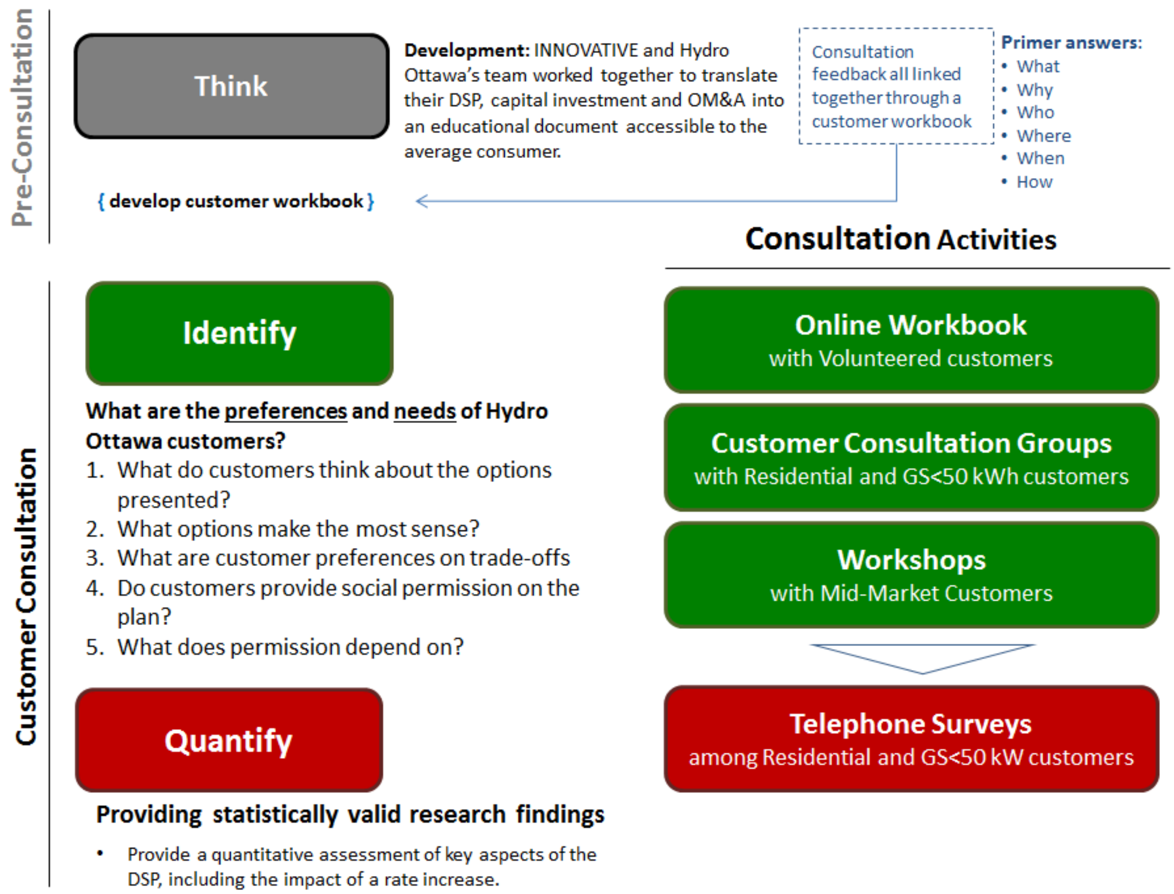
- **Identify**: The second step was to find out the range of views held by Hydro Ottawa's customers regarding the system plan through qualitative elements of the process. This included an open access online workbook to collect customer feedback and a series of customer discussion groups among randomly recruited residential and General Service (GS) customers.

- **Quantify**: The third step was quantitative – a randomly recruited telephone surveys of residential and GS customers. Randomly recruited surveys allow for generalizable conclusions that can be applied to the broader population of Hydro Ottawa's customers. The surveys were developed based on the feedback from the qualitative research.

Hydro Ottawa's consultation encompassed five core elements of customer engagement.

1. **Online Workbook**: The online workbook was promoted through print and online advertising with local media outlets, social media, inserts in customer bills and e-bills, as well as Hydro Ottawa's website. This first phase of the consultation was available to any Hydro Ottawa customer who wanted to participate.
2. **General Service and Residential Consultation Focus Groups:** Similar to the online workbook, this qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately inform the quantitative phases of the consultation. The customer focus groups were randomly recruited and held at a focus group facility in downtown Ottawa. A workbook was used to provide the participants with core information customers about both the provincial and local electricity system, Hydro Ottawa's proposed capital investment and operating spend to maintain system reliability, as well as the rate impact for each respective rate classes. The groups were catered and participants were provided with an incentive in recognition of their time commitment and to help ensure participation from across Hydro Ottawa's diverse customer base.
3. **Mid-Market Workshops**: General Service customers over 50 kW (GS > 50kW) were engaged through a randomly recruited workshop. This workshop included a presentation delivered by Hydro Ottawa's regulatory and engineering staff on the utility's DSP and rate implication for this rate class, a Q&A session with Hydro Ottawa staff, and "breakout style" discussion groups lead by INNOVATIVE staff. Participants were provided incentives in recognition of their time commitment and to help ensure diverse participation among Hydro Ottawa's mid-market customers.
4. **Key Account Validation Interviews**: Key Accounts were consulted on the proposed 5-Year plan by Hydro Ottawa staff. INNOVATIVE followed-up by telephone with large users after their consultation session to validate the process and to verify that Hydro Ottawa provided these customers with the information they needed to provide informed feedback on the proposed plan.
5. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys among residential and general service (GS < 50 kW) customers to provide a generalizable assessment of Hydro Ottawa's system plan and rate implications. Customers were randomly selected by INNOVATIVE from lists provided by Hydro Ottawa.

An overview of Hydro Ottawa's consultation roadmap is illustrated in the diagram below.




The consultation was designed so any customer who is interested would have an opportunity to participate in the process through the online workbook. However, in our approach, we distinguish between responses from the opinion research discipline (random recruits and scientific polls) and responses from an "open invitation" consultation discipline.

The small group results are presented as numeric counts to help readers remember that qualitative research only identifies points of view; it does not project the incidence of that point of view in the broader public.

The results from the online workbook and random surveys are presented as percentages due to the larger numbers involved.

- Readers are cautioned that the online workbook results represent the views of volunteers. The online workbook sample is not randomly selected and cannot be generalized to the broader Hydro Ottawa customer base.
- The telephone surveys are based on random samples so we can reliably project the incidence to the broader population of Hydro Ottawa's customers.
- In some instances, the quantitative total may be greater than 100% due to rounding. This is in keeping with standard research practice.

## Workbook Development

As we noted earlier, a key challenge in getting customer feedback on Hydro Ottawa's rate application is the lack of knowledge customers have toward Ontario's electricity system and Hydro Ottawa's role as the local distributor within the system. Hydro Ottawa's proposed distribution system plan, capital investment plan and Operations, Maintenance and Administration (OM&A) budget are all very detailed and extensive documents that use technical language. Hydro Ottawa's challenge was to briefly cover these key issues and frame meaningful questions about customer needs and preferences.

The process of developing the consultation workbook began in the fall of 2014. INNOVATIVE and Hydro Ottawa staff began the process of developing the workbook by reviewing the utility's draft DSP. After developing a draft workbook, INNOVATIVE conducted two nights of focus groups in early February 2015 with randomly selected Residential and General Service customers to ensure the workbook was deemed accessible by a diverse cross section of customers with varying degrees of electricity system knowledge and to ensure the questions concerning value trade-offs were balanced and deemed appropriate. Customer feedback from focus groups was then incorporated into the final design of the consultation workbook.

The workbook was divided into key sections that explained Hydro Ottawa' electric system, the challenges facing the system, and how Hydro Ottawa intended to meet those challenges over time.

There are nine themes, or sections, within the workbook:

1. ***Have Your Say*** invites customers to participate in the survey by providing a short background on why the customer consultation is taking place, and its role within the rate-setting process.
2. ***Electricity 101*** begins with an explanation of the three main components (generation, transmission and distribution) of the electricity system and provides a short description of each.
3. ***About Your Bill*** describes the breakdown of customer electricity bills, explaining that distribution services represents only a small portion of the total bill.
4. ***How Are Your Electricity Rates Determined?*** gives a brief summary of how electricity rates are determined.
5. ***Hydro Ottawa's Distribution Network Today*** provides facts and figures regarding the Hydro Ottawa system, and addresses topics like aging infrastructure and reliability. The primary goal of this section is to educate customers about the volume of aging assets currently in the system as well as how these aging assets and other factors contribute to reliability issues.
6. ***Reliability*** details the primary causes of power outages, and provides data on average frequency and duration of outages
7. ***Challenges Facing Hydro Ottawa*** sets out forecasted capital spending plans for 2016 to 2020 and provides some details on the four key investment areas: replacing aging infrastructure, serving a growing city, improving the power system, and buildings and equipment.
8. ***Finding Efficiencies and Cost Savings*** outlines the four cost saving initiatives that Hydro Ottawa is focusing on, namely: using innovative techniques, leveraging technology to improve reliability, programs to improve productivity, and effective planning.

9. ***The Dollars and Cents*** details the rate impact of the proposed plan for both residential and small commercial customers.

As customers progressed through the consultation workbook they were prompted with questions relating to system reliability, system challenges, and preferences on the direction of Hydro Ottawa's proposed system plan, capital investment and operating spend. In developing the questions, we looked for those that could also work on the telephone, without requiring all of the information in the workbook.

**Identifying customer *needs***. We started with a basic satisfaction question and then asked an open-ended question about how Hydro Ottawa could improve its services. We let customers discuss whatever topics they wanted to without boundaries. Later in the workbook we probed satisfaction with the number and length of power service interruptions and subsequently the impacts of those outages.

**Identifying customer *preferences***. We were looking for value choices rather than technical issues. Preference questions included understanding the investment and spending priorities and which areas should have more or less priority.

**The final substantive question asked about the cost of the plan and the outcomes it planned to achieve**. Sometimes this questions is asked with a simple support or oppose response scale, but previous research has demonstrated that this type of scale does not effectively capture customer sentiment as it relates to distributor rate increases. Instead, customers were given three options, as well as a "don't know" option:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't know

**Note**: Throughout this report the term "**social permission**" is used in place of "support" in reference to Hydro Ottawa's proposed rate increase. In this context, it's not so much that customers *support* a rate increase so much as they accept that it is necessary. It is less likely that customers will *support* a rate increase because it means more money coming out of their pockets, however they may acknowledge that there is a *need* for a rate increase and so they give it social permission.

The workbook concluded with a final set of five questions to assess the workbook and process itself.

The customer workbooks can be found in the **Appendix** of this report.

# Executive Summary

Subsequent sections of this report will present detailed findings on the needs and preferences of Hydro Ottawa's residential and general service customers. In this section, we provide an overall summary of Hydro Ottawa customers' needs and preferences.

This executive summary includes findings from both the *qualitative* and *quantitative* customer engagement activities that were included in this consultation exercise.

## Customer Needs & Preference

#### A Satisfied Customer Base

Customers are generally satisfied with the service they receive from Hydro Ottawa. Across all consultation activities, most customers indicated that they are either *very* or *somewhat* satisfied with their service.

**Overall Satisfaction across Consultation Activities**

| Response | Directional (Focus Groups) | | Directional (Online)[2] | Directional (Workshop) | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|
| | General Service | Residential | Residential | GS > 50 kW | General Service | Residential |
| Very satisfied | 1 | 6 | 48% | 6 | 31% | 38% |
| Somewhat satisfied | 9 | 2 | 42% | 9 | 50% | 46% |
| Not very satisfied | 0 | 1 | 6% | 0 | 10% | 8% |
| Not satisfied at all | 0 | 0 | 3% | 0 | 7% | 5% |
| Don't know / Refused | 0 | 1 | 1% | 1 | 3% | 3% |
| **TOTAL** | **n=10** | **n=10** | **n=4,745** | **n=16** | **n=200** | **n=1,036** |

Asked what Hydro Ottawa could do to improve service, almost half of those who took part in the online survey did not provide a response, suggesting (in conjunction with the high level of stated satisfaction) that they are already satisfied with Hydro Ottawa's service. Those who did give suggestions for improved service focused primarily on reducing rates; reducing power outages was also mentioned, but to a much lesser degree.

This trade-off between rates and system reliability is a dynamic that we explored in all customer consultations. In additional to getting a sense of customers' experiences with power outages, customers were also asked about the extent to which they feel Hydro Ottawa should be investing in

[2] Business respondents are not included as only n=55 completed the online workbook.

order to address the current frequency and duration of power outages – should the goal be to reduce or maintain current levels, or would customers prefer to keep costs down?

#### Reliability of Service

In the consultation groups and workshops, customers were for the most part satisfied with the number of outages they are experiencing. While a few experienced more, most experienced few if any outages. The impact of these outages varied widely from those who were not inconvenienced at all to small business and GS > 50kW customers who were greatly impacted in the form of lost productivity and revenue.

The telephone survey built on this input and quantified the extent to which customers are impacted by service outages.

About a third in each customer group (35% residential; 34% general service) did not experience any outages in the past twelve months. Among those who did experience at least one outage, many reported that their most recent outage lasted for less than an hour (47% residential; 39% general service). Business customers (50%) are much more likely than residential customers (12%) to consider their most recent outage a "major inconvenience".

Regarding the number of power outages:

- Almost one quarter (23%) of residential customers think Hydro Ottawa should be spending what is needed to reduce the number of power outages. Most (55%) would prefer that they spend what is need to maintain the current level of outages, while only one-in-ten (11%) are willing to accept more outages in order to keep customer costs from rising.
- The result is similar among general service customers: 27% want Hydro Ottawa to spend what is needed to reduce the number of power outages, 56% want them to spend what is needed to maintain the current level. Fewer than one-in-ten (8%) small business customers are prepared to accept more outages to keep customer costs from rising.

Regarding the length of power outages:

- Half (51%) of residential customers would like Hydro Ottawa to spend what is needed to maintain the current length of power outages, while another 22% would like them to spend what is needed to reduce the current length. Fewer than two-in-five (18%) prefer to accept longer outages in order to keep customer costs from rising.

- Likewise, half (51%) of general service customers would like Hydro Ottawa to spend to maintain, while another 27% would like them to spend to reduce the current length of outages. Significantly fewer (15%) are prepared to accept longer outages in exchange for keeping customer costs down.

Survey respondents were informed of Hydro Ottawa's proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact.

- 56% of residential customers and 57% of general service customers say Hydro Ottawa should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases their monthly electricity bill by a few dollars over the next few years.

- 57% of residential customers and 61% of general service customers think the benefits of new technology and infrastructure are important and should be a priority for Hydro Ottawa.
- 66% of residential customers and 61% of general service customer feel that, while Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

**Affordable Electricity**

While some residential customers report feeling financially strained by their electricity bills, even more say they are willing to pay more for their electricity:

- 51% agree that *"the cost of my electricity bill has a major impact on my finances and requires that I do without some other important priorities"*. Yet, larger proportions agree that *"I can personally afford to pay more for electricity, but I am worried about the impact a rate increase will have on others"* (62%) and that *"I'm willing to pay a bit more for my electricity because investing in upgrading the system is money well spent"* (62%).

Among general service customers there is a more balanced picture:

- 64% agree that *"the cost of my electricity has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off"*.
- 63% agree that *"I'm willing to pay a bit more for y electricity because investing in the system is money well spent"*
- 61% agree that *my organization can afford to pay more for electricity, but I'm worried about the impact a rate increase will have on others"*

## Customer Reaction to Proposed Rate Increase

As a rule, customers don't want to pay more than they are currently paying for the same product or service. Therefore, we don't ask customers whether they support or oppose a rate increase - it is not realistic to expect that anyone would *support* paying more. Rather, we asked customers about the extent to which they feel the rate increase is reasonable in order to get a measure of "social permission". For the purposes of this analysis, we define social permission as those who find the rate increase reasonable and support it, in addition to those who don't like the rate increase but think it is necessary.

**Social Permission Across Consultation Activities**

| Response | Directional (Focus Groups) | | Directional (Online)[3] | Directional (Workshop) | Generalizable (Telephone Surveys) | |
|---|---|---|---|---|---|---|
| | General Service | Residential | Residential | GS > 50 kW | General Service | Residential |
| The rate increase is reasonable and I support it | 3 | 1 | 10% | 0 | 22% | 23% |
| I don't like it, but I think the rate increase is necessary | 4 | 8 | 40% | 5 | 44% | 47% |
| The rate increase is unreasonable and I oppose it | 3 | 1 | 45% | 8 | 32% | 27% |
| Don't know / Refused | 0 | 0 | 5% | 3 | 3% | 3% |
| **Social Permission** | 7 | 9 | 50% | 5 | 66% | 70% |
| **TOTAL** | n=10 | n=10 | n=4,745 | n=16 | n=200 | n=1,036 |

There was some variation across consultation activities on the social permission question. The level of social permission was highest in the consultation focus groups and the telephone survey, while lower in the mid-market workshop and the online survey. It is worth noting that in the second week of the online survey, there was significant local media coverage that was primarily negative in tone. As shown in the detailed report for the online survey, those who completed the survey prior to the media coverage were more likely to give social permission than those who completed the survey after the media coverage had begun.

Similarly, participants in the mid-market workshop expressed frustration that some of the questions they had asked during the introductory presentation had not been answered to their satisfaction. This may or may not have impacted their feelings about the rate increase.

The most reliable social permission measure comes from the telephone survey, which is statistically valid and is generalizable to the entire residential and general service <50 kW population. Two-thirds (66%) of residential customers and 70% of general service customers are prepared to give social permission to the rate increase, albeit mostly reluctantly.

This level of reluctant acceptance for a rate increase is indicative of the struggle customers face when having to choose between reliability and price. Despite their reluctance regarding a rate increase, it is clear (as detailed in this report) that customers favour a proactive approach to system maintenance in order to maintain reliability.

[3] Business respondents are not included as only n=55 completed the online workbook.

# Online Workbook

**Online Workbook**
with Volunteered customers

**PURPOSE:** To inform customers on the details of Hydro Ottawa's plan, obtain feedback on the proposed options, and collect input for subsequent telephone survey design.

## Summary

The following summary highlights key findings from the online workbook and survey that was conducted between February 23rd and March 20th, 2015.

### Familiarity and Satisfaction

- At the outset of the online survey, respondents report high levels of familiarity (94%) and satisfaction (90%) with Hydro Ottawa. When asked if there is anything Hydro Ottawa can do to improve its service, 2,301 of 4,745 respondents did not provide a response, suggesting that they do not have suggestions for improvements. Of those who did provide a response 19% mention reduced rates, while 17% say there is nothing Hydro Ottawa can do because they are already satisfied.

### System Reliability

- One quarter (24%) report not having any power outages in the past year. This figure ranges from 47% in Ottawa Centre to only 5% in Goulbourn. Almost all (95%) are satisfied with the reliability of electricity services provided by Hydro Ottawa.
- With regard to addressing the *number* of customer power outages, 49% say Hydro Ottawa should spend what is needed to maintain the current level of outages.
- Similarly, when asked how they should address the *length* of power outages, 50% say Hydro Ottawa should spend what is needed to maintain the current length of outages.

### Investment Planning & Cost Drivers

- Half (50%) feel Hydro Ottawa should invest what it forecasts is required to replace the system's aging infrastructure, even if that increases their monthly electricity bill by a few dollars over the next few years.
- Half (52%) feel that, while Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.
- Most (87%) feel they understand the cost drivers that Hydro Ottawa is responding to, and more than half (53%) think Hydro Ottawa is doing well at managing these cost drivers while meeting customer expectations.

- Just under half (45%) are satisfied with the efforts of Hydro Ottawa to find efficiencies and cost savings.

### Response to Hydro Ottawa's Plan

- Almost two thirds (63%) say Hydro Ottawa's investment plan seems like it is going in the right direction.
- Three quarters (75%) say the plan covers the topics they expected, and two thirds (67%) think Hydro Ottawa is doing well at planning for the future.

### Acceptance of Rate Increase

- Half (50%) of respondents are prepared to accept the proposed rate increase, though most of this group (40% overall) do so reluctantly – they don't like the increase, but they feel it is necessary. Conversely, 45% feel the rate increase is unreasonable and they oppose it.

# Methodology

## About the Online Workbook

Beginning in December of 2014, Hydro Ottawa and INNOVATIVE collaborated on the development of an informative workbook geared toward residential and general service < 50 kW customers. This workbook was designed for use in the customer consultation groups and it served as the basis of the "Have Your Say" online customer survey.

The goal of the workbook was to provide customers with background information regarding Hydro Ottawa and its role within the provincial electrical system; what the Hydro Ottawa system looks like today; and the challenges it is facing in the future. Throughout the workbook, there are embedded questions to gather customer feedback on issues like overall satisfaction and reliability, investment options and Hydro Ottawa's plans for the future. The final question ascertains the extent to which customers are willing to accept Hydro Ottawa's proposed rate increase.

While INNOVATIVE provided examples of other (publicly available) workbooks and guidance throughout the development process, creation of this workbook was handled primarily by Hydro Ottawa, who had final say on its content and design.

**NOTE:** Results contained within this section of the report are based on self-selected or volunteered participation and therefore should not be interpreted as a representative sample of Hydro Ottawa customers.

Recall, the purpose of the online workbook is to identify potentially unique issues, concerns, needs and preferences that relate to Hydro Ottawa's investment and spending plan and use this customer feedback to help design the generalizable telephone survey in the subsequent phase of the consultation.

## Online Workbook Design

The content and questions contained within the online workbook were based primarily on the workbook that was used in the customer consultation groups, with some slight modifications, and to make it user-friendly in an online environment.

There are nine themes, or sections, within the workbook:

10. ***Have Your Say*** invites customers to participate in the survey by providing a short background on why the customer consultation is taking place, and its role within the rate-setting process.
11. ***Electricity 101*** begins with an explanation of the three main components (generation, transmission and distribution) of the electricity system and provides a short description of each.
12. ***About Your Bill*** describes the breakdown of customer electricity bills, explaining that distribution services represents only a small portion of the total bill.
13. ***How Are Your Electricity Rates Determined?*** gives a brief summary of how electricity rates are determined.
14. ***Hydro Ottawa's Distribution Network Today*** provides facts and figures regarding the Hydro Ottawa system, and addresses topics like aging infrastructure and reliability. The primary goal of this section is to educate customers about the volume of aging assets currently in the system as well as how these aging assets and other factors contribute to reliability issues.
15. ***Reliability*** details the primary causes of power outages, and provides data on average frequency and duration of outages
16. ***Challenges Facing Hydro Ottawa*** sets out forecasted capital spending plans for 2016 to 2020 and provides some details on the four key investment areas: replacing aging infrastructure, serving a growing city, improving the power system, and buildings and equipment.
17. ***Finding Efficiencies and Cost Savings*** outlines the four cost saving initiatives that Hydro Ottawa is focusing on, namely: using innovative techniques, leveraging technology to improve reliability, programs to improve productivity, and effective planning.
18. ***The Dollars and Cents*** details the rate impact of the proposed plan for both residential and small commercial customers.

There are a total of 16 feedback questions contained within the workbook, as well as a series of five "final thoughts" questions which invite respondents to share their opinions on the workbook and the customer consultation process.

## Field Dates

The online workbook was accessible to Hydro Ottawa customers from February 23rd to March 20th 2015.

## Promoting the Online Workbook

The online workbook survey was promoted to customers using a variety of print and electronic media:

- Print Newspaper: 1/3 page ads during the weeks of February 23rd, March 2nd and March 9th in the Ottawa Citizen, Le Droit, Metroland, Ottawa Sun, and Metro Ottawa
- Online Newspaper: a total of 352,000 impressions February 23rd to March 15th, on OttawaCitizen.com, LeDroit.com, OttawaSun.com and MetroNews.ca/News/Ottawa
- Bill inserts
- A notice on www.HydroOttawa.com with links to the English and French survey sites
- Social media

Promotions included mention of a prize draw. All participants who completed the entire survey were eligible to enter a draw to win one of three Apple™ iPad™ Air 2 Wi-Fi 16GB.

***NOTE:*** See section below – Local Media Coverage – for details on unplanned promotion of the online workbook.

## Publishing the Workbook Online

The workbook was available in both official languages and was hosted by INNOVATIVE. The English version was available at www.hydroottawa.com/survey and the French version was available at www.hydroottawa.com/sondage.

The website prevented customers from completing the survey multiple times. Upon completion, the site was no longer accessible at the web address given.

Note that INNOVATIVE does not ever link to the personal information submitted on the website. All responses were kept anonymous and confidential.

## Validating Customer Responses

Customers who filled out the workbook were tagged with an identification number based on their postal code and their response as a residential or business customer of Hydro Ottawa. Postal codes were checked against a list of FSAs (Forward Sortation Area) provided by Hydro Ottawa for validity and those deemed invalid were removed from the final sample. IP addresses were also used to verify that responses were unique and human.

## Sample Characteristics

The breakdown of online workbook responses are as follows:

- 11,709 unique visitors came to the landing page.
- 118 surveys were deemed invalid according to postal code and were removed from the final data set. Of note, most of these individuals provided Orleans postal codes, so it is likely they are Hydro One customers who mistakenly believe they are Hydro Ottawa customers.
- 4,800 customers (including 55 business respondents) completed the entire online workbook.

The workbook was made available in both official languages. A total of 152 respondents completed the French version (149 residential customers and 3 business customers).

The information provided by customers was aggregated anonymously and used only for exploratory analysis in this report.

### Business Respondents

Since only 55 business customers finished the workbook out of a total of 4,800 respondents, the focus of the online workbook report will be on the views and opinions of residential customers.

## Local Media Coverage

While Hydro Ottawa executed several planned promotional notices regarding the workbook, there was also extensive local media coverage including callers on a “talk radio” program the week of March 2nd, 2015. This unplanned earned media coverage continued for several days, and included a radio interview with Hydro Ottawa’s CEO, Bryce Conrad.

It is reasonable to assume this media coverage had an impact in terms of drawing customers to the survey site as there was a noticeable jump in responses during and immediately following the coverage. Furthermore, while similar surveys have been carried out in other jurisdictions, none have had such a high response rate.

There is anecdotal evidence to suggest that much of the attention the survey received in the media was negative in tone as is apparent in the samples of customer emails and customer calls into a talk radio program provided below. Much of the negativity was focused on the feeling that Hydro Ottawa should be funding maintenance and repairs out of its profit, rather than paying a dividend to the city.

To get a sense of the impact of this coverage on survey responses, we have used the timestamp that was applied to each survey to divide them into Pre- and Post-media coverage categories. In the end, a total of 963 surveys were completed prior to the start of local media coverage on March 2nd, 2015, while most (3,782) were completed *after* the media coverage began. Significant variations between the two groups are highlighted in this report.

**Sample Comments from Hydro Ottawa Customers:**

> *For a number of years Hydro Ottawa has paid a dividend to the city of Ottawa. Now is the time to ask for the money to be returned for the above reasons. Where is Hydro Ottawa’s reserve fund to pay for the above equipment replacements and upgrades?*
>
> *Did a monopoly seriously just commission a research firm to conduct a survey? What a waste of public funds.*
>
> *I am not in favour of rate increases - I think that any improvements to your network should come from the millions of dollars in profits that you give to the City of Ottawa!*
>
> *Why can’t the company use part of the $32 000 000 profit they made first? Obviously the company is really over charging us. It’s called GREED!*

*What would be a really good thing to put in [the survey] would be that every year we take your money, we set aside a certain amount for maintenance and upgrading. And if they haven't been doing that on an ongoing basis, what the hell are they doing?*

*I'm just a little put out with Hydro, because I have had occasion to read in the newspaper that they pay out a substantial – I think they call it a dividend instead of a profit – to the city of Ottawa every year. If they are asking for more money, they are already making a profit. What are they doing with that besides giving it back to the city so they can throw it out somewhere else?*

## Respondent Profiles

The following chart displays a breakdown of the residential respondents by region, household size, and living situation. The subsequent chart presents the breakdown of commercial respondents in terms of business operations and monthly spending on electricity.

**Figure A1: Residential Respondent Profile**

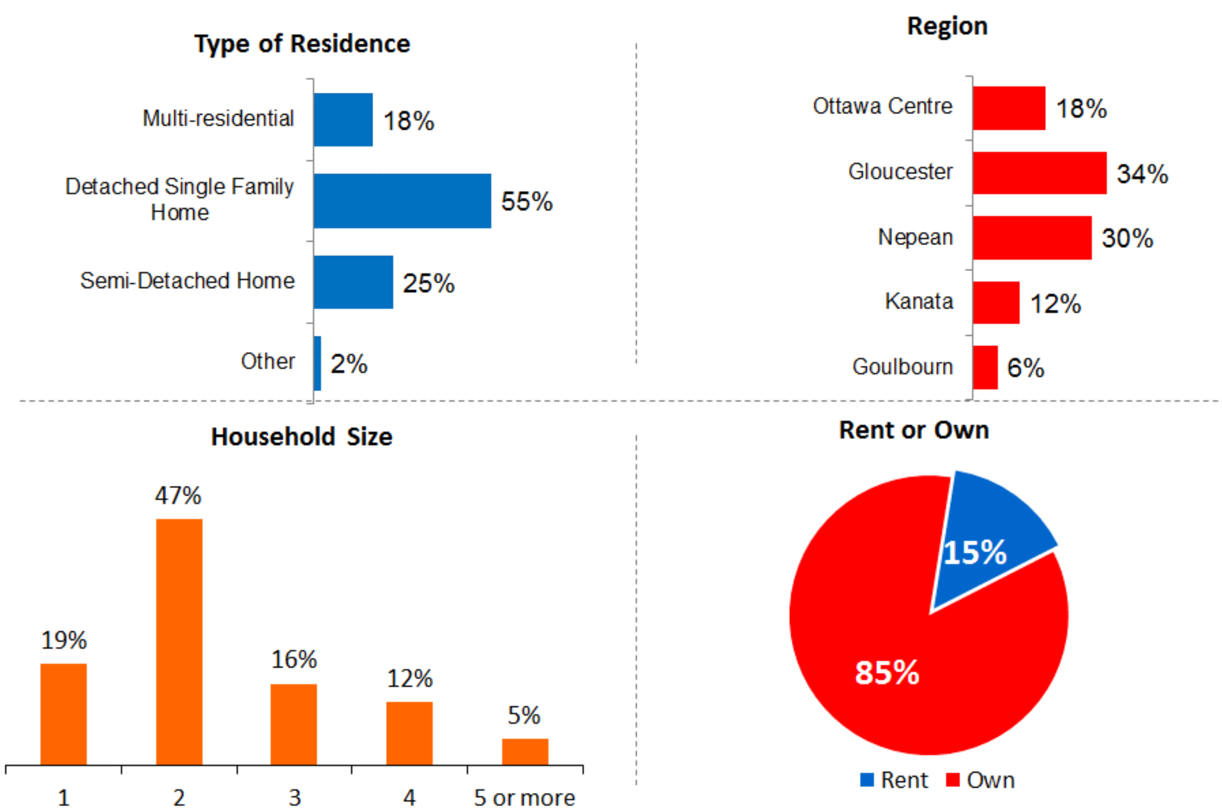
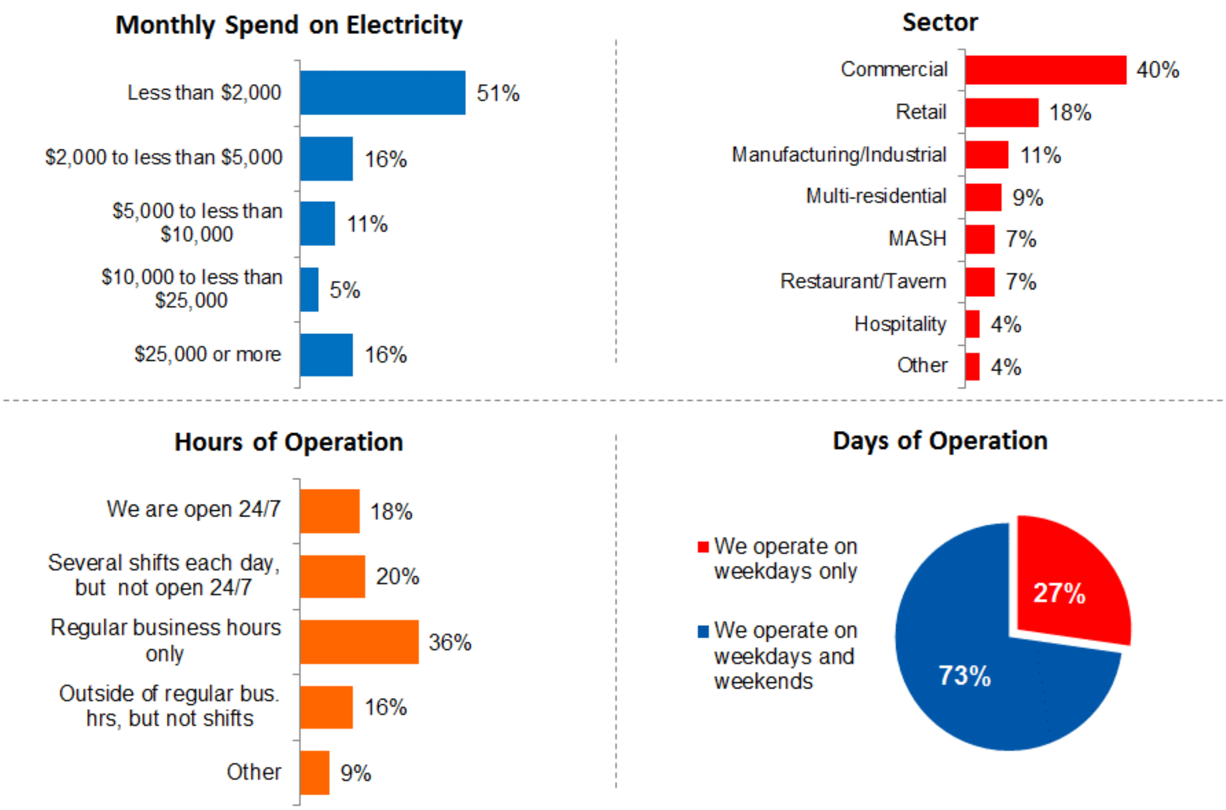


**Figure A2: Business Respondent Profile**



# Customer Feedback

In total, 4,800 respondents answered questions to the end of the workbook (including 55 business respondents). Note that the number of responses will vary on the open-ended questions as respondents were not required to provide a response. The sample sizes for residential respondents and business respondents are indicated separately.

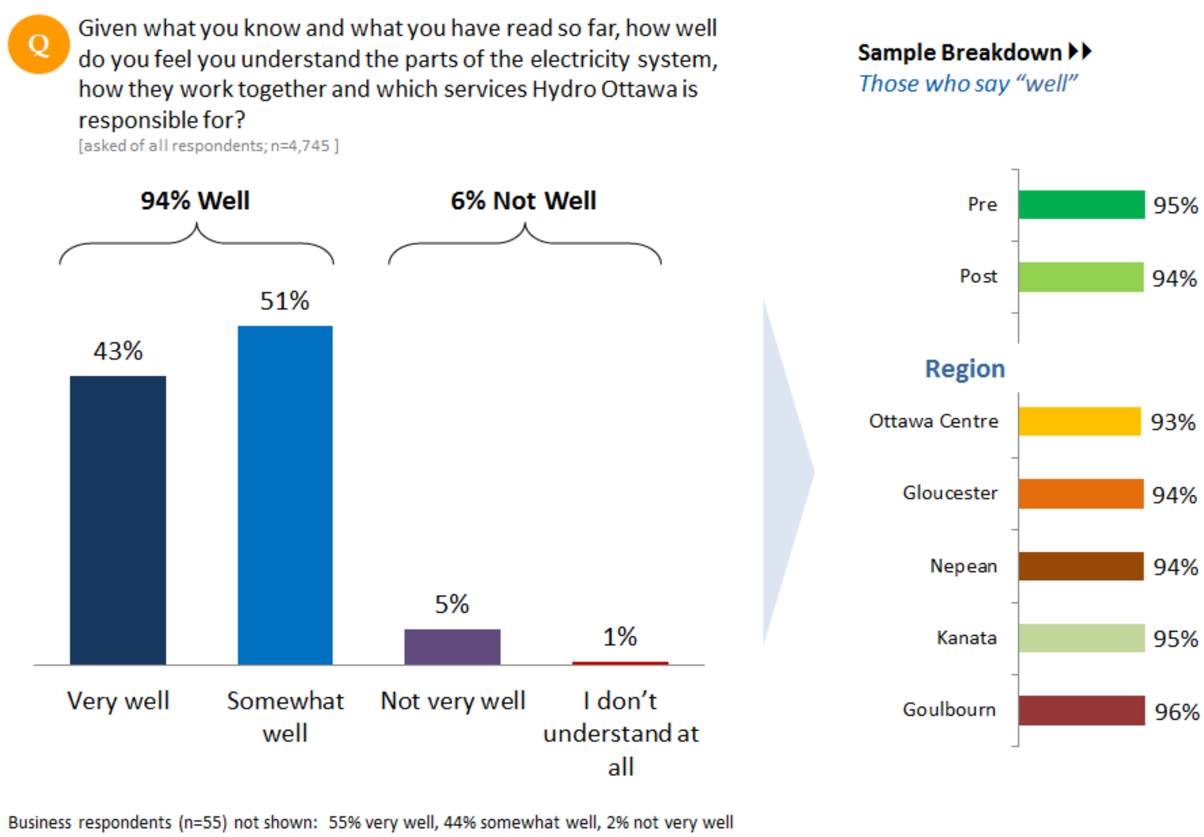
## Familiarity and Satisfaction

The first series of questions asks customers how familiar they are with the electricity system and which services Hydro Ottawa is responsible for, how satisfied customers are with the service they receive from Hydro Ottawa, and suggestions for improvement.

### Familiarity and Understanding of the System

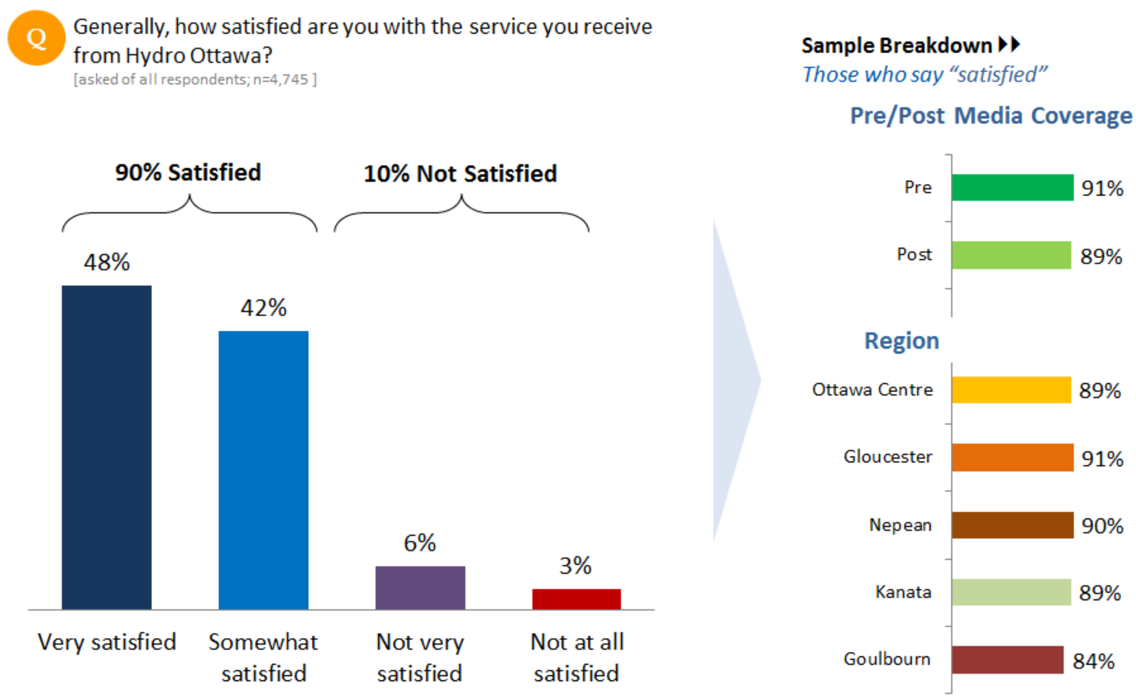
Residential customers feel they understand the parts of the electricity system and which services Hydro Ottawa is responsible for, with almost all (94%) saying they understand it either *very* (43%) or *somewhat* well (51%). At 91% overall, the level of understanding is lowest among single-person households.

**Figure 1: Familiarity with Electricity Distribution System**



In addition to feeling they have a good understanding of the services Hydro Ottawa is responsible for, a solid majority (90%) are satisfied with the service they receive from Hydro Ottawa. Almost half (48%) are *very* satisfied. Only ten percent are not satisfied. Residents of Goulbourn are slightly less satisfied with Hydro Ottawa than residents of other regions, though the majority (84%) there are satisfied.

**Figure 2: Satisfaction with Hydro Ottawa**



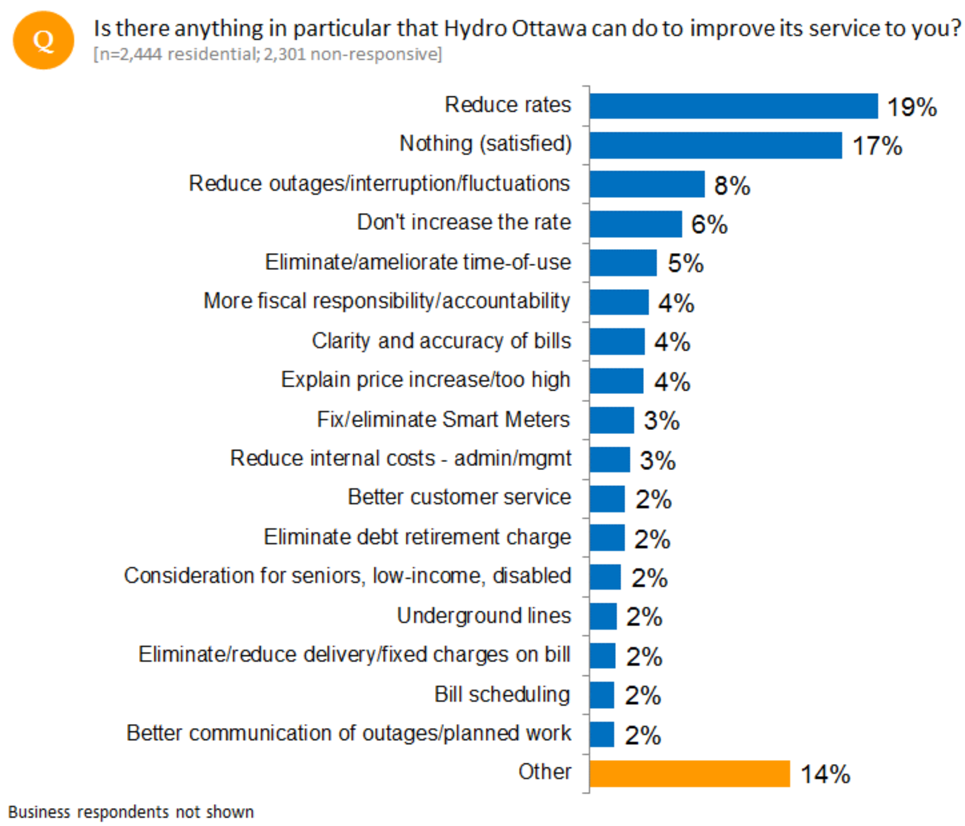

**Note:** 'Don't know' (1%) not shown

Business respondents (n=55) not shown: 42% very satisfied, 40% somewhat satisfied, 16% not very satisfied, 2% not at all satisfied

When asked if there is anything Hydro Ottawa can do to improve its service, one-in-five (19%) mention reduced rates, while almost as many (17%) say there is nothing Hydro Ottawa can do because they are already satisfied. Almost half (n=2,301) of respondents did not provide a response to this open-ended question, suggesting that they, too, are already satisfied with the service they receive.

Less frequently cited suggestions for improvement include reducing outages (8%), don't increase the rate (6%) and eliminate/ameliorate time-of-use (5%).

**Figure 3: Improving Customer Service**



## System Reliability

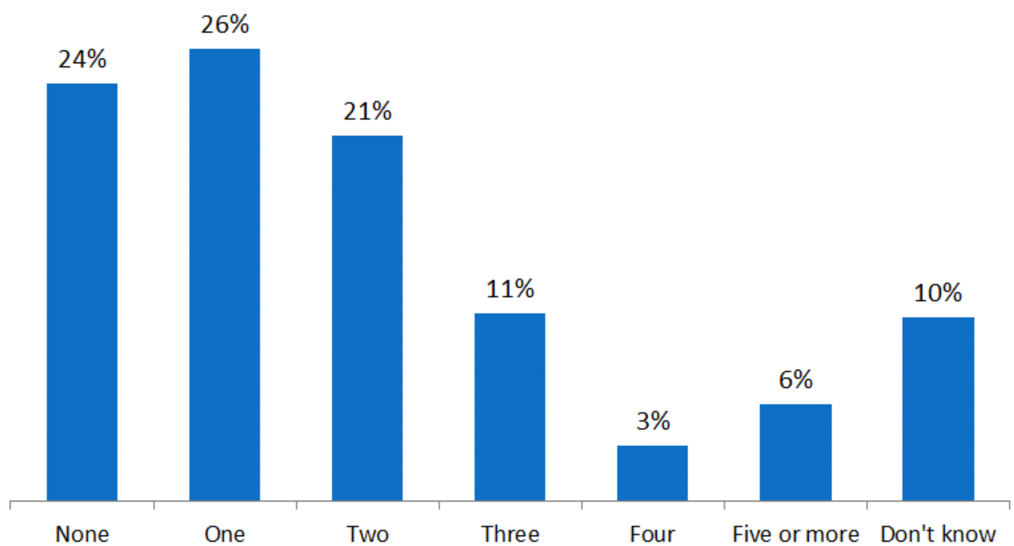
This series of questions addressed customers' current level of satisfaction with system reliability, and asked customers what they feel the goal should be with regard to outage frequency and duration: reduce current levels, maintain current levels, or accept more and longer outages?

A quarter (24%) of Hydro Ottawa customers report they have not experienced any power outages in the past year. Almost half have experienced one (26%) or two (21%) outages, while 19% have experienced three or more. Looking across the service territories, only 5% in Goulbourn report not having had any power outages, compared to 13% in Kanata, 16% in Nepean, 25% in Gloucester, and 47% in Ottawa Centre.

Those living in multi-residential units are much more likely to report an absence of outages than those living in a detached or semi-detached residence (41% versus 19%, respectively).

**Figure 4: Outages Experienced**

Q When averaged across the entire customer population, a Hydro Ottawa customer experiences 1.1 power outages per year. Do you recall how many outages you experienced in the past year?
[asked of all respondents; n=4,745 ]

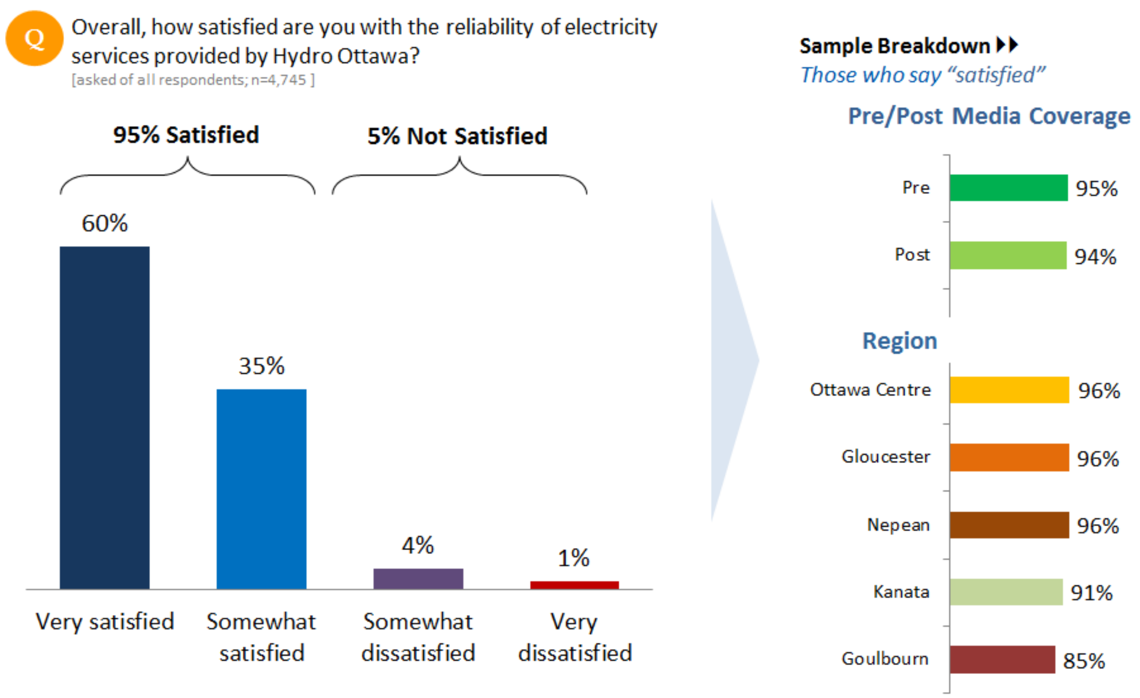



Business respondents (n=55) not shown: 24% none, 25% one, 15% two, 13% three, 0% four, 4% five or more, 20% don't know

A majority (60%) are *very* satisfied with the reliability of electricity services provided by Hydro Ottawa, and an additional 35% are *somewhat* satisfied. Not surprisingly, the proportion who are *very* satisfied in each of the five service areas reflects the frequency of reported power outages: 37% are *very* satisfied in Goulbourn, 47% in Kanata, 58% in Nepean, 63% in Gloucester and 71% in Ottawa Centre.

Along a similar vein, residents of multi-unit buildings are more likely to be *very* satisfied with the reliability of their electricity than those living in detached or semi-detached buildings (67% versus 58%).

**Figure 5: Satisfaction with Reliability of Service**




**Note:** 'Don't know' (0%) not shown

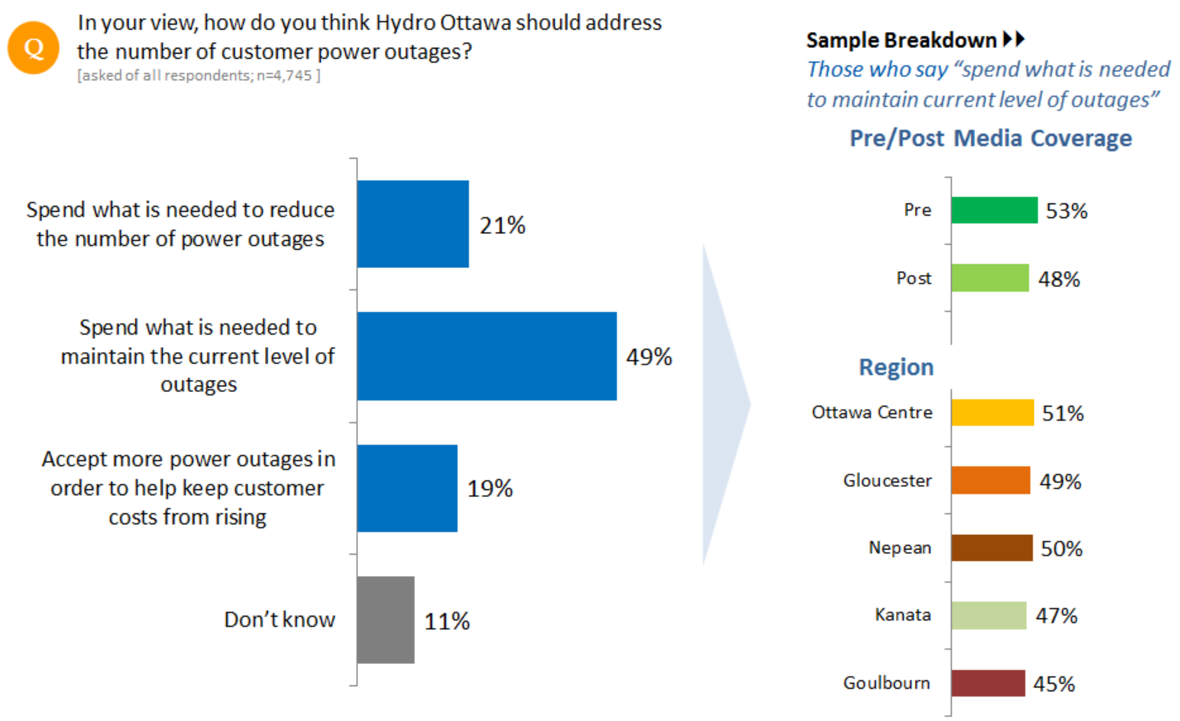
Business respondents (n=55) not shown: 53% very satisfied, 40% somewhat satisfied, 2% somewhat dissatisfied, 4% very dissatisfied, 2% don't know

Half (49%) of residential customers feel Hydro Ottawa should spend what is needed to *maintain* the current level of customer outages. One-in-five (21%) feel they should spend what is needed to *reduce* the number of outages, and slightly fewer (19%) would prefer to *accept more outages* in order to keep customer costs from rising.

Customers who responded in the first week of the survey – prior to any local media coverage – are more likely to vote for spending what is needed to *maintain* the current level of outages than those who responded after the media coverage had begun (53% versus 48%, respectively).

Likely a reflection of the lower number of reported outages, residents of Ottawa Centre are less likely than residents of other regions to want Hydro Ottawa to spend what is needed to reduce the current number of outages (18% compared to 21% to 24% in other regions).

**Figure 6: Addressing the Number of Customer Outages**

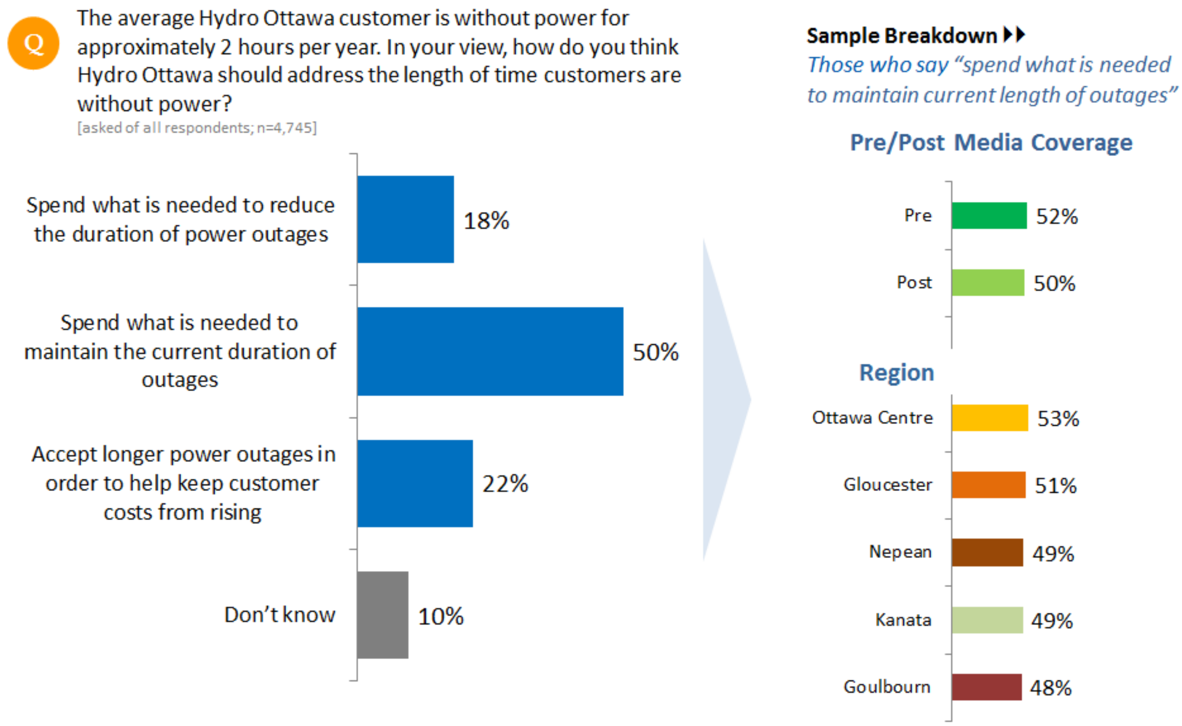



Business respondents (n=55) not shown: 15% spend what is needed to reduce the number of power outages, 55% spend what is needed to maintain the current level of outages, 13% accept more power outages in order to help keep customer costs from rising, 18% don't know

When it comes to addressing the current length of outages, half (50%) think Hydro Ottawa should spend what is needed to *maintain* the current length of outages.  More than one-in-five (22%) are willing to *accept longer outages* if it will keep customer costs from rising, while 18% would like Hydro Ottawa to spend what is needed to *reduce* the current length of power outages.

Customers living in Ottawa Centre are least likely to want Hydro Ottawa to spend what is needed to reduce the current length of power outages (15%, compared to 18% to 21%).

**Figure 7: Addressing the Length of Customer Outages**




Business respondents (n=55) not shown: 11% spend what is needed to reduce the duration of power outages, 56% spend what is needed to maintain the current duration of outages, 18% accept longer power outages in order to help keep customer costs from rising, 15% don't know

## Investment Planning & Cost Drivers

This section looks at customer preferences for spending on capital expenses, as well as looking at how well customers feel they understand Hydro Ottawa's cost drivers and how well they are managing them while meeting customer expectations. The survey questions followed a description of Hydro Ottawa's forecasted capital spending for 2016-2020, and how they work to find efficiencies and cost savings in the system.

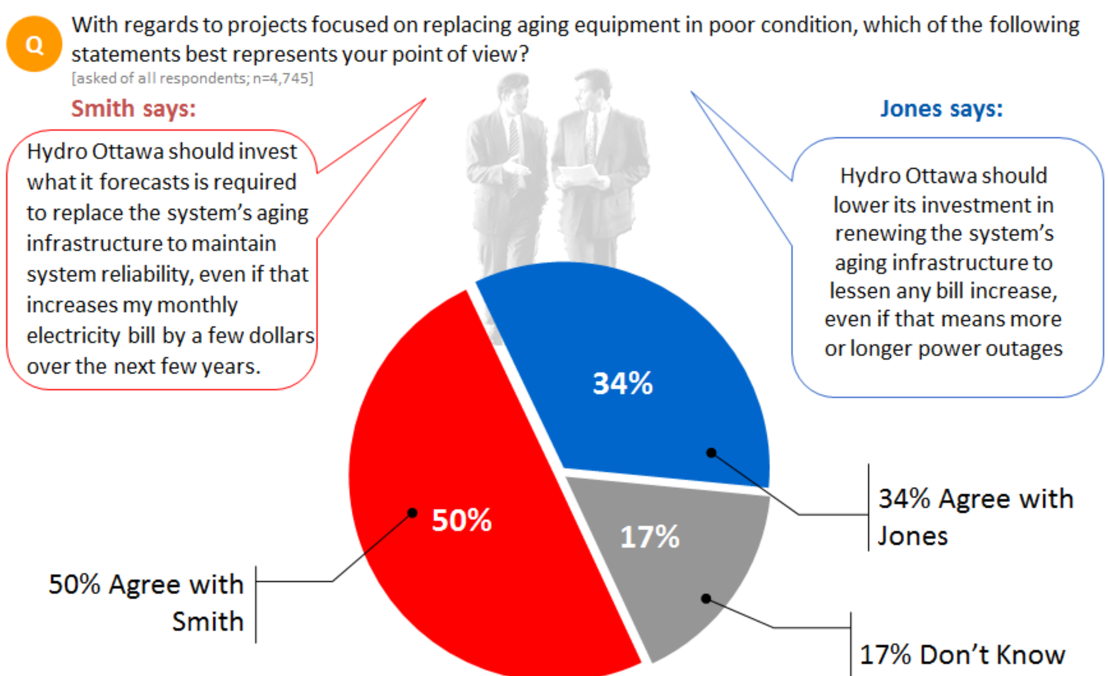
When it comes to investing in the system's aging infrastructure, half (50%) feel that Hydro Ottawa should invest what it forecasts is required to replace the system's aging infrastructure in order to maintain system reliability – even if that means a bill increase of a few dollars over the next few years. One third (34%) say Hydro Ottawa should lower its investment in renewing the aging infrastructure to lessen any bill increase – even if that means more or longer power outages. Almost one-in-five (17%) don't know which option they prefer.

Customers who completed the survey prior to the local media coverage are more likely to say Hydro Ottawa should spend what it forecasts is required than those who responded after the media coverage had begun (55% versus 49%).

At 56%, customers living in Ottawa Centre are more likely to share this view than those living in any other region (50% in Gloucester, 49% Nepean, 48% Kanata, 40% Goulbourn).

Customers living in two-person households are more likely than any other household size to feel Hydro Ottawa should invest what it thinks is required (54%, compared to 40% to 50%).

**Figure 8: Investing in Infrastructure**




**Note:** Statements randomized

Business respondents (n=55) not shown: 53% Hydro Ottawa should invest what it forecasts is required to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years, 35% Hydro Ottawa should lower its investment in renewing the system's aging infrastructure to lessen any bill increase, even if that means more or longer power outages, 13% don't know

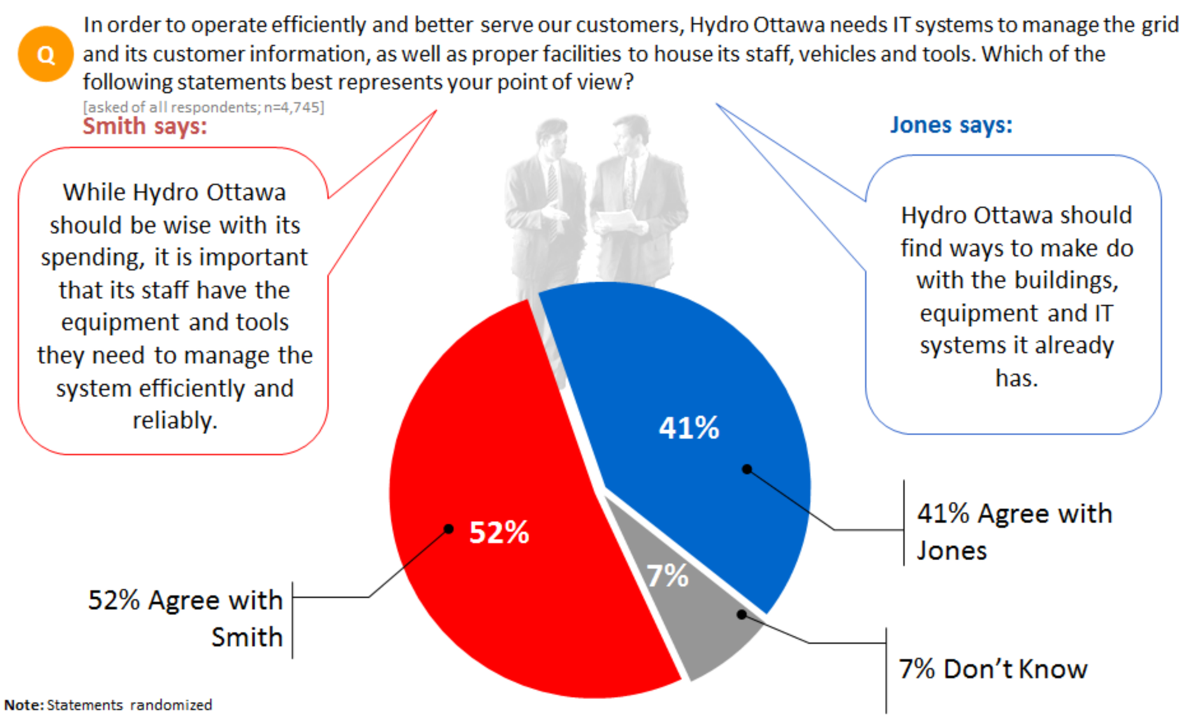
Turning to general plant assets, half (52%) feel that, while Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. Two-in-five (41%) think Hydro Ottawa should find ways to make do with the buildings, equipment and IT systems it already has, and the remaining 7% don't know.

Customers who completed the survey after the local media coverage had begun are more likely to say Hydro Ottawa should make do with its current general plant assets than those who completed the survey before the local media coverage began (42% versus 38%, respectively).

Respondents in Ottawa Centre are least likely to prefer this option at 36%, compared to 41% in Gloucester, 42% in Nepean, 43% in Kanata, and 47% in Goulbourn.

Customers living in single (39%) or two-person (38%) households are less likely to say Hydro Ottawa should find ways to make do with its current assets than those living in larger households.

**Figure 9: General Plant Investment**



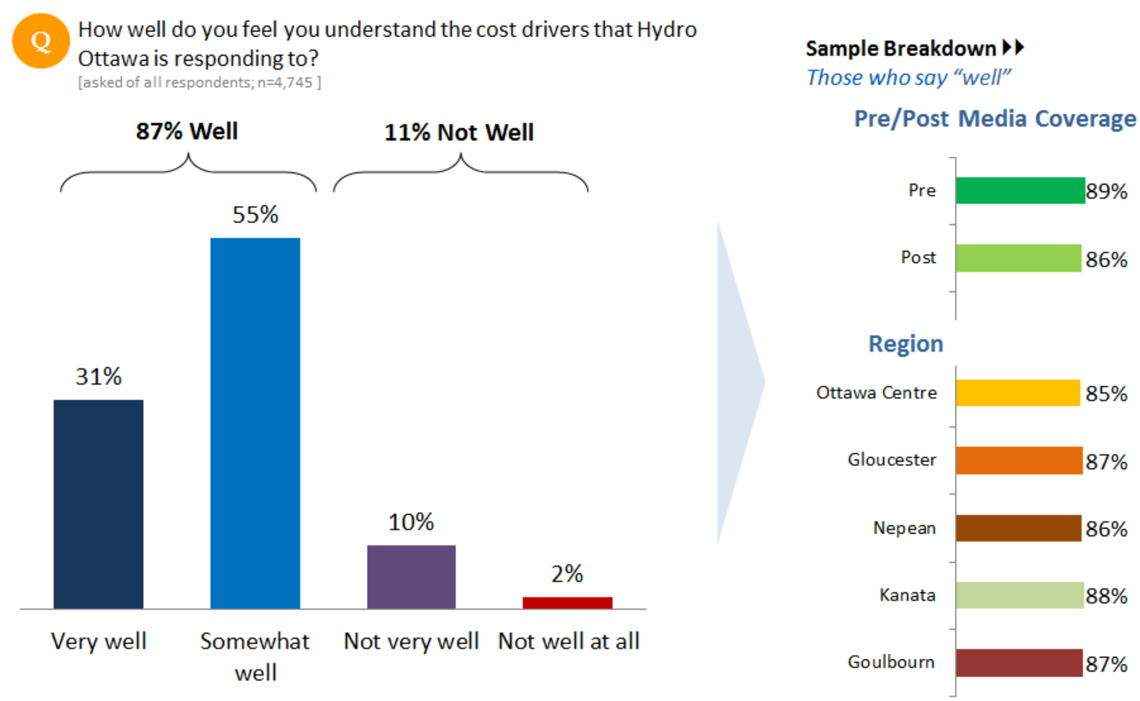

Business respondents (n=55) not shown: 62% While Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably, 31% Hydro Ottawa should find ways to make do with the buildings, equipment and IT systems it already has, 7% don't know.

While a majority (87%) feel they understand well the cost drivers that Hydro Ottawa is responding to, most (55%) only understand them *somewhat* well. One-in-ten (10%) feel they understand these cost pressures *not very well*, while only 2% describe their level of understanding as *not well at all*.

Earlier respondents are more likely to say they understand the cost drivers than those who completed it after the local media coverage began on week two of the data collection period (89% versus 86%, respectively).

Residents of detached or semi-detached homes are more likely to say they understand Hydro Ottawa's cost drivers than those who live in a multi-unit building (88% versus 82%, respectively).

**Figure 10: Understanding Cost Drivers**




**Note:** 'Don't know' (2%) not shown

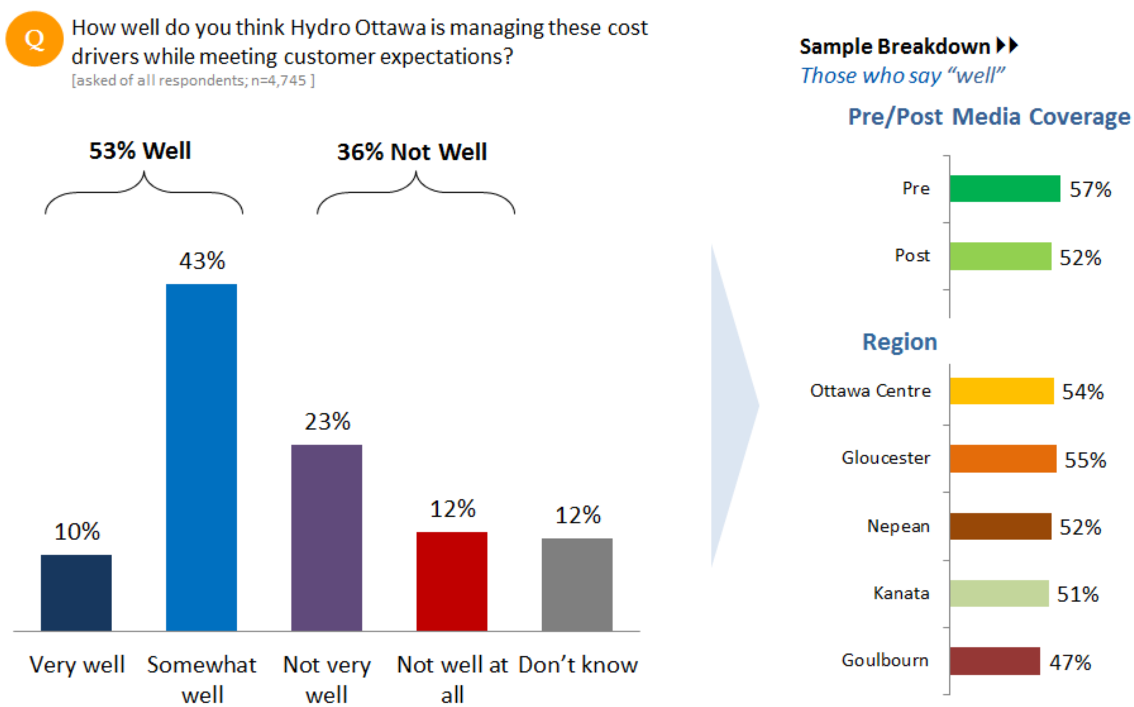
Business respondents (n=55) not shown: 33% very well, 58% somewhat well, 4% not very well, 2% not well at all, 4% don't know

Just over half (53%) feel Hydro Ottawa is managing their cost drivers either *very* (10%) or *somewhat* (43%) well. About a third (36%) say they are not managing their cost drivers well, and the remaining 12% *don't know*.

Those who responded prior to local media coverage are more likely to feel Hydro Ottawa is responding well to its cost drivers than those who answered after the media coverage had begun (57% versus 52%, respectively).

At 47%, customers living in Goulbourn are *least* likely to say Hydro Ottawa is managing their cost drivers well (compared to 51% to 55% in other regions). Those living in a household with one other person are slightly *more* likely than any other household sizes to feel Hydro Ottawa is doing well at responding to their cost drivers (55%).

**Figure 11: Managing Cost Drivers**



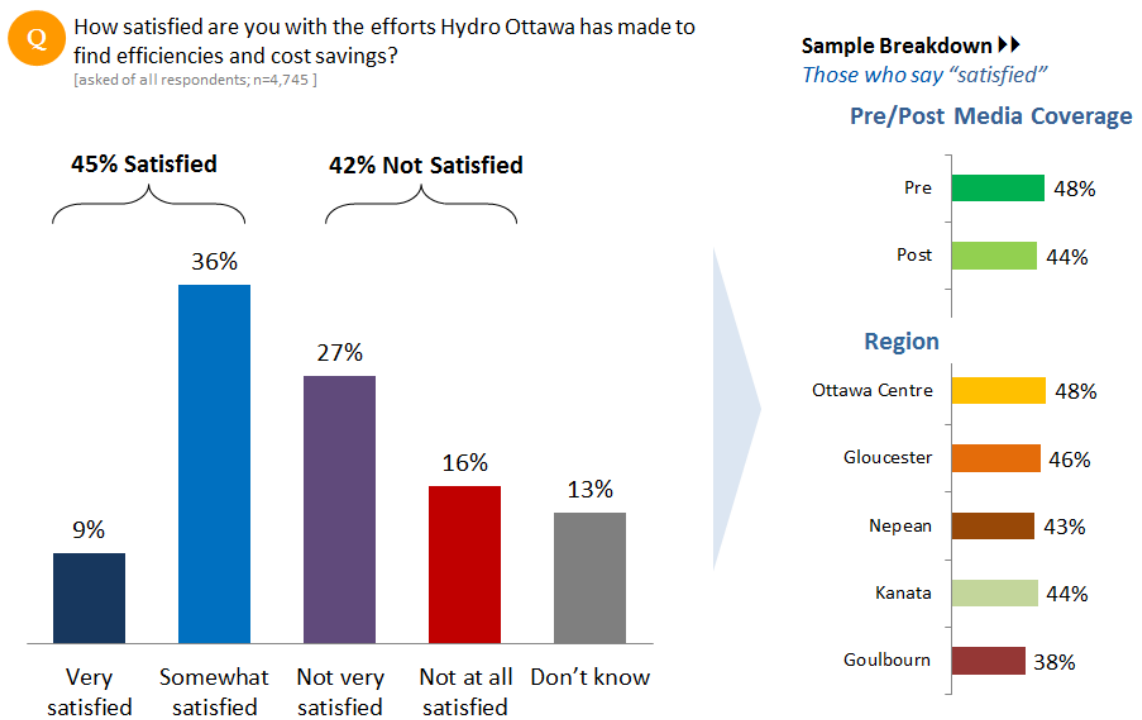

Business respondents (n=55) not shown: 15% very well, 42% somewhat well, 16% not very well, 11% not well at all, 16% don't know

Respondents are fairly evenly divided when it comes to their level of satisfaction with Hydro Ottawa's efforts to find efficiencies and cost savings: 45% say they are satisfied, while 42% are not satisfied. Of note is that almost twice as many respondents are *not at all satisfied* (16%) as are *very satisfied* (9%).

Fewer than two-in-five (38%) in Goulbourn are satisfied with Hydro Ottawa's efforts to find efficiencies and cost savings; compared to 43% in Nepean, 44% in Kanata, 46% in Gloucester and 48% in Ottawa Centre.

Consistent with previous findings that suggest a more critical mindset among those who completed the online survey after the local media coverage had started, 48% of pre-media coverage respondents are satisfied with efforts at finding efficiencies and cost savings, compared to 44% of post-media coverage respondents.

**Figure 12: Finding Efficiencies and Cost Savings**




Business respondents (n=55) not shown: 15% very satisfied, 36% somewhat satisfied, 18% not very satisfied, 16% not at all satisfied, 15% don't know

## Response to Hydro Ottawa's Plan

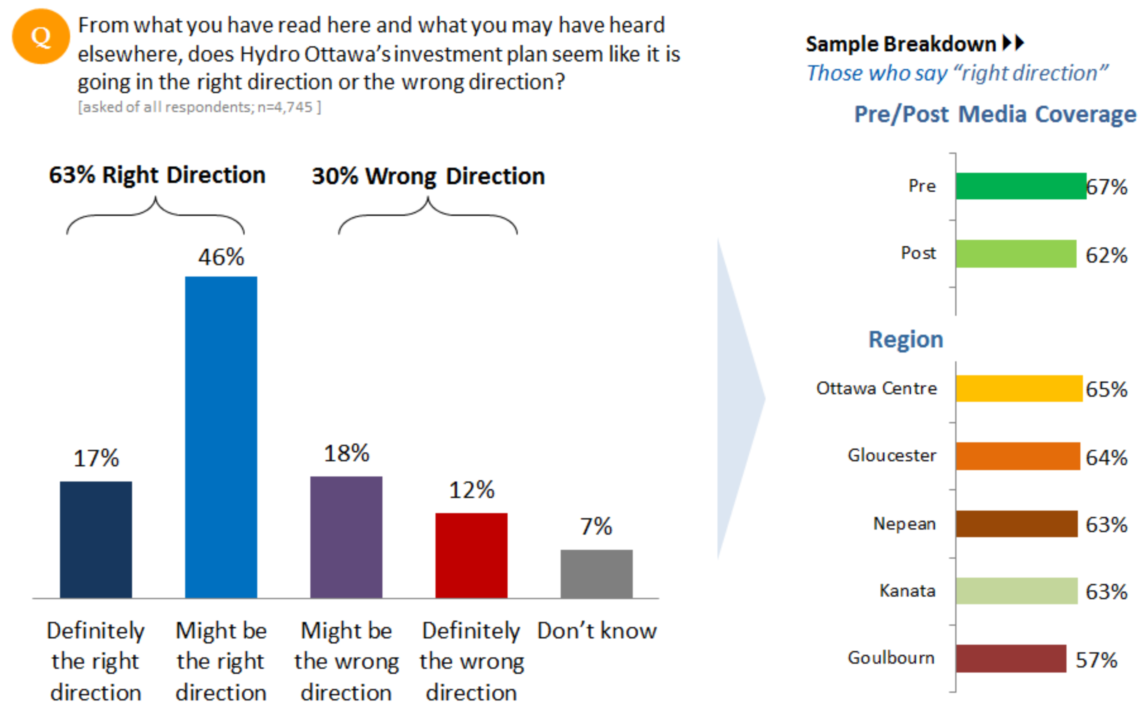
Based on what they read in the online workbook and what they may have heard elsewhere, almost two thirds (63%) feel that Hydro Ottawa's investment plan is headed in the right direction. Most of this group (46%) say it *might be* headed in the right direction, while only 17% are prepared to say it is *definitely* headed in the right direction. Just over one-in-ten (12) feel the investment plan is *definitely* going on the wrong direction.

Two thirds (67%) of pre-media coverage respondents feel the investment plan is headed in the right direction, compared to 62% of those who completed the survey after the media coverage had begun.

At the regional level, customers living in Goulbourn are *least* likely (at 57%) to feel the plan is headed in the right direction, compared to 63% to 65% among customers living in the other four regions.

Customers living in single (62%) or two-person (68%) households are more likely to feel Hydro Ottawa's investment plan is going in the right direction than those living in larger households.

**Figure 13: Hydro Ottawa's Investment Plan**

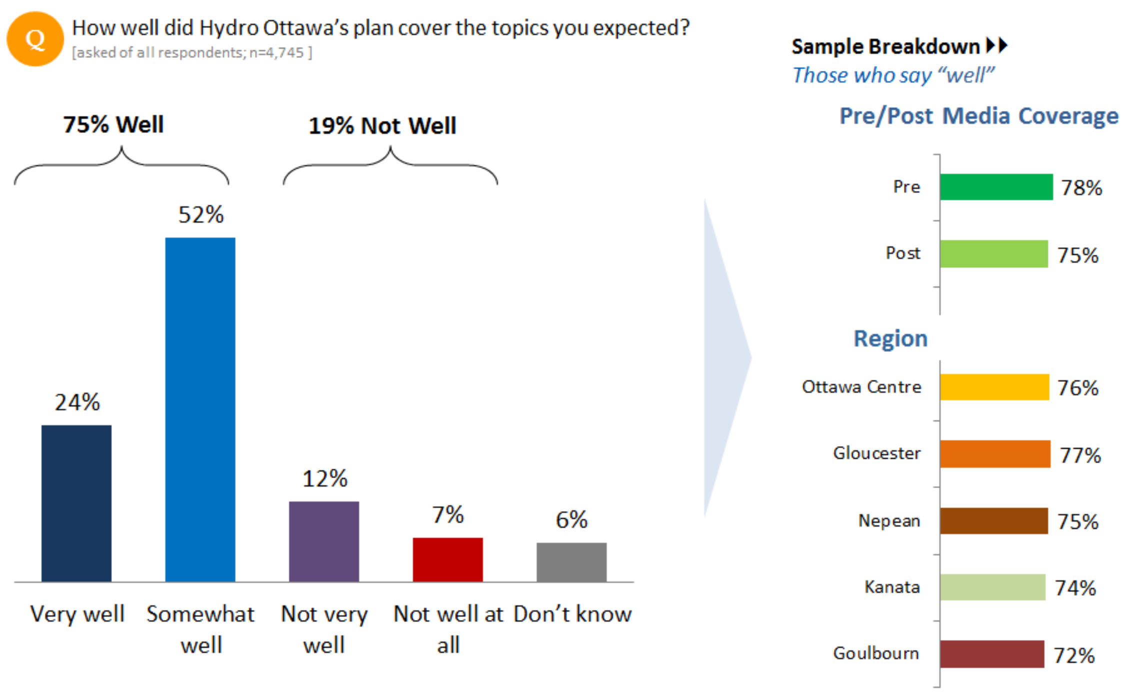



Business respondents (n=55) not shown: 31% definitely the right direction, 42% might be the right direction, 11% might be the wrong direction, 11% definitely the wrong direction, 5% don't know

Three quarters of respondents feel Hydro Ottawa's plan covered the topics they expected either *very* (24%) or *somewhat* (52%) well. One-in-five (19%) say the plan did not cover the topics they expected well.

At 70%, residents in households of five or more are *least* likely to say the plan covered the topics they expected well.

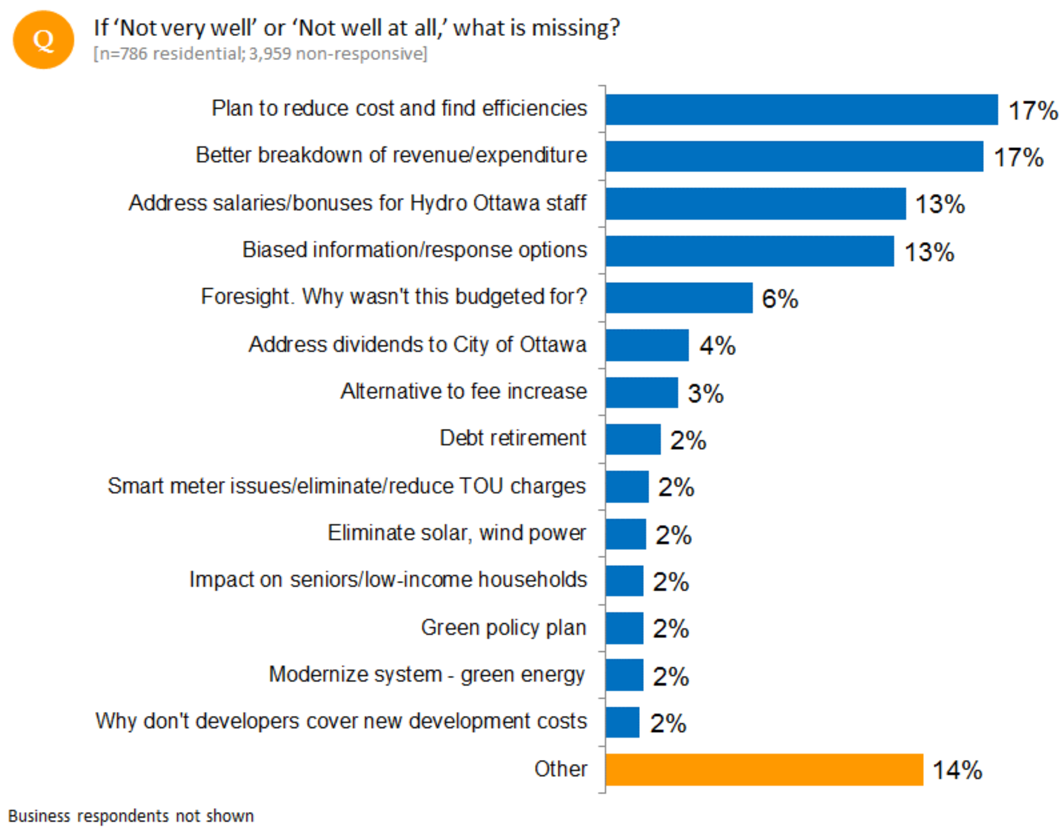
**Figure 14a: Coverage of Topics**




Business respondents (n=55) not shown: 35% very well, 45% somewhat well, 5% not very well, 9% not well at all, 5% don't know

Those who said the plan did not cover the topics they expected were asked what was missing. About one-in-six (17%) wanted more information on plans to reduce costs and find efficiencies, and as many (17%) wanted a better breakdown of revenue/expenditures. Slightly fewer (13%) wanted information on salaries/bonuses for Hydro Ottawa staff. Over one-in-ten (13%) felt the information and question response options were biased.

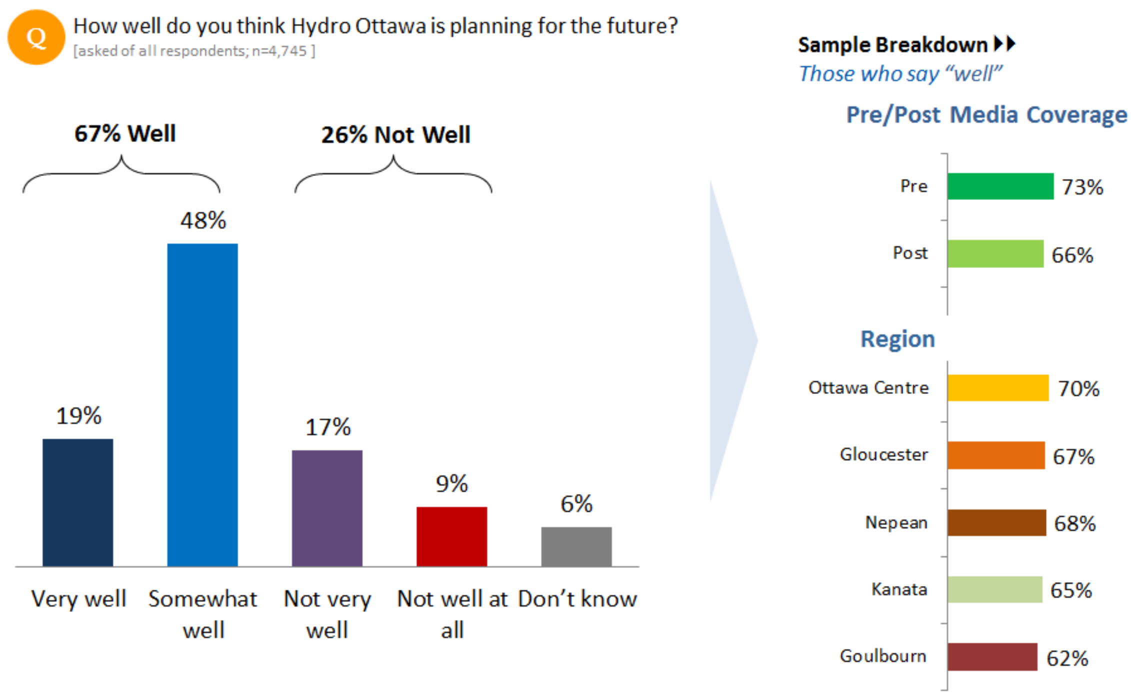
**Figure 14b: Coverage of Topics: What Was Missing?**



Two thirds (67%) feel Hydro Ottawa is doing well when it comes to planning for the future, with one-in-five (19%) saying they are planning *very* well and almost half (48%) saying they are planning *somewhat* well. Only a quarter (26%) feel Hydro Ottawa is not planning well for the future.

Those who responded prior to the media coverage are more likely to say Hydro Ottawa is planning well for the future than those who responded later (73% versus 66%, respectively). Customers in Goulbourn (62%) are less likely than those living in Ottawa Centre (70%) to say Hydro Ottawa is planning well.

**Figure 15: Planning for the Future**



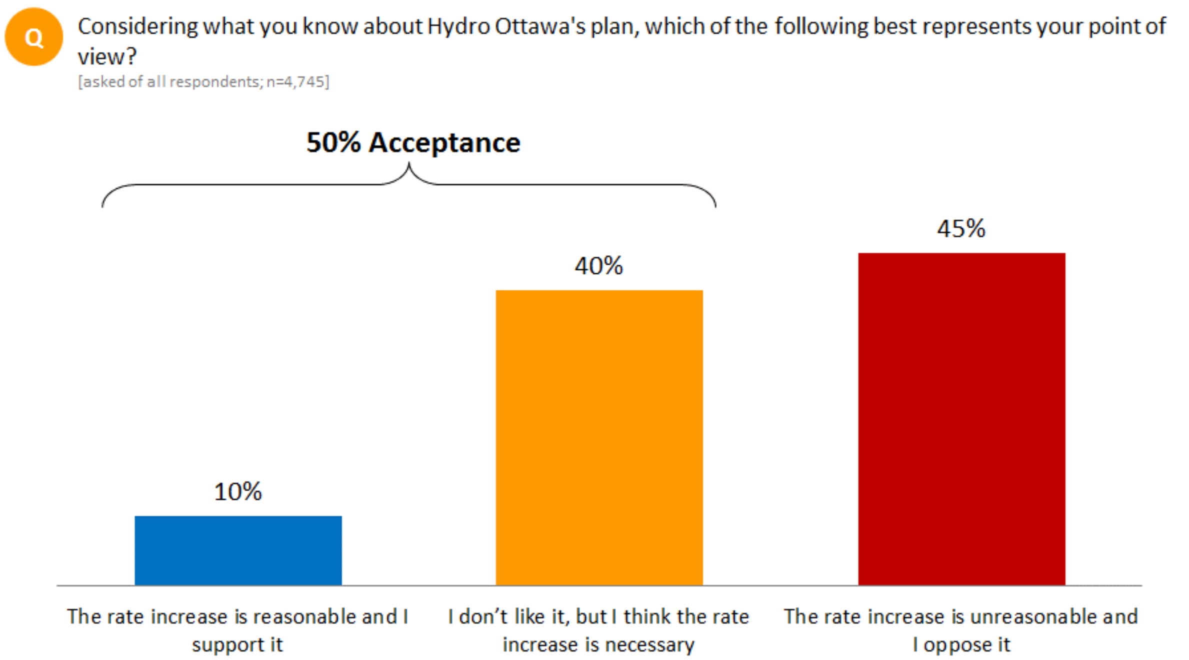

Business respondents (n=55) not shown: 24% very well, 45% somewhat well, 13% not very well, 9% not well at all, 9% don't know

## Acceptance of Rate Increase

At the end of the workbook – and after they have been informed of what the rate impact will be – customers are asked the extent to which they accept the proposed rate increase.

Half (50%) of residential customers indicate that they are prepared to accept the rate increase, although most of this group (40%) say they don't like it, but feel a rate increase is necessary. Only 10% feel the rate increase is reasonable and they support it. Almost half (45%) feel the rate increase is unreasonable and they oppose it.

**Figure 16a: Acceptance of Rate Increase - Overall**




**Note:** 'Don't know' (5%) not shown

Business respondents (n=55) not shown: 9% the rate increase is reasonable and I support it, 44% I don't like it but I think the rate increase is necessary, 38% the rate increase is unreasonable and I oppose it, 9% don't know

Looking across the various regions, acceptance of the rate increase is highest in Ottawa Centre at 56%, and is lowest in Goulbourn at 41% overall.

**Figure 16b: Acceptance of Rate Increase – Region**

| | Total | Ottawa Centre | Gloucester | Nepean | Kanata | Goulbourn |
|---|---|---|---|---|---|---|
| The rate increase is reasonable and I support it | 10% | 12% | 10% | 9% | 9% | 6% |
| I don't like it, but I think the rate increase is necessary | 40% | 44% | 40% | 41% | 37% | 35% |
| The rate increase is unreasonable and I oppose it | 45% | 39% | 45% | 47% | 48% | 51% |
| Overall Acceptance | **50%** | **56%** | **50%** | **50%** | **45%** | **41%** |

**Note:** 'Don't know' not shown
Residential respondents only

There is a significant difference in willingness to accept the rate increase depending on when respondents completed the survey in relation to the local media coverage. Of those who responded pre-media coverage, 57% accept the rate increase. This, compared to 48% among those who completed the survey after the media coverage began.

**Figure 16c: Acceptance of Rate Increase – Pre/Post Media Coverage**

| | Total | PRE Media Coverage | POST Media Coverage |
|---|---|---|---|
| The rate increase is reasonable and I support it | 10% | 12% | 9% |
| I don't like it, but I think the rate increase is necessary | 40% | 44% | 39% |
| The rate increase is unreasonable and I oppose it | 45% | 38% | 47% |
| Overall Acceptance | **50%** | **57%** | **48%** |

**Note:** 'Don't know' not shown
Residential respondents only

## Customer Feedback on Online Workbook

In the appendix, respondents were asked a series of questions to give feedback on the workbook; their impression of the workbook itself, the volume of information, the depth of coverage, and suggestions for future consultations.

**Overall Impression**

- Among those who provided a response, 47% described the workbook as "good/well done/informative", while about half as many (22%) found it "biased/in favor of hydro/misleading"
- One-in-four (24%) did not provide a response to this question

**Volume of Information**

- Of those who provided a response, more than half (56%) said the volume of information was "right amount/adequate/informative/not bad/just enough"
- Some (14%) found there was "not enough/irrelevant/needed more", while others (13%) felt there was "too much"
- 29% did not provide a response to this question

**Content Covered**

- Asked if there was any content missing that they would like to have seen, one-in-four (24%) said "none"
- One-in-ten (11%) wanted to see information about executive salaries/bonuses
- More than a third (35%) did not provide a response to this question

**Outstanding Questions**

- More than one-in-four (26%) indicated that they did not have any outstanding questions, and 42% did not provide a response at all
- Of those who did have outstanding questions, 7% wanted a breakdown of management salaries/bonuses, and another 7% wanted to know how profits are being invested or used to cover the cost of system improvements

**Suggestions for Future Consultations**

- Almost half (48%) did not make any suggestions regarding future consultations
- Of those who did provided input, 35% said they would like things done "the same way", and 18% would like to see the use of "internet/email/social media"

# Customer Consultation Groups

**Customer Consultation Groups**
with Residential and General Service customers

**PURPOSE:** To gain qualitative input on Hydro Ottawa's plan from residential and GS < 50 kW customers and to help inform the design of the subsequent telephone surveys.

## Summary

### General Satisfaction

Both general service and residential customers are generally satisfied with the service that they currently receive from Hydro Ottawa. Hydro Ottawa, which was frequently compared to Hydro One and other service providers such as Rogers and Bell, fares well in terms of customer service and response times to various customer inquiries.

While satisfaction is generally high, knowledge of Hydro Ottawa's role in the electricity system is somewhat low amongst both general service and residential customers. Generally, both rate classes had little pre-existing knowledge regarding the amount of their overall bill that was remitted to Hydro Ottawa.

### System Reliability

Satisfaction with system reliability was high amongst both general service and residential customers. Many customers in both rate classes felt that they had not experienced the average number/length of outages over the past 12 months, as laid out in the workbook.

System reliability was generally not a big concern for residential customers, while business customers approached the issue from a lost productivity and revenue angle. Some customers in the general service rate class requested compensation from Hydro Ottawa when outages occurred.

### Impact of Outages

The impact of outages varied based on rate class. Many general service customers found that outages were manageable, however, some reported significant losses when the power is out. For general service customers, outage impacts can result in legal, safety, monetary and productivity issues.

Residential customers generally expressed fewer concerns when it came to outage impacts. For most customers in this rate class, an outage is more of an inconvenience than anything else. In fact, some customers found outages were a positive experience where they could "disconnect and spend time with family". That being said, some customers showed concern regarding potential outages during winter months, where they would be more than merely an inconvenience. Some customers wondered whether Hydro Ottawa would be able to quickly restore power if an outage occurred in the depths of winter.

## Areas for Improvement

In both rate classes, there were three central areas in which customers believe that Hydro Ottawa can improve.

Many residential and general service customers believe that Hydro Ottawa could improve communication during outages. Some general service customers feel that better communicating estimated recovery times would drastically improve their ability to react to both planned and unplanned outages.

Second, some customers in both rate classes believe that Hydro Ottawa should be responsible for improving the readability of the bills. Despite being told that they are OEB mandated, customers generally feel that the bills are overly complicated, and leave them unsure as to exactly what they are paying for, and how much it is costing them.

Finally, some customers, mostly in the residential rate class, believe that the only area improvement for Hydro Ottawa is rates. These customers felt that the rates are too high, and if Hydro Ottawa wants to improve, they must find a way to make the distribution rates lower.

## Hydro Ottawa's Proposed Plan and Rate Impact

In general, both general service and residential customers felt that Hydro Ottawa's proposed rate increase was necessary. Although the majority of customers do not like it, they understand that there are improvements that need to be made, and therefore, the proposed increase was seen as reasonable for many.

Many customers fear that this is only the first step in a series of rate increases, ultimately making it difficult to keep up with rising costs. Despite this sentiment being held by some, other customers found the rate increase to be quite reasonable, and really not something that would affect them all that much.

In addition to being concerned that this is the first step in a series of rate increases, a number of customers felt that they needed more information regarding Hydro Ottawa's proposed plan in order to make a more informed decision. For instance, some general service customers wanted to understand how these investments over the next five years would improve their specific company's reliability.

## How Could the Consultation Process be Improved?

The consultation process was generally well received by customers in both rate classes. Some residential customers, however, felt that the workbook was only presenting one side of an "argument", and in order to make a well informed decision, they wanted to hear the other side. In addition to wanting the "other side", some residential and general service customers felt that more information was needed overall.

# Methodology

## About the General Service and Residential Customer Consultation

In the first phase of the customer consultation research program for Hydro Ottawa, INNOVATIVE conducted focus groups with general service under 50 kW and residential customers. The purpose of these focus groups was to provide customers with some education about their local distribution system, and then to gather their feedback on Hydro Ottawa's proposed investment plan for 2016-2020.

The consultation sessions were held in Ottawa on March 17th and 18th, 2015. A total of 34 general service and residential customers participated in these consultation sessions.

| | |
|---|---|
| General Service under 50 kW Rate Class | 18 participants |
| Residential Rate Class | 16 participants |

### Recruiting Consultation Participants

All customer recruitment lists were randomly generated and provided to INNOVATIVE by Hydro Ottawa.

Customers were then contacted by telephone and screened to determine whether or not they were appropriate participants for the consultation. General service customers in the under 50 kW rate class qualified for the consultation if they managed or oversaw their business' electricity bill. Residential customers were screened to ensure that they are the person in the household who is primarily responsible for paying the electricity bill. The screening criteria were designed to ensure participants were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

An incentive of $100 was provided to all general service and $80 to all residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and verbatim quotes.

### Consultation Session Structure

As a primary tool for the customer consultations, INNOVATIVE and Hydro Ottawa developed an informational workbook to provide research participants with an overview of the electricity system, Hydro Ottawa's role within it and their challenges, efficiencies, investment plans and impact on distribution rates. The consultation sessions were structured around the themes contained in this workbook, which was developed in the fall of 2014.

The workbook themes included the following:

1. Have Your Say
2. Electricity Grid 101
3. About Your Bill

4. How are your Electricity Rates Determined?
5. Hydro Ottawa's Distribution Network Today
6. Reliability
7. Challenges Facing Hydro Ottawa
8. Finding Efficiencies and Cost Savings
9. The Dollars and Cents

Each focus group began with an overview explaining the purpose of the consultation and why Hydro Ottawa is seeking feedback from general service and residential customers.

After explaining the purpose of the consultation, the facilitator distributed hardcopy workbooks to act as a guide for the rest of the session. The workbooks contained questions to gather feedback from customers on specific aspects of the system, Hydro Ottawa's investment plan, and resulting impact on rates.

The facilitator then led participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.

Participants were asked to independently respond to the questions within the workbook. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for their household or business.

The hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately 2 hours.

### Informing the Consultation Process

In addition to identifying customer needs and preferences as they relate to the proposed distribution system plan, feedback collected from this phase of the consultation was used to inform the design of the telephone survey consultation phase of Hydro Ottawa's customer engagement program.

**NOTE:** Results contained within this report are based on a limited sample and should be interpreted as directional only.

# Participant Feedback

The following participant feedback was gathered from the consultations on March 17th and 18th with general service customers.

## General Service under 50 kW Rate Class

### General Satisfaction

In general, customers in this rate class are satisfied with the service that they receive from Hydro Ottawa. When compared to other similarly perceived companies, such as, Hydro One, Bell and Rogers, Hydro Ottawa fares well in terms of general satisfaction. Due to proximity and relatability, Hydro One was used frequently as a point of reference when talking about satisfaction.

> *"I've always been pretty impressed with Hydro Ottawa. I've found them to be extremely responsible"*

> *"Speaking from a former Hydro One customer, I would take Hydro Ottawa any day"*

> *"Hydro Ottawa is generally seen as much better than Hydro One"*

### Understanding of Hydro Ottawa's Role in the Electricity System

There was a limited understanding of Hydro Ottawa's role within the electricity system. Many general service customers approached this consultation with cynicism and questioned the merits of the electricity system as a whole.

It seems that many general service customers have a difficult time separating Hydro Ottawa's role in the distribution system from the generation and transmission aspects of the electricity system. As such, very few had prior knowledge that only roughly 20 per cent of their bill went to Hydro Ottawa.

> *"It's amazing that the transmission costs are way in excess of the actual electricity usage"*

> *"I can only buy it from Hydro Ottawa and Hydro Ottawa can only buy it from the mismanaged Hydro One? Sounds like a monopoly"*

### Hydro Ottawa Profits and Stakeholders

A central part of the discussion with general service customers was with regards to Hydro Ottawa's profits, saving for the future, and providing a return to the municipality. Many customers felt that Hydro Ottawa should be able to create a "savings fund" in order to help plan financially for necessary future investments.

Additionally, general service customers repeatedly compare Hydro Ottawa to their own businesses, expressing that they are not able to charge more for their product or service when they have to make improvements to their business.

> *"The reality is that we go through the same things as businesses. You either lose money or you find ways to be more efficient"*

Finally, some felt that Hydro Ottawa should not be remitting profits to the municipality, and that those profits should be spent on making improvements to the system. Hydro Ottawa was often referred to as the government, and therefore garners the same mistrust.

> *"I don't trust the government with my money!"*

## System Reliability

General service customers were generally satisfied with Hydro Ottawa's system reliability. In fact, a plurality of customers had experienced no outages of the past year. Altogether, both Hydro Ottawa's service and system reliability are seen very positively.

> *"I don't think we've actually ever had to close for the day because of a power outage"*

> *"I don't recall going down at all, flashes, but not extended power outages at all"*

> *"The number of outages has been pretty minimal. I have been there ten years and I don't remember ever having to shut down"*

For those customers who had experienced outages in the past year, some felt that they should be compensated for the lost wages and productivity that they experience as a result of Hydro Ottawa's lack of reliability.

> *"With all the downtime that customers are facing, that's a big cost that customers have to bear. How do we get that money back?"*

## Impact of Outages

Within the general service rate class, there was noticeable variation regarding the impact of outages on businesses. Some businesses express experiencing substantial losses to revenue and productivity during an outage. For instance, in the food services industry, an outage exceeding one hour might result in having to send employees home. In cases like this, an outage directly effects the company's bottom line.

On the other hand, a number of businesses find outages to be merely an inconvenience. For one participant who operates a printing business, an outage might result in having to work later, but is not necessarily a major concern. Altogether, some businesses are substantially effected by outages, while others see them more as an inconvenience.

> *"I can absorb it with no issues at all"*

> *"It's pretty minor. We stay open as long as necessary. For us, it's just a disruption, it means we have to stay at work later. The impact for me is just largely psychological"*

> *"After 30 or 40 minutes we have to start sending everybody home"*

While many felt that the impact of outages was somewhat manageable, other companies reported more severe losses to productivity during shorter outages under five minutes. For some businesses, short outages, or "blips" can cause their computer systems to shut down, which can be costly.

> *"I think the main thing that happens during an outage is our computer systems go down. Sometimes they even have to bring in crews to get things working again"*

> *"For me, if the power is out for more than a few minutes, it's a big inconvenience"*

Other customers noted that outages of various length can cause health and safety concerns. Although these instances were more isolated, they nonetheless posed a concern for some general service customers.

> *"We have to close, it's dark and we're a really large store. It's a safety issue. The doors automatically get locked"*

### Duration vs. Frequency of Outages

For most general service customers, the length of an outage is more important than the frequency. As was noted in the previous section, many customers find short outages manageable, however, when outage duration increases, so do potential loses in productivity and product. Again, while some customers found any outage to be unacceptable, others found outage duration to be the more important factor.

### Communication During Outages

When it comes to outages, many customers suggested improved communication as a means to mitigate potentially negative impacts. Knowing an estimated time of recovery would help many businesses decide whether to send their employees home or stay open during an outage. Furthermore, some customers felt that the communication tools were inadequate for their needs and that improving these methods should be a priority, especially during outages. Again, being able to prepare for the duration of an outage can help a business make difficult cost-saving decisions.

> *"I'm good as long as I have some sort of guess how long it's going to be"*

> *"I would say that [Hydro Ottawa's] estimated times of restoration are very off"*

> *"You call when there's an outage and you don't get an answer, you get an automated recording"*

### Direction of Plan

Many general service customers found it difficult to say whether Hydro Ottawa's proposed investment plan was going in the right direction. While some might have understood their goals, there was little understanding or clarity regarding how they plan to get there.

> *"I know the goals, but I just don't understand the plan itself"*

As many business customers have a more advanced understanding of Hydro Ottawa's role in the electricity system, they often requested more information to contextualize the proposed rate increase compared to current and previous investment plans. In order to understand where Hydro Ottawa is going, many customers wanted a deeper understanding of where they have been, and even where they are today.

> *"I think that it's at such a high level that it's hard to say whether they're going in the right direction or not"*

> *"I don't think you can say [if it's the right direction] without knowing what the current investment plan is"*

In addition to understanding what has happened in the past, some customers also want to know what will happen at the end of this five-year investment plan. Will the rate increases stop here, or continue beyond five years? If in fact these proposed investments are made, many customers want to know what the state of the system will look like, compared to what it is today.

> *"At the end of this five year period, where are we going to be? What's going to be the state of the infrastructure?"*

## Hydro Ottawa's Proposed Rate Impact

While most might not like it, the majority of general service customers believe that this proposed rate increase is necessary. General service customers understand that Hydro Ottawa's system is in need of maintenance and improvements, and overall, the proposed rate increase is seen to be manageable.

Again, although most customers believe that the proposed rate increase is necessary, many fear the combination of increases on all portions of the electricity bill. The proposed rate increase on the distribution portion of the bill might be manageable, but many believe that if everything increases steadily, their company's electricity bills will become gradually more difficult to afford.

> *"If 20 per cent of our bill is going to go up, what will happen to the rest of the bill?"*

Finally, many customers wanted more concrete examples of how the money will be used should the proposed rate increase be approved. Simply put, how will service improve if this money is spent?

> *"If I'm agreeing to 182 million dollars, what does that get me?"*

## Residential Rate Class

### General Satisfaction

Residential customers are generally satisfied with the service that they receive from Hydro Ottawa. Customer-facing aspects were seen positively by many, as they had experienced quick response times to requests and overall satisfaction with customer service.

> *"To me, the service we are getting is fantastic"*

In lieu of general satisfaction, many customers felt that they do not have a choice one way or another, they need electricity, and Hydro Ottawa is their only option. They often compare rates to that of their neighbours in Quebec, and wonder why it is so much more expensive in Ottawa.

> *"I have no choice. I have to pay my electricity bill"*

With regards to satisfaction, some residential customers approached this consultation and rate application somewhat skeptically. These customers felt as if the rates are going to go up regardless, and whatever they say will have little impact.

> *"They're going to raise the rates anyway, they are just trying to figure out how to make it palatable"*

While customers were widely satisfied, they had almost no pre-existing knowledge that Hydro Ottawa was only responsible for operating and maintaining the distribution system. Additionally, very few customers knew that 20 per cent of their bills went to Hydro Ottawa. Because of this, a number of residential customers had a difficult time focusing the discussion on Hydro Ottawa's investment plan.

### System Reliability

As with general satisfaction, residential customers are mostly satisfied with Hydro Ottawa's system reliability. About half have experienced zero outages in the past 12 months, and altogether electricity reliability is not seen to be an overly big concern. In fact, many customer felt that they did not experience the "average" length of outages over the past year.

> *"I think service is pretty good. Is it possible to maybe bury some of the lines underground?"*

> *"I think that the infrastructure is old, and I think that there are more power outages in certain parts of the city. I'm surprised that I didn't get any power outages this year"*

### Outage Impacts

When it comes to outage impacts, most residential customers felt that it was more of an inconvenience than anything. Because only a few customers had experienced more than one outage in the past year, very few expressed impacts more than "re-setting the clocks" or "not being able to watch TV".

> *"What is convenient is that the outage I had happened during the night, you only have to reset your clocks"*

> *"When the power last went out, it was fun. The TV wasn't on, there was no music playing, there were no computers on and everyone just got centred again"*

*"When I was a student working on an assignment and the power went out, it would affect me that way"*

While the outages that they had experience were an inconvenience, a number of customers fear the potential impacts of prolonged outages during the winter. Although no customer had experienced a prolonged outage in the winter, they were concerned that Hydro Ottawa will not be able to respond quickly enough should such an outage occur.

*"I'm more worried about outages when we get lots of snow and there are back-to-back minus days"*

*"In the summertime it's okay, but if it went off in the winter for seven or eight hours, that would be a different story"*

It was widely held that Hydro Ottawa should spend in order to maintain the current level of reliability. Because few residential customers saw reliability as a major concern, and even fewer expressed having experienced the average number/duration of outages, maintaining the current reliability is seen to be more than adequate.

## Customer Billing

Many residential customers felt that the bills were overly confusing. Almost nobody was aware of the portion of the bill that is remitted to Hydro Ottawa, and they felt that this lack of understanding caused them further confusion when reviewing their bills. Because most were generally unaware of the different components of the electricity system, they found it difficult to understand the various lines on the bill, and who exactly the money was going to.

*"[The bills] are overly confusing"*

*"It feels like they're trying to trick you to convince you that your hydro bill is less"*

Additionally, there was some desire amongst residential customers to make bills more easily accessible. Some suggested making bills more easily accessible online, while others simply want a better explanation of the different components.

*"They should make the bill a little bit easier to access"*

## Areas for Improvement & Additional Services

In general, residential customers found very few areas in which Hydro Ottawa could improve or provide additional services. Because satisfaction is high, and reliability concerns are low, customers in these groups generally felt that they were receiving the quality of service that they wanted.

*"In terms of improving the system as it serves me, I can't think of anything"*

One improvement that several customers pointed to was reduced rates. Again, many customers feel that their overall electricity bill has become too high, and the one suggested improvement that was heard throughout the groups was reduced rates.

*"Cheaper electricity, but that's not going to happen"*

## Hydro Ottawa's Proposed Rate Impact & Plan

For the most past, residential customers believe that the proposed rate impact is necessary. Customers generally understood that there is a need to invest in aging infrastructure and new equipment, and while they might not like the rate increase, they see that it is necessary to maintain current reliability.

For some customers, while they might not necessarily like the proposed rate increase, when put in perspective, the total increase to their monthly bill will not be something that they can't afford. Altogether, it's not ideal, considering other aspects of electricity will also be increasing, but the proposed rate increase is not unreasonable for most.

> *"I spend more than that on my cup of coffee in the morning"*

## How Could the Consultation Process be Improved?

A number of residential customers felt that they did not have adequate information to provide a response to Hydro Ottawa's proposed investment plan. Because they didn't have anything to compare the plan to, some customers felt that they were only hearing "one side of the argument" and this left some feeling like they were being "told, not consulted".

> *"Right now we're hearing one side of the debate and we still need to hear the other"*

> *"I can't really say because I don't know what is backing up those numbers [in the workbook]. Is it really a reasonable number? I don't know"*

> *"It's as if they wrote [the workbook] for a really general audience, but they underestimated the general audience. I'm looking for supplementary information at the back – an index"*

Despite this sentiment, which was held by some customers, a number of participants felt that this consultation process was useful, and nearly everybody expressed having left with more information regarding Hydro Ottawa and the system that they operate.

# Questionnaire Results

**1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Hydro Ottawa is responsible for?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very well | 7 | 5 | **12** |
| Somewhat well | 11 | 7 | **18** |
| Not very well | 0 | 3 | **3** |
| I don't understand at all | 0 | 0 | **0** |
| Missing value | 0 | 1 | **1** |
| **TOTAL** | **18** | **16** | **34** |

**2. Generally, how satisfied are you with the service you receive from Hydro Ottawa?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very satisfied | 4 | 9 | **13** |
| Somewhat satisfied | 14 | 4 | **18** |
| Not very satisfied | 0 | 1 | **1** |
| Not at all satisfied | 0 | 0 | **0** |
| Don't know | 0 | 1 | **1** |
| Missing value | 0 | 1 | **1** |
| **TOTAL** | **18** | **16** | **34** |

**4. When averaged across the entire customer population, a Hydro Ottawa customer experiences 1.1 power outages per year. Do you recall how many outages you experienced in the past year?**

| Response | GS | Res | Total |
|---|---|---|---|
| None | 4 | 8 | **12** |
| One | 2 | 4 | **6** |
| Two | 4 | 2 | **6** |
| Three | 2 | 0 | **2** |
| Four | 2 | 0 | **2** |
| More than four | 2 | 2 | **4** |
| Don't know | 2 | 0 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**5. Overall, how satisfied are you with the reliability of electricity services provided by Hydro Ottawa?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very satisfied | 7 | 13 | **20** |
| Somewhat satisfied | 8 | 3 | **11** |
| Somewhat dissatisfied | 2 | 0 | **2** |
| Very dissatistied | 0 | 0 | **0** |
| Don't know | 1 | 0 | **1** |
| **TOTAL** | **18** | **16** | **34** |

**6. In your view, how do you think Hydro Ottawa should address the number of customer power outages?**

| Response | GS | Res | Total |
|---|---|---|---|
| Spend what is needed to reduce the power of outages | 3 | 3 | **6** |
| Spend what is needed to maintain the current level of outages | 13 | 9 | **22** |
| Accept more power outages in order to help keep customer costs | 1 | 3 | **4** |
| Don't know | 1 | 1 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**7. The average Hydro Ottawa customer is without power for approximately 2 hours per year. In your view, how do you think Hydro Ottawa should address the length of time customers are without power?**

| Response | GS | Res | Total |
|---|---|---|---|
| Spend what is needed to reduce the duration of power outages | 3 | 1 | **4** |
| Spend what is needed to maintain the current duration of outages | 12 | 9 | **21** |
| Accept longer power outages in order to help keep customer costs from rising | 1 | 4 | **5** |
| Don't know | 2 | 2 | **4** |
| **TOTAL** | **18** | **16** | **34** |

**8. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?**

| Response | GS | Res | Total |
|---|---|---|---|
| Hydro Ottawa should invest what it forcasts is required to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years | 12 | 10 | **22** |
| Hydro Ottawa should lower its investment in renewing the system's aging infrastructure to lessen any bill increase, even if that means more or longer power outages | 5 | 2 | **7** |
| Don’t know | 1 | 2 | **3** |
| Missing value | 0 | 2 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**9. In order to operate efficiently and better serve our customers, Hydro Ottawa needs IT systems to manage the grid and its customer information, as well as proper facilities to house its staff, vehicles and tools. Which of the following statements best represents your point of view?**

| Response | GS | Res | Total |
|---|---|---|---|
| While Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably | 11 | 11 | **22** |
| Hydro Ottawa should find ways to make do with the buildings, equipment and IT systems it already has | 6 | 1 | **7** |
| Don’t know | 1 | 2 | **3** |
| Missing value | 0 | 2 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**10. How well do you feel you understand the cost drivers that Hydro Ottawa is responding to?**

| Response | GS | Res | |
|---|---|---|---|
| Very well | 4 | 3 | **7** |
| Somewhat well | 10 | 6 | **16** |
| Not very well | 4 | 4 | **8** |
| Not well at all | 0 | 0 | **0** |
| Don’t know | 0 | 1 | **1** |
| Missing value | 0 | 2 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**11. How well do you feel you think Hydro Ottawa is managing these cost drivers while meeting customer expectations?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very well | 2 | 1 | **3** |
| Somewhat well | 6 | 6 | **12** |
| Not very well | 5 | 1 | **6** |
| Not well at all | 2 | 1 | **3** |
| Don't know | 3 | 5 | **8** |
| Missing value | 0 | 2 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**12. How satisfied are you with the efforts Hydro Ottawa has made to find efficiencies and cost savings?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very satisfied | 0 | 1 | **1** |
| Somewhat satisfied | 7 | 6 | **13** |
| Not very satisfied | 4 | 1 | **5** |
| Not at all satisfied | 3 | 1 | **4** |
| Don’t know | 4 | 5 | **9** |
| Missing value | 0 | 2 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**13. From what you have read here and what you may have heard elsewhere, does Hydro Ottawa's investment plan seem like it is going in the right direction or the wrong direction?**

| Response | GS | Res | Total |
|---|---|---|---|
| Definitely the right direction | 2 | 0 | **2** |
| Might be the right direction | 10 | 13 | **23** |
| Might be the wrong direction | 2 | 1 | **3** |
| Definitely the wrong direction | 0 | 1 | **1** |
| Don't know | 3 | 1 | **4** |
| Missing value | 1 | 0 | **1** |
| **TOTAL** | **18** | **16** | **34** |

**14. How well did Hydro Ottawa's plan cover the topics you expected?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very well | 2 | 0 | **2** |
| Somewhat well | 11 | 9 | **20** |
| Not very well | 3 | 4 | **7** |
| Not well at all | 1 | 2 | **3** |
| Don't know | 1 | 1 | **2** |
| **TOTAL** | **18** | **16** | **34** |

**15. How well do you think Hydro Ottawa is planning for the future?**

| Response | GS | Res | Total |
|---|---|---|---|
| Very well | 3 | 3 | **6** |
| Somewhat well | 11 | 7 | **18** |
| Not very well | 1 | 2 | **3** |
| Not well at all | 0 | 0 | **0** |
| Don't know | 3 | 4 | **7** |
| **TOTAL** | **18** | **16** | **34** |

**16. Considering what you know about the local distribution system, which of the following best represents your point of view?**

| Response | GS | Res | Total |
|---|---|---|---|
| The rate increase is reasonable and I support it | 4 | 1 | **5** |
| I don't like it, but I think the rate increase is necessary | 10 | 10 | **20** |
| The rate increase is unreasonable and I oppose | 4 | 2 | **6** |
| Don't know | 0 | 3 | **3** |
| **TOTAL** | **18** | **16** | **34** |

# Mid-Market Workshop

**Mid-Market Workshop**
with General Service customers

**PURPOSE:** To gain qualitative input on Hydro Ottawa's plan from GS > 50 kW customers and to obtain feedback on the proposed options.

## Summary

### Understanding Customer Bills

Understanding customer bills was a central part of the discussion in both breakout groups. There was a distinct focus on this area because, in general, customers had a difficult time understanding the various components of their electricity bills. Customers had a limited understanding of how much was remitted to Hydro Ottawa, and as such, many customers pointed to the "ridiculous" billing as a source of frustration and confusion.

### Overall Satisfaction

Overall, customers are generally satisfied with the service that they receive from Hydro Ottawa. Although breakout discussions focused more on outage impacts and the proposed rate increase, customers were quite vocal in their overall satisfaction. That being said, there was an apparent desire for improved communication between Hydro Ottawa and its mid-market customers. Many of these customers want help understanding their bills, as well as what they can do to reduce them. Again, while overall satisfaction was high, customers generally believe that there is room for improvement, particularly with regard to reducing bills.

### Impact of Outages

Much of the discussion in the breakout groups was focused on outage impacts. Mid-market customers generally respond to outages with great variation. For certain customers, an outage can be extremely costly; causing food spoilage, lost wages and productivity. For other customers, an outage is more of an inconvenience.

It is difficult to paint a broad picture of the impact of outages on mid-market customers, as the severity is dependent on a number of factors. Factors which dictate severity of impact include; nature of business, time of outage, security/safety precautions and number of employees.

Because there is variation of severity within the rate class, customers were generally divided on whether Hydro Ottawa should improve or maintain reliability. For those who see significant losses during an outage, improving reliability is important, while for others, maintaining reliability is enough.

### Communication During Outages

For many customers, beyond rates and outages, the most important improvement that Hydro Ottawa can make is with regard to communication during outages. Receiving information regarding estimated outage recovery times is an important feature for many customers. When the power goes out, making decisions as to how best react is important for many businesses, and understanding outage recovery times helps make the decision whether to shut down, send employees home or wait until the power is restored.

### Hydro Ottawa's Proposed Rate Impact

The proposed rate increase was received with pushback from mid-market customers. Approaching the rate increase from a business perspective, many customers felt that the proposed amount far exceeded anything that they could pass on to their own customers. With salary freezes, fixed budgets and financially strapped businesses, many customers felt that this rate increase was unreasonable and that electricity was becoming increasingly difficult to afford.

| Response | Mid-Market |
|---|---|
| The rate increase is reasonable and I support it | 0 |
| I don't like it, but I think the rate increase is necessary | 5 |
| The rate increase is unreasonable and I oppose | 8 |
| Don't know | 3 |
| **TOTAL** | **16** |

### Concern with Consultation

There was some concern within the two breakout groups, as well as in Hydro Ottawa's presentation, regarding the objectivity of the consultation. A number of customers felt that they were being told of this plan, without a real opportunity to provide impactful input. Again, some mid-market customers felt that questions they had regarding the rate increase, and proposed investment plan were not adequately answered, and this generated pushback within both groups.

While customers generally appreciated the opportunity to learn and provide feedback, there was a desire for more, supplemental information to help further understand the details of the proposed plan.

# Methodology

## About the Mid-Market GS Workshop Consultation

In the second phase of the customer consultation research program for Hydro Ottawa, INNOVATIVE conducted a workshop with mid-market general service > 50 kW customers. The purpose of this workshop was to provide customers with some education about their local distribution system, and then to gather their feedback on Hydro Ottawa's proposed investment plan for 2016-2020.

The workshop session was held in Ottawa on March 18th, 2015. A total of 16 mid-market general service customers participated in this workshop consultation session.

### Recruiting Consultation Participants

All customer recruitment lists were randomly generated and provided to INNOVATIVE by Hydro Ottawa.

Customers were then contacted by telephone and screened to determine whether or not they were appropriate participants for the research. Mid-market general service customers qualified for the workshop if they managed or oversaw their business' electricity bill. The screening criteria were designed to ensure participants were knowledgeable of their business' electricity costs and could have an informed discussion on the impact of the proposed rate increases.

An incentive of $150 was provided to all customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and verbatim quotes.

### Consultation Session Structure

The workshop session began with a presentation from Hydro Ottawa employees, explaining the challenges facing the system, the proposed investment plan, and the customer impacts. This presentation lasted approximately two hours, and included a Q&A period with customers in the audience.

Following the Hydro Ottawa presentation and Q&A, customers were separated into equal-sized groups and taken to breakout rooms to begin the next step of the consultation - a small, moderator-lead focus group discussion.

As a primary tool for the customer consultations, INNOVATIVE and Hydro Ottawa developed an informational workbook to provide research participants with an overview of the electricity system, Hydro Ottawa's role within it and their challenges, efficiencies, investment plans and impact on distribution rates. These break-out focus group sessions were structured around the themes contained in this workbook, which was developed in the fall of 2014.

The workbook themes included the following:

1. Have Your Say
2. Electricity Grid 101
3. About Your Bill

4. How are your Electricity Rates Determined?
5. Hydro Ottawa's Distribution Network Today
6. Reliability
7. Challenges Facing Hydro Ottawa
8. Finding Efficiencies and Cost Savings
9. The Dollars and Cents

Because customers had already heard a presentation from Hydro Ottawa, the breakout focus group sessions were quickly able to focus on the topics explored in the workbook.

The facilitator used the hardcopy workbooks distributed during the presentation as a guide for the remainder of the session. The workbooks contained questions to gather feedback from customers on specific aspects of the system, Hydro Ottawa's investment plan, and resulting impact on rates.

The facilitator then led participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.

Participants were asked to independently respond to the questions within the workbook. The facilitator then led a group discussion on the answers participants provided and what the various issues meant for their business.

The hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each breakout session ran for approximately 1 hour.

**NOTE:** Results contained within this report are based on a limited sample and should be interpreted as directional only.

# Participant Feedback

The following participant feedback was gathered from the consultations on March 18th, 2015 with mid-market general service customers.

## Mid-Market (GS Over 50 kW) Rate Class

### Understanding Customer Bills

In general, most mid-market customers did not understand the various components of their bills. This includes; who collects what, what Hydro Ottawa is responsible, and how much is remitted to Hydro Ottawa for distribution. Because these aspects were unclear for many, the comments regarding electricity bills were mostly negative in nature.

> *"Your [Hydro Ottawa] name is on the bill. Archaic, complicated. There's no way to tell what the Hydro Ottawa portion is"*
>
> *"How many kilowatts do I use? Am I close to the average bill, or way down?"*
>
> *"The delivery of the information to the customer to determine how I achieved the bill I received is terrible"*
>
> *"The bill - it doesn't matter how many times you look at a Hydro Ottawa bill, you still get confused. It should be simpler"*

### Overall Satisfaction

While overall general satisfaction with service was high, there were some comments made in the breakout sessions about improving the communication and relationship between Hydro Ottawa and mid-market customers. Some customers felt that because their bills were so high, Hydro Ottawa should be doing more to help explain the aspects of their consumption, and find ways for them to save money. Again, the root of many of these concerns was related to the fact that many customers did not understand the different components of their bills, and exactly how much was remitted to Hydro Ottawa.

> *"There needs to be more interaction with the businesses. With this 7% I want to know how much of it goes to wages; I want to know how much management of each department makes; I want to know what their union rate of pay is. This is all lumped into the distribution cost"*
>
> *"I'm paying $460/month for a $12 commodity charge. I've gone to Hydro Ottawa until I'm blue in the face and their response to me is that it's because of my high consumption. There seems to be an ignorance within the customer service. If they're going to talk about this, customer service needs to be better educated"*

### Impact of Outages

Customer electricity usage in the mid-market rate class varies substantially, and as such, so does the impact of outages. Throughout the breakout sessions, it was quite apparent that business type and size were important variables in determining the impact of an outage.

For many customers who operate machinery and equipment, the cost of lost productivity during an outage can be expensive. An outage can result in a lengthy "re-boot", lost revenue, and the cost of paying employees who are not able to work during the outage.

> *"When the power goes out, I'm still paying all of my employees, and I'm waiting until the power goes back on"*
>
> *"It costs my business $600 an hour. That's $600 in revenue, plus I'm paying the expense of the employees that are not working. It's probably closer to $1000 an hour"*
>
> *"Power for us is crucial. If our power goes down, we have a window of no more than four hours. Anything past that we lose our ice surface – that costs us fifteen thousand to rebuild, and time and effort. So for us it's absolutely crucial"*
>
> *"The level of outages here, is higher than the other jurisdictions that I've worked in. I think they should spend to reduce the number and duration. An outage is always going to be more expensive than preventing it. So it's cost savings and an improvement"*
>
> *"We have a manufacturing component and when it's down it's a big problem. It means we can't deliver. Our customers are forgiving and we don't have a surcharge, but if the outages were longer than what we do have it would be a very big problem. We wouldn't be able to supply our demand"*
>
> *"Big problem – the whole building is commercial so once the power goes out everyone is stuck. The last big one was two and a half hours – there were people stuck in the elevator"*

In addition to lost wages and productivity, an outage can also present health and safety concerns for some customers. In the hospitality industry and senior care, customers are obligated to have generators in the case of an outage to mitigate any potential health and safety concerns.

> *"We have a generator that services life safety. Elevator and emergency lighting"*
>
> *"If it's going to be over 24-hours we start calling families to make arrangements for the people. There is no major cost, but it is an inconvenience"*
>
> *"We're right downtown so we've had two in the past year, not more than half an hour each, it's not a big deal. It's residential so people are inconvenienced, but we have an emergency generator for the elevator and garage doors, emergency lighting. It's not a huge issue for us"*

While a number of businesses and industries struggle during an outage, some mid-market customers see an outage as more of an inconvenience than anything. Many of these customers had not experienced an above average number of outages in the past year, and therefore do not really see them as an issue or concern. As such, many of these customers felt that Hydro Ottawa should invest in maintaining current reliability, instead of improving it.

> *"I'm that person that gets an outage once a year, and it's never been a long outage"*
>
> *"I think we had one outage last year at our business, and at the house I'm not sure we even had one. But then you hear on the radio that someone in another part of town is out of power. I'm one of the lucky ones, so I'm tempted to put 'spend what is needed to maintain the current level of outages' because it doesn't affect me. But then you hear about someone else – depending on what part of town you're in you'll have a different answer"*

*"Inconvenience – with the church, were not generating revenue so it's not so severe. I'm not there all the time but I don't ever recall an outage even within the last five years. We just expect the power to be there and it is"*

*"No real effect. We always just expect the power to be on. We've only had about two [outages] in the past year. We have about eleven hundred members, so they might have trouble accessing things on the internet but it really is low key in terms of outages"*

Overall, outage impacts are variable based on the size, nature and industry in which a customer operates. For some customers, even one outage can be extremely damaging, while for others, it is more of an inconvenience. This variation was extremely evident in these breakout sessions, as no two companies were alike when it came to outage impacts.

## Communication During Outages

While there was a great deal of variation regarding outage impacts, many customers agree that aside from restoring power, effective communication during an outage is extremely important. When an outage occurs, many businesses rely on estimated recovery times to make important decisions that can ultimately be very costly. For the most part, customers were satisfied with the level of communication they received from Hydro Ottawa during an outage, however, some felt that there could be improvements to this aspect.

Being able to receive an estimated time of recovery is important for many businesses because it allows them to make a decision as to whether to shut down, or remain in operation. For instance, one customer who operates a restaurant lost business to a competitor down the street because they were not able to receive an accurate projection as to when the power would be restored. Next to actually restoring power, communicating outage durations is the most important aspect for most mid-market customers.

*"I'm usually the first person to report an outage. I'll phone them and they'll tell me they're investigating the problem. And I'll wait maybe 1 or 2 hours and then I'll call them back again and they will say that the crew is on site but we don't know what's going to happen"*

*"Once we get a projection of the amount of time it's going to be out, if it's going to be short duration we basically don't do anything, we just wait. If it's going to be over 24-hours we start calling families to make arrangements for the people. There is no major cost, but it is an inconvenience"*

## Hydro Ottawa's Proposed Rate Impact

For many mid-market customers, "inflation" was the key word when it came to Hydro Ottawa's proposed rate increase. As business owners, customers in these two groups expressed not being able to increase what they charge much beyond inflation, and generally they feel that Hydro Ottawa should not be able to either.

Businesses are continuously having to make do with fewer employees and resources, and as such, many customers felt that Hydro Ottawa should do the same. Many of these small businesses are struggling, and they believe it will be difficult to afford this increase without passing it on to their customers and tenants. In fact, one customer who manages retail properties believes that this increase could result in some businesses not being able to stay open.

Altogether, while these customers generally understand that there is a need to make investments in the system, most will not grant permission to an increase of this size, with the information that they received. Approaching this proposed rate increase in the context of their own businesses, many customers in these groups believe that Hydro Ottawa should find ways to make it work without a rate increase of this size.

> *"We're still charging the same as we did 15 or 20 years ago. You can't just raise the price because everything else is going up"*

> *"My members are union members. The entire province of Ontario hasn't had an increase in their pay for teachers for three years and judging by the way things are going they won't. A small portion of their fess, that's how we make our funds and that hasn't increased"*

> *"The last thirteen years that I've been with my company, we started out with fourteen employees doing the production that I do today with five. That's the only way that I can make money today, because I'm more efficient"*

> *"The percentage [rate increase] is the only figure that matters, because you make this bill such a piece of garbage that we have no way of figuring it out"*

> *"If the inflation rate is 2.5% how are you going to justify a 35% increase?"*

> *"They can't possibly expect people to be comfortable with that 4.5% from 2017 to 2020. That's an additional $5000 a year, and that's after taxed income. I understand there's infrastructure, there's capital investment that has to be done, but there has to be another solution. I think hitting the user with the cost is unacceptable"*

> *"The size of the increase is unrealistic and not a single one of our customers would accept this. As a commercial landlord I'm accountable to my tenants and I try and hold the line of inflation to two or three percent for operating costs and such. If I tried to hit them with a 12% increase in the first year I would be hung"*

> *"I have retail tenants – Jomi the shawarma guy is going to have to sell an extra four hundred shawarmas a month to pay his bill. It's small business that are struggling, and if he can't pay his rent, he's going to go dark and it's going to affect my topline"*

## Concern with Consultation

For some customers, there was skepticism when it came to the whole consultation process. A number of mid-market customers felt that this was a "one-sided debate" wherein Hydro Ottawa was just looking to tell their story without answering the tough questions that customers had. A number of customers wanted to see an alternative viewpoint wherein they could compare the two sides, and determine which was best for their individual business.

Again, customers in these groups approached the consultation and Hydro Ottawa's plan from the perspective of their own businesses, and therefore, many wanted more detailed information, including finances, salaries and budgets. These perceived information gaps resulted in a good deal of skepticism in these groups, and overall, customers were generally unhappy with the plan being presented.

> *"In the feedback, I'm putting some don't knows because I don't feel that I can answer those questions, without a sufficient answer to some of the questions I'm asking"*

*“I would like to see somebody else present the other side of the argument”*

*“How can we help you [Hydro Ottawa] make your decisions when we don’t really know what we’re talking about?”*

*“This was an extremely one-sided presentation. We’re getting Hydro Ottawa’s view of the situation and the problems that they face, there is no energy critic in here giving us the other point of view of how they see the industry and the problems that they see with the industry”*

*“My impression when I read this workbook is that they wanted me to come down here and give them a pat on the back for being such a good service provider and say you guys are doing a great job and we will give you the increase you’re asking for”*

*“When we were reading these questions, we felt geared to only answer in a certain way for Hydro Ottawa, there is no real feedback”*

*“I don’t think Hydro Ottawa came here expecting to get the questions that we are asking. They came to show us what their presentation is”*

# Questionnaire Results

**1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Hydro Ottawa is responsible for?**

| Response | Mid-Market |
|---|---|
| Very well | 12 |
| Somewhat well | 3 |
| Not very well | 1 |
| I don't understand at all | 0 |
| Missing value | 0 |
| TOTAL | 16 |

**2. Generally, how satisfied are you with the service you receive from Hydro Ottawa?**

| Response | Mid-Market |
|---|---|
| Very satisfied | 6 |
| Somewhat satisfied | 9 |
| Not very satisfied | 0 |
| Not at all satisfied | 0 |
| Don't know | 1 |
| Missing value | 0 |
| TOTAL | 16 |

**4. When averaged across the entire customer population, a Hydro Ottawa customer experiences 1.1 power outages per year. Do you recall how many outages you experienced in the past year?**

| Response | Mid-Market |
|---|---|
| None | 2 |
| One | 5 |
| Two | 3 |
| Three | 5 |
| Four | 0 |
| More than four | 1 |
| Don't know | 0 |
| TOTAL | 16 |

**5. Overall, how satisfied are you with the reliability of electricity services provided by Hydro Ottawa?**

| Response | Mid-Market |
|---|---|
| Very satisfied | 10 |
| Somewhat satisfied | 4 |
| Somewhat dissatisfied | 0 |
| Very dissatistied | 1 |
| Don't know | 1 |
| TOTAL | 16 |

**6. In your view, how do you think Hydro Ottawa should address the number of customer power outages?**

| Response | Mid-Market |
|---|---|
| Spend what is needed to reduce the power of outages | 4 |
| Spend what is needed to maintain the current level of outages | 9 |
| Accept more power outages in order to help keep customer costs | 1 |
| Don't know | 2 |
| TOTAL | 16 |

**7. The average Hydro Ottawa customer is without power for approximately 2 hours per year. In your view, how do you think Hydro Ottawa should address the length of time customers are without power?**

| Response | Mid-Market |
|---|---|
| Spend what is needed to reduce the duration of power outages | 2 |
| Spend what is needed to maintain the current duration of outages | 10 |
| Accept longer power outages in order to help keep customer costs from rising | 1 |
| Don't know | 3 |
| TOTAL | 16 |

**8. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?**

| Response | Mid-Market |
|---|---|
| Hydro Ottawa should invest what it forcasts is required to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years | 8 |
| Hydro Ottawa should lower its investment in renewing the system's aging infrastructure to lessen any bill increase, even if that means more or longer power outages | 2 |
| Don't know | 5 |
| Missing value | 1 |
| **TOTAL** | **16** |

**9. In order to operate efficiently and better serve our customers, Hydro Ottawa needs IT systems to manage the grid and its customer information, as well as proper facilities to house its staff, vehicles and tools. Which of the following statements best represents your point of view?**

| Response | Mid-Market |
|---|---|
| While Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably | 9 |
| Hydro Ottawa should find ways to make do with the buildings, equipment and IT systems it already has | 4 |
| Don't know | 2 |
| Missing value | 1 |
| **TOTAL** | **16** |

**10. How well do you feel you understand the cost drivers that Hydro Ottawa is responding to?**

| Response | Mid-Market |
|---|---|
| Very well | 7 |
| Somewhat well | 6 |
| Not very well | 1 |
| Not well at all | 0 |
| Don’t know | 0 |
| Missing value | 2 |
| TOTAL | 16 |

**11. How well do you think Hydro Ottawa is managing these cost drivers while meeting customer expectations?**

| Response | Mid-Market |
|---|---|
| Very well | 3 |
| Somewhat well | 4 |
| Not very well | 2 |
| Not well at all | 2 |
| Don't know | 4 |
| Missing value | 1 |
| TOTAL | 16 |

**12. How satisfied are you with the efforts Hydro Ottawa has made to find efficiencies and cost savings?**

| Response | Mid-Market |
|---|---|
| Very satisfied | 0 |
| Somewhat satisfied | 6 |
| Not very satisfied | 2 |
| Not at all satisfied | 1 |
| Don’t know | 5 |
| Missing value | 2 |
| TOTAL | 16 |

**13. From what you have read here and what you may have heard elsewhere, does Hydro Ottawa's investment plan seem like it is going in the right direction or the wrong direction?**

| Response | Mid-Market |
|---|---|
| Definitely the right direction | 2 |
| Might be the right direction | 7 |
| Might be the wrong direction | 2 |
| Definitely the wrong direction | 1 |
| Don't know | 3 |
| Missing value | 1 |
| **TOTAL** | **16** |

**14. How well did Hydro Ottawa's plan cover the topics you expected?**

| Response | Mid-Market |
|---|---|
| Very well | 1 |
| Somewhat well | 7 |
| Not very well | 5 |
| Not well at all | 3 |
| Don't know | 0 |
| **TOTAL** | **16** |

**15. How well do you think Hydro Ottawa is planning for the future?**

| Response | Mid-Market |
|---|---|
| Very well | 2 |
| Somewhat well | 6 |
| Not very well | 4 |
| Not well at all | 0 |
| Don't know | 4 |
| **TOTAL** | **16** |

**16. Considering what you know about the local distribution system, which of the following best represents your point of view?**

| Response | Mid-Market |
|---|---|
| The rate increase is reasonable and I support it | 0 |
| I don't like it, but I think the rate increase is necessary | 5 |
| The rate increase is unreasonable and I oppose | 8 |
| Don't know | 3 |
| **TOTAL** | **16** |

# Key Account Validation Interviews

## Summary

**Key Account Interviews**
with Volunteered customers

**PURPOSE:** To validate the consultation process and verify that Hydro Ottawa provided Key Account customers with the information they needed to form an informed opinion on the proposed plan.

INNOVATIVE conducted followed-up interviews with 6 of 9 key account customers who participated in one-on-one consultation sessions with Hydro Ottawa staff. The interviews were designed to validate the process and to verify that Hydro Ottawa provided these customers with the information they needed to provide informed feedback on the proposed plan. The following summary highlights key findings from the validation interviews.

### Assessment of Plan

Overall, based on their pre-existing knowledge and the consultation they had with Hydro Ottawa staff, all six key account users responded positively to the proposed Distribution System Plan.

More specifically, key account customers generally understood the reasons behind the proposed rate increase. Because key account customers have a unique perspective and knowledge of the existing system, they generally see the need to replace aging infrastructure. Furthermore, a number of customers felt that because they serviced a variety of tenants (residential and commercial), any Hydro Ottawa plan should be able to accommodate the needs of all customers.

Ultimately, few interviewees were happy with the proposed rate increase, however, they felt that Hydro Ottawa staff did an adequate job explaining the challenges and infrastructure needs that they are faced with.

### Coverage of Distribution System Topics

All six key account customers believed that Hydro Ottawa's Distribution System Plan covered the key areas they expected (e.g. rate increases, system renewal, system access, system service, and general plant issues).

## System Renewal and Rate Impact

Overall, considering what they know about the plan, all six key account customers granted permission for the proposed rate increase. Four of six customers did not like it, but found it necessary, while the remaining two found it reasonable and supported it.

| | |
|---|---|
| The proposed rate increase is reasonable and I support it | n=2 |
| I don’t like it, but I think the proposed rate increase is necessary | n=4 |
| The proposed rate increase is unreasonable and I oppose it | n=0 |

# Methodology

Innovative Research Group (INNOVATIVE) was engaged by Hydro Ottawa to conduct a series of validation phone calls with key account customers. Key account customers were briefed on the proposed five year Distribution System Plan by Hydro Ottawa staff. INNOVATIVE followed-up by telephone with key account customers after their briefing session to validate the process and to verify that Hydro Ottawa provided these customers with the information they needed to provide informed feedback on the proposed plan.

The initial Hydro Ottawa interviews were held throughout the last three weeks of March, 2015. A total of nine key accounts customers participated in these consultation sessions. INNOVATIVE followed up with six of the nine key accounts customers interviewed soon after their conversations with Hydro Ottawa staff. The three remaining key account customers were either unavailable for a follow-up interview or did not respond to INNOVATIVE'S requests for an interview.

**NOTE:** Results contained within this report are based on a very limited sample and should be interpreted as directional only.

## Recruiting Key Account Participants

The key account participants were recruited from a client-provided list. The key account customers represented a diverse range of interests from a cross-section of manufacturing, public works and property management.

The six larger users who completed the validation interviews with INNOVATIVE were promised confidentiality.  As such, responses are not assigned to any particular individual in this report, nor are names provided.

# Key Account Consultation Process

INNOVATIVE assisted Hydro Ottawa in developing the framework to consult with the key account rate class and to collect feedback on how the five year Distribution System Plan will affect them.

The basic concept of the key account discussion was to cover the same issues as the broader consultation (which follows the consultation workbook). However, as expected, key accounts had a much stronger initial knowledge base and a much more specific understanding of their needs. That meant there was a higher demand for specific information about specific circuits, performance on those circuits and initiatives to enhance the reliability and security of those circuits.

With only a handful of key accounts, Customer Account managers at Hydro Ottawa customized their consultation sessions for each customer, focusing on the issues that were most relevant to the client.

## Key Account Interview Structure

| | |
|---|---|
| Introduction | Ensure the customer understands the scope and purpose of this consultation. |
| Knowledge | Ensure the customer has the core background information to participate in the rest of the discussion. |
| Customer Needs | How well is the customer being served? Can the customer give us unprompted suggestions as to how to improve Hydro Ottawa's service? |
| Challenges | Provide the customer with background as to the challenges Hydro Ottawa must manage in providing service to that |
| Outage Impacts | Ask the customer to describe the impact of outages on their organizations. |
| DS Plan | Inform the customer about the impact on their rates of the proposed plan and secure their feedback |
| Rate Impacts | Inform the customer about the impact on their rates of the proposed plan and secure their feedback |

# Participant Feedback

The following section highlights the general feedback from the key account rate class group.

### Overall Take-Away

Overall, based on their pre-existing knowledge and the consultation they had with Hydro Ottawa staff, all six key account users interviewed supported the proposed rate increase. Four key account users did not like the proposed rate increase, but thought it was necessary, while two users found the proposed rate increase reasonable and supported it.

Generally, the six key account users interviewed responded quite positively to the proposed rate increase and felt comfortable with their existing relationship with Hydro Ottawa.

More specifically, key account users understood the reasons behind the proposed rate increase. One interviewee stated that he realized the existing infrastructure's life was coming to an end and *"it would have been nice to plan ahead"*, yet he understood that it was not possible.

Furthermore, those customers who managed both residential and commercial properties felt that each property type had different perspectives when it came to the DSP. Commercial properties focus more on infrastructure, while residential properties are more concerned with rates and health/safety (i.e. high rise buildings).

### Customer Experience and Expectations

All six of the key account users interviewed felt that they had an adequate opportunity to express their concerns about how well Hydro Ottawa is meeting their needs. Furthermore, all were highly satisfied with the level of explanation they received regarding Hydro Ottawa's challenges in maintaining the system. A number of customers felt that the presentation they received was *"clear, concise and to the point".* Overall, these customers were very positive when discussing the Hydro Ottawa staff members who conducted the original consultation.

### Coverage of Distribution System Topics

Again, all six key account customers who were interviewed felt that Hydro Ottawa's Distribution System Plan covered all the key areas that they expected. A number of customers were pleased with regards to the *"fluency and clarity"* of the plan and were thankful that so many of the important aspects were covered thoroughly.

One key account customer said that their business is located near a substation owned by Hydro One, and they always have a *"backup plan"*, and if they do experience an outage, it doesn't usually last long.

Altogether, key account customers were pleased with the areas touched on in the DSP, and also felt that the plan was clearly explained by Hydro Ottawa staff.

One customer, while not being able to remember many of the details of the plan, noted that his tenants had multiple needs. For some of his tenants, a power outage is a big deal, he said, *"workers go home after half an hour and lose the whole day".* Additionally, power outages can become a health and safety concern for those tenants residing in high rise buildings. Ultimately, within his company, there are varying needs that the DSP should address.

### System Renewal and Rate Impact

All six key account customers interviewed felt that the rate of system renewal was "about right". One customer commented that *"[Hydro Ottawa] seems to have balanced the plan and rate impact well".* Additionally, when it came to system renewal, one customer said, *"They are coming clean. I felt that the presentation was real and now I'm waiting to hear more about it in the media".*

All six customers interviewed gave social permission to the proposed rate increase. Four of six customers did not like it, but found it necessary, while the remaining two found it reasonable and supported it. Again, these customers felt that they had received all the information they needed to make an informed decision and that Hydro Ottawa did a good job of explaining the different aspects of the plan.

### Consultation Process

The six customers unanimously felt that the presentation included all the information they needed, and ultimately, should they have more questions about the plan, they would not hesitate to contact Hydro Ottawa.

One customer said that their company was *"very happy with their continuing relationship with Hydro Ottawa"* and should they have any questions on the plan or new ways to save money, they will reach out to Hydro Ottawa.

# Validation Interview Questionnaire Results

The following tables are the tabulations of key account user feedback to validation questions INNOVATIVE asked when following up on Hydro Ottawa's interviews with their key account rate class.

Reponses to *open-ended* questions are included in the body text of the previous sections.

[KA = Key Account]

***1. Can you please confirm that you recently met with representatives of Hydro Ottawa about their Distribution System Plan?***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| Yes | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| No | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

***2. Did you have an opportunity to express any concerns about how well Hydro Ottawa is meeting your needs?***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| Yes | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| No | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

***3. Did Hydro Ottawa do a good job explaining the challenges they are facing in maintaining the system?***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| Yes | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| No | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

***4. Did the Distribution System plan cover the key areas you expected?***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| Yes | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| No | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

***5. Do you feel Hydro Ottawa's proposed rate of system renewal is too fast, too slow or about right?***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| Too fast | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| About right | 1 | 1 | 1 | 1 | 1 | 1 | 6 |
| Too slow | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

***6. Considering what you know about the local distribution system, which of the following best represents your point of view:***

| Response | KA1 | KA2 | KA3 | KA4 | KA5 | KA6 | Count |
|---|---|---|---|---|---|---|---|
| The proposed rate increase is reasonable and I support it | 1 | 0 | 1 | 0 | 0 | 0 | 2 |
| I don't like it, but I think the proposed rate increase is necessary | 0 | 1 | 0 | 1 | 1 | 1 | 4 |
| The proposed rate increase is unreasonable and I oppose it | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 1 | 1 | 1 | 1 | 1 | 1 | 6 |

# Customer Telephone Surveys

**Telephone Surveys**
among Residential and GS customers

**PURPOSE:** To obtain statistically significant quantitative customer feedback on Hydro Ottawa's plan and assess reaction to customer opinions obtained from the previous research phases.

## Summary

The following summary highlights the key findings from telephone surveys of 1,036 Hydro Ottawa residential customers and 200 general service (GS) <50 kW customers.

### General Satisfaction

A solid majority of residential (84%) and general service (81%) customers are satisfied with the job Hydro Ottawa is doing managing their local distribution system. Among residential customers, 38% are *very* satisfied, and another 46% are *somewhat* satisfied. Three-in-ten (31%) general service customers are *very* satisfied, while another 50% are *somewhat* satisfied.

Asked what Hydro Ottawa could do to improve their service, 22% of residential customers and 25% of general service customers said they "don't know". Another 18% of residential customers and 10% of business customers said there was nothing Hydro Ottawa could do because they are already satisfied with their service. The main suggestion for improving service among both respondent groups was "lower rates" (29% residential, 26% general service).

### Electricity Bill Knowledge Summary

All respondents were read a brief preamble that explained how much of their total electricity bill is remitted to Hydro Ottawa (20% in the case of residential customers, 19% in the case of small business customers). One third (34%) of residential customers and slightly more (37%) business customers indicated that they had been aware of the bill breakdown prior to the survey.

### System Reliability

More than one third (35%) of residential customers reported not having experienced any power outages in the past 12 months. Among those who did almost half (47%) reported that it lasted for less than an hour. The vast majority (87%) of residential customers described their most recent outage as a minor (66%) or no (21%) inconvenience.

The result is similar among general service customers: 34% did not experience any outages, but among those who did, the duration was often (39%) less than an hour. Another 28% report that their last outage lasted between one and three hours. Half of general service customers (50%) report that their most recent outage was a major inconvenience.

The majority of residential (55%) and small business (56%) customers think Hydro Ottawa should spend what is needed to maintain the current *number* of outages. Similarly, half (51%) of each respondent group thinks Hydro Ottawa should spend what is needed to maintain the current *length* of outages.

## System Challenges & Priorities

When it comes to spending on the system's aging infrastructure, a majority of residential (56%) and general service (57%) customers say Hydro Ottawa should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases their monthly electricity bill.

As for investing in new technology, most residential (57%) and small business (61%) customers think the benefits of new technology and infrastructure are important and should be a priority for Hydro Ottawa.

Both respondent groups agree (residential 66%; general service 61%) that, while Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

## Overall Assessment of Plan

***Residential Social Permission:***

At the end of the survey, 70% of residential customers give the proposed rate increase social permission. One-in-four (23%) feel it is reasonable and they support it, while another 47% don't like it but feel it is necessary.

***General Service Social Permission:***

Only slightly fewer general service customers (66%) are prepared to give the rate increase social permission. One-in-five (22%) support it outright, and another 44% reluctantly accept it as being necessary.

# Methodology

INNOVATIVE conducted two random digit dialing customer telephone surveys for Hydro Ottawa:

- A **residential customer survey** was conducted among 1,036 respondents between April 1 and April 12, 2015. Respondents were randomly selected from a customer list provided by Hydro Ottawa (40,000 residential records). A sample of 1,036 residential customers is considered accurate to within ±3.0 percentage points, 19 times out of 20.
- A **general service customer (GS < 50 kW) survey** was conducted among 200 respondents between April 2 and April 9, 2015. Respondents were randomly selected from a customer list provided by Hydro Ottawa (8,000 GS records). A sample of 200 residential customers is considered accurate to within ±6.9 percentage points, 19 times out of 20.

The margin of error in both surveys will be larger within each sub-grouping of the samples.

## Questionnaire Design

The residential and general service questionnaires were designed to simulate the journey that respondents to the online workbook and participants in the Customer Consultation Focus Groups experienced. This included a combination of educating the customer, having customers reflect on their personal experience with the distribution system, and having them make value judgments on trade-offs between system reliability and bill impact.

As part of simulating the "*workbook journey*", the questionnaire was informed by, and incorporated feedback from, the previous qualitative consultation phases of Hydro Ottawa customer engagement. This included sharing both supportive and non-supportive feedback in the survey from previous phases of Hydro Ottawa's customer consultation as it related to the utility's proposed rate increase. Wording of questions differed slightly between the Residential and General Service surveys – for example, in the preambles the size of monthly bills differed between residential and general service customers – but otherwise remained generally consistent.

Both surveys are practically identical and ran at approximately 10 minutes in length.

## Fielding the Surveys

**Residential (RS) Customer Survey**:

For the purposes of executing the residential survey, Hydro Ottawa provided INNOVATIVE with a confidential list containing 40,000 of their residential customers' contact information.

The contact list included only residential customers with contact information on file and who had been a customer of Hydro Ottawa since at least January 1, 2014. The information contained in the contact list included customer name, home telephone number, home address, service area, and total annual usage between January 1 and December 31, 2014.

Only one customer per household was eligible to complete the residential survey. Survey respondents were screened to certify that only the customer primarily responsible for paying their Hydro Ottawa electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions about their electricity bill and how Hydro Ottawa's proposed rate increase would impact their household.

Before retiring any randomly selected telephone number from the contact list, 8 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard refusal. Each night a new sample was released from the contact list to replace completed or retired telephone numbers.

Residential customers were contacted using the primary contact telephone number on file with Hydro Ottawa between 4pm and 9pm on weekdays; between 10am and 9pm on Saturdays; and between 11am and 9pm on Sundays.

While most customers completed the telephone survey from their home (84%), 15% of respondents completed the survey on their cellular phone and 1% at their place of work. Respondents who completed the survey over their cellular phone were screened to ensure they were not operating a motorized vehicle and could safely respond to the survey questions.

**General Service (GS) Customer Survey**:

The sample for the general service survey consisted of 8,000 customers drawn from a confidential list provided to INNOVATIVE by Hydro Ottawa. General service respondents were screened to ensure they were in charge of managing or overseeing the electricity bill at their organization.

General service customers were contacted at their place of work on weekdays between 9am to 5pm.

All fieldwork for both surveys was conducted using a computer-assisted telephone interviewing (CATI) system.

## Sample Design

The two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, region and electricity consumption). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In both surveys, residential and general service customers were divided by the **region** that roughly corresponded to the service territories of the former utilities that merged to form Hydro Ottawa in 2000 and quartiles based on **annual electricity consumption** to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households and small businesses.

Ensuring the samples represented the known customer consumption profiles reduces non-response bias in the survey estimates.

**Note**: A non-response bias occurs in a survey if the answers of respondents differ from that of the potential answers of those who did not answer.

**Residential Sample Design:**

The following table illustrates the segmentation of the residential survey sample by region.

| Service Area | Customer Distribution | Target Sample | Actual Sample | Difference |
|---|---|---|---|---|
| Ottawa Centre | 28% | 277 | 286 | **+9** |
| Gloucester[4] | 29% | 290 | 306 | **+16** |
| Nepean | 27% | 265 | 269 | **+4** |
| Kanata | 11% | 109 | 114 | **+5** |
| Goulbourn | 6% | 58 | 61 | **+3** |
| **TOTAL** | **100%** | **1,000** | **1,036** | **+36** |

Within service area populations, customers were divided into quartiles based on annual electricity usage. The table below illustrates the actual survey interviews by usage quartile within Hydro Ottawa's five regions.

| Service Area | Low Usage | Medium-Low Usage | Medium-High Usage | High Usage | Total |
|---|---|---|---|---|---|
| Ottawa Centre | 72 | 72 | 70 | 72 | **286** |
| Gloucester | 78 | 75 | 77 | 76 | **306** |
| Nepean | 69 | 66 | 68 | 66 | **269** |
| Kanata | 29 | 29 | 29 | 27 | **114** |
| Goulbourn | 15 | 16 | 15 | 15 | **61** |
| **TOTAL** | **263** | **258** | **259** | **256** | **1,036** |

**GS Sample Design:**

The survey of general service customers also divided the respondents by region and annual electricity usage to reflect the actual distribution of Hydro Ottawa's customers:

| Service Area | Customer Distribution | Target Sample | Actual Sample | Difference |
|---|---|---|---|---|
| Ottawa Centre | 42% | 84 | 84 | **0** |
| Gloucester | 27% | 54 | 56 | **+2** |
| Nepean | 21% | 41 | 40 | **-1** |
| Kanata | 5% | 9 | 8 | **-1** |
| Goulbourn | 6% | 11 | 12 | **+1** |
| **TOTAL** | **100%** | **200** | **200** | **0** |

[4] Respondents from Casselman were included in the distribution for Gloucester in both the residential and GS surveys.

Again, within service area populations, general service customers were divided into quartiles based on annual electricity usage. The table below illustrates the number of survey interviews by usage quartile within Hydro Ottawa's five regions.

| Service Area | Low Usage | Medium-Low Usage | Medium-High Usage | High Usage | Total |
|---|---|---|---|---|---|
| Ottawa Centre | 21 | 21 | 21 | 21 | **84** |
| Gloucester | 14 | 14 | 14 | 14 | **56** |
| Nepean | 10 | 10 | 10 | 10 | **40** |
| Kanata | 2 | 2 | 2 | 2 | **8** |
| Goulbourn | 3 | 3 | 3 | 3 | **12** |
| **TOTAL** | **50** | **50** | **50** | **50** | **200** |

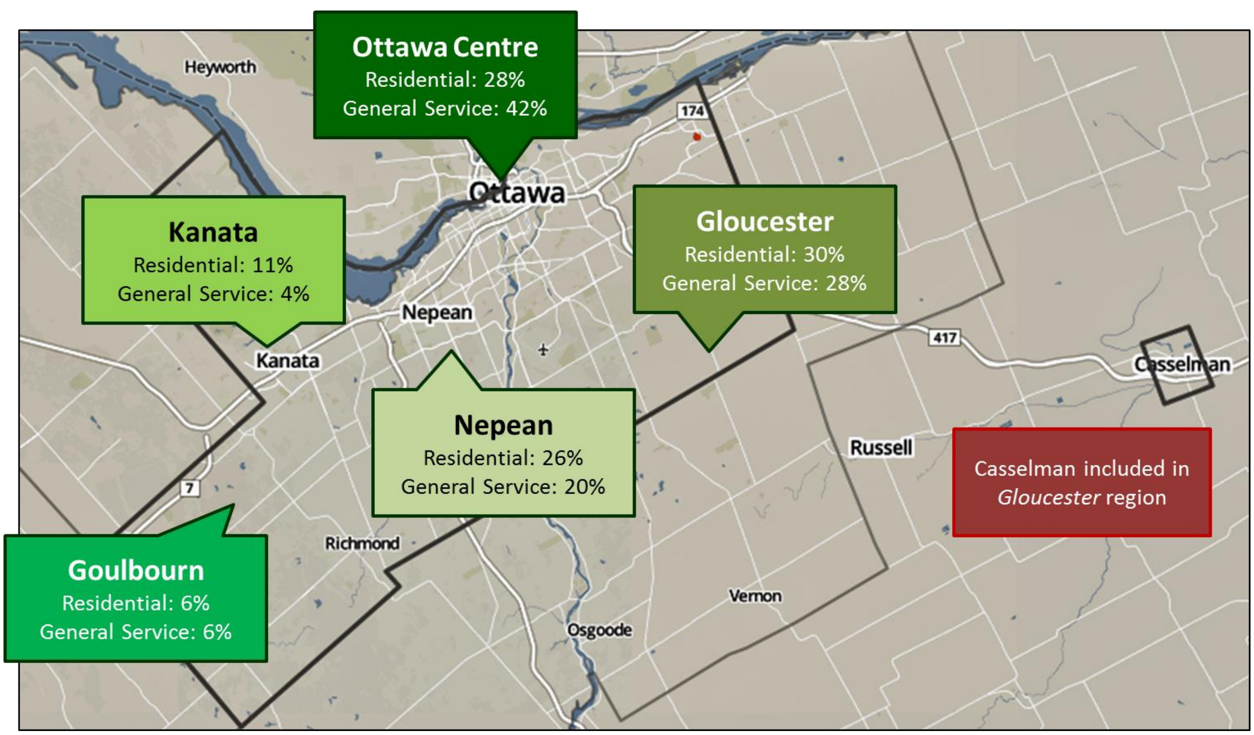
## Sample Weights

Weights have not been applied to either the residential or general service data as the stratified random samples provide an accurate representation of Hydro Ottawa's actual customer base.

## Regional Segmentation

The following diagram illustrates the regional distribution of residential and general service customers in Hydro Ottawa's service area.

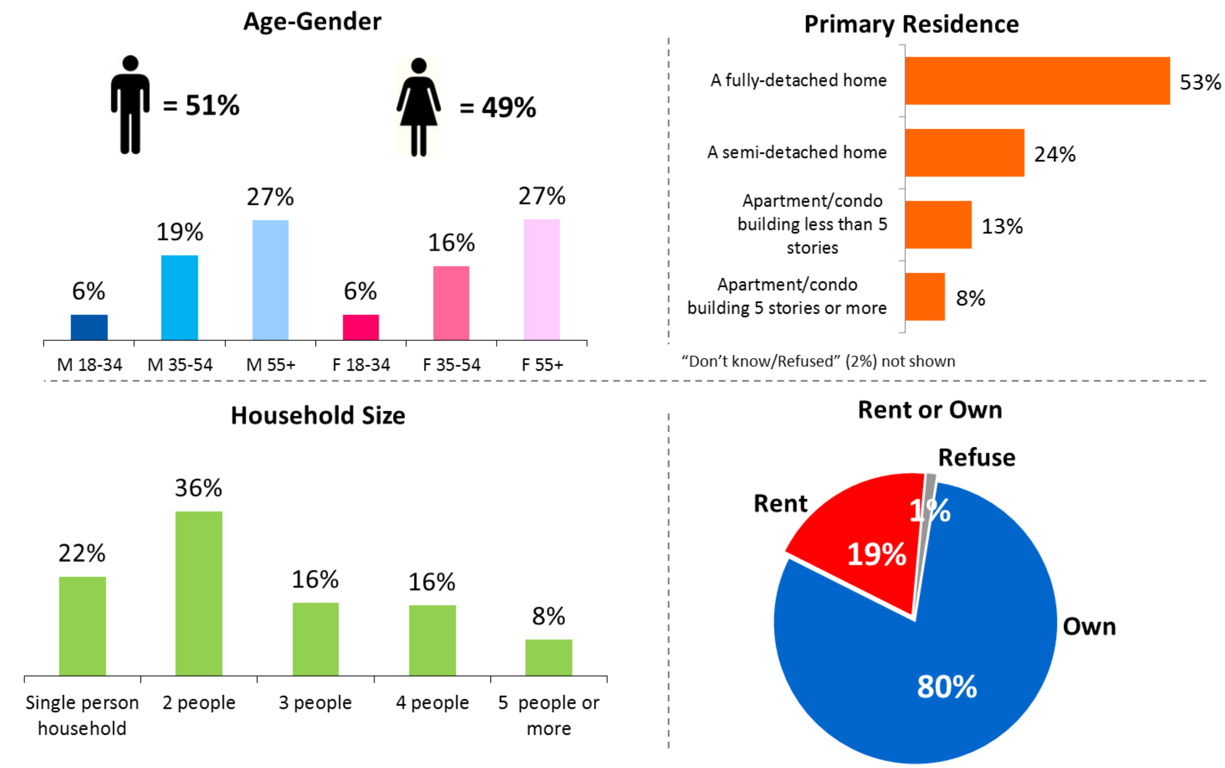
**Figure A: Regional Segmentation**



## Demographic Profiles

The following details the demographic characteristics of respondents who completed the Residential Ratepayer Survey [n=1,036].

#### Figure B: Residential Customer Profile

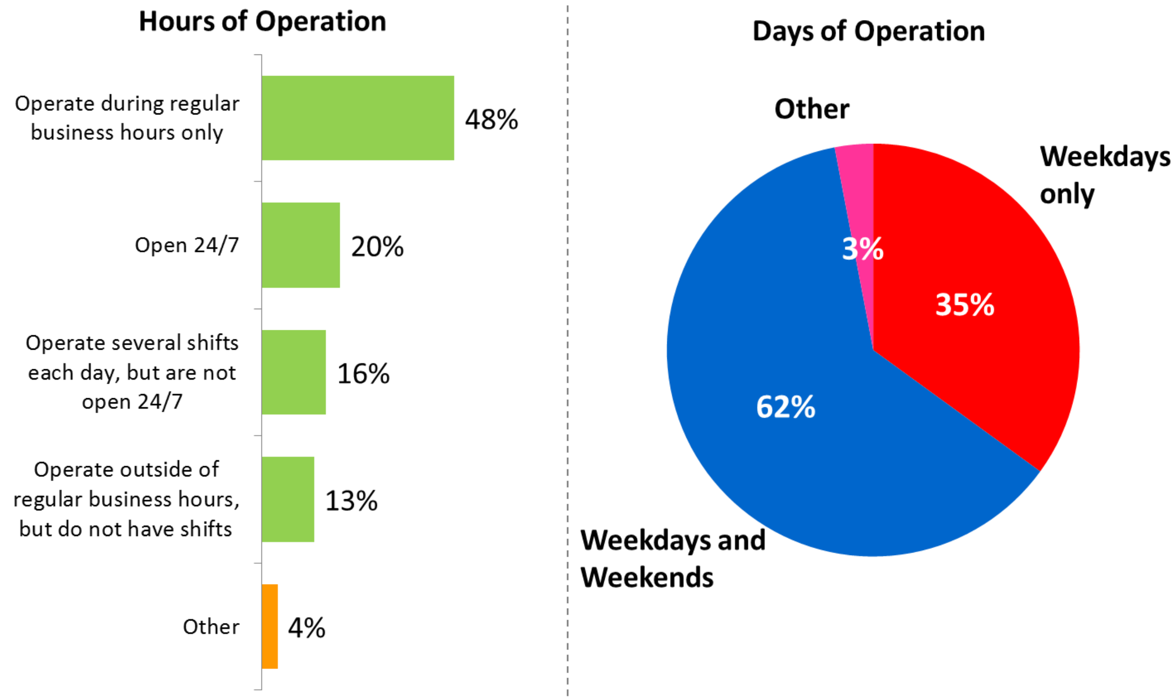



"Don't know/Refused" (2%) not shown

## Firmographic Profiles

Below are the firmographics of respondents who completed the general service ratepayer survey [n=200].

**Figure C: GS Customer Profile**



# Respondent Feedback

## Familiarity and Satisfaction

In the first section of the survey, we asked respondents about their level of familiarity with Hydro Ottawa, and whether or not they are generally satisfied with them. We also invited input on how Hydro Ottawa could improve their service.

### Familiarity and Satisfaction Summary

- Fewer than half (46%) of residential customers claim to be familiar with their local electricity distribution system. This figure is slightly higher among general service customers (49%).
- A strong majority of residential customers (84%) are satisfied with the service they receive from Hydro Ottawa, as are 81% of general service customers.
- The primary suggestion for improving service is "lower rates" (29% residential; 26% general service). 18% of residential customers and 10% of general service customers say there is nothing Hydro Ottawa can do to improve their service.

Prior to answering the questions in the General Satisfaction Section, respondents were presented with a preamble concerning key components of Ontario's electricity system.

**The preamble read as follows:**

*"To start, I'd like to ask you a few questions about the electricity system…*

*As you may know, Ontario's electricity system has three key components:* ***generation***, ***transmission*** *and* ***distribution***.

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

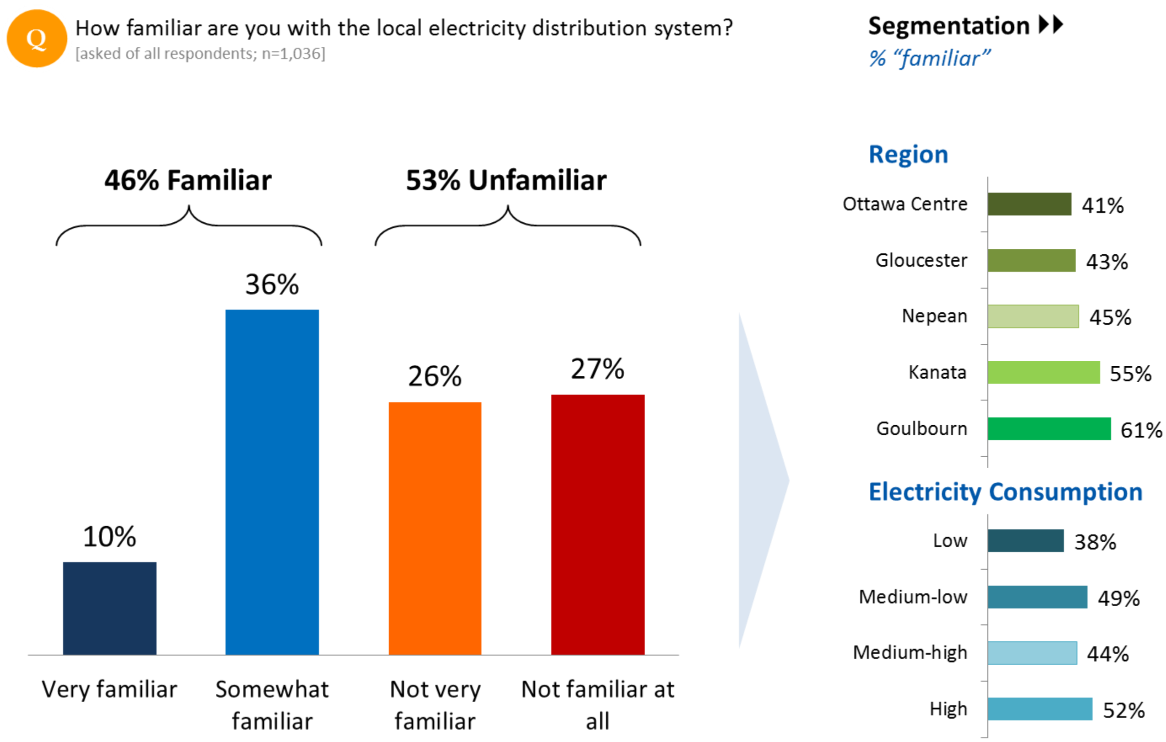
*Today we're going to talk about your* ***local distribution system*** *which is maintained and operated by* ***Hydro Ottawa***."

## Familiarity with Local Electricity Distribution System

Fewer than half (46%) of residential customers say they are either *somewhat* (36%) or *very* (10%) familiar with their local electricity distribution system. A majority (53%) of residential customers are unfamiliar with their local distribution system, with over one-in-four (27%) report that they are *not familiar at all* with the system.

- Degree of familiarity is directionally higher among those with high electricity consumption (52%) compared to low levels of consumption (38%).
- Regionally, residential customers in Ottawa Centre are least familiar (41%). Customers in Goulbourn are relatively more familiar (61%) with the local distribution system.

**Figure RS.1: Familiarity with the Local Distribution System**

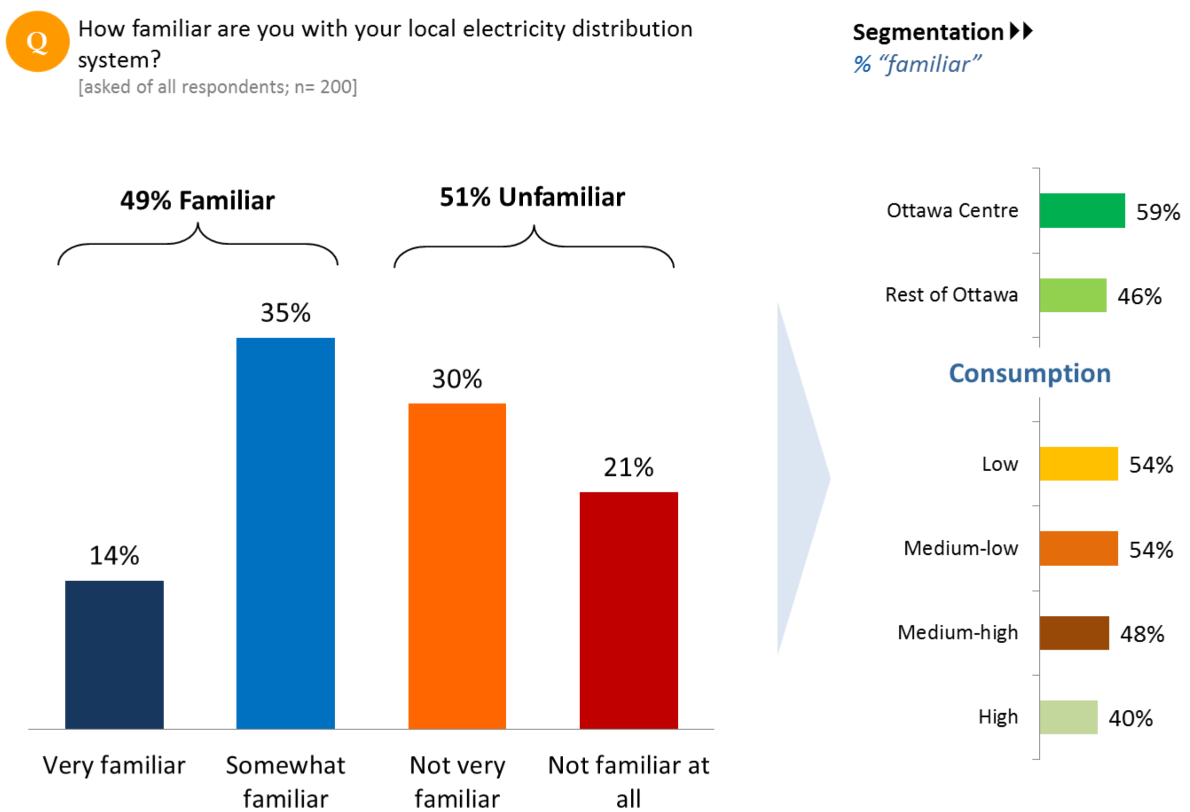



**Note:** 'Don't know' (1%) not shown

Familiarity is slightly higher among general service respondents, with almost half saying they are *somewhat* (35%) or *very* (14%) familiar with their local electricity system. One-in-five (21%) say they are *not familiar at all* with the system.

- Familiarity is lowest among GS<50 kW customers with a high level of consumption.
- Regionally, general service customers in Ottawa Centre are more familiar than customers across the rest of Hydro Ottawa's service area.

**Figure GS.1: Familiarity with the Local Distribution System**

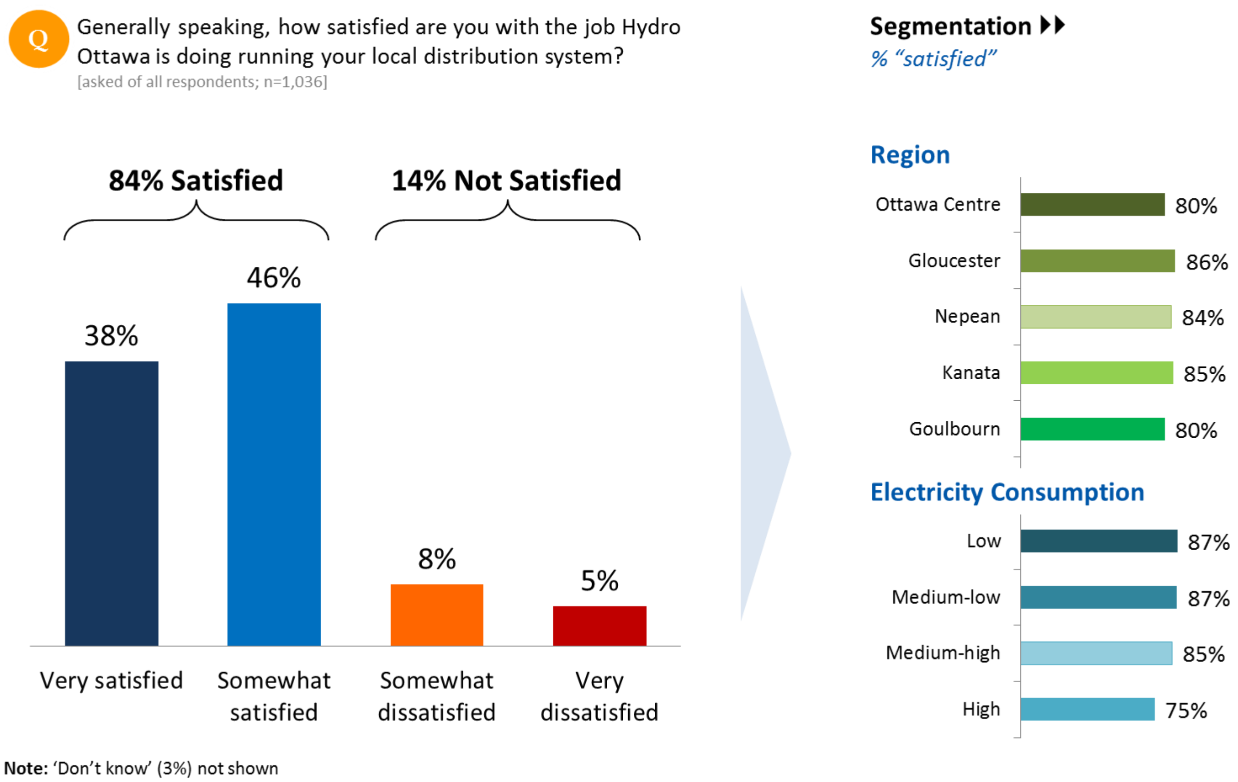


## Satisfaction with how Hydro Ottawa is Running the Distribution System

A large majority (84%) of residential customers are satisfied with the job Hydro Ottawa is doing running their local electricity distribution system, with 38% being *very* satisfied and a further 46% being *somewhat* satisfied. Only 14% percent report being *dissatisfied* with the job Hydro Ottawa is doing.

- Satisfaction ranges from 75% among high consumption customers to a high of 87% among those with a low and medium-low consumption level.
- Regionally, customer satisfaction levels are relatively consistent across Hydro Ottawa's service territory.

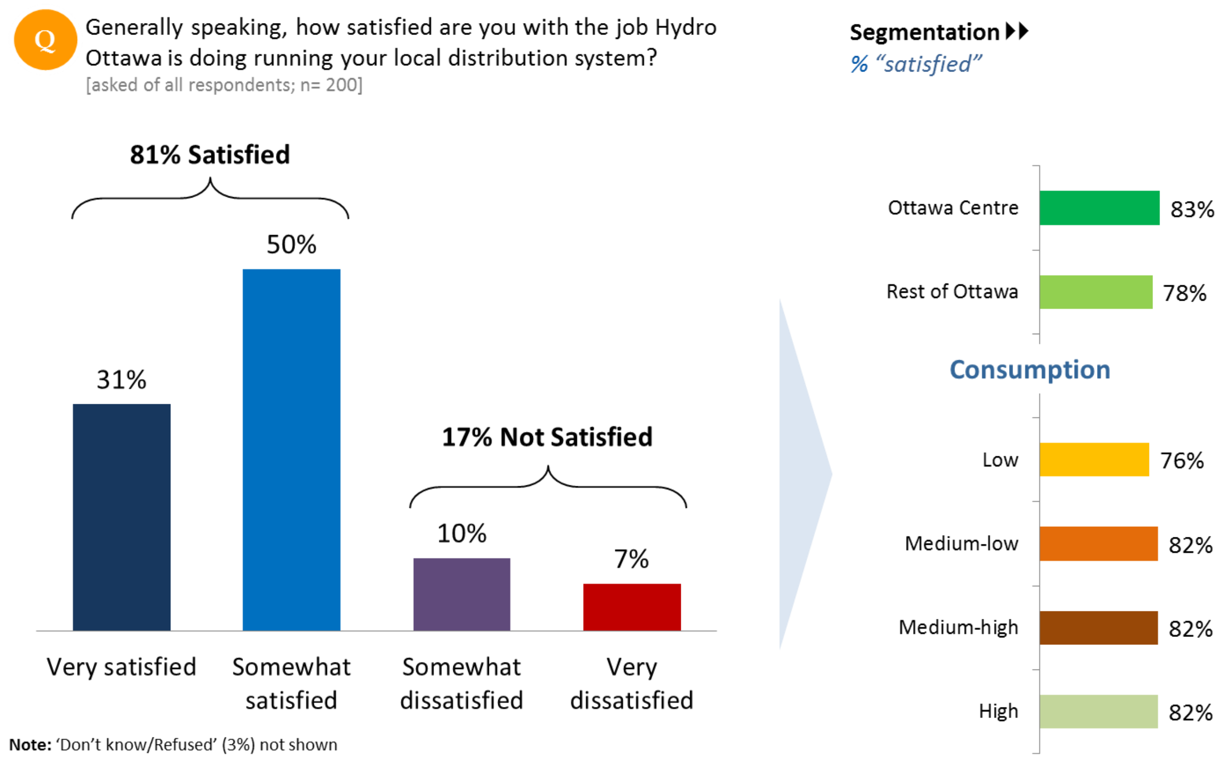
**Figure RS.2: Satisfaction with Hydro Ottawa**



Like residential customers, a majority (81%) of general service customers reporting being satisfied with the job Hydro Ottawa is doing, with 31% *very* satisfied and another 50% who are *somewhat* satisfied. Almost 1-in-5 (17%) general service customers are *dissatisfied.*

- There are no statistically significant differences in satisfaction across regions or consumption levels.

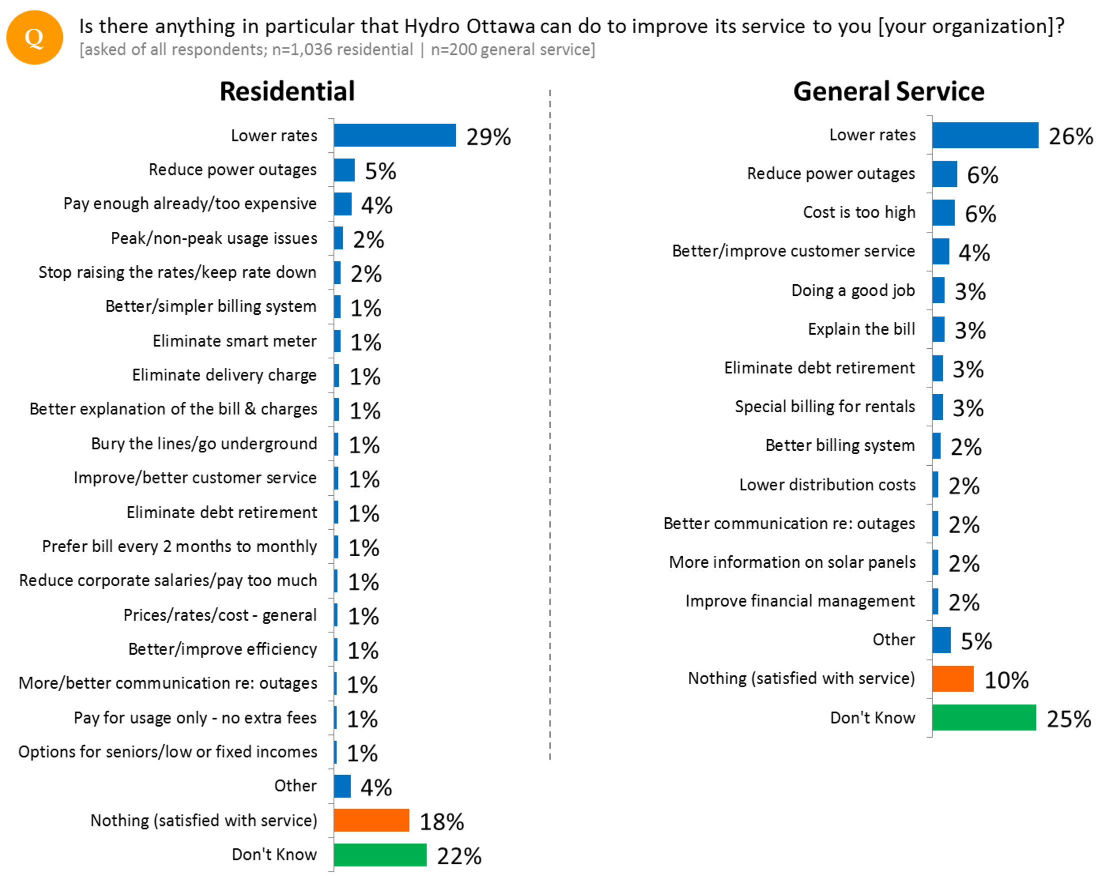
**Figure GS.2: Satisfaction with Hydro Ottawa**



## How to Improve Service

When asked how Hydro Ottawa could improve their service, 18% of residential customers and 10% of general service customers say there is nothing they can do – they are already satisfied. Among both respondent groups, the primary suggestion for improving service is "lower rates" (29% residential; 26% general service). This is followed distantly by "reduce power outages" (5% residential; 6% general service).

### Figure RS/GS.3: How to Improve Service



## Electricity Bill Knowledge

Before asking respondents about their familiarity with their electricity bill, residential and general service customers were presented with a preamble on the breakdown of their electricity bill:

***Residential Survey Preamble:***

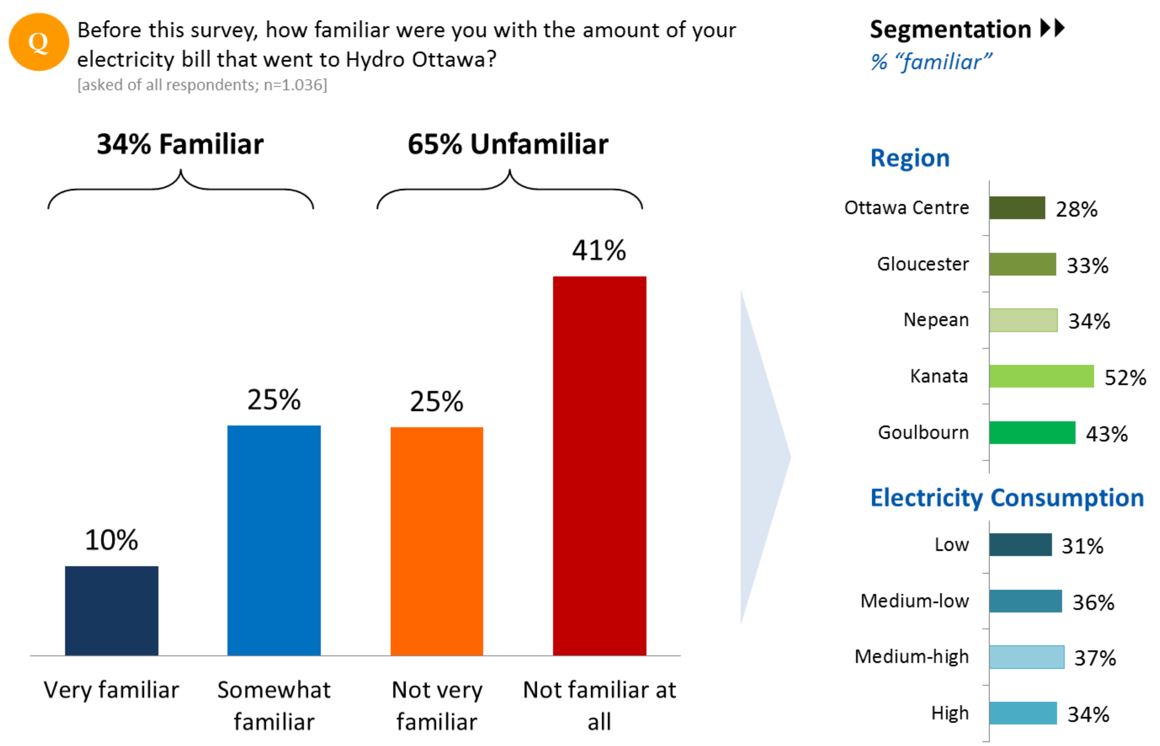
*I'd now like to talk with you about your electricity bill …*

*While some customers pay more and other pay less, the* ***average residential customer pays about $130 a month*** *for electricity of* ***which $26 or approximately 20% goes to Hydro Ottawa****. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.*

Most (65%) residential respondents were unfamiliar with how much of their energy bill goes to Hydro Ottawa. In fact, 41% were *not familiar at all*. Just over a third (34%) said they were familiar with the bill breakdown.

- Familiarity is highest among Kanata residents, lowest among residential customers living in Ottawa Centre.

**Figure RS.4: Familiarity with Electricity Bill**




**Note:** 'Don't know' (0%) not shown

***General Service Survey Preamble:***

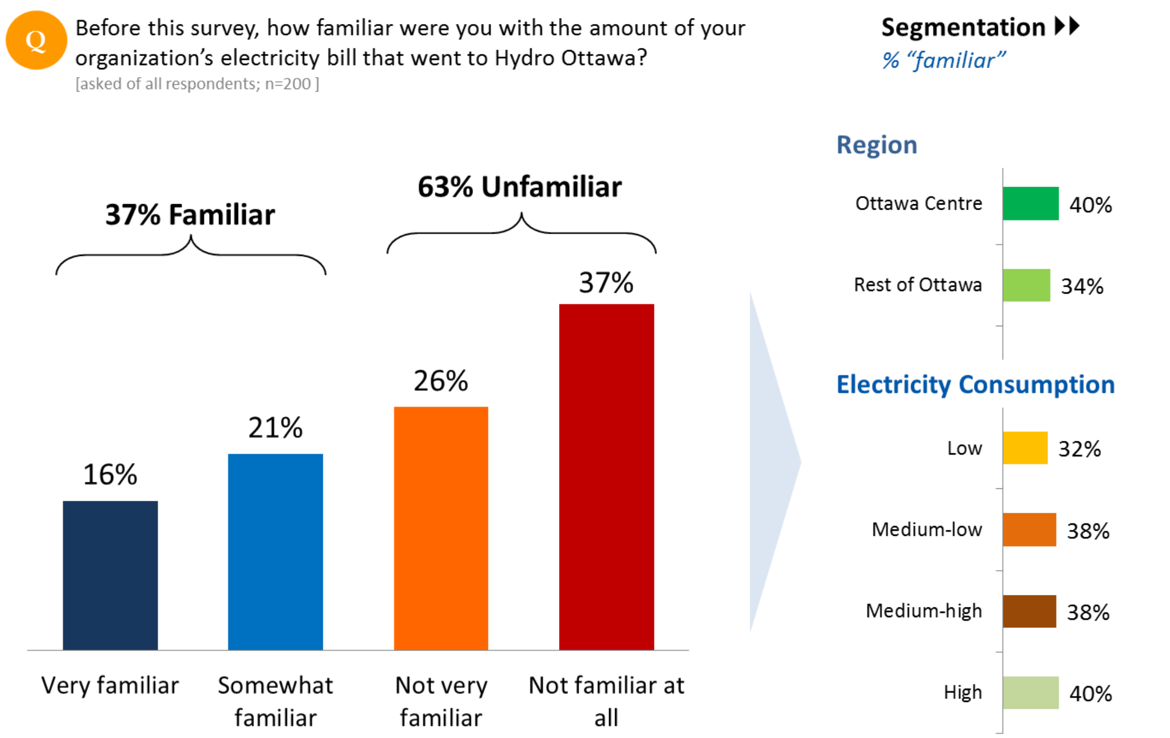
*I'd now like to talk with you about your electricity bill …*

*While some customers pay more and others pay less, the* ***average small business pays about $311 a month for electricity*** *of which* ***$59 or approximately 19% goes to Hydro Ottawa****. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.*

Among general service customers, six-in-ten (63%) were unfamiliar with how much of their energy bill went to Hydro Ottawa, with 37% being *not familiar at all.* Conversely, 37% reported being familiar with this bill breakdown.

- There are no significant variations across the sub-segments of the general service sample.

**Figure GS.4: Familiarity with Electricity Bill**



## System Reliability

This section of the survey focused on customers' experiences with reliability. We also asked respondents what they think Hydro Ottawa's priorities should be when it comes to investing in system reliability.

***System Reliability Preamble*** *(read to both Residential and General Service customers):*

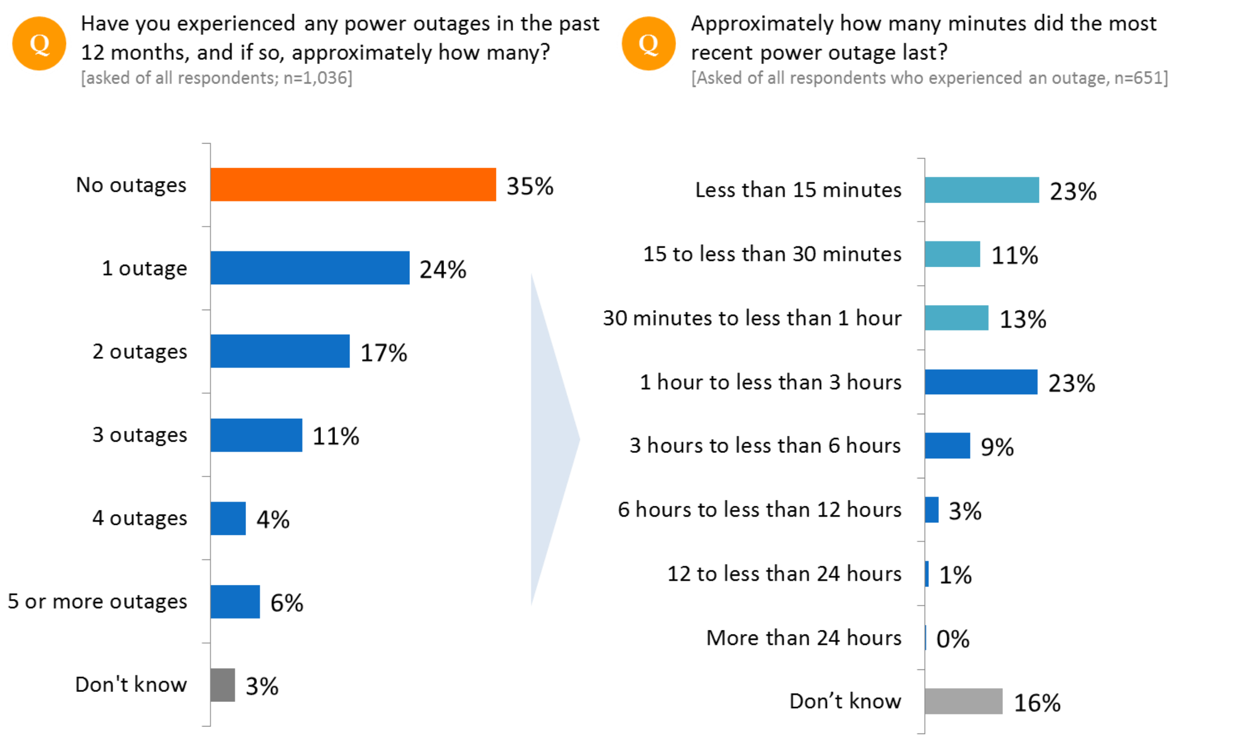
*Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.*

*With that said, the average Hydro Ottawa customer experiences **one** power outage per year.*

Over a third (35%) of residential customers did not experience an outage in the prior 12 months. Among those who recall a power outage over the past 12 months, half (52%) experienced between one and three outages, with only 10% experiencing four or more.

Among residential customers who experienced a power outage, almost half (47%) report that their most recent outage lasted less than one hour. In fact, almost half (46%) say it was less than 15 minutes in duration. Just over a third (36%) reported their most recent power outage over the past 12 months lasting over an hour.

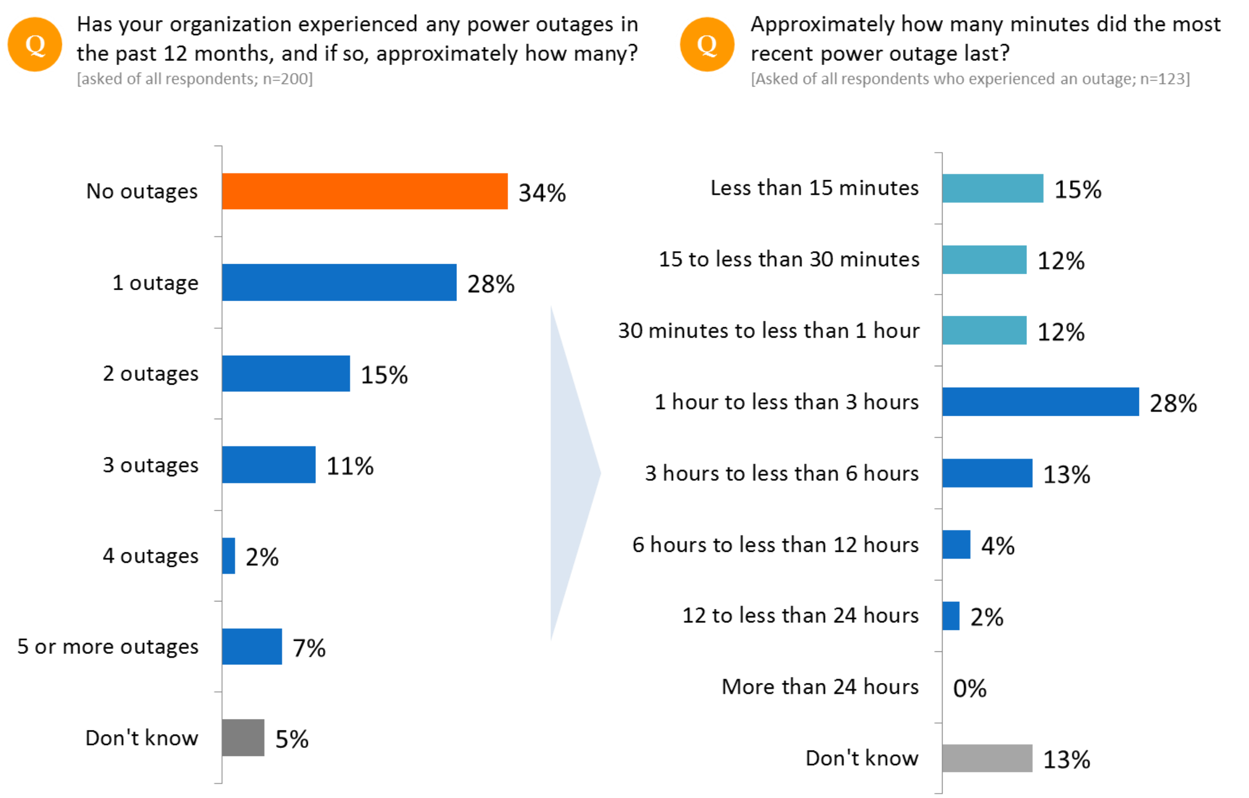
**Figure RS.5: Power Service Interruptions**



One third (34%) of general service customers did not experience any outages, while just over half (54%) experienced between one and three outages.  Only-one-in ten (9%) reported four or more outages.

General service customers reported shorter outages than residential customers.  Four-in-ten (39%) said their most recent outage lasted less than an hour (15% said less than 15 minutes), while nearly half (47%) said over an hour.

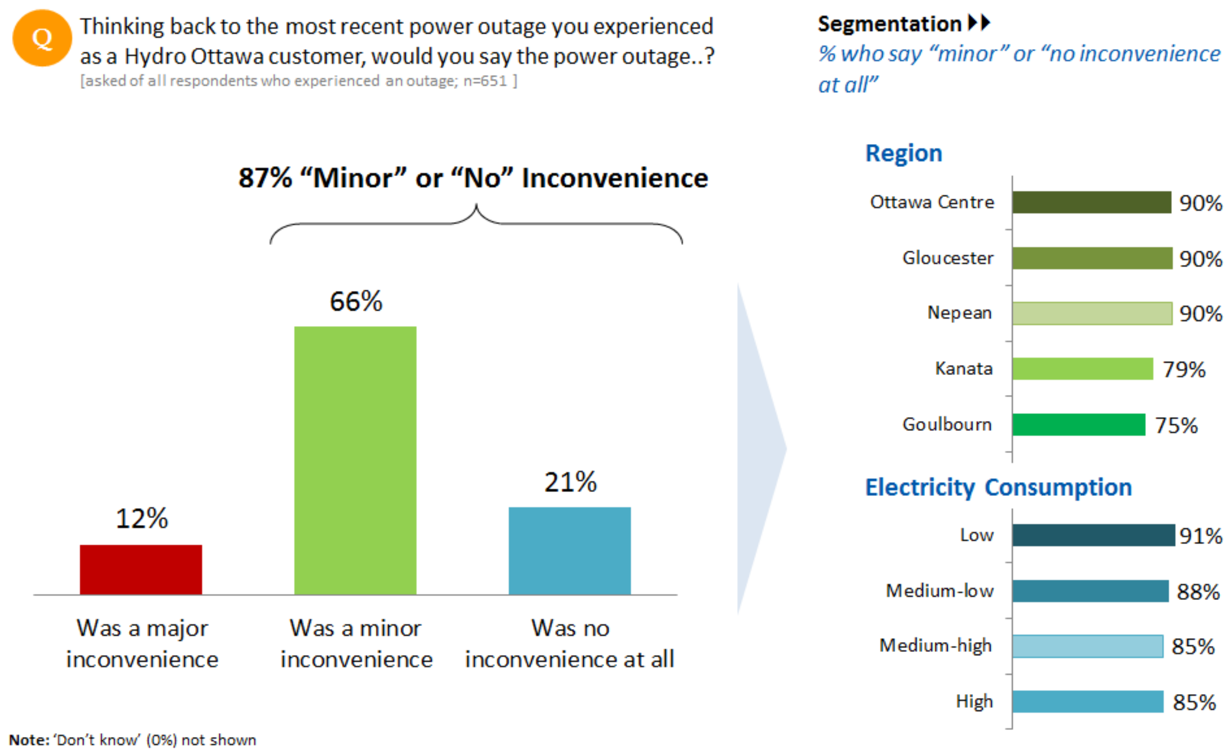
**Figure GS.5: Power Service Interruptions**



Regardless of duration, nine-in-ten (87%) residential customers say their most recent power outage either had a minor or caused no inconvenience. 12% said their most recent power outage over the past 12 months was a major inconvenience.

- Customers in Goulbourn (75%) are least likely to say their most recent power outage was a minor inconvenience or caused no inconvenience.

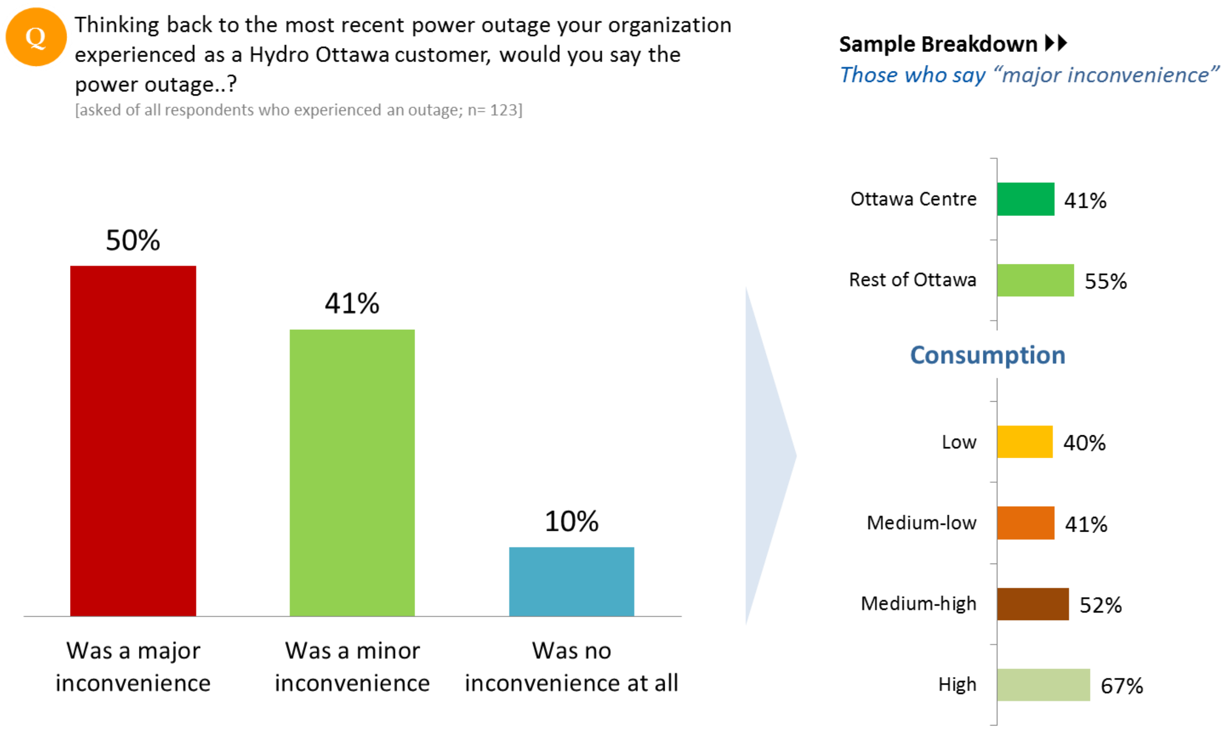
### Figure RS.6: Impact of Most Recent Power Service Interruption



Unlike residential customers, 50% of general service customers reported that their most recent power outage was a major inconvenience.  On the other hand, 51% of general service customers say their most recent power outages was either a minor inconvenience or caused no inconvenience at all.

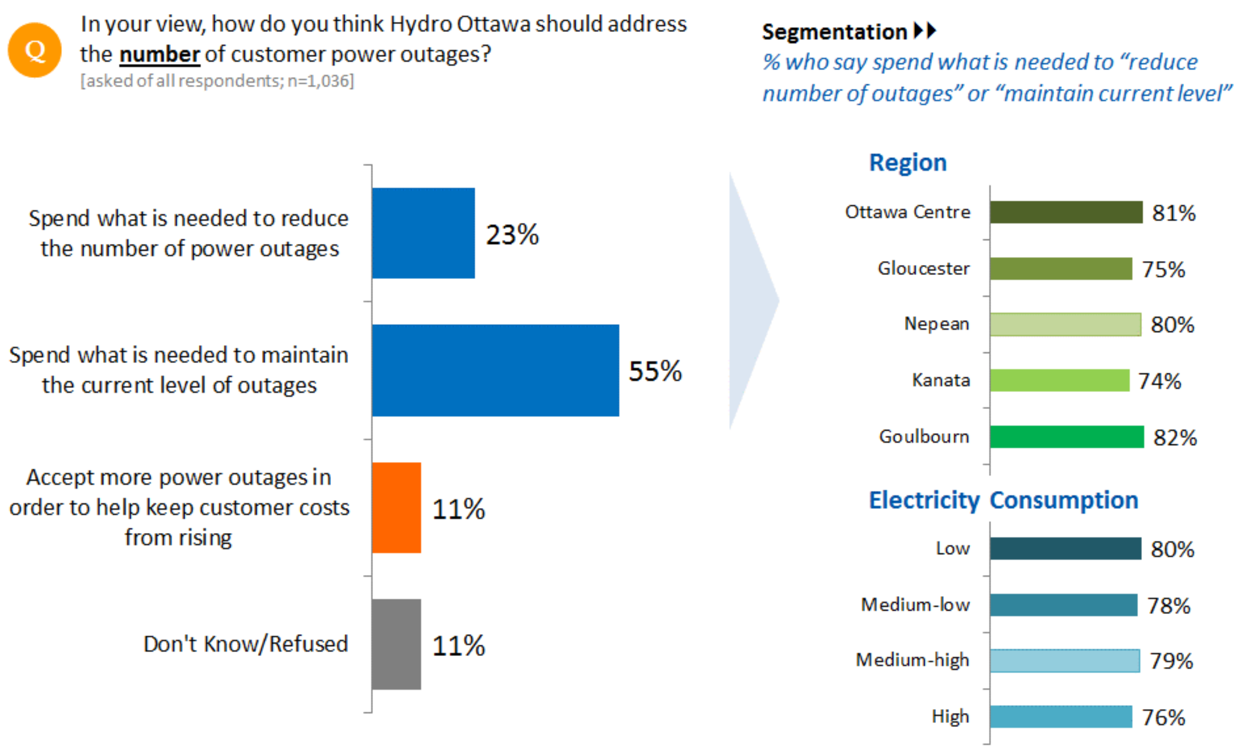
- Those with a higher level of electricity consumption are most likely to say the last power outage was a major inconvenience (67%).

### Figure GS.6: Impact of Most Recent Power Service Interruption



When asked what Hydro Ottawa should do to address the number of power outages, eight-in-ten (78%) residential customers say Hydro Ottawa should spend what is needed to reduce the number or maintain the current level of power outages. Only one-in-ten (11%) say they are willing to accept more outages to help keep customer costs from rising.

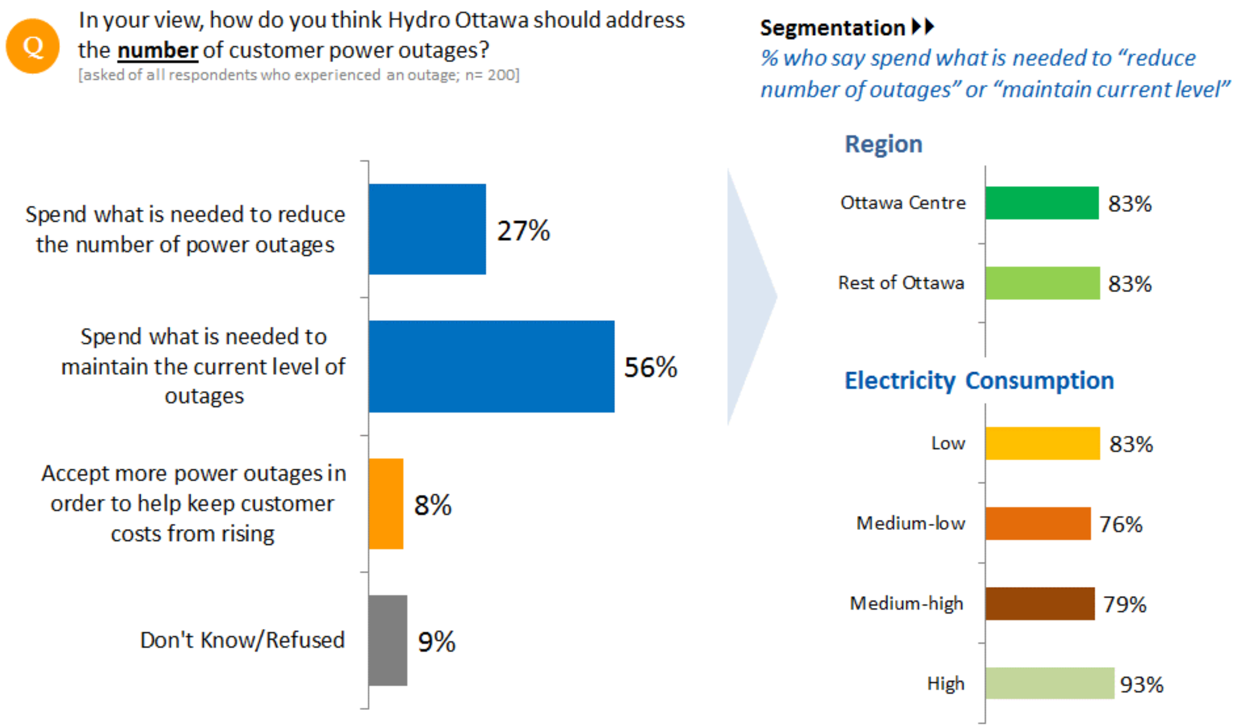
**Figure RS.7: Addressing the Number of Power Service Interruption**



Among general service customers, the preference (56%) is also for Hydro Ottawa to spend what is needed to maintain the current level of unexpected power outages. Three-in-ten (27%) would like them to spend what is needed to reduce the current number, but only eight percent are willing to accept more outages in order to keep customer costs from rising.

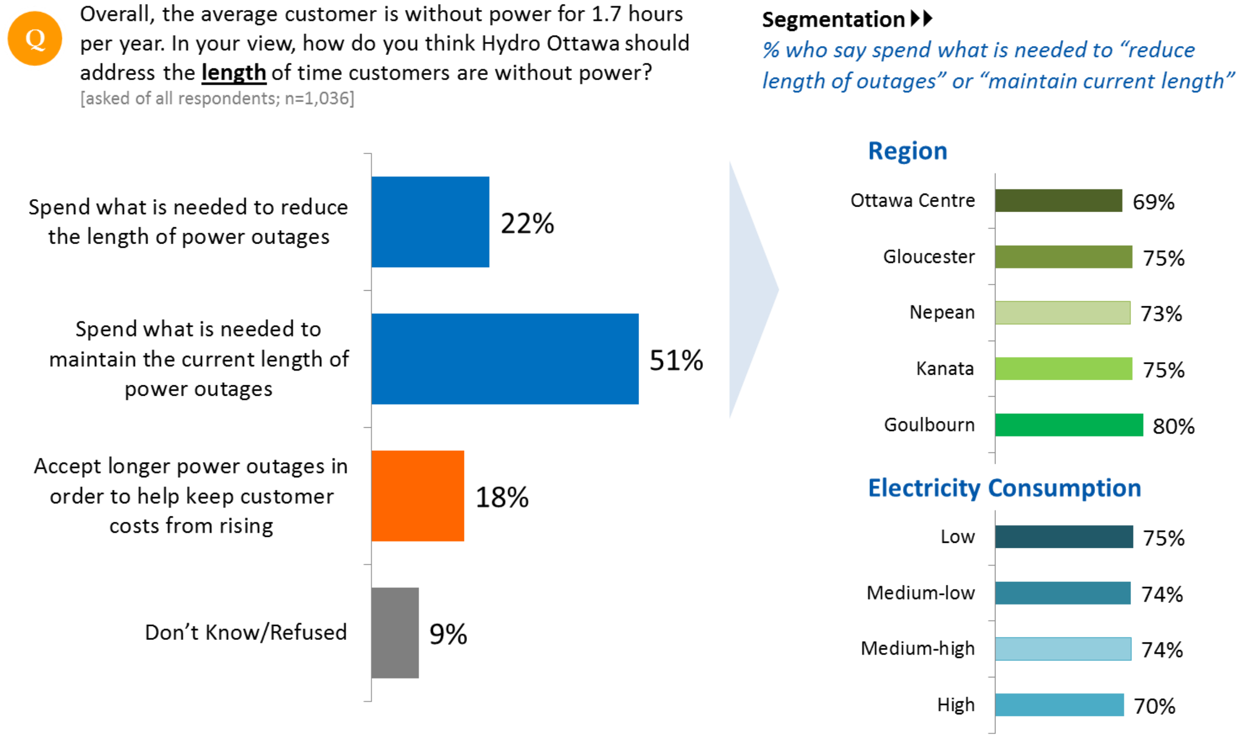
- Businesses with high electricity consumption levels are most likely (93%) to prefer a spending plan that either reduces the number of power outages or maintains the current level of reliability.

**Figure GS.7: Addressing the Number of Power Service Interruption**



Consistent with their preference for spending what is needed to maintain the current number of outages, residential customers also want maintenance to be the objective when it comes to spending on the duration of power outages (51%). Two-in-ten (22%) would prefer that Hydro Ottawa spend what is needed to reduce the length of power outages, while fewer (18%) say they would accept long time without power in order to keep customer costs from rising.

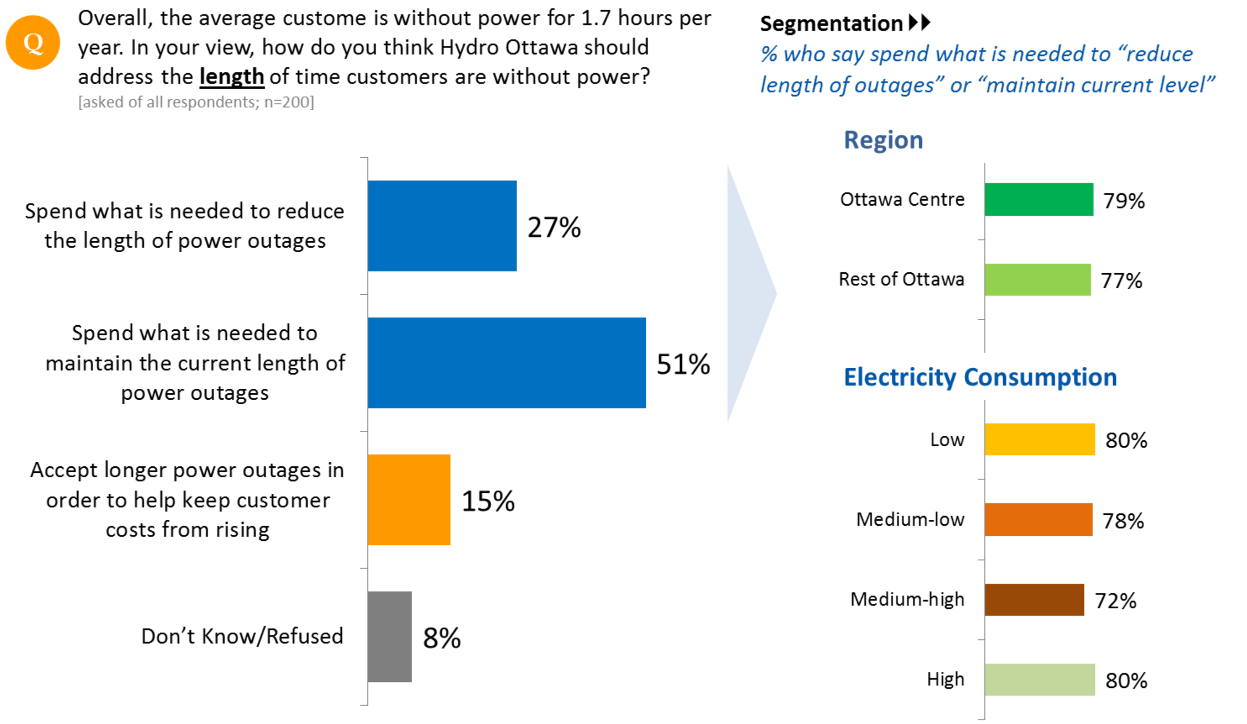
#### Figure RS.8: Addressing the Length of Power Service Interruption



Again, like residential customers, a majority of general service customers prefer a spending level with the goal of maintaining the current length of power outages (51%). Fewer than one-in-five (15%) are prepared to accept longer time without power to keep customer costs from rising, while 27% would like Hydro Ottawa to spend what is needed to reduce the current length of outages.

- There are no significant variations across the sub-segments of the general service sample.

**Figure GS.9: Addressing the Length of Power Service Interruption**



## System Challenges and Priorities

This series of questions gathered feedback on investment in the areas of System Renewal, System Service and General Plant. Preambles prior to each question provided respondents with some background information to help them give a more informed opinion.

### System Renewal

Before asking respondents about Hydro Ottawa's investment priorities, residential and general service customers were read the following preamble related to the utility's proposed system renewal program.

***System Renewal Preamble*** *(read to both Residential and General Service customers):*

*A significant amount of* ***Hydro Ottawa's*** *electrical infrastructure was built in the 1960s and 70s, and is still in-service today. While* ***Hydro Ottawa*** *believes it has done its best to prolong the life of these assets, many of these assets are approaching or have exceeded the end of their useful life.*

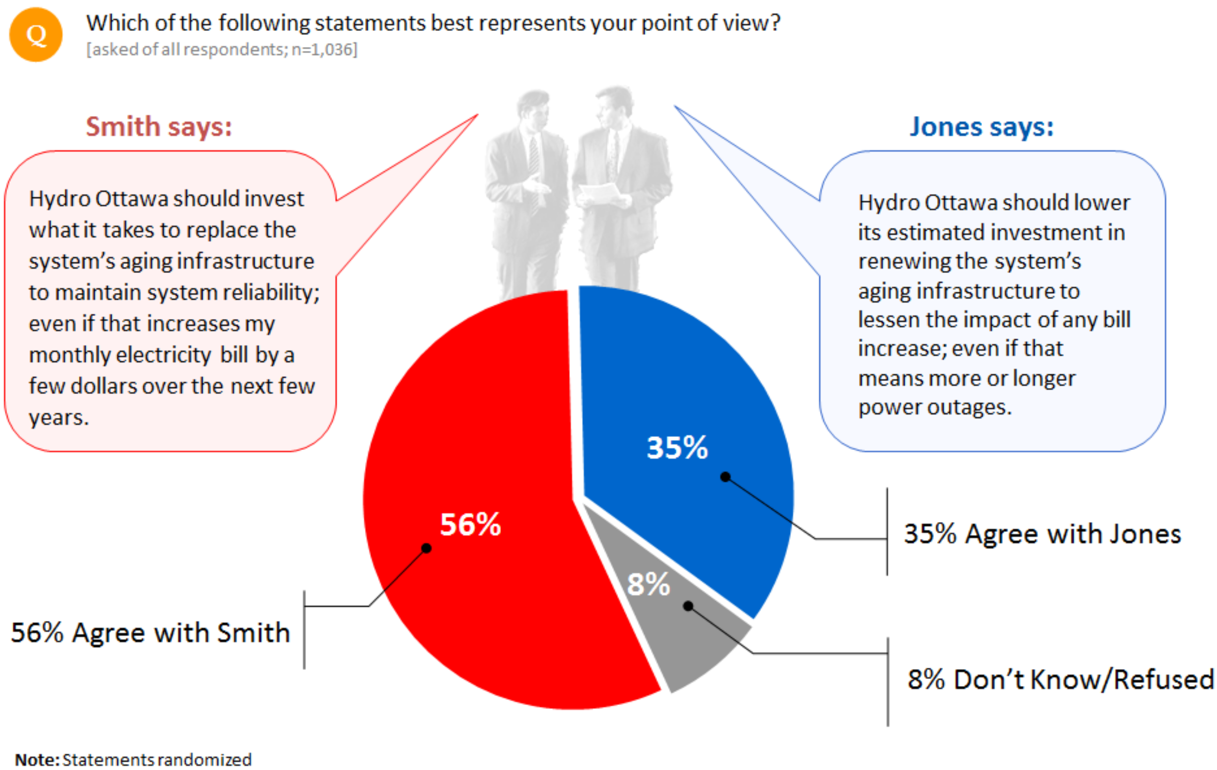
*As part of its investment plan,* ***Hydro Ottawa*** *is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is* ***$181 million*** *over the next 5 years.*

*Although this plan will allow* ***Hydro Ottawa*** *to make the necessary investments to maintain system reliability,* ***it will have an impact on customer bills****.*

A majority (56%) of residential customers feel Hydro Ottawa should invest what it takes to replace the system's aging infrastructure to maintain system reliability. More than a third (35%) say Hydro Ottawa should lower its investment in system renewal in order to lessen the impact of a bill increase; even if it means more or longer power outages.

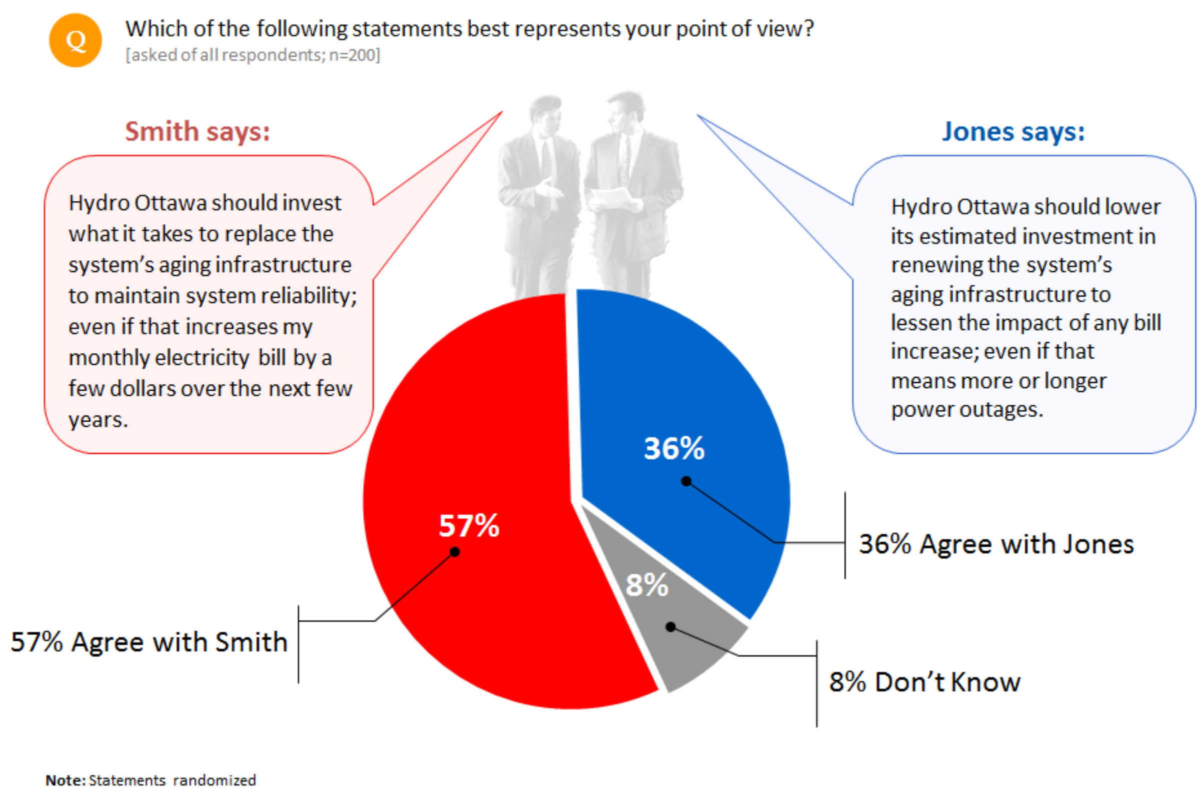
- In households that are not under financial strain due to their electricity bill, 70% think Hydro Ottawa should invest what it takes to replace the system's aging infrastructure. Almost half (45%) of those who are under some financial strain feel the same way.

### Figure RS.10: System Renewal Preferences



Similar to residential customers, a majority (57%) of general service customers feel Hydro Ottawa should invest what it takes to replace the system's aging infrastructure, while 36% would rather they lower the estimated investment in renewing the system's aging infrastructure to lessen the impact of any bill increase.

**Figure GS.10: System Renewal Preferences**



## System Service

***System Service Preamble*** *(read to both Residential and General Service customers):*

*New technology and electricity infrastructure can have many impacts on distribution systems:*

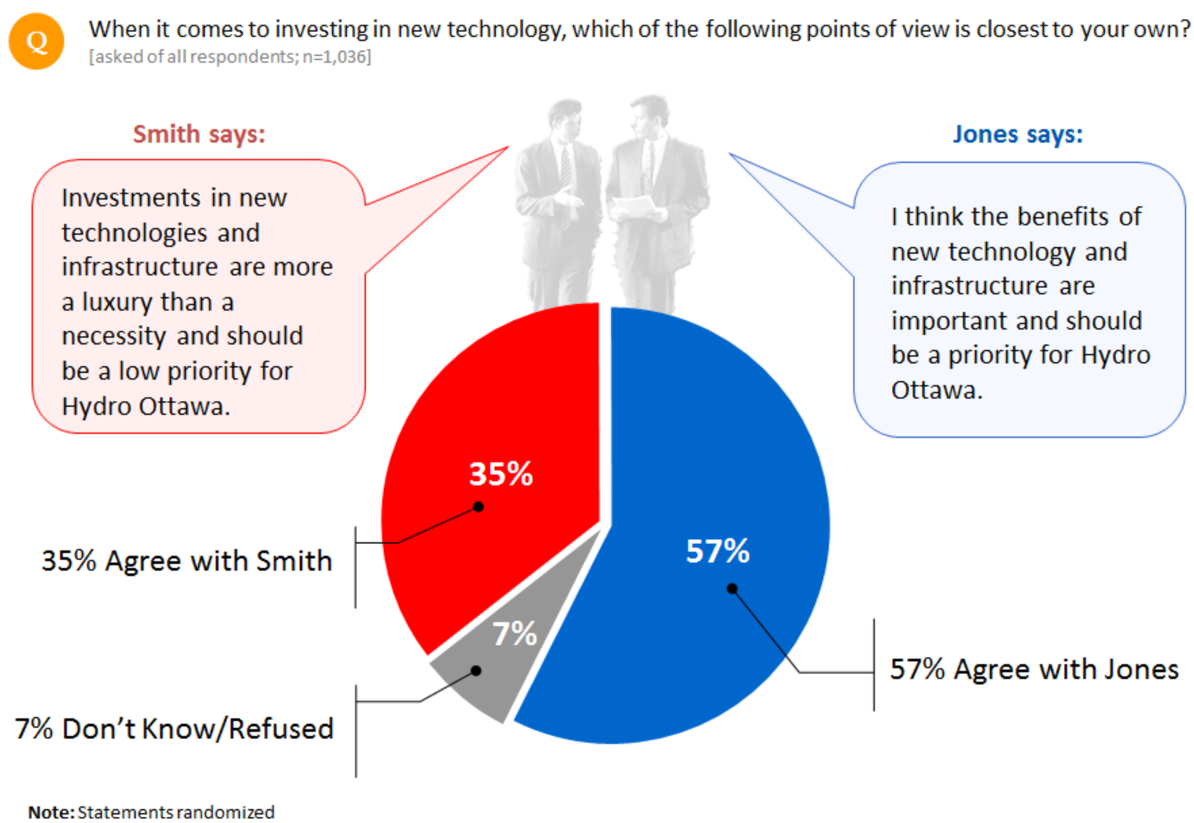
- *New substations to ensure growing communities have the electricity capacity they need.*
- *New computer systems, sensors and monitoring equipment provide pinpointed information about outages to both system controllers and customers in real time.*
- *Remotely controlled equipment and switches allow power to be restored to many customers much more quickly than in the past.*

*While there are benefits from new technology and equipment, there are also costs.*

Most (57%) residential customers think the benefits of new technology and infrastructure are important and should be a priority for Hydro Ottawa. About one third (35%) feel these types of investments are more of a luxury than a necessity.

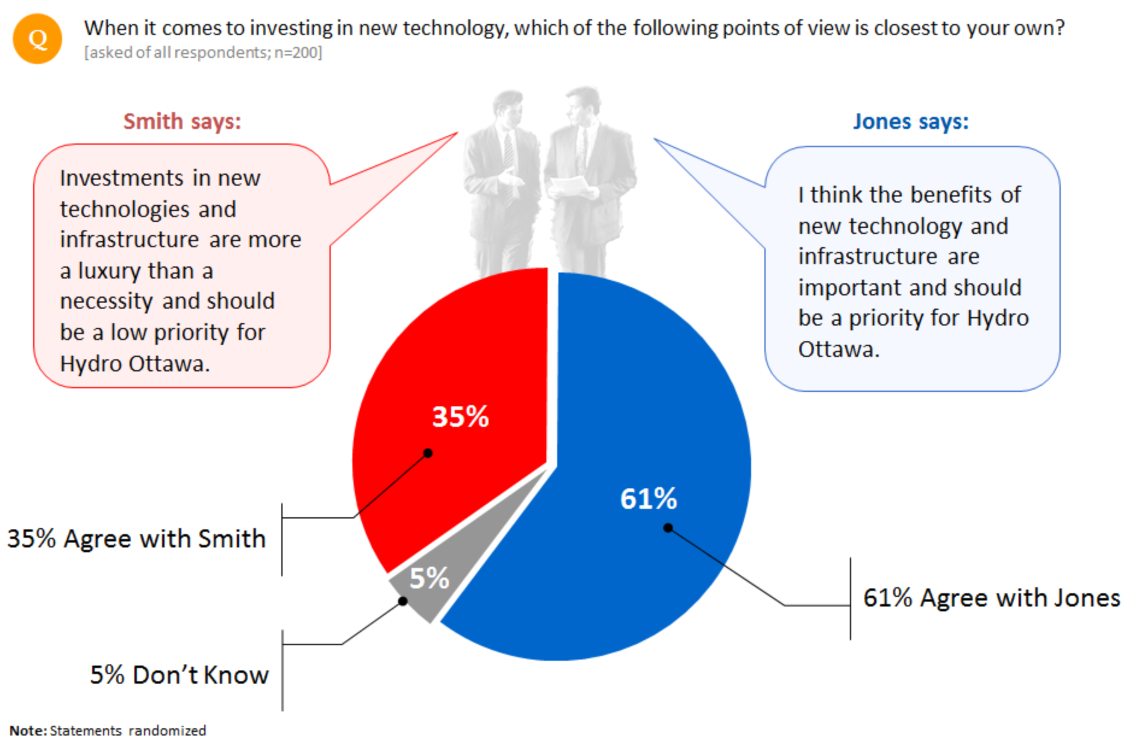
- Residential customers living in households whose electricity bill causes financial strain are more likely than others to feel that investments in new technologies and infrastructure are more of a luxury (40% versus 30%, respectively).
- At 27% respondents living in three-person households are less likely to feel such investments are a luxury than respondents living in either larger or smaller households.

**Figure RS.11: System Service Preferences**



Once again, similar to residential customers, most (61%) general service customers think the benefits of new technology and infrastructure are important and should be a priority for Hydro Ottawa, while just over a third (35%) feel these investments are more of a luxury and should be a low priority for Hydro Ottawa.

**Figure GS.11: System Service Preferences**



## General Plant

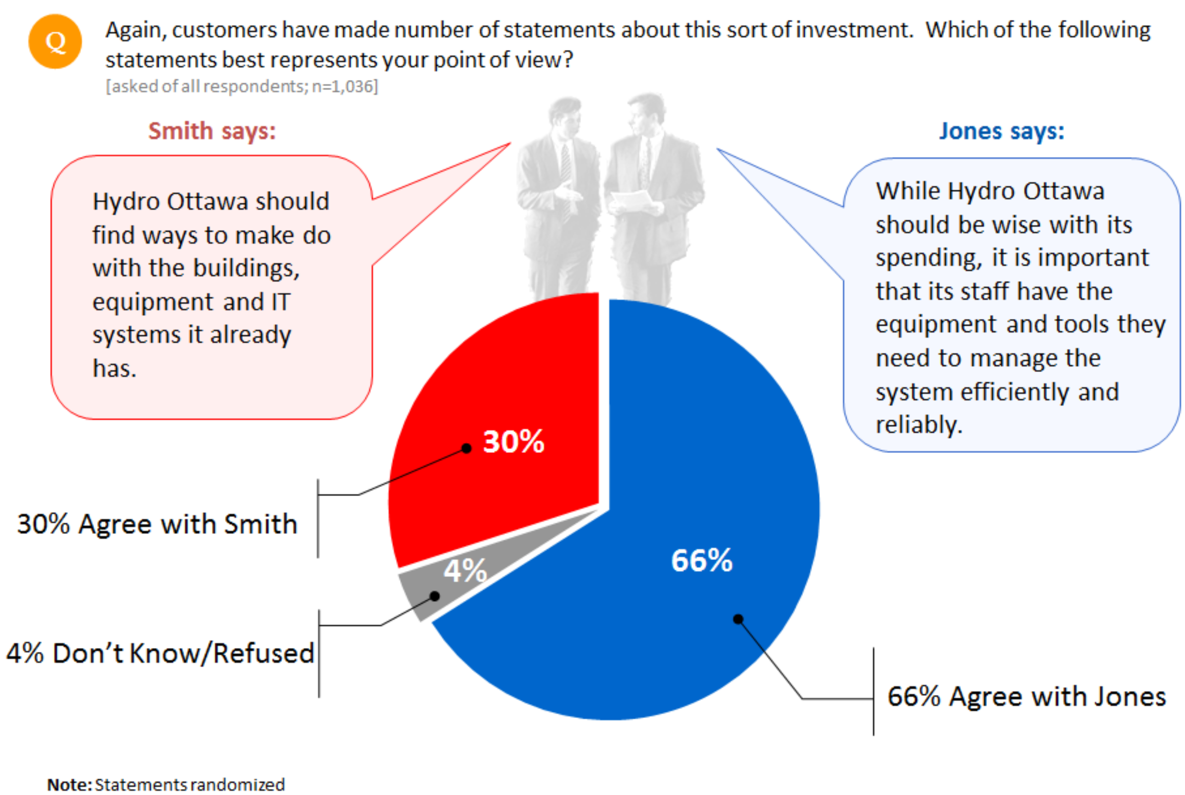
***General Plant Preamble*** *(read to both Residential and General Service customers):*

*Hydro Ottawa is not just the local electricity distribution system itself, but a company that operates the system. As a company, Hydro Ottawa needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.*

Two thirds (66%) of residential customers feel that, while Hydro Ottawa should be wise with its spending; that it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. Less than a third (30%) say Hydro Ottawa should make do with its current general plant assets.

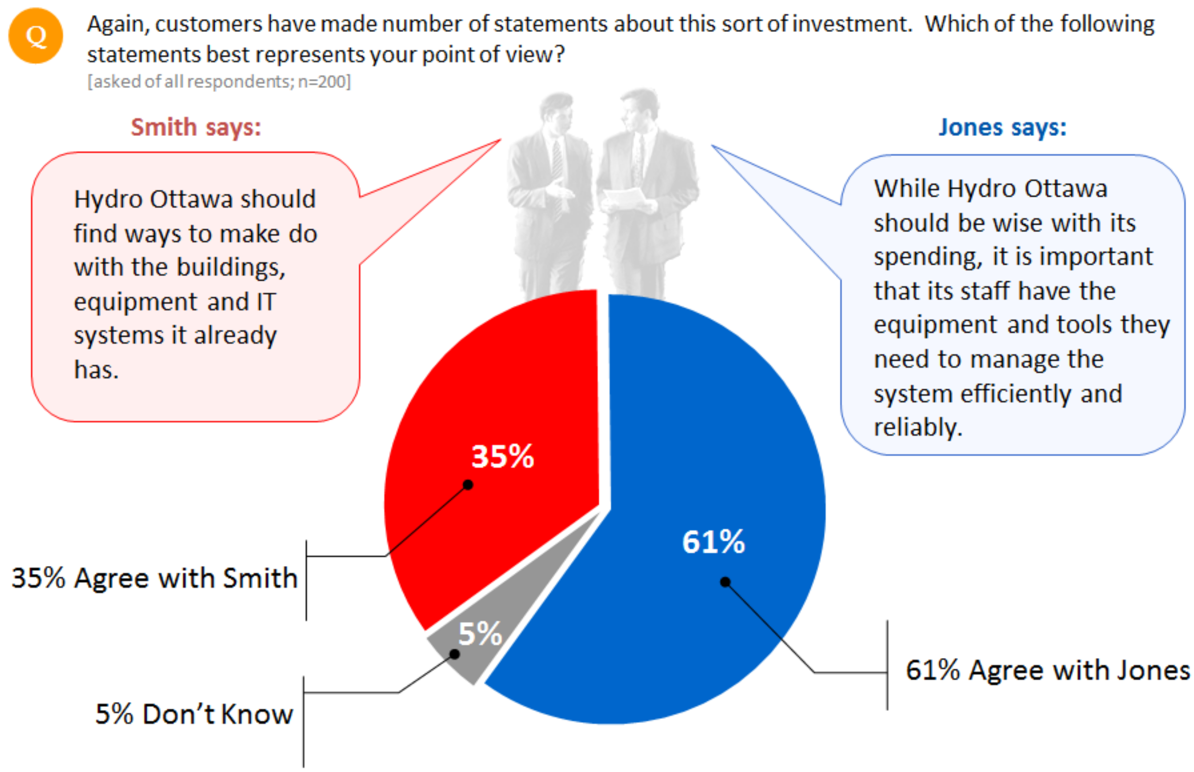
- Customers living in households that not under financial strain due to their electricity bill are most likely to say it is important for Hydro Ottawa staff to have the equipment and tools they need (71%).

**Figure RS.12: General Plant Preferences**



Among general service customers, the results are similar: 61% feel that while Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. About one third (35%) feel they should find ways to make do with the equipment they already have.

**Figure GS.12: General Plant Preferences**




**Note:** Statements randomized

## Reaction to Customer Consultation Feedback

This section measures agreement with some of the key opinion statements provided by Hydro Ottawa's customers in the previous phases of the consultation. There were a total of fourteen statements in the questionnaire, and respondents were asked to indicate their level of agreement with each one.

### Customer Reaction Statements

The statement "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" garnered the highest level of total agreement (strongly + somewhat agree) among both residential and business customers.

Among residential customers, the statement with the lowest level of agreement was "When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers".

General service customers, on the other hand, were least likely to agree that "Hydro Ottawa should have charged its customer more over the past decade to create a reserve fund that could have helped pay to replace the system's aging electrical infrastructure.

### Residential Customer Reaction

Of the fourteen statements tested, the only one that failed to get less than a majority agreement was "when it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers" (37% agreed). Aside from that statement, all others had a level of agreement of 51% or more.

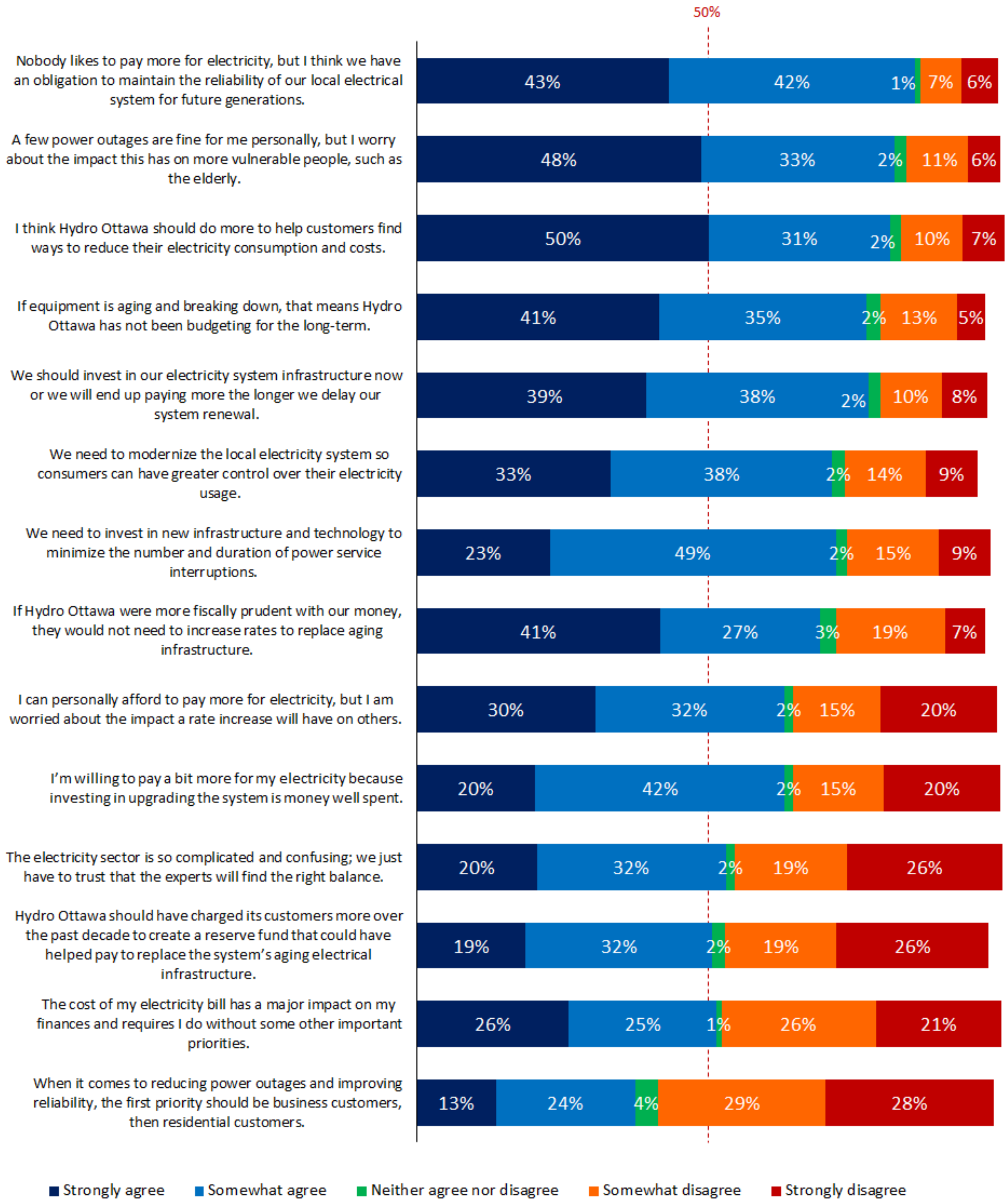
While the highest total agreement was for "nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" (85% total agreed), the highest level of *strong* agreement was in response to the statements "I think Hydro Ottawa should do more to help customers find ways to reduce their electricity consumption and costs" (50% strongly agree) and "A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly" (48% strongly agree).

Two other statements that were agreed to by at least three quarters were "We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal" (77% total agreement) and "If equipment is aging and breaking down, that means Hydro Ottawa has not been budgeting for the long-term" (76% total agreement).

The three statements that received the lowest levels of agreement are "Hydro Ottawa should have charged its customers more over the past decade to create a reserve fund that could have helped pay to replace the system's aging electrical infrastructure" (51%), "The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities" (51%) and "When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers" (37%).

## Figure RS.13: Reaction to Previous Customer Input

Q The following statements have been made by customers throughout Hydro Ottawa's community consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked of all respondents; n=1,036]




**Note:** 'Don't know' not shown

## GS Customer Reaction

More than half (57%) of general service customers *strongly* agree with the statement "I think Hydro Ottawa should do more to help customers find ways to reduce their electricity consumption and costs". However, the highest total level of agreement was for "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" (87% total agreement).

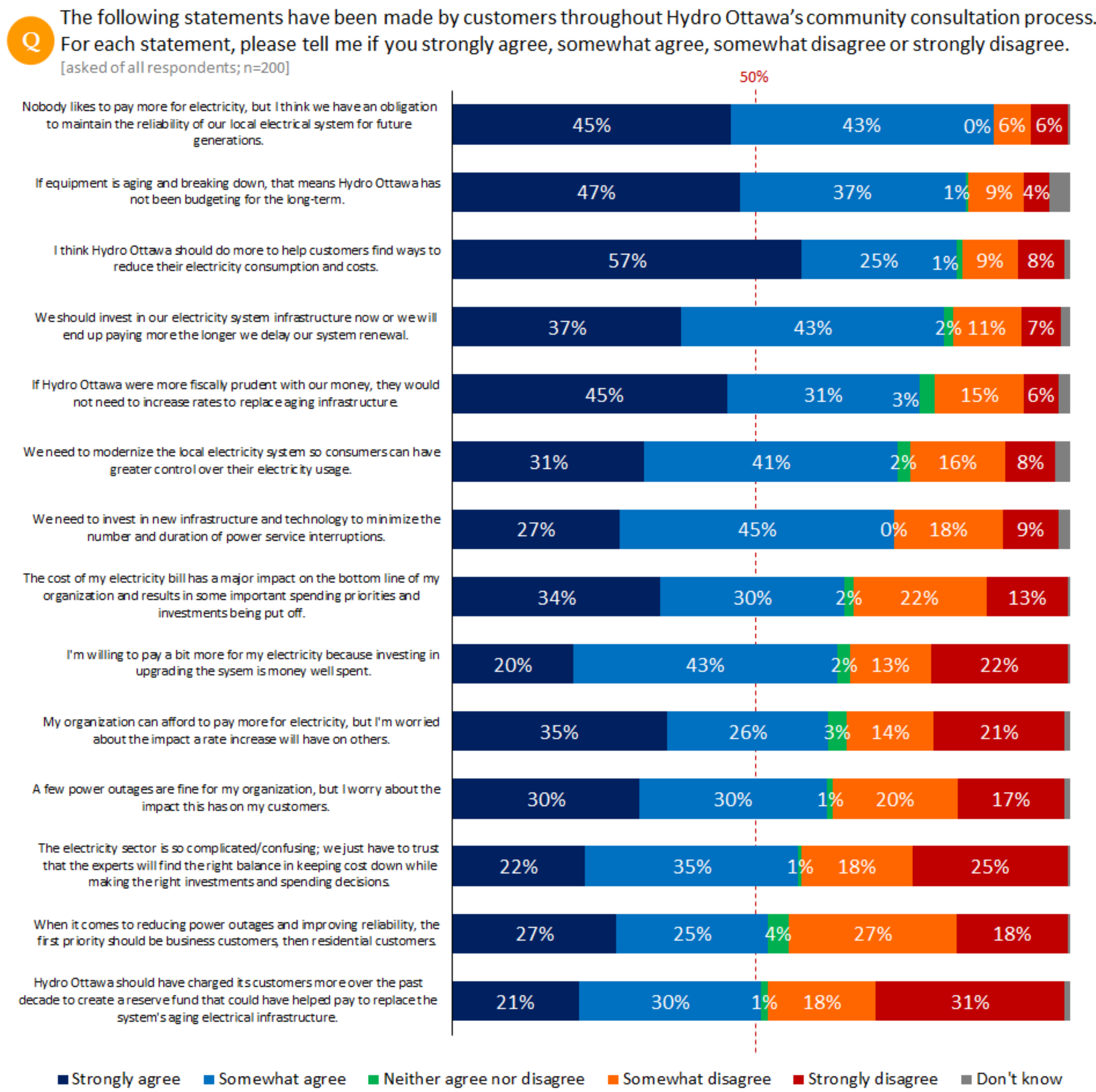
In total, five of the fourteen statements tested garnered agreement from at least three quarters of general service customers:

- "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations" (87%)
- "If equipment is aging and breaking down, that means Hydro Ottawa has not been budgeting for the long-term" (84%)
- "I think Hydro Ottawa should do more to help customers find ways to reduce their electricity consumption and costs" (82%)
- "We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal" (80%).
- "If Hydro Ottawa were more fiscally prudent with our money, they would not need to increase rates to replace aging infrastructure" (76%)

While all remaining statements were agreed to by at least 51% of respondents, the two statements receiving the lowest levels of agreement are:

- "When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers" (52%)
- "Hydro Ottawa should have charged its customers more over the past decade to create a reserve fund that could have helped pay to replace the system's aging infrastructure" (51%)

## Figure GS.13: Reaction to Previous Customer Input




**Note:** 'Don't know' not shown

## Overall Assessment of Plan

The final section of the questionnaire sets out the rate impact for residential and general service customers and then asks to what extent they are prepared to accept it. "Acceptance" for the purposes of this analysis is those who feel the increase is reasonable and support it, and those who don't like it but feel it is necessary (reluctant acceptance). Using open-ended questions, respondents are also asked why they accept or oppose the rate increase.

### Acceptance of Rate Increase Summary

A strong majority (70%) of residential customers are prepared to accept the rate increase, with 23% supporting it outright, and another 47% reluctantly accepting it as necessary. The remaining 27% find the rate increase unreasonable and they oppose it.

Among general service customers, there is also a strong degree of support (66% total acceptance), Just over one-in-five (22%) find the increase reasonable and they accept it, while twice as many (44%) don't like it, but think the rate increase is necessary. One third (32%) say the increase is unreasonable and they oppose it.

### Financial Flexibility and Level of Acceptance

The degree to which customers are willing to accept the rate increase varies according to whether or not their electricity bill places their household or business under financial strain.

Among residential customers who are under financial strain, 61% accept the rate increase (17% support it outright), compared to 80% of those who are not financially strained (30% of whom support it outright).

It is a similar story among general service customers: 54% of those under financial strain accept the increase (18% supporting it outright), while 72% of those not under financial strain accept it (30% outright).

### Reasons why customers accept or oppose Hydro Ottawa's proposed plan

- Among residential customers, "affordable/reasonable" (53%) is the most commonly cited reason for supporting the rate increase, followed by "necessary to upgrade/maintain" (31%).
- Residential customers who oppose the rate increase say they "pay too much now/rates are high enough" (16%), or they mention "financial/administrative mismanagement" (11%), or that "developers should pay increased costs" (10%).
- Looking at the general service breakdown, supporters say it is "affordable/reasonable" (43%) or "need it/necessary" (39%).
- Similar to residential customers, general service customers who oppose the rate increase say they "pay too much now/high enough" (22%), or "financial/administrative mismanagement" (10%). They also say it's "too much for small business" (10%) or that the "increase is too much" (10%).

## Social Permission

Before being asked to assess Hydro Ottawa's investment plan, customers were presented with a preamble concerning the estimated breakdown of costs for Hydro Ottawa's plan over the next 5 years and the impact this would have on customer rates. They were then asked to indicate their level of "social permission" or acceptance of the rate increase.

***Social Permission Preamble:***

*To maintain the reliability of the local electricity system, Hydro Ottawa's proposed 5 year plan will spend an estimated* ***$537 million*** *on capital investments. This includes …*

- ***$181 million*** *to replace aging infrastructure;*
- ***$150 million*** *to integrate new technologies into the power system;*
- ***$145 million*** *to invest in buildings and equipment;*
- ***$62 million*** *to serve new communities, connect customers and to power new high-rises and condo projects.*

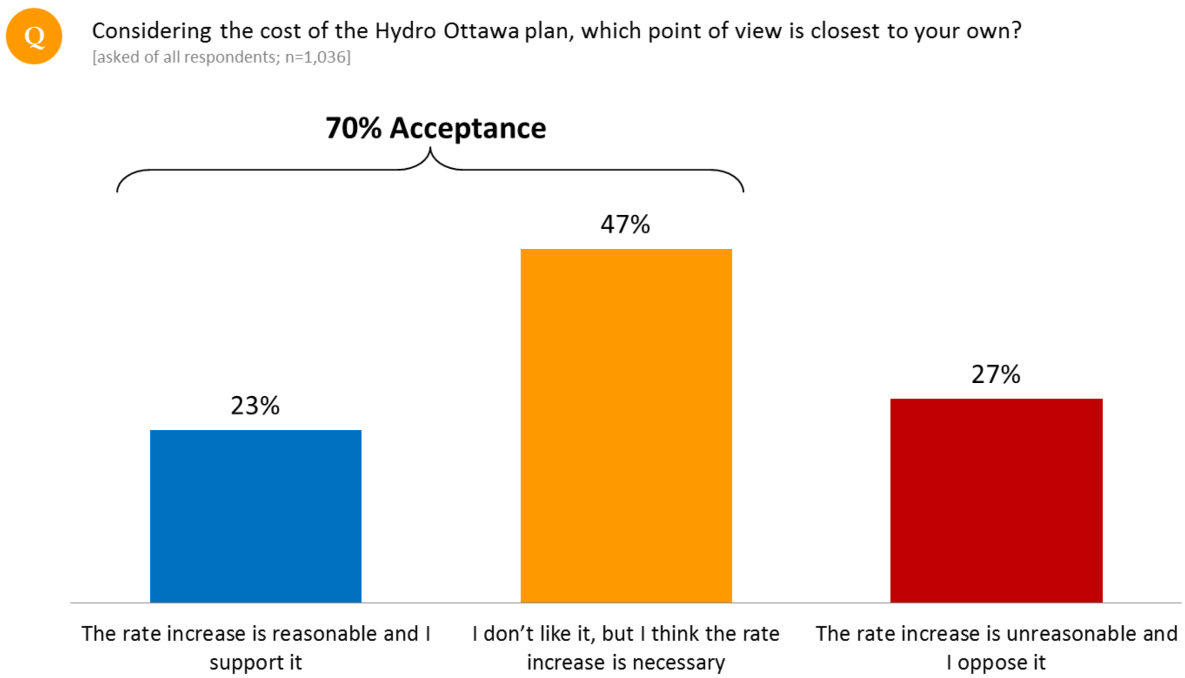
*To fund this plan, Hydro Ottawa is proposing the* ***average residential customers' rate increase by approximately $2.00 per month*** *on the distribution portion of their bill over the next five years. So, by 2020, the average residential household will be paying an* ***estimated $10.00 <u>more</u> per month*** *on the distribution portion of their electricity bill.*

*(Note: in the GS Survey, the two bolded phrases in the last paragraph were replaced with "…* ***small business' rate increase by about $4.04 per month*** *on the distribution portion of their bill over the next five years. So, by 2020, the average small business will be paying an* ***estimated $20.20 <u>more</u> per month*** *on the distribution portion of their electricity bill.***"** *respectively. The rest of the preamble remained the same for organizational customers.)*

When residential respondents were asked the social permission question, a strong majority (70%) give the proposed increase permission. Just under a quarter (23%) support the increase, while another 47% don't like it, but think it is necessary. The remaining 27% find the rate increase unreasonable and they oppose it.

- Men (26%) are more likely than women (20%) to support the rate increase. Women are must more likely to reluctantly accept the plan than men (53% versus 41%).
- Those living in financially strained household are less likely to support the rate increase than those who are not financially strained (17% versus 30%).

#### Figure RS.14 – Social Permission




**Note:** 'Don't know'/'Refused' (3%) not shown

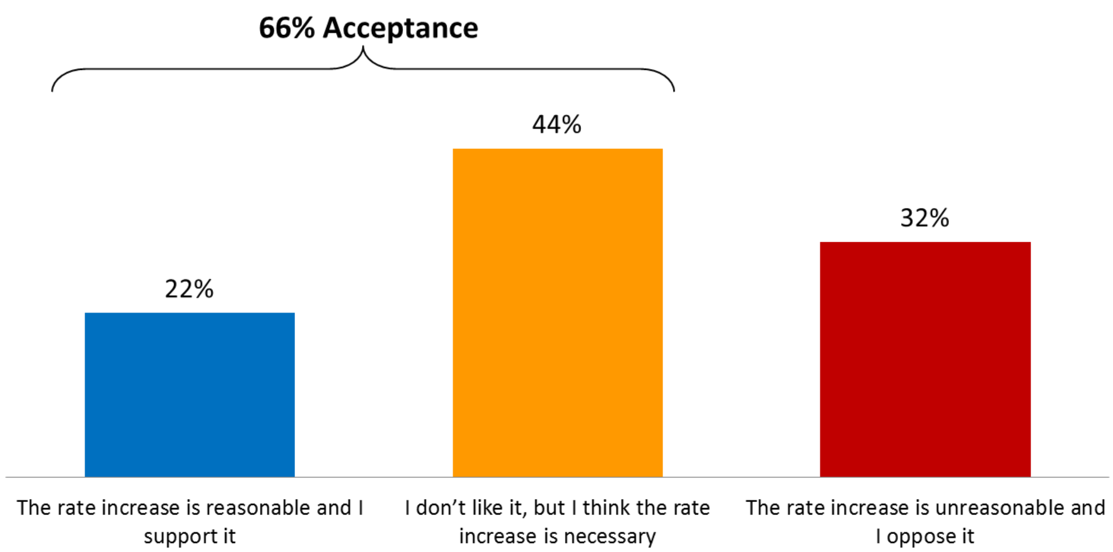
General service customers also grant social permission for the rate increase (66% overall), with 22% supporting it outright and another 44% offering reluctant acceptance.  One third (32%) find the rate increase unreasonable and oppose it.

- Overall acceptance is highest among businesses with medium-low consumption levels (72%), and businesses whose electricity bill does not cause them financial strain (72%).

**Figure GS.14 – Social Permission**

Q Considering the cost of the Hydro Ottawa plan, and what it means for your business, which point of view is closest to your own?

[asked of all respondents; n=200]




**Note:** 'Don't know'/'Refused' (3%) not shown

## Ability to Pay and Level of Acceptance

Based on their responses to an earlier question about whether or not their electricity bill has a major impact on their household/organization's finances, we are able to divide respondents into households/businesses that are financially strained and those that are not financially strained.

Among residential customers, those who are not financially strained are much more likely (80%) to grant the proposed rate increase social permission than those who are financially strained (61%). In fact, financially strained households are more than twice as likely to oppose the rate increase as those in non-financially strained households (37% versus 16%). Nonetheless, a plurality (44%) of those in financially strained households do reluctantly accept the rate increase.

**Figure RS.15 – Social Permission by Ability to Pay**

| Responses | Financially Strained | Not Financially Strained | All Residential Customers |
|---|---|---|---|
| The rate increase is reasonable and I support it | 17% | 30% | 23% |
| I don't like it, but I think the rate increase is necessary | 44% | 50% | 47% |
| The rate increase is unreasonable and I oppose it | 37% | 16% | 27% |
| Don't know | 2% | 4% | 3% |
| **Social Permission** | **61%** | **80%** | **70%** |

The pattern is similar among general service customers. Among financially strained businesses, 63% give the rate increase social permission, compared to 72% among businesses that are not financially strained by their electricity bills. Three-in-ten (30%) non-financially strained businesses give their full acceptance to the rate increase, while another 42% accept it reluctantly. One-in-four (25%) oppose the rate increase. Among those businesses that are financially strained, 18% support the rate increase, and another 44% offer reluctant acceptance. More than one third (36%) oppose the rate increase.

**Figure GS.15 –Social Permission by Ability to Pay**

| Responses | Financially Strained | Not Financially Strained | All GS Customers |
|---|---|---|---|
| The rate increase is reasonable and I support it | 18% | 30% | 22% |
| I don't like it, but I think the rate increase is necessary | 44% | 42% | 44% |
| The rate increase is unreasonable and I oppose it | 36% | 25% | 32% |
| Don't know | 2% | 3% | 3% |
| **Social Permission** | **63%** | **72%** | **66%** |

## Opinions on Proposed Rate Increase

Among residential customers who support the rate increase outright, 53% say it is “affordable/reasonable”, and 31% say it is “necessary to upgrade/maintain” (31%).

Those who don’t like the rate increase, but feel it is necessary cite “need it/necessary to upgrade/maintain” (39%) as the primary reason for their opinion. There are a variety of other reasons given by small number of respondents, such as “financial/administrative mismanagement” (6%).

Among those who opposed the rate increase, the three most commonly cited reasons are “pay too much now/high enough” (16%), “financial/administrative mismanagement” (11%), and “developers should pay increased costs” (10%).

### Figure RS.16 – Opinion on Proposed Rate Increase

Q Why do you say that? (i.e. Hydro Ottawa’s proposed rate increase)

| PERMISSION: Reasonable, support it | % RS |
|---|---|
| Affordable/reasonable | 53% |
| Necessary to upgrade/maintain | 31% |
| Better to pay now than more later | 4% |
| Everything/cost of living increases | 3% |
| Funding has to come from somewhere | 2% |
| Developers should pay increased costs | 2% |
| Other | 6% |
| **Sample Size** | **n=232** |

| NO PERMISSION: Unreasonable, oppose it | % RS |
|---|---|
| Pay too much now/high enough | 16% |
| Financial/ administrative mismanagement | 11% |
| Developers should pay increased costs | 10% |
| Have limited/fixed income/can't afford | 8% |
| Increase will be more than stated/don't trust | 7% |
| Company should be more cost efficient | 6% |
| Use profits to upgrade | 5% |
| Increase is too much | 4% |
| Salaries/bonuses too high | 4% |
| Should have planned better | 4% |
| Because of the debt retirement | 2% |
| Rates have increased too much over years | 2% |
| Rates keep increasing | 2% |
| Other | 18% |
| Don't Know | 1% |
| **Sample Size** | **n=279** |

| PERMISSION: Don’t like, but necessary | % RS |
|---|---|
| Need it/necessary to upgrade/maintain | 39% |
| Financial/ administrative mismanagement | 6% |
| Pay too much now/high enough | 5% |
| Have limited/fixed income/can't afford | 4% |
| Should have planned better | 4% |
| Affordable/reasonable | 4% |
| No one wants to pay more | 4% |
| Developers should pay increased costs | 3% |
| Everything/cost of living increases | 3% |
| Increase will be more than stated/don't trust | 3% |
| Funding has to come from somewhere | 3% |
| Better to pay now than more later | 3% |
| Use profits to upgrade | 2% |
| Salaries/bonuses too high | 2% |
| Need breakdown/explanation of charges | 2% |
| Other | 12% |
| Don't Know | 1% |
| **Sample Size** | **n=471** |

General service customers tend to support the rate increase because it is “affordable/reasonable” (43%) or that they “need it/necessary” (39%).

Those who reluctantly accept the rate increase say they “need it/necessary” (32%) or that they “pay too much now/high enough” (17%).

Among general service customers who oppose the rate increase, the main reasons are “pay too much now/high enough” (22%), “financial/administrative mismanagement” (10%), “too much for small businesses” (10%), and “increase is too much” (10%).

**Figure GS.16 – Opinion on Proposed Rate Increase**

Q Why do you say that? (i.e. Hydro Ottawa’s proposed rate increase)

| PERMISSION: Reasonable, support it | % GS |
|---|---|
| Affordable/reasonable | 43% |
| Need it/necessary | 39% |
| Everything increasing | 7% |
| Has to come from somewhere | 5% |
| Other | 7% |
| **Sample Size** | **n=44** |

| NO PERMISSION: Unreasonable, oppose it | % GS |
|---|---|
| Pay too much now/high enough | 22% |
| Financial/ administrative mismanagement | 10% |
| Too much for small businesses | 10% |
| Increase is too much | 10% |
| Salaries/bonuses too high | 8% |
| Don't need/not necessary | 8% |
| Where did/do all the profits go | 5% |
| Should have planned better | 5% |
| Alternative energy | 3% |
| Developers should pay increased costs | 3% |
| Everyone should pay the same | 3% |
| Everything increasing | 2% |
| Because of the debt retirement | 2% |
| Other | 11% |
| **Sample Size** | **n=63** |

| PERMISSION: Don’t like, but necessary | % GS |
|---|---|
| Need it/necessary | 32% |
| Pay too much now/high enough | 17% |
| Financial/ administrative mismanagement | 9% |
| No one wants to pay more | 5% |
| Has to come from somewhere | 5% |
| Affordable/reasonable | 3% |
| $20.00 increase is a lot of money | 6% |
| Better to pay now than more later | 3% |
| Other | 17% |
| Don’t know | 1% |
| **Sample Size** | **n=87** |

# Appendix:

## Hydro Ottawa's 2016 Rate Application Review

HydroOttawa

# HAVE YOUR SAY 2016-2020 RATE APPLICATION

Hydro Ottawa distributes electricity to more than **319,500** homes and businesses in Ottawa and Casselman. As the third largest municipally-owned electrical utility in Ontario, it is an important community asset for the citizens of Ottawa.

# TABLE OF CONTENTS



# HAVE YOUR SAY

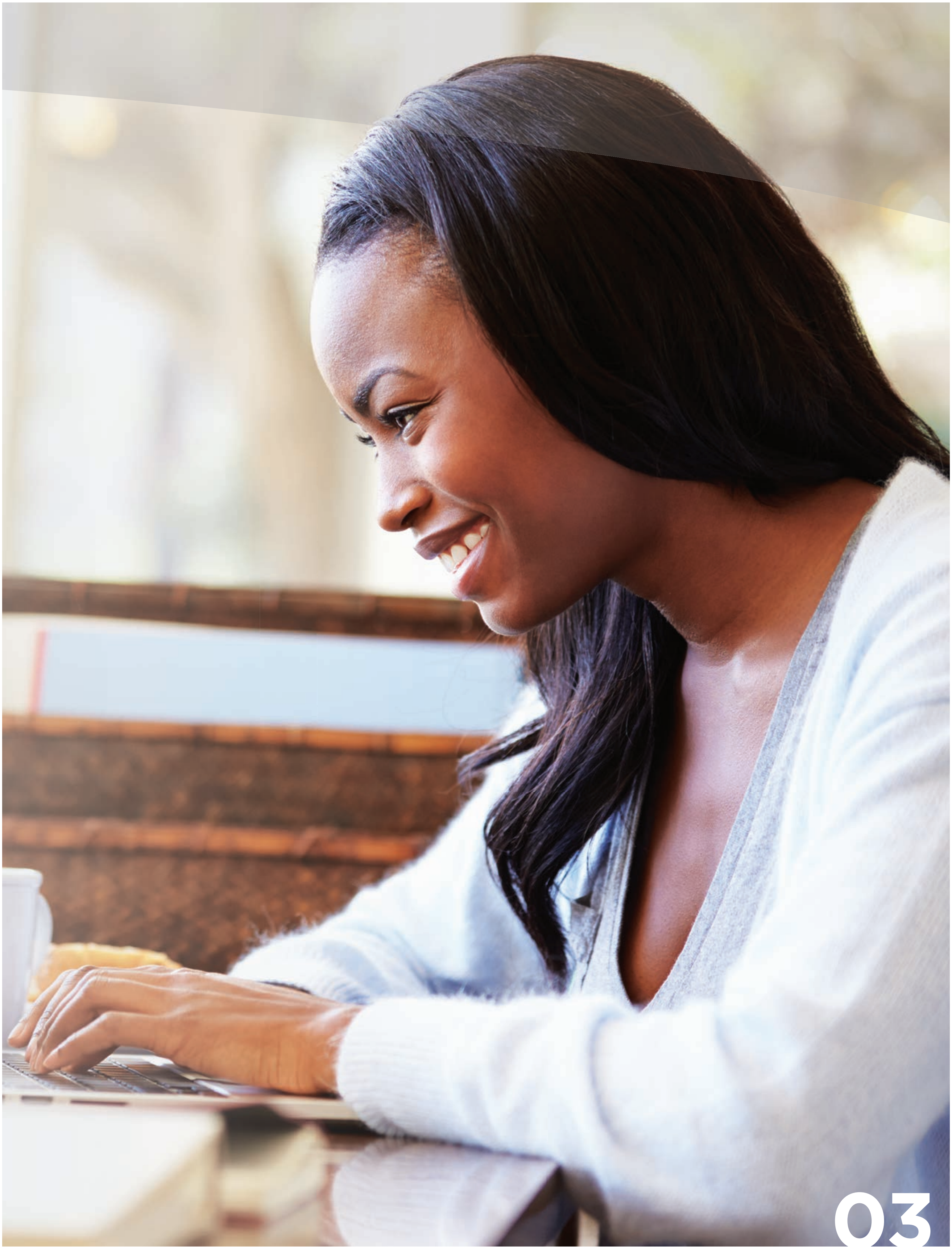
Hydro Ottawa is planning for the future, and we're looking for your feedback on our plans.

Our goal is to continue delivering the electricity local homes and businesses depend on, reliably and efficiently. With aging infrastructure and a growing city, significant investments must be made to achieve this goal.

There is a balancing act that all utilities must consider when planning for the future; system reliability versus the cost to consumers. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of Ottawa's electricity distribution system and the spending decisions Hydro Ottawa will need to make over the next five years. Ultimately, this will inform our regulator, the Ontario Energy Board, and other stakeholders in the rate setting process, and help Hydro Ottawa align its plans with customer needs and preferences.

This is your opportunity to tell Hydro Ottawa what you think about the proposed plan and the cost implications for you. **Have your say by completing this survey.**



03

# ELECTRICITY 101

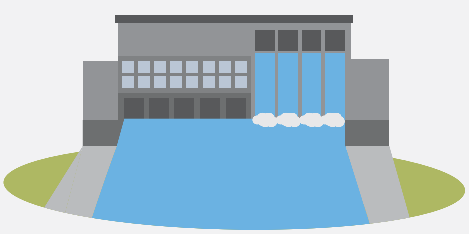
Understanding Hydro Ottawa's role in Ontario's Electricity System

There are three main components to all electricity systems: generation, transmission and distribution.

## Generation:

**Where electricity comes from**

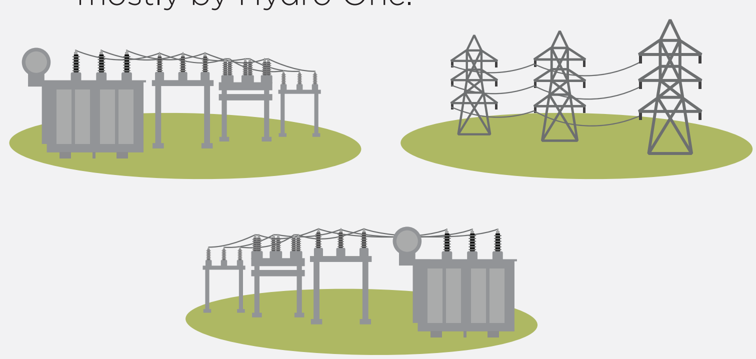
Ontario's electricity is generated by nuclear and natural gas, as well as hydroelectric and other renewable technologies. In Ontario, 70% of electricity is generated by Ontario Power Generation, which has generation stations across the province.

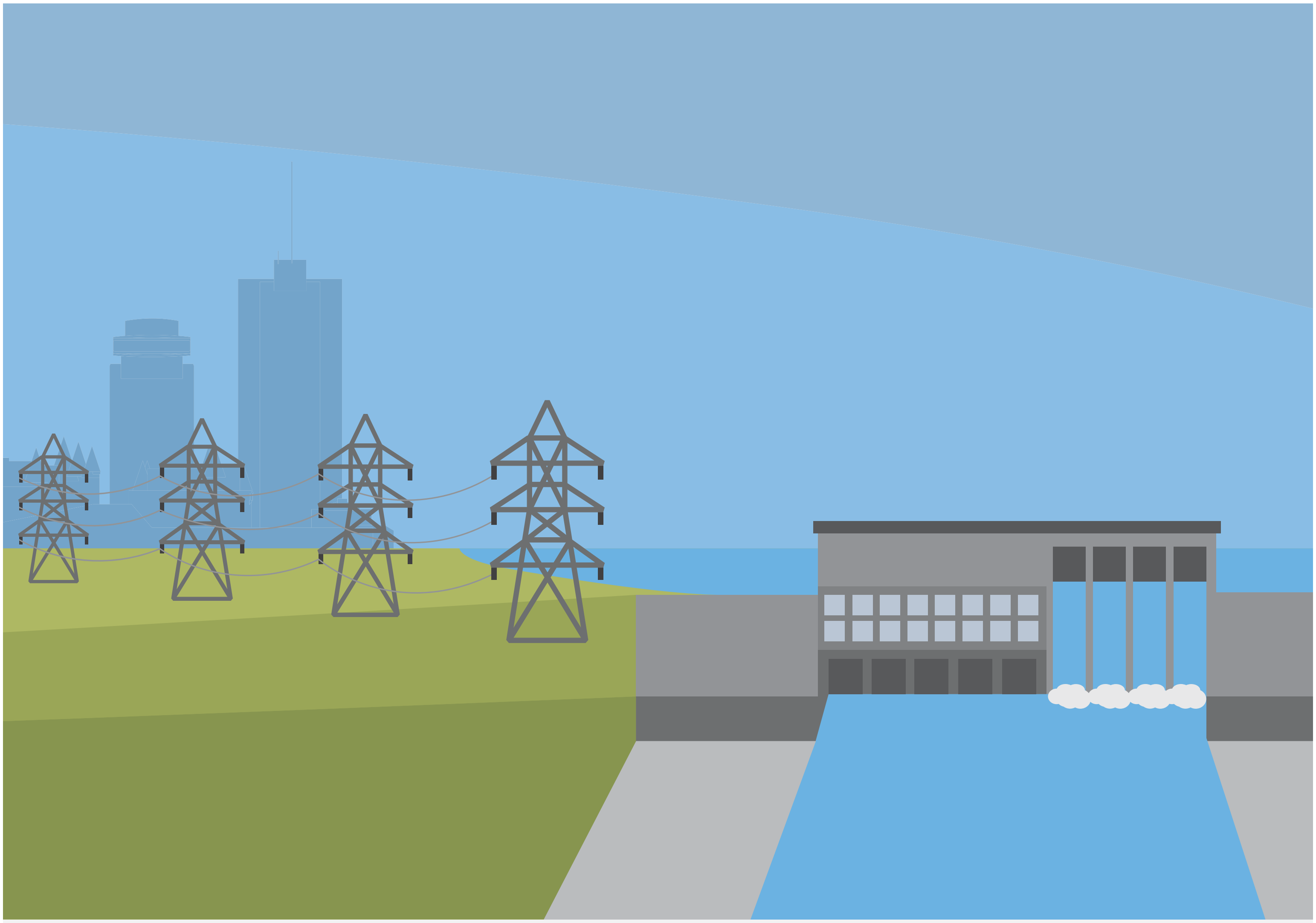


## Transmission:

**Electricity travels across Ontario**

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, owned mostly by Hydro One.





# Distribution:

## Delivering power to homes and businesses

Hydro Ottawa is responsible for the last step of the journey: distributing electricity to customers in the region through its distribution network. This local grid includes transformer stations of various sizes and designs that decrease the voltage of the electricity so it can be used in your home. There are 59,450 poles, 2,703 km of overhead power lines and 2,781 km of underground cable. Through this distribution network, Hydro Ottawa delivers electricity to more than 319,500 homes and businesses.

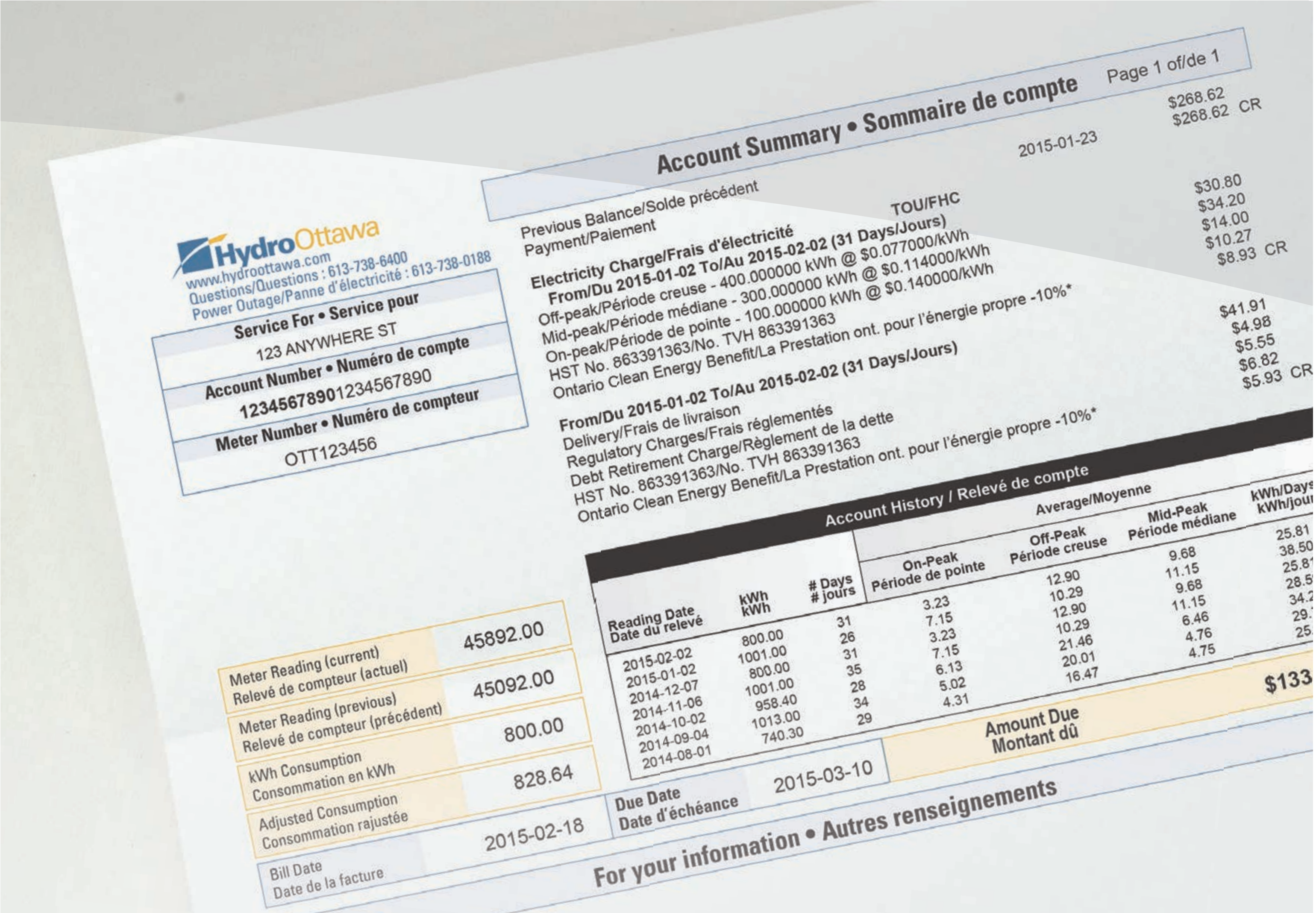
# > ABOUT YOUR BILL

About 20% of your bill goes to Hydro Ottawa. The total cost of Hydro Ottawa's operations and services represents about one fifth of your bill. It is only this portion that is the subject of this consultation and the topic on which we are seeking your feedback.

Hydro Ottawa bills customers and collects payments, but only keeps about 20 percent of what the customer pays. The other 80 percent is passed on, without mark-up, to the other companies responsible for generating electricity, transmitting it, and to regulators and the provincial government.

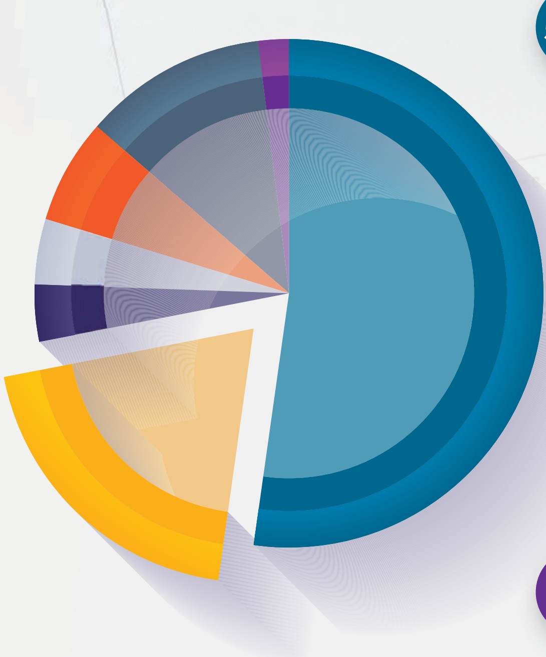
The revenues from the portion of your payment retained by Hydro Ottawa are used for capital investments and operating expenses, including operating and maintaining the electricity distribution network, and providing customer services.

Hydro Ottawa continues to make long-term investments to cover future growth by expanding electricity service into new developments, upgrading older equipment, maintaining poles, transformers, overhead wires, underground cables and the infrastructure needed to operate the electricity network in our service area.




| Reading Date / Date du relevé | kWh / kWh | # Days / # jours | On-Peak / Période de pointe | Off-Peak / Période creuse | Mid-Peak / Période médiane | kWh/Days / kWh/jour |
|---|---|---|---|---|---|---|
| 2015-02-02 | 800.00 | 31 | 3.23 | 12.90 | 9.68 | 25.81 |
| 2015-01-02 | 1001.00 | 26 | 7.15 | 10.29 | 11.15 | 38.50 |
| 2014-12-07 | 800.00 | 31 | 3.23 | 12.90 | 9.68 | 25.81 |
| 2014-11-06 | 1001.00 | 35 | 7.15 | 10.29 | 11.15 | 28.5 |
| 2014-10-02 | 958.40 | 28 | 6.13 | 21.46 | 6.46 | 34.2 |
| 2014-09-04 | 1013.00 | 34 | 5.02 | 20.01 | 4.76 | 29. |
| 2014-08-01 | 740.30 | 29 | 4.31 | 16.47 | 4.75 | 25. |

## Components of the Electricity Bill[1]



- 52.4% Electricity Generation
- 19.6% Hydro Ottawa Charges
- 3.8% Debt Retirement Charge
- 4% Regulatory Charges
- 6.8% Hydro One Transmission
- 11.5% HST
- 1.9% Adjusted Consumption

1 Residential customer consuming 800 kilowatt-hours per month.


# > HOW ARE ELECTRICITY RATES DETERMINED?

Hydro Ottawa's distribution rates must be approved by the Ontario Energy Board based on applications by the utility. The rate setting process is open and transparent, with opportunities for public participation. Hydro Ottawa must submit evidence to demonstrate the amount of funding it needs to safely and reliably distribute electricity to its customers.

# FEEDBACK

**1** Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Hydro Ottawa is responsible for?

- ❑ Very well
- ❑ Somewhat well
- ❑ Not very well
- ❑ I don't understand at all

**2** Generally, how satisfied are you with the service you receive from Hydro Ottawa?

- ❑ Very satisfied
- ❑ Somewhat satisfied
- ❑ Not very satisfied
- ❑ Not at all satisfied
- ❑ Don't know

**3** Is there anything in particular that Hydro Ottawa can do to improve its service to you?

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# HYDRO OTTAWA'S DISTRIBUTION NETWORK TODAY

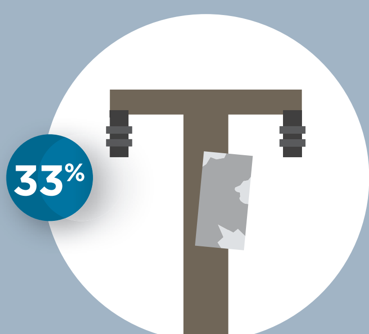
Hydro Ottawa's electricity distribution network delivers electricity to more than 319,500 customers. Its service territory of 1,104 square kilometres includes a mix of urban, suburban and rural customers.

As the City of Ottawa's population continues to grow, additional pressure is put on the local distribution system. The network is expanding to accommodate new suburban subdivisions, downtown redevelopment projects and Ottawa's Light Rail Transit.

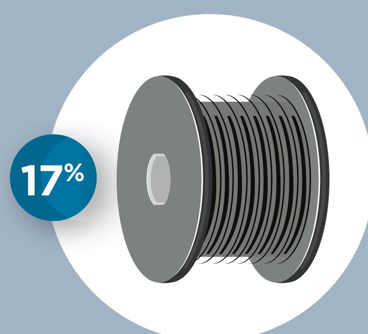
At the same time, Hydro Ottawa's assets are aging. Large segments of the network were constructed in the 1960s, 70s and 80s. As most electrical infrastructure has a lifespan of around 50 years, a considerable number of components are approaching or have exceeded their anticipated end-of-life. While continued maintenance has prolonged the life of these assets, infrastructure investments are now needed.

Hydro Ottawa's plan includes increasing investments in this infrastructure. If these aging assets aren't addressed, they will have a negative impact on reliability.

## OUR INFRASTRUCTURE IS AGING




33% of pole-mounted transformers are 50+ years old




17% of distribution cables need replacing


12% of wood poles are in poor or critical condition

Hydro Ottawa's distribution system is an even mix of overhead and underground wires. While underground wires are less likely to be damaged by storms or adverse weather, they are much more expensive to build and maintain. And, if there is a power outage it often takes longer to locate and repair the problem, compared to overhead wires.

# RELIABILITY

Hydro Ottawa tracks both the average number of power outages per customer and how long those interruptions last.

While most customers experience no outages from year to year, we measure reliability in terms of an average across the entire customer population. In 2014, this figure was 1.1 outages per customer with an average duration of 1.7 hours.

No system delivers perfectly reliable electricity. There is a balancing act between reliability and the cost of running the system.

Together, equipment failure and adverse weather, including lightning, represent 47% of all power outages. Moving forward, it is critical that investment levels for equipment replacement increase in order to reinforce the system against future storms and to get ahead of the curve on aging equipment.

**The frequency of outages due to defective equipment has increased by 12% since 2010.**

Hydro Ottawa monitors the health of its infrastructure very closely and conducts audits of its assets. These audits help Hydro Ottawa prioritize which parts of the system get upgraded or rebuilt first.

**21% of outages are storm-related.**

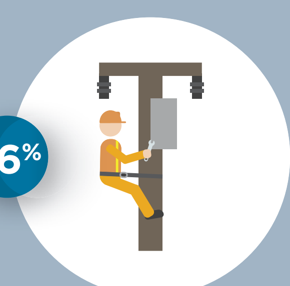
While adverse weather is beyond Hydro Ottawa's control, our ability to respond to these challenges is not.

Each year Hydro Ottawa trims more than 40,000 trees near power lines. When trees are close enough to potentially contact power lines, public safety and reliability can be compromised.

In addition to this regular maintenance, Hydro Ottawa started an extensive tree trimming project in 2014 to limit the impact of future ice or wind storms. This project focuses on branches that are overhanging power lines in 2,600 locations across the city.

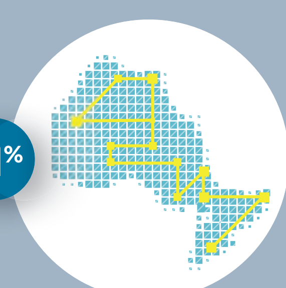
## CAUSES OF POWER OUTAGES – 2014

26%



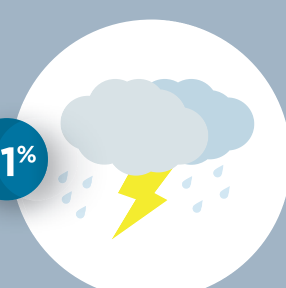
Equipment failure

21%



Loss of supply from the provincial grid

21%



Weather/lightning damage

# > FEEDBACK

**4** When averaged across the entire customer population, a Hydro Ottawa customer experiences 1.1 power outages per year. Do you recall how many outages you experienced in the past year?

- ❑ None
- ❑ One
- ❑ Two
- ❑ Three
- ❑ Four
- ❑ More than four
- ❑ Don't know

**5** Overall, how satisfied are you with the reliability of electricity services provided by Hydro Ottawa?

- ❑ Very satisfied
- ❑ Somewhat satisfied
- ❑ Somewhat dissatisfied
- ❑ Very dissatisfied
- ❑ Don't know

**6** In your view, how do you think Hydro Ottawa should address the number of customer power outages?

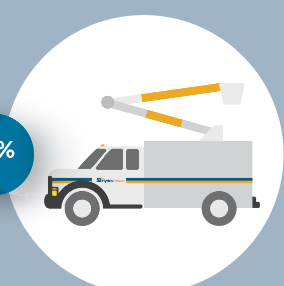
- ❑ Spend what is needed to reduce the number of power outages
- ❑ Spend what is needed to maintain the current level of outages
- ❑ Accept more power outages in order to help keep customer costs from rising
- ❑ Don't know

**7** The average Hydro Ottawa customer is without power for approximately 2 hours per year. In your view, how do you think Hydro Ottawa should address the length of time customers are without power?

- ❑ Spend what is needed to reduce the duration of power outages
- ❑ Spend what is needed to maintain the current duration of outages
- ❑ Accept longer power outages in order to help keep customer costs from rising
- ❑ Don't know

13%

Vehicle, animal or tree damage



9%

Human element

7%

Scheduled outages

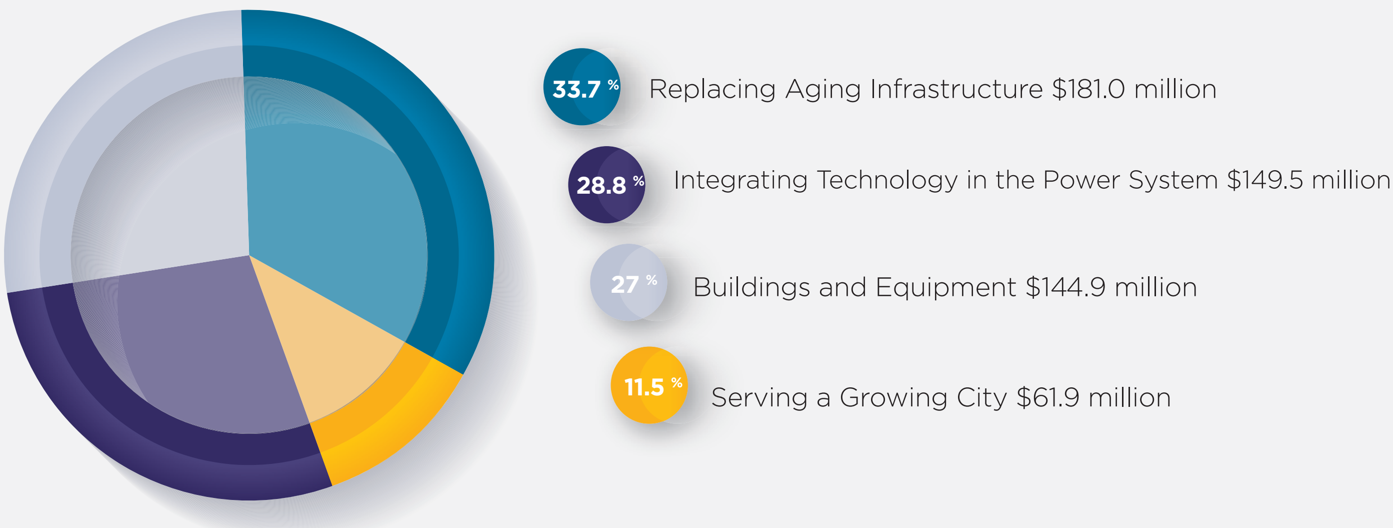
3%

Unknown/other

# CHALLENGES FACING HYDRO OTTAWA

## What are the major issues we need to address?

**2016-2020 Forecasted Capital Spending**




### Replacing Aging Infrastructure

Over the years, Hydro Ottawa has worked hard to keep equipment maintained and working well to get maximum value for money. However, Hydro Ottawa's key challenge now comes from the need to replace aging equipment.

As mentioned above, large segments of Hydro Ottawa's power system were constructed in the 1960s, 70s and 80s. As most electrical infrastructure has a lifespan of around 50 years, a considerable number of components are approaching or have exceeded their anticipated end-of-life. Hydro Ottawa's plan includes increasing investments in this infrastructure. If these aging assets aren't addressed, they will negatively impact reliability.

To assist us in prioritizing what needs to be replaced and when, Hydro Ottawa assesses each type of equipment. This allows us to make strategic investments to replace assets that are in poor or critical condition.

Our plans include replacing a significant number of wooden poles in older neighbourhoods, as well as major equipment such as transformers to ensure reliable electricity supply.

**Serving a Growing City**

Ottawa continues to grow in population, primarily in four regions: the downtown core, Nepean/Riverside South, Kanata South/Stittsville, and Orléans. The city has not seen any slowing of development as a result of the economic downturn and growth is expected to continue into the future.

This growth is being seen through the development of new mixed retail/residential communities as well as intensification of existing communities and the Light Rail Transit project. Moving forward, significant investment will be required to catch up to and maintain pace with the demand.

Hydro Ottawa is planning ahead to serve new communities, accommodate the intensification of existing neighbourhoods and to power Ottawa's Light Rail Transit project.

**Integrating Technology in the Power System**

Hydro Ottawa is planning a number of targeted investments to improve reliability. This includes adding automated switches and enhancing the communications equipment used to monitor the network. These investments help us identify the causes of power outages more quickly and/or restore power outages remotely, thereby reducing their duration.

**Buildings and Equipment**

Just like the power system, the buildings and equipment Hydro Ottawa needs to support the business are also in need of refurbishment and replacement.

It has been determined that some of Hydro Ottawa's existing administrative offices and operations and training centres are beyond their useful lives. They cannot accommodate future growth and the costs of maintenance and upgrades on these facilities continue to escalate. In addition, as the City of Ottawa has grown over the last six decades, Hydro Ottawa's main facility is now very poorly located in a residential neighbourhood. In some cases, it is more prudent to invest in building new facilities rather than investing the equivalent amount in functionally obsolete buildings.

Hydro Ottawa plans to sell three existing facilities and prudently construct a new administrative, technical and training headquarters and a new operations centre. The existing facilities are not optimally situated to respond quickly across the city, as they are located away from major transportation routes. The buildings are overcrowded, have poor energy efficiency, and will require significant expenditures to meet increased standards for accessibility.

The combined savings from reductions in costs and improvements in operational productivity will have the lowest long-term impact on electricity rates.

# FINDING EFFICIENCIES AND COST SAVINGS

Hydro Ottawa is focused on improving productivity to cut costs. Ontario Energy Board comparisons have consistently shown that Hydro Ottawa's operating, maintenance and administration costs are below the provincial average. We're focused on continuous improvement to keep rates reasonable for our customers.

The following list outlines a number of cost saving initiatives Hydro Ottawa is focusing on:

**Using Innovative Techniques**

Hydro Ottawa has started a pilot project using a new technique to extend the life of existing buried cables; which if successful would represent significant savings over the cost to excavate and replace these cables and allow monies to be redirected to replacing other aging assets.

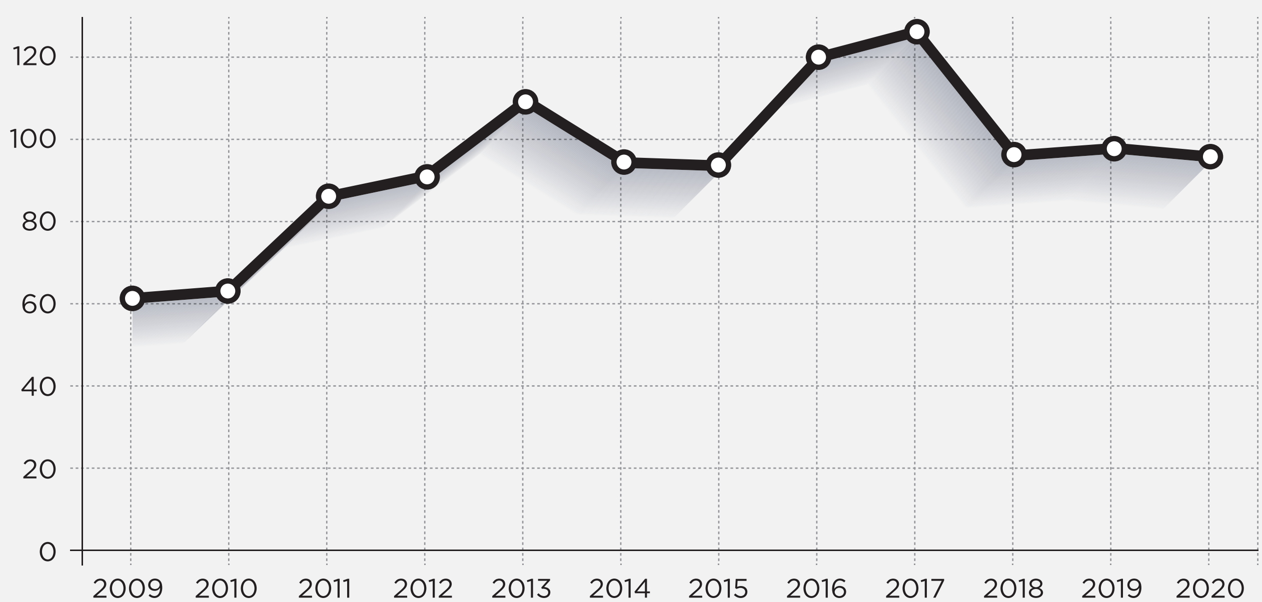
**Leveraging technology to improve reliability**

The electricity grid is becoming 'smarter' as we incorporate new technology, such as switches and sensors. Signals sent through this monitoring system identify faults, reducing the time spent trouble-shooting the cause of a power outage. Remotely-operated switches reduce the manual effort needed to restore power, and can cut the response time to power outages. Through the use of these technologies, less manual effort is required – creating efficiencies and improving reliability.

## Planning effectively

Through an ever improving inspection, testing, and project prioritization process, Hydro Ottawa has developed a plan that allows us to make smart investments in the distribution system. We're implementing new software to further improve this asset planning.

**Capital Expenditures ($ million)**



# FEEDBACK

**8** With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?

- ❑ Hydro Ottawa should invest what it forecasts is required to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
- ❑ Hydro Ottawa should lower its investment in renewing the system's aging infrastructure to lessen any bill increase, even if that means more or longer power outages.
- ❑ Don't know

**9** In order to operate efficiently and better serve our customers, Hydro Ottawa needs IT systems to manage the grid and its customer information, as well as proper facilities to house its staff, vehicles and tools. Which of the following statements best represents your point of view?

- ❑ While Hydro Ottawa should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.
- ❑ Hydro Ottawa should find ways to make do with the buildings, equipment and IT systems it already has.
- ❑ Don't know

**10** How well do you feel you understand the cost drivers that Hydro Ottawa is responding to?

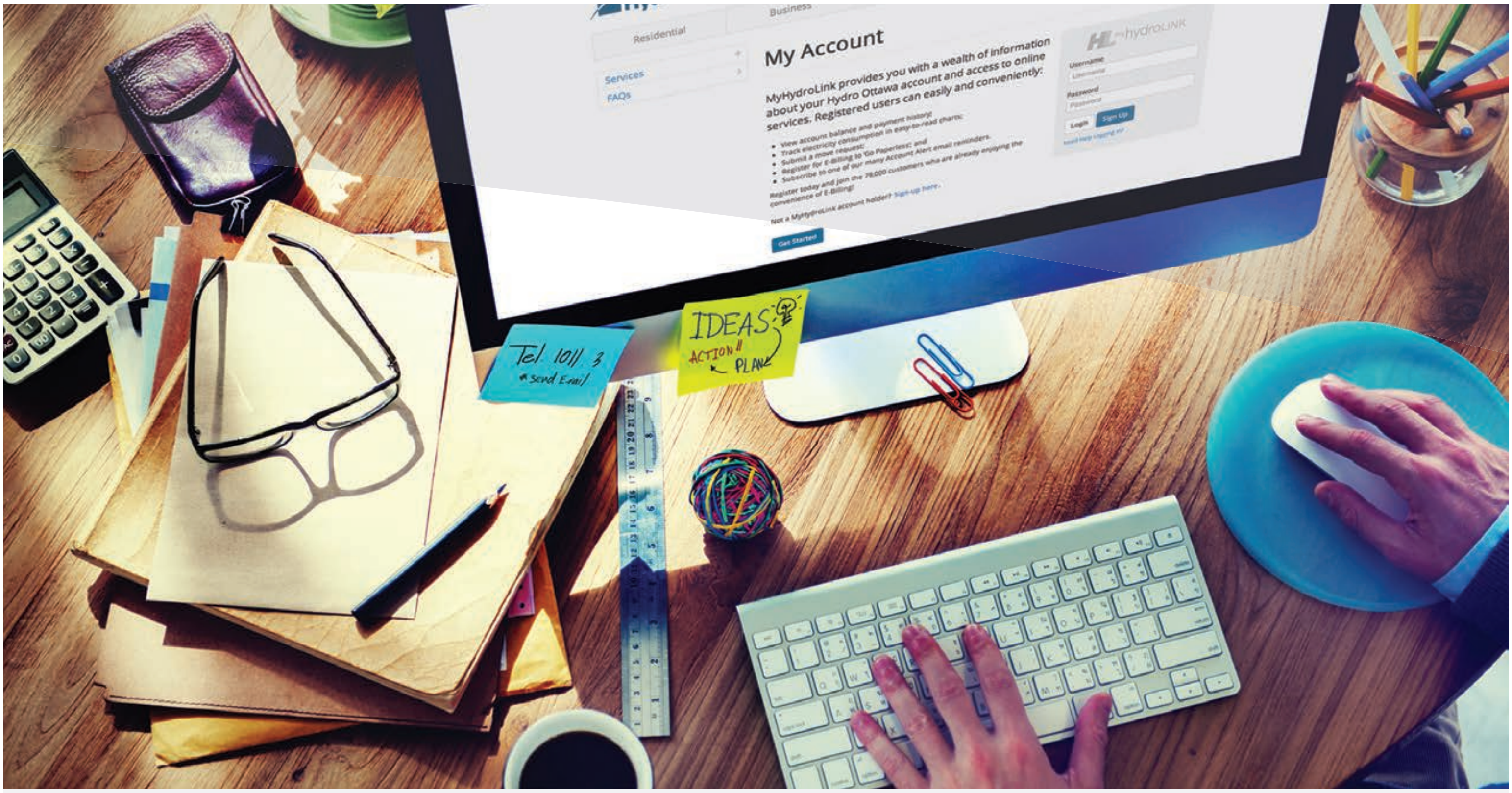
- ❑ Very well
- ❑ Somewhat well
- ❑ Not very well
- ❑ Not well at all
- ❑ Don't know

**11** How well do you think Hydro Ottawa is managing these cost drivers while meeting customer expectations?

- ❑ Very well
- ❑ Somewhat well
- ❑ Not very well
- ❑ Not well at all
- ❑ Don't know

**12** How satisfied are you with the efforts Hydro Ottawa has made to find efficiencies and cost savings?

- ❑ Very satisfied
- ❑ Somewhat satisfied
- ❑ Not very satisfied
- ❑ Not at all satisfied
- ❑ Don't know




# THE DOLLARS AND CENTS

## What does the proposed Hydro Ottawa plan mean for residential customers?

In the first year, a typical **residential**[1] customer will see an increase of $3.60 per month annually on the delivery portion of their bill. In each of the following four years, from 2017 to 2020, a typical residential customer's bill will increase by an average of $1.55 per month annually. As such, by 2020, the average residential household will be paying an estimated $9.80 more per month on the delivery portion of their electricity bill.

## What does the proposed Hydro Ottawa plan mean for commercial customers?

In the first year, a typical **commercial**[2] customer will see an increase of $7.40 per month annually on the delivery portion of their bill. In each of the following four years, from 2017 to 2020, a typical commercial customer's bill will increase by an average of $3.20 per month annually. As such, by 2020, the average commercial customer will be paying an estimated $20.20 more per month on the delivery potion of their electricity bill.

1 Residential customer consuming 800 kilowatt-hours per month.
2 General Service customer consuming 2,000 kilowatt-hours per month and having a monthly demand of less than 50 kilowatts.

# FEEDBACK

**13** From what you have read here and what you may have heard elsewhere, does Hydro Ottawa's investment plan seem like it is going in the right direction or the wrong direction?

❑ Definitely the right direction
❑ Might be the right direction
❑ Might be the wrong direction
❑ Definitely the wrong direction
❑ Don't know

**14** How well did Hydro Ottawa's plan cover the topics you expected?

❑ Very well
❑ Somewhat well
❑ Not very well
❑ Not well at all
❑ Don't know

If 'Not very well' or 'Not well at all,' what is missing?

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**15** How well do you think Hydro Ottawa is planning for the future?

❑ Very well
❑ Somewhat well
❑ Not very well
❑ Not well at all
❑ I don't know

**16** Considering what you know about the local electricity distribution system, which of the following best represents your point of view?

❑ The rate increase is reasonable and I support it
❑ I don't like it, but I think the rate increase is necessary
❑ The rate increase is unreasonable and I oppose it
❑ Don't know

# FINAL THOUGHTS

Hydro Ottawa values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

**Overall Impression:** What did you think about the survey?

**Volume of Information:** Did Hydro Ottawa provide too much information, not enough, or just the right amount?

**Content Covered:** Was there any content missing that you would have liked to have seen included?

**Outstanding Questions:** Is there anything that you would still like answered?

**Suggestions for Future Consultations:** How would you prefer to participate in these consultations?

Hydro Ottawa

# AUDITED FINANCIAL STATEMENTS FOR 2012, 2013 and 2014

Hydro Ottawa Limited's Audited Financial Statements for 2013 (with 2012 comparatives) are attached as Attachment A-4(A). The 2014 audited financial statements will be filed as Attachment A-4(B) when available.

# *Hydro Ottawa Limited*

Financial Statements

December 31, 2013

## Table of Contents

## Report of Management

Management is responsible for the integrity of the financial data reported by Hydro Ottawa Limited ['the Company']. Fulfilling this responsibility requires the preparation and presentation of financial statements using management's best judgment and estimates in accordance with Canadian generally accepted accounting principles, applied on a basis consistent with the preceding year.

Management maintains appropriate systems of internal control and corporate-wide policies and procedures, which provide reasonable assurance that the Company's assets are safeguarded and that financial records are relevant and reliable.

The Board of Directors of the Company, with the advice of the Audit Committee of Hydro Ottawa Holding Inc., ensures that management fulfills its responsibility for financial reporting and internal control. At regular meetings, the Audit Committee, including membership of outside directors of the Board of Directors of the Company, reviews internal controls and financial reporting matters with management for Hydro Ottawa Holding Inc. and its subsidiaries. Directors of the Company who are members of the Audit Committee, as well as the Chief Executive Officer and the Chief Financial Officer, advise the Board of Directors of the Company of any matters of concern raised by the Audit Committee in reviewing the financial affairs of the Company.

On behalf of Management,

Bryce Conrad
President and Chief Executive Officer

Geoff Simpson
Chief Financial Officer

# INDEPENDENT AUDITORS' REPORT

To the Shareholder of
**Hydro Ottawa Limited**

We have audited the accompanying financial statements of **Hydro Ottawa Limited**, which comprise the balance sheet as at December 31, 2013, and the statement of income, comprehensive income and retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

## Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Hydro Ottawa Limited** as at December 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ottawa, Canada,
April 3, 2014.

Chartered Accountants
Licensed Public Accountants

## Hydro Ottawa Limited

Statement of Income, Comprehensive Income and Retained Earnings
Year ended December 31
[in thousands of Canadian dollars]

| | 2013 | 2012 |
|---|---|---|
| **Revenues [Note 21]** | | |
| Power recovery | **$ 768,079** | $ 709,935 |
| Distribution sales | **152,392** | 151,936 |
| Other revenue | **32,319** | 24,223 |
| | **952,790** | 886,094 |
| **Expenses** | | |
| Purchased power [Note 21] | **768,079** | 709,935 |
| Operating costs [Note 21] | **99,751** | 92,645 |
| Depreciation | **29,388** | 28,939 |
| Amortization | **7,711** | 6,580 |
| | **904,929** | 838,099 |
| **Income before other expenses (recoveries) and payments in lieu of corporate income taxes** | **47,861** | 47,995 |
| Financing costs [Note 17] | **15,672** | 15,626 |
| Recovery of regulatory asset write-down [Note 6] | **-** | (679) |
| | **15,672** | 14,947 |
| **Income before payments in lieu of corporate income taxes** | **32,189** | 33,048 |
| **Payments in lieu of corporate income taxes [Note 18]** | **6,750** | 6,635 |
| **Net income and comprehensive income** | **25,439** | 26,413 |
| **Retained earnings, beginning of year** | **92,074** | 80,661 |
| **Dividends declared and paid [Note 15]** | **(15,000)** | (15,000) |
| **Retained earnings, end of year** | **$ 102,513** | $ 92,074 |

*The accompanying notes are an integral part of these financial statements*

# Hydro Ottawa Limited

Balance Sheet
As at December 31
[in thousands of Canadian dollars]

| | | 2013 | | 2012 |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current assets** | | | | |
| Cash | $ | **5,038** | $ | 1,639 |
| Accounts receivable [Notes 4 and 21] | | **65,842** | | 70,223 |
| Payments in lieu of corporate income taxes receivable | | **457** | | 1,211 |
| Unbilled revenue [Note 5] | | **106,551** | | 89,935 |
| Prepaids | | **2,931** | | 2,475 |
| Regulatory assets [Note 6] | | **31** | | 1,969 |
| Future income tax assets [Note 18] | | **818** | | 628 |
| | | **181,668** | | 168,080 |
| **Non-current assets** | | | | |
| Regulatory assets [Note 6] | | **12,441** | | 7,603 |
| Property, plant and equipment [Note 7] | | **651,577** | | 595,632 |
| Intangible assets [Note 8] | | **44,733** | | 29,683 |
| Future income tax assets [Note 18] | | **19,893** | | 24,165 |
| **Total assets** | | **910,312** | | 825,163 |
| | | | | |
| **Liabilities and shareholder's equity** | | | | |
| **Current liabilities** | | | | |
| Accounts payable and accrued liabilities [Notes 9 and 21] | | **178,816** | | 149,323 |
| Regulatory liabilities [Note 6] | | **19,173** | | 22,097 |
| Regulatory liability for future income tax assets [Note 18] | | **818** | | 628 |
| | | **198,807** | | 172,048 |
| **Non-current liabilities** | | | | |
| Regulatory liabilities [Note 6] | | **12,915** | | 20,144 |
| Regulatory liability for future income tax assets [Note 18] | | **19,893** | | 24,165 |
| Employee future benefits [Note 11] | | **8,533** | | 10,246 |
| Customer deposits | | **13,085** | | 11,782 |
| Notes payable [Note 12] | | **387,185** | | 327,185 |
| Asset retirement obligations [Note 10] | | **300** | | 438 |
| | | **640,718** | | 566,008 |
| **Shareholder's equity** | | | | |
| Share capital [Note 15] | | **167,081** | | 167,081 |
| Retained earnings | | **102,513** | | 92,074 |
| | | **269,594** | | 259,155 |
| **Total liabilities and shareholder's equity** | $ | **910,312** | $ | 825,163 |

**Contingent liabilities and commitments [Notes 19 and 20]**

ON BEHALF OF THE BOARD:

Director

Director

*The accompanying notes are an integral part of these financial statements*

## Hydro Ottawa Limited

Statement of Cash Flows
Year ended December 31
[in thousands of Canadian dollars]

| | 2013 | 2012 |
|---|---|---|
| **Net inflow (outflow) of cash related to the following activities:** | | |
| **Operating** | | |
| Net income and comprehensive income | **$ 25,439** | $ 26,413 |
| Items not affecting cash | | |
| Depreciation | **29,388** | 28,939 |
| Amortization | **7,711** | 6,580 |
| Net loss on disposal of property, plant and equipment [Note 7] | **989** | 1,779 |
| Allowance for funds used during construction [Notes 7 and 8] | **(2,376)** | (1,773) |
| Employee future benefits [Note 11] | **109** | 105 |
| Changes in non-cash working capital and other operating balances | | |
| Decrease (increase) in accounts receivable | **4,381** | (7,905) |
| Increase in unbilled revenue | **(16,616)** | (2,680) |
| Decrease in payments in lieu of corporate income taxes receivable | **754** | 4,704 |
| Increase in prepaids | **(456)** | (703) |
| (Increase) decrease in regulatory assets, net of liabilities [Note 11] | **(14,949)** | 13,456 |
| Increase in accounts payable and accrued liabilities [Notes 7 and 8] | **4,529** | 4,633 |
| | **38,903** | 73,548 |
| **Investing** | | |
| Acquisition of property, plant and equipment [Note 7] | **(107,054)** | (98,549) |
| Acquisition of intangible assets [Note 8] | **(23,069)** | (10,634) |
| Proceeds from disposal of property, plant and equipment | **1,765** | 45 |
| Contributions in aid of construction [Note 7] | **21,419** | 22,191 |
| | **(106,939)** | (86,947) |
| **Financing** | | |
| Issuance of notes payable [Note 12] | **60,000** | - |
| Proceeds from cash advances from parent [Note 21] | **26,000** | 27,000 |
| Increase (decrease) in customer deposits [Note 9] | **435** | (1,375) |
| Dividends paid [Note 15] | **(15,000)** | (15,000) |
| | **71,435** | 10,625 |
| **Net change in cash** | **3,399** | (2,774) |
| **Cash, beginning of year** | **1,639** | 4,413 |
| **Cash, end of year** | **$ 5,038** | $ 1,639 |
| **Supplementary cash flow information** | | |
| Interest paid | **18,030** | 17,369 |
| Payments in lieu of corporate income taxes paid, net of refunds | **5,783** | 1,980 |

*The accompanying notes are an integral part of these financial statements*

## 1. DESCRIPTION OF BUSINESS

Hydro Ottawa Limited [the 'Company'] was incorporated on October 3, 2000 pursuant to the *Business Corporations Act (Ontario)* as mandated by the Ontario government's *Electricity Act, 1998*. The Company is a wholly owned subsidiary of Hydro Ottawa Holding Inc., which in turn is wholly owned by the City of Ottawa.

The Company is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Village of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, the Company invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services and for debt retirement.

## 2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ['pre-changeover Canadian GAAP'], including principles prescribed by the Ontario Energy Board ['OEB'] in the Accounting Procedures Handbook ['AP Handbook']. In the opinion of management, all adjustments necessary for fair presentation are reflected in the financial statements. The financial statements reflect the significant accounting policies summarized below.

### (a) Regulation

The Company is regulated by the OEB under the authority of the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfil obligations to connect and service customers.

The Company operates under an incentive regulation mechanism ['IRM'] prescribed by the OEB. Under IRM a distributor first sets base rates through a cost-of-service application every four years. This application determines the appropriate revenue requirement to recover approved costs, and provide a rate of return on a deemed capital structure applied to approved rate base assets. For subsequent years in which no cost-of-service application is filed, rates are adjusted by an inflation factor less a productivity factor.

The Company applies for distribution rates based on estimated costs of service. Once the rate is approved, it is not adjusted as a result of actual costs of service being different from those which were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates. The OEB has the general power to include or exclude costs and revenue in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company.

The Company continues to assess the likelihood of recovery of all regulatory assets subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, the Company will recognize the provision in operating costs for the period.

The following regulatory treatments have resulted in accounting treatments that differ from pre-changeover Canadian GAAP for enterprises operating in a non-regulated environment:

#### (i) Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers for electricity services and the costs that the Company incurs to purchase these services.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (a) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

The Company accrues interest on the regulatory asset and liability balances as directed by the OEB.

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after the reporting period. All other regulatory asset and liability balances are classified as long-term on the balance sheet.

Regulatory balances are comprised principally of the following:

- Regulatory asset/liability refund account ['RARA'/'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.

- Settlement variances relate primarily to the charges the Company incurred for transmission services, the commodity, wholesale market operations and the global adjustment that were not settled with customers during the period. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time and they are reported at year end dates in accordance with rules prescribed by the OEB.

- Deferred smart meter costs represent the differences between the amounts funded through rates for smart meters and actual program costs. Program costs include operating, maintenance, depreciation and administrative expenses directly related to smart meters, a return on smart meter assets, and the net book value of conventional meters removed upon the installation of smart meters.

- Other Post Employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to post-retirement benefits relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

Other regulatory variances and deferred costs:

- The OEB allows electricity distributors to record in a deferral account the difference between low voltage charges paid to Hydro One Networks Inc. and those charged to customers.

- The OEB allows electricity distributors to record in a deferral account the net cost of providing retailer billing services and transaction request services.

- The OEB approved a deferral account for distributors to record one-time administrative incremental International Financial Reporting Standards ['IFRS'] transition costs, which were not already approved and included for recovery in distribution rates.

- In its Guidelines released June 16, 2009, the OEB created four new deferral accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid. These deferral accounts were authorized to be used to record qualifying incremental capital investments or operating, maintenance and administrative expenses.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (a) Regulation [continued]

#### (i) Regulatory assets and liabilities [continued]

- In its Guidelines released January 5, 2012, the OEB required the Company to record the difference between the actual authorized Conservation and Demand Management ['CDM'] activities and activities included in the Company's load forecast. This variance is recorded in the Lost Revenue Adjustment Mechanism variance account.

- The OEB directed distributors to record the input tax credit savings arising from the elimination of the provincial sales tax and the implementation of the harmonized sales tax on July 1, 2010 in a separate account. The OEB concluded that fifty percent of the balances should be returned to the ratepayers for the period up to the rebasing date, which for the Company was January 1, 2012.

#### (ii) Contributions in aid of construction

Contributions in aid of construction received from outside sources are used to finance additions to property, plant and equipment. According to the AP Handbook prescribed by the OEB, contributions in aid of construction are treated as a reduction to property, plant and equipment and are depreciated at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

#### (iii) Allowance for funds used during construction ['AFUDC']

An allowance for the cost of funds used during the construction period has been applied to major capital and development projects.

#### (iv) Payments in lieu of corporate income taxes ['PILs']

The Company is considered to be a Municipal Electric Utility ['MEU'] for purposes of the PILs regime contained in the *Electricity Act, 1998*, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The *Electricity Act, 1998* provides that an MEU that is exempt from tax under the *Income Tax Act (Canada)* ['ITA'] and the *Taxation Act, Ontario* ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

The Company follows the liability method for recording income taxes in accordance with pre-changeover Canadian GAAP recommendations. Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The AP Handbook provides for the recovery of PILs by the Company through annual distribution rate adjustments as approved by the OEB. The Company recognizes regulatory liabilities and assets for the amounts of future income taxes expected to be refunded to or recovered from customers in future electricity rates.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (b) Revenue recognition

The Company recognizes revenue when persuasive evidence of an arrangement exists, services have been delivered, the price has been fixed or is determinable and collection is reasonably assured.

(i) Distribution sales

The Company charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Company to recover its prudently incurred costs and earn a fair return on invested capital. Distribution sales are recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates.

(ii) Power recovery

Power recovery revenue represents the pass-through of the cost of power to the consumer as purchased by the Company and is recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system.

(iii) Unbilled revenue

Unbilled revenue represents an estimate of the electricity consumed by the customers that has not yet been billed as at December 31, 2013.

(iv) Other revenue

Other revenue related to sales of other services is recognized as services are rendered.

Conservation and demand management ['CDM'] revenue stems from the delivery of provincial government programs that promote conservation and is recognized on a cost-recovery basis.

### (c) Financial instruments

All financial instruments are initially recorded at fair value, unless fair value cannot be reliably determined. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. The subsequent measurement of each financial instrument depends on the financial instruction classification elected by the Company.

The Company classifies and measures its financial instruments as follows:

- Cash is classified as held-for-trading and is measured at fair value.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (c) Financial instruments [continued]

- Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value with the exception of related party transactions which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, Related Party Transactions. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

- Accounts payable and accrued liabilities, customer deposits and notes payable are classified as other financial liabilities and are initially measured at their fair value with the exception of related party transactions which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, Related Party Transactions. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

### (d) Property, plant and equipment

Property, plant and equipment include buildings and fixtures, land, furniture and equipment, rolling stock, electricity distribution infrastructure, and assets under construction.

Spare parts and standby equipment, which are expected to be used during more than one year, are considered to be assets under construction, and are depreciated only once they are put into service.

Property, plant and equipment are recorded at cost and include directly attributable contracted services, materials, labour, engineering costs, overheads and AFUDC. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions in aid of construction received are treated as a contra account to property, plant and equipment. The amount is depreciated by a charge to accumulated depreciation and a reduction in depreciation expense at an equivalent rate to that used for the depreciation of the related asset.

Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is increased, reliability is improved above original design standards or if operating costs are reduced by a substantial and quantifiable amount.

Depreciation is recorded on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for property, plant and equipment classes are as follows:

| | |
|---|---|
| Buildings and fixtures | 20 to 75 years |
| Furniture and equipment | 5 to 10 years |
| Rolling stock | 7 to 15 years |
| Electricity distribution infrastructure | 10 to 60 years |

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (d) Property, plant and equipment [continued]

Land and assets under construction are not subject to depreciation.

The Company reviews its property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Company will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Company's primary measure of fair value is based on discounted cash flows.

### (e) Intangible assets

Intangible assets include land rights, line connection contributions and computer software.

Computer software is recorded at cost and includes directly attributable contracted services, materials, labour, overheads and AFUDC. Land rights and line connection contributions are recorded at cost.

Intangible assets are amortized on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for intangible assets are as follows:

| | |
|---|---|
| Land rights | 50 years |
| Line connection contributions | 45 years |
| Computer software | 5 to 10 years |

Assets which are not ready for use are not subject to amortization.

The Company reviews its intangible assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Company will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Company's primary measure of fair value is based on discounted cash flows.

### (f) Asset retirement obligations

The Company recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of a liability for an asset retirement obligation is recognized in the period during which it is incurred if a reasonable estimate can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows are reflected in the liability. The liability is adjusted for an annual accretion charged to operating costs. A gain or loss may be incurred upon settlement of the liability.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (g) Employee future benefits

(i) Pension plan

The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

Although the plan is a defined benefit plan, sufficient information is not available to the Company to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the fund. As a result, the Company accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs.

(ii) Employee future benefits other than pension plan

Employee future benefits other than pensions provided by the Company include life insurance benefits, accumulated sick leave credits and a retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The accrued benefit obligation and current service costs are calculated using the projected unit credit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are deferred as permitted by the OEB. In the absence of rate regulation, the actuarial gains and losses are included in the statement of income, comprehensive income and retained earnings.

### (h) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

### (i) Leases

At the inception of a lease, or an arrangement that contains a lease, the Company evaluates whether the lease should be classified as a capital lease or an operating lease. Leases that transfer substantially all the risks and rewards incidental to ownership of the related asset are classified as capital leases. All other leases are classified as operating leases. Classification is reassessed if the terms of the lease are changed.

All of the Company's leases are classified as operating leases.

[in thousands of Canadian dollars]

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (j) Measurement uncertainty

The preparation of financial statements in conformity with pre-changeover Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Accounts receivable and unbilled revenue are reported net of an appropriate allowance for unrecoverable amounts. Other significant estimates are used in determining the useful lives and asset impairments of long-lived assets, payments in lieu of corporate income taxes, employee future benefits and certain accruals.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB or the provincial government. The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies.

## 3. CHANGES IN ACCOUNTING POLICIES

### Future - International Financial Reporting Standards

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to International Financial Reporting Standards ['IFRS'] effective January 1, 2011. While the Company is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board [‘IASB’]. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 - Regulatory Deferred Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted. The Company will adopt IFRS and early adopt IFRS 14 on January 1, 2015.

## 4. ACCOUNTS RECEIVABLE

| | | **2013** | | 2012 |
|---|---|---|---|---|
| Electricity receivables, net of allowance for doubtful accounts of $1,919 [2012 – $1,411] | **$** | **52,126** | $ | 52,449 |
| Other receivables, net of allowance for doubtful accounts of $66 [2012 – $139] | | **9,757** | | 14,210 |
| Amounts due from related parties [Note 21] | | **3,959** | | 3,564 |
| | **$** | **65,842** | $ | 70,223 |

[in thousands of Canadian dollars]

## 5. UNBILLED REVENUE

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Unbilled revenue | $ | **106,757** | $ | 90,003 |
| Less allowance for doubtful accounts | | **(206)** | | (68) |
| | $ | **106,551** | $ | 89,935 |

## 6. REGULATORY ASSETS AND LIABILITIES

The Company files a rate application to settle its regulatory assets and liabilities as required. The time period for settlement is determined by the OEB based on the magnitude of the balances to be cleared.

Information about the Company's regulatory assets and liabilities is as follows:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| **Regulatory assets** | | | | |
| Deferred smart meter costs | $ | **-** | $ | 1,939 |
| OPEB deferral account [Note 11] | | **3,109** | | 4,977 |
| Settlement variances | | **5,527** | | - |
| RARA | | **475** | | 253 |
| Other | | **3,361** | | 2,403 |
| | | **12,472** | | 9,572 |
| Less current portion | | **(31)** | | (1,969) |
| Total non-current regulatory assets | $ | **12,441** | $ | 7,603 |
| | | | | |
| **Regulatory liabilities** | | | | |
| Settlement variances | $ | **27,374** | $ | 39,917 |
| Deferred smart meter costs | | **1,045** | | - |
| RLRA | | **2,002** | | 678 |
| Other | | **1,667** | | 1,646 |
| | | **32,088** | | 42,241 |
| Less current portion | | **(19,173)** | | (22,097) |
| Total non-current regulatory liabilities | $ | **12,915** | $ | 20,144 |

## 6. REGULATORY ASSETS AND LIABILITIES [CONTINUED]

### (a) Regulatory asset/liability refund accounts

The RARA/RLRA is the net aggregate of all regulatory assets and liabilities which have been approved for recovery or disposition and includes accrued interest costs up to December 31, 2013 of $178 [2012 – interest cost of $107] less amounts already settled through distribution rates.

On December 5, 2013, the OEB approved the disposition of regulatory liabilities of $19,173, consisting of settlement variances and low voltage variance account accumulated up to December 31, 2012. The December 5, 2013 approved disposition will be transferred to RLRA on January 1, 2014, which is when this disposition is effective in rates.

### (b) Settlement variances

Settlement variances include accrued interest costs of $284 [2012 – $458].

### (c) Other

Other variance and deferred costs include accrued interest earned of $34 [2012 – $13].

### (d) Income before PILs

In the absence of rate regulation, the income before PILs for the year ended December 31, 2013 would be lower by $13,052 [2012 – higher by $12,305].

### (e) Recovery of regulatory asset write-down

In 2013, the Company recorded a recovery of regulatory asset write-down of nil (2012 – $679).

[in thousands of Canadian dollars]

## 7. PROPERTY, PLANT AND EQUIPMENT

| | **2013** | | |
|---|---|---|---|
| | **Cost** | **Accumulated depreciation** | **Net book value** |
| Land | **$ 24,995** | **$ -** | **$ 24,995** |
| Buildings and fixtures | **80,274** | **21,689** | **58,585** |
| Furniture and equipment | **17,970** | **11,768** | **6,202** |
| Rolling stock | **24,711** | **15,417** | **9,294** |
| Electricity distribution infrastructure | **1,131,821** | **437,739** | **694,082** |
| Assets under construction | **43,324** | **-** | **43,324** |
| | **1,323,095** | **486,613** | **836,482** |
| Contributions in aid of construction | **(233,023)** | **(48,118)** | **(184,905)** |
| | **$ 1,090,072** | **$ 438,495** | **$ 651,577** |

| | 2012 | | |
|---|---|---|---|
| | Cost | Accumulated depreciation | Net book value |
| Land | $ 5,381 | $ - | $ 5,381 |
| Buildings and fixtures | 72,336 | 19,604 | 52,732 |
| Furniture and equipment | 20,820 | 15,030 | 5,790 |
| Rolling stock | 23,665 | 15,612 | 8,053 |
| Electricity distribution infrastructure | 1,045,846 | 414,664 | 631,182 |
| Assets under construction | 61,574 | - | 61,574 |
| | 1,229,622 | 464,910 | 764,712 |
| Contributions in aid of construction | (212,751) | (43,671) | (169,080) |
| | $ 1,016,871 | $ 421,239 | $ 595,632 |

During the year, the Company capitalized an AFUDC of $1,295 [2012 – $1,478] to property, plant and equipment and credited financing costs [Note 17]. The average annual interest rate for 2013 was 4.5% [2012 – 4.8%].

During the year, the Company incurred a loss on disposal of property, plant and equipment of $989 [2012 – $1,779].

The Company entered into significant non-cash transactions that have been excluded from the statement of cash flows. These transactions were related to property, plant and equipment additions of $10,616 [2012 – $9,321], which represent amounts included in accounts payable and accrued liabilities at year end.

[in thousands of Canadian dollars]

## 8. INTANGIBLE ASSETS

| | | 2012 | | Acquisitions | | Retirements | | 2013 |
|---|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | | |
| Land rights | $ | 2,437 | $ | 2 | $ | - | $ | 2,439 |
| Line connection contributions | | 2,808 | | 354 | | - | | 3,162 |
| Computer software | | 64,065 | | 2,159 | | (5,265) | | 60,959 |
| Computer software under development | | 13,690 | | 20,246 | | - | | 33,936 |
| | $ | 83,000 | $ | 22,761 | $ | (5,265) | $ | 100,496 |

| | | 2012 | | Amortization | | Retirements | | 2013 |
|---|---|---|---|---|---|---|---|---|
| **Accumulated amortization** | | | | | | | | |
| Land rights | $ | 612 | $ | 49 | $ | - | $ | 661 |
| Line connection contributions | | 830 | | 54 | | - | | 884 |
| Computer software | | 51,875 | | 7,608 | | (5,265) | | 54,218 |
| | $ | 53,317 | $ | 7,711 | $ | (5,265) | $ | 55,763 |

| | | Cost | | Accumulated amortization | | Net book value |
|---|---|---|---|---|---|---|
| **Net book value as at December 31, 2013** | | | | | | |
| Land rights | $ | 2,439 | $ | 661 | $ | 1,778 |
| Line connection contributions | | 3,162 | | 884 | | 2,278 |
| Computer software | | 60,959 | | 54,218 | | 6,741 |
| Computer software under development | | 33,936 | | - | | 33,936 |
| | $ | 100,496 | $ | 55,763 | $ | 44,733 |

[in thousands of Canadian dollars]

## 8. INTANGIBLE ASSETS [CONTINUED]

| | 2011 | Acquisitions | Retirements | 2012 |
|---|---|---|---|---|
| Cost | | | | |
| Land rights | $ 2,427 | $ 10 | $ - | $ 2,437 |
| Line connection contributions | 2,808 | - | - | 2,808 |
| Computer software | 61,486 | 2,579 | - | 64,065 |
| Computer software under development | 3,801 | 9,889 | - | 13,690 |
| | $ 70,522 | $ 12,478 | $ - | $ 83,000 |

| | 2011 | Amortization | Retirements | 2012 |
|---|---|---|---|---|
| Accumulated amortization | | | | |
| Land rights | $ 563 | $ 49 | $ - | $ 612 |
| Line connection contributions | 777 | 53 | - | 830 |
| Computer software | 45,398 | 6,478 | - | 51,875 |
| | $ 46,738 | $ 6,580 | $ - | $ 53,317 |

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Net book value as at December 31, 2012 | | | |
| Land rights | $ 2,437 | $ 612 | $ 1,825 |
| Line connection contributions | 2,808 | 830 | 1,978 |
| Computer software | 64,065 | 51,875 | 12,190 |
| Computer software under development | 13,690 | - | 13,690 |
| | $ 83,000 | $ 53,317 | $ 29,683 |

During the year, the Company capitalized an AFUDC of $1,081 [2012 – $295] to computer software and credited financing costs [Note 17]. The average annual interest rate for 2013 was 4.5% [2012 – 4.8%].

There was no impairment of intangible assets for the years ended December 31, 2013 and 2012.

The Company entered into significant non-cash transactions that have been excluded from the statement of cash flows. These transactions were related to intangible asset additions of $729 [2012 – $2,119], which represent amounts included in accounts payable and accrued liabilities at year end.

[in thousands of Canadian dollars]

## 9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Purchased power payable | $ | **67,033** | $ | 62,813 |
| Trade payable and accrued liabilities | | **33,936** | | 33,021 |
| Customer deposits | | **14,306** | | 15,174 |
| Customer credit balances | | **7,364** | | 9,146 |
| Due to related parties [Notes 13 and 21] | | **56,177** | | 29,169 |
| | $ | **178,816** | $ | 149,323 |

## 10. ASSET RETIREMENT OBLIGATIONS

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Balance, beginning of year | $ | **438** | $ | 627 |
| Liabilities settled during the year | | **(141)** | | (203) |
| Accretion expense | | **26** | | 19 |
| Revisions in estimated cash flows | | **(23)** | | (5) |
| | $ | **300** | $ | 438 |

As at December 31, 2013, the Company estimates an asset retirement obligation ['ARO'] of $300 [2012 – $438] related to the removal and destruction of polychlorinated biphenyls ['PCBs'] in distribution transformers and other clean-up related to PCBs. The ARO is calculated using an estimated undiscounted cash flow over two years [2012 – one year] totaling $357 [2012 – $498] and a discount rate of 5.3% [2012 – 5.3%]. No assets have been legally restricted for settlement of the liability.

## 11. EMPLOYEE FUTURE BENEFITS

### (a) Pension plan

The Company's participating employer contributions under OMERS for the year ended December 31, 2013 amounted to $5,335 [2012 – $4,537].

### (b) Employee future benefits other than pension plan

Employee future benefits are calculated using an annual compensation rate increase of 3.1% [2012 – 3.1%] and a discount rate of 4.8% [2012 – 3.8%] to calculate the liabilities. The valuation also includes several other economic and demographic assumptions including mortality rates. The mortality assumption at December 31, 2013 has been updated resulting in an actuarial remeasurement of employee future benefits. The mortality assumption is now based on the most recent Canadian Pensioners Mortality information published by the Canadian Institute of Actuaries in July 2013.

[in thousands of Canadian dollars]

## 11. EMPLOYEE FUTURE BENEFITS [CONTINUED]

### (b) Employee future benefits other than pension plan [continued]

Information about the Company's defined benefit plans is as follows:

| | **2013** | | |
|---|---|---|---|
| | **Accumulated liability** | **Expense for the year** | **Benefits paid** |
| Life insurance | **$ 5,118** | **$ 481** | **$ 434** |
| Retirement grant provision | **927** | **83** | **21** |
| Sick leave | **5** | **-** | **-** |
| | **6,050** | **$ 564** | **$ 455** |
| Accrued benefit obligation | **9,159** | | |
| Deferred actuarial loss [Note 6] | **$ (3,109)** | | |

| | 2012 | | |
|---|---|---|---|
| | Accumulated liability | Expense for the year | Benefits paid |
| Life insurance | $ 5,071 | $ 568 | $ 510 |
| Retirement grant provision | 865 | 80 | 32 |
| Sick leave | 5 | - | - |
| | 5,941 | $ 648 | $ 542 |
| Accrued benefit obligation | 10,918 | | |
| Deferred actuarial loss [Note 6] | $ (4,977) | | |

An actuarial extrapolation was performed as at December 31, 2013. As a result of this exercise, the Company decreased the accrued benefit obligation by $1,759 [2012 – increased by $1,165]. Changes in the accumulated actuarial loss are non-cash transactions that have been excluded from the cash flow statement.

The current liability portion of the accrued employee future benefits included in trade accounts payables and accrued liabilities amounts to $626 [2012 – $672] and the non-current portion was $8,533 [2012 – $10,246].

[in thousands of Canadian dollars]

## 12. NOTES PAYABLE

On May 14, 2013, the Company converted all of the then outstanding due on demand promissory notes payable to Hydro Ottawa Holding Inc. totaling $282,185 [December 31, 2012 –- $282,185] and all of the then outstanding grid promissory notes payable to Hydro Ottawa Holding Inc. totaling $75,000 [December 31, 2012 –- $45,000] into new promissory note agreements which are summarized as follows:

- A $200,000 promissory note bearing interest at 5.04% per annum due February 9, 2015, unless otherwise agreed to by the two parties.
- A $50,000 promissory note bearing interest at 4.968% per annum due December 19, 2036, unless otherwise agreed to by the two parties.
- A $107,185 promissory note bearing interest at 4.144% per annum for the first five years [3.991% thereafter] due May 14, 2043, unless otherwise agreed to by the two parties.

Also on May 14, 2013, the Company established a new grid promissory note facility with Hydro Ottawa Holding Inc. of which $30,000 is outstanding at December 31, 2013 [2012 – nil]. Interest on this note is fixed and is based on the cost of long-term debt for Ontario's Regulated Utilities in accordance with OEB's cost of capital calculations, which was 4.94% for this draw.

The promissory notes and the grid promissory note facility are subordinated and postponed to the obligation of the Company to a third party for the payment in full of any secured indebtedness and any and all security interests granted to secure such obligations of the Company. Amounts outstanding on the grid promissory note are due on demand and Hydro Ottawa Holding Inc. has confirmed that it does not intend to recall any amounts on this note within one year.

| | **2013** | 2012 |
|---|---|---|
| 5.040% promissory note payable, re-issued May 14, 2013 | **$ 200,000** | $ 200,000 |
| 4.968% promissory note payable, issued May 14, 2013 | **50,000** | - |
| 4.144% promissory note payable, issued May 14, 2013 | **107,185** | - |
| 4.940% grid promissory note payable, issued December 10, 2013 | **30,000** | - |
| 5.900% promissory note payable, issued July 1, 2005 | **-** | 32,185 |
| 5.218% promissory note payable, issued December 20, 2006 | **-** | 50,000 |
| 5.750% grid promissory note payable, issued December 21, 2009 | **-** | 15,000 |
| 5.870% grid promissory note payable, issued April 30, 2010 | **-** | 15,000 |
| 5.550% grid promissory note payable, issued July 5, 2011 | **-** | 15,000 |
| | **$ 387,185** | $ 327,185 |

## 13. CREDIT FACILITY

The Company continues to maintain a $90,000 revolving demand credit facility and a $600 commercial card facility available from Hydro Ottawa Holdings Inc. As at December 31, 2013, $53,000 [December 31, 2012 – $27,000] was drawn against the revolving demand credit facility via advances of $23,000 and $30,000 maturing on January 2 and 7, 2014 respectively. The rate of interest is based on the rate applicable to Hydro Ottawa Holding Inc.'s outstanding bankers' acceptances drawn on that date [if any]. Otherwise, the rate of interest is based on the Bank of Canada's 'Bankers Acceptances 1 month' rate.

[in thousands of Canadian dollars]

## 14. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- Ensure continued access to funding to maintain and improve the operations and infrastructure of the Company;
- Ensure compliance with covenants related to the credit facilities and senior unsecured debentures entered into by its parent company, Hydro Ottawa Holding Inc.; and
- Align the Company's capital structure with the debt to equity structure recommended by the OEB.

The Company's capital consists of the following:

| | **2013** | 2012 |
|---|---|---|
| Credit facility [Note 13] | **$ 53,000** | $ 27,000 |
| Notes payable [Note 12] | **387,185** | 327,185 |
| Total debt | **440,185** | 354,185 |
| Shareholder's equity | **269,594** | 259,155 |
| Total capital | **$ 709,779** | $ 613,340 |
| Debt capitalization ratio | **62 %** | 58 % |

The Company does not have any external debt arrangements as all financing is received from its parent company, Hydro Ottawa Holding Inc., which is in compliance with all financial covenants and limitations associated with its long-term debt.

The Company is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Company's actual capital structure may differ from the OEB deemed structure.

The Company met its capital management objectives, which have not changed during the year.

[in thousands of Canadian dollars]

## 15. SHARE CAPITAL

### (a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share
Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting [10 votes per share] fourth preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares
Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holders of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

### (b) Issued

| | | **2013** | | 2012 |
|---|---|---|---|---|
| 154,789,001 Class A common shares | **$** | **167,081** | $ | 167,081 |

Any invitation to the public to subscribe for shares of the Company is prohibited by shareholder resolution.

On April 4, 2013, the Board of Directors declared a $7,500 dividend on the common shares of the Company outstanding on December 31, 2012. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on April 10, 2013 [2012 – April 3, 2012, the Board of Directors declared a $7,500 dividend which was paid on April 5, 2012].

On August 22, 2013, the Board of Directors declared a $7,500 dividend on the common shares of the Company outstanding on June 30, 2013. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on September 5, 2013 [2012 – August 23, 2012, the Board of Directors declared a $7,500 dividend which was paid on September 5, 2012].

## 16. FINANCIAL INSTRUMENTS

### (a) Carrying values

The Company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer deposits and notes payable. The only financial instrument recorded at fair value is cash and it is classified as level 1 in the pre-changeover Canadian GAAP Section 3862 fair value hierarchy. The carrying amounts approximate fair value because of the short maturity of the current portion, and the discounted long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance. The carrying values of the Company's remaining financial instruments, except for notes payable, approximate their fair values because of the short maturities of the instruments.

The Company has estimated the fair value of the notes payable as at December 31, 2013 as amounting to $399,000 [2012 – $332,000]. The fair value has been determined based on discounting all future payments of interest and the principal repayment on January 1, 2014 , at the estimated interest rate of 4% [2012 – 4%] that would be available to the Company on December 31, 2013.

### (b) Risk factors

In the normal course of business, the Company is exposed to market risk, credit risk and liquidity risk. The Company's risk exposure and strategies to mitigate these risks are noted below.

(i) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risk: interest rate risk, currency risk and other price risk such as equity risk.

The Company is exposed to interest rate risk on its borrowings. The Company mitigates exposure to interest rate risk by fixing interest rates on its notes payable with its parent company. Under Hydro Ottawa Holding Inc.'s credit facilities, any advances on its operating line would expose the Company to fluctuations in short-term interest rates related to prime rate loans and bankers' acceptances as all short-term financing requirements are obtained through its parent company, which passes on its borrowing costs. The interest rate risk is deemed to be low due to the immaterial cost of its short-term borrowings. For the most part, the borrowing requirements are for a very short duration as the advances serve to bridge gaps between the cash outflow related to the monthly power bill and the inflows related to the settlements with customers and, as such, there is very limited exposure to interest rate risk.

As at December 31, 2013, the Company has limited exposure to fluctuations in foreign currency exchange rates. The Company does purchase a small proportion of goods and services which are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

As at December 31, 2013, the Company has not entered into any hedging transactions or derivative contracts.

[in thousands of Canadian dollars]

## 16. FINANCIAL INSTRUMENTS [CONTINUED]

### (b) Risk factors [continued]

#### (ii) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss. Concentration of credit risk associated with accounts receivable and unbilled revenue is limited due to the large number of customers the Company services. The Company has approximately 315,000 customers, the majority of which are residential. As a result, the Company did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

The Company performs ongoing credit evaluations of its customers and requires collateral to support customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB legislation. Effective October 2010, the OEB instituted changes to the Distribution System Code requirements for residential security deposits. Security deposits on hand must be applied to active residential accounts in arrears prior to the customer entering into a payment arrangement, rather than as a deposit to be applied to the final bill. Further, additional amendments prohibit the Company from collecting deposits from low income residential customers. Management has concluded that residential security deposits are no longer as effective for mitigating credit risk. Effective January 1, 2011, the Company ceased collecting residential security deposits, and began refunding all residential deposits on hand. The Company continues to hold collateral to support customer accounts receivable on non-residential accounts. As at December 31, 2013, the Company held security deposits related to power recovery and distribution sales in the amount of $14,514 [2012 – $12,882].

The carrying amount of accounts receivable and unbilled revenue is reduced by an allowance for doubtful accounts based on the credit risk applicable to particular customers, and historical and other information. The Company records an allowance for doubtful accounts when the recoverability of an amount becomes doubtful. The amount of the related impairment loss is recognized in income in the period during which such assessment is made. When the receivable amount is deemed to be uncollectible, it is written off and the allowance for doubtful accounts adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of operating costs in the statement of income, comprehensive income and retained earnings. As at December 31, 2013, the allowance for doubtful accounts was $2,191 [2012 – $1,479] and there have been no significant fluctuations in the allowance during the year.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

| | **2013** | 2012 |
|---|---|---|
| Total accounts receivable | **$ 67,827** | $ 71,773 |
| Total unbilled revenue | **106,757** | 90,003 |
| Less allowance for doubtful accounts | **(2,191)** | (1,618) |
| | **$ 172,393** | $ 160,158 |
| Of which | | |
| Outstanding for less than 30 days | **60,203** | 64,410 |
| Outstanding for more than 31 days but not more than 120 days | **5,665** | 5,845 |
| Outstanding for more than 121 days | **1,959** | 1,518 |
| Unbilled revenue | **106,757** | 90,003 |
| Less allowance for doubtful accounts | **(2,191)** | (1,618) |
| | **$ 172,393** | $ 160,158 |

[in thousands of Canadian dollars]

## 16. FINANCIAL INSTRUMENTS [CONTINUED]

### (b) Risk factors [continued]

#### (ii) Credit risk [continued]

As at December 31, 2013, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties and 11% [2012 – 10%] of the Company's accounts receivable was aged more than 30 days. The Company's maximum exposure to credit risk is equal to the carrying value of accounts receivable and unbilled revenue less deposits held.

#### (iii) Liquidity risk

Liquidity risk is the risk that the Company will not meet its financial obligations as they come due. The Company's parent, Hydro Ottawa Holding Inc., manages all the financing and investing activities for the Company. The Company has access to credit facilities with Hydro Ottawa Holding Inc.. The liquidity risks associated with financial commitments relate to grid promissory notes, promissory notes or advances issued to/from its parent company, Hydro Ottawa Holding Inc., and accounts payable and accrued liabilities in the amount of $178,816 that are due within one year [2012 – $149,323].

The Company has access to a $90,000 [2012 – $90,000] credit facility with Hydro Ottawa Holding Inc. as well as a $600 commercial card facility. As at December 31, 2013, the Company has drawn $53,000 [2012 – $27,000] [Note 13]. These credit facilities are available to the Company to help meet its financial obligations as they come due.

## 17. FINANCING COSTS

| | | **2013** | | 2012 |
|---|---|---|---|---|
| Interest expense on notes payable | **$** | **18,030** | $ | 17,369 |
| Other interest expense [net of interest income] | | **18** | | 30 |
| Less AFUDC | | **(2,376)** | | (1,773) |
| | **$** | **15,672** | $ | 15,626 |

[in thousands of Canadian dollars]

## 18. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Federal and Ontario statutory income tax rate | | **26.50 %** | | 26.50% |
| Income before provision for PILS | **$** | **32,189** | $ | 33,048 |
| Provision for PILs at statutory rate | **$** | **8,530** | $ | 8,758 |
| Increase (decrease) resulting from | | | | |
| Permanent differences | | **1,088** | | 876 |
| Impact of changes to expected future tax rates on opening temporary differences | | **-** | | (857) |
| Regulatory offset to temporary differences and changes in future tax rates | | **(3,001)** | | (996) |
| Future tax benefit recognized on actuarial gains (losses) recorded in OPEB deferral account | | **495** | | (1,319) |
| Prior year adjustments | | **(58)** | | 404 |
| Tax credits | | **(162)** | | (249) |
| Other | | **(142)** | | 18 |
| | **$** | **6,750** | $ | 6,635 |
| Effective income tax rate | | **20.97 %** | | 20.08 % |

The Company as a rate-regulated enterprise is required to recognize future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Provision for PILs consists of the following:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Payments in lieu of corporate income taxes | **$** | **6,750** | $ | 6,635 |
| Future PILs corporate income tax provision | | | | |
| Future income tax provision before regulatory adjustment | | **4,083** | | 961 |
| Regulatory adjustment for the recovery of future income tax provision | | **(4,083)** | | (961) |
| | **$** | **6,750** | $ | 6,635 |

The Company's future income tax assets are presented on the balance sheet as follows:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Future income tax assets, current | **$** | **818** | $ | 628 |
| Future income tax assets, non-current | | **19,893** | | 24,165 |
| | **$** | **20,711** | $ | 24,793 |

[in thousands of Canadian dollars]

## 18. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES [CONTINUED]

Significant components of the Company's future income tax assets are as follows:

| | **2013** | 2012 |
|---|---|---|
| Property, plant and equipment and intangible assets | **$ 16,816** | $ 20,471 |
| Employee future benefits | **3,303** | 3,936 |
| Other temporary differences | **592** | 386 |
| | **$ 20,711** | $ 24,793 |

The Company's regulatory liabilities for the amounts of future income taxes expected to be refunded to customers in future electricity rates are presented on the balance sheet as follows:

| | **2013** | 2012 |
|---|---|---|
| Regulatory liability for future income tax assets, current | **$ 818** | $ 628 |
| Regulatory liability for future income tax assets, non-current | **19,893** | 24,165 |
| | **$ 20,711** | $ 24,793 |

## 19. CONTINGENT LIABILITIES

Purchasers of electricity in Ontario, including the Company, through the Independent Electricity System Operator ['IESO'], are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2013, Hydro Ottawa Holding Inc. had drawn standby letters of credit in the amount of $16,000 [2012 – $16,000] against its credit facility to cover its prudential support obligation.

The Company participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Company is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

In December 2012, Hydro Ottawa was charged with five charges under the Occupational Health and Safety Act in respect of an incident occurring on March 22, 2012, which resulted in the fatality of an employee of a third party sub-contractor. No charges have been or can be brought against directors, officers or employees arising from this incident. The maximum fine for each count is $500. The Corporation, through external counsel, is defending the charges. At this time, it is not possible to quantify the effect, if any, of these charges on these financial statements.

Various lawsuits have been filed against the Company for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Company’s insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

[in thousands of Canadian dollars]

## 20. COMMITMENTS

The Company has $43,237 in total open commitments, of which $34,835 are for 2014, $6,806 for 2015, $1,552 for 2016, $44 for 2017 and nil for 2018. This includes commitments relating to a customer information system services agreement, construction projects, spare parts and standby equipment, and overhead and underground services.

## 21. RELATED PARTY TRANSACTIONS

The Company is wholly owned by Hydro Ottawa Holding Inc., which in turn is wholly owned by the City of Ottawa. Hydro Ottawa Holding Inc. is also the sole shareholder of Energy Ottawa Inc. Chaudiere Hydro L.P. is wholly owned by Energy Ottawa Inc.

The following table provides the transactions entered into with related parties as well as outstanding balances at year end. These transactions occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties.

Trade amounts due from and to Hydro Ottawa Holding Inc. and Energy Ottawa Inc. are non-interest bearing and due on demand.

| | **2013** | | **2013** | |
|---|---|---|---|---|
| | **Transactions during the year** | | **Balances at year end** | |
| | **Sales to related parties** | **Purchases from related parties** | **Due from related parties** | **Due to related parties** |
| **City of Ottawa** | | | | |
| Sale of electricity [1] | **$ 33,852** | **$ -** | **$ -** | **$ -** |
| Other services [2] | **7,684** | **-** | **-** | **-** |
| Fuel, permits and other services [3] | **-** | **1,183** | **-** | **-** |
| Property taxes [3] | **-** | **2,053** | **-** | **-** |
| Conservation and demand management [3] | **-** | **57** | **-** | **-** |
| Accounts receivable [Note 4] | **-** | **-** | **3,899** | **-** |
| Accounts payable and accrued liabilities [Note 9] | **-** | **-** | **-** | **222** |
| | **$ 41,536** | **$ 3,293** | **$ 3,899** | **$ 222** |

[in thousands of Canadian dollars]

## 21. RELATED PARTY TRANSACTIONS [CONTINUED]

| | 2013 Transactions during the year: Sales to related parties | 2013 Transactions during the year: Purchases from related parties | 2013 Balances at year-end: Due from related parties | 2013 Balances at year-end: Due to related parties |
|---|---|---|---|---|
| **Hydro Ottawa Holding Inc.** | | | | |
| Administrative and corporate support services [2] [3] | $ 771 | $ 3,623 | $ - | $ - |
| Financing [4] | - | 105 | - | - |
| Interest [4] | - | 17,971 | - | - |
| Accounts payable and accrued liabilities [Note 9] | - | - | - | 54,893 |
| Notes payable [Note 12] | - | - | - | 387,185 |
| | $ 771 | $ 21,699 | $ - | $ 442,078 |
| **Energy Ottawa Inc.** | | | | |
| Purchase of electricity [5] | $ - | $ 2,832 | $ - | $ - |
| Conservation and demand management initiatives [3] | - | 1,211 | - | - |
| Administrative and corporate support services [2] | 1,015 | - | - | - |
| Accounts payable and accrued liabilities [Note 9] | - | - | - | 1,062 |
| | $ 1,015 | $ 4,043 | $ - | $ 1,062 |
| **Chaudiere Hydro L.P.** | | | | |
| Accounts receivable [Note 4] | $ - | $ - | $ 60 | $ - |
| Total | $ 43,322 | $ 29,035 | $ 3,959 | $ 443,362 |

[1] Included in power recovery and distribution sales revenue
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs
[4] Included in financing costs
[5] Included in purchased power

[in thousands of Canadian dollars]

## 21. RELATED PARTY TRANSACTIONS [CONTINUED]

| | 2012 Transactions during the year | | 2012 Balances at year end | |
|---|---|---|---|---|
| | Sales to related parties | Purchases from related parties | Due from related parties | Due to related parties |
| **City of Ottawa** | | | | |
| Sale of electricity [1] | $ 33,995 | $ - | $ - | $ - |
| Other services [2] | 4,017 | - | - | - |
| Fuel, permits and other services [3] | - | 730 | - | - |
| Property taxes [3] | - | 1,849 | - | - |
| Conservation and demand management initiatives [3] | - | 254 | - | - |
| Accounts receivable [Note 4] | - | - | 3,510 | - |
| Accounts payable and accrued liabilities [Note 9] | - | - | - | 46 |
| | $ 38,012 | $ 2,833 | $ 3,510 | $ 46 |
| **Hydro Ottawa Holding Inc.** | | | | |
| Administrative and corporate support services [2] [3] | $ 744 | $ 3,746 | $ - | $ - |
| Financing [4] | - | 169 | - | - |
| Interest [4] | - | 17,231 | - | - |
| Accounts payable and accrued liabilities [Note 9] | - | - | - | 28,286 |
| Notes payable [Note 12] | - | - | - | 327,185 |
| | $ 744 | $ 21,146 | $ - | $ 355,471 |
| **Energy Ottawa Inc.** | | | | |
| Purchase of electricity [5] | $ - | $ 2,383 | $ - | $ - |
| Conservation and demand management initiatives [3] | - | 864 | - | - |
| Administrative and corporate support services [2] | 533 | - | - | - |
| Accounts payable and accrued liabilities [Note 9] | - | - | - | 837 |
| | $ 533 | $ 3,247 | $ - | $ 837 |
| **Chaudiere Hydro L.P.** | | | | |
| Accounts receivable [Note 4] | $ - | $ - | $ 54 | $ - |
| Total | $ 39,289 | $ 27,226 | $ 3,564 | $ 356,354 |

[1] Included in power recovery and distribution sales
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs
[4] Included in financing costs
[5] Included in purchased power

## 22. COMPARATIVE FIGURES

In certain instances, the 2012 information presented for comparative purposes has been reclassified to conform to the financial statement presentation adopted for the current year.

# 2014 AUDITED FINANCIAL STATEMENTS

To be filed as Attachment A-4(B) when available.

# RECONCILLIATION OF 2012, 2013 and 2014 AUDITED FINANCIAL STATEMENTS

The reconciliations of Hydro Ottawa Limited's 2012 and 2013 audited Financial Statements are attached as Attachment A-4(F) and A-4(G) respectively. The 2014 reconciliation will be filed as Attachment A-4(H) when available.

# RECONCILLIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICTION

The following table reconciles Hydro Ottawa Limited's ("Hydro Ottawa") 2012 Audited Financial Statements to Information for the Historical Year (2012) that is provided in this Application:

**Table 1 – Statement of Income**

| Statement of Income | CGAAP Audited 2012 ($'000) | MIFRS Adjustment (1) ($'000) | Unregulated Business (2) (3) ($'000) | 2012 Regulated Balances (2) (3) ($'000) |
|---|---|---|---|---|
| REVENUES | | | | |
| Power recovery | $ 709,935 | $ - | $ - | $ 709,935 |
| Distribution sales | 151,936 | - | - | 151,936 |
| Other revenue | 24,223 | - | (13,180) | 11,043 |
| TOTAL REVENUES | **886,094** | **-** | **(13,180)** | **872,914** |
| EXPENSES | | | | |
| Purchased power | 709,935 | - | - | 709,935 |
| Operating costs | 92,645 | (697) | (13,000) | 78,947 |
| Amortization/Depreciation | 35,519 | 193 | (20) | 35,692 |
| OTHER | | | | |
| Financing costs | 15,626 | - | - | 15,626 |
| Recovery of regulatory asset write-down | (679) | - | - | (679) |
| PILS | 6,635 | 26 | - | 6,661 |
| TOTAL EXPENSE | **859,682** | **(479)** | **(13,020)** | **846,182** |
| **NET INCOME** | 26,412 | 479 | (159) | 26,732 |

The following table provides a reconciliation of Capital Assets as reported in the 2012 Audited Financial Statement and the information on the Historical Year (2012) that is provided in this Application

[1] Net book value for capital assets and depreciation are different between CGAAP and MIFRS due to different capitalization policies between CGAAP and MIFRS prior to January 1, 2012. Capitalization policies under both accounting standards have been aligned starting January 1, 2012.
[2] For the purposes of this rate application, and in accordance with Ontario Energy Board policies, all revenue and expenses associated with Conservation and Demand Management ("CDM") has been excluded from the costs and revenues in this rate application. In addition, revenues and expenses related to other non-utility operations, such as rental of properties not in rate base, have also been excluded.
[3] For financial statement purposes interest earned (Account 4405) is an offset to interest expense (and in other revenue for regulatory accounting) and certain short-term interest is recorded as an operating expense.
[4] Remove Non-Utility Assets
[5] Adjustment includes reclassification differences between CGAAP and MIFRS between Properties, plant and equipment, Intangible, Investment properties and deferred income

1 **Table 2 – Capital Assets**
2

| | CGAAP Audited 2012 ($'000) | MIFRS Adjustment (1) (5) ($'000) | Unregulated Business (4) ($'000) | 2012 Regulated Balances ($'000) |
|---|---|---|---|---|
| Property, plant and equipment | $ 595,632 | $ 46,801 | $ (2,414) | **$ 640,019** |
| Intangible asets | 29,683 | (921) | - | **28,762** |
| Investment properties | - | 2,184 | - | **2,184** |
| Deferred income | - | (48,940) | - | **(48,940)** |
| TOTAL | **$ 625,315** | **$ 45,880** | **$ (2,414)** | **$ 668,781** |

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# RECONCILLIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICTION

The following tables reconcile Hydro Ottawa Limited's ("Hydro Ottawa") 2013 Audited Financial Statements to Information for the Historical Year (2013) that is provided in this Application

## Table 1 – Statement of Income

| Statement of Income | CGAAP Audited 2013 ($'000) | MIFRS Adjustment (1) ($'000) | Unregulated Business (2) (3) ($'000) | 2013 Regulated Balances (2) (3) ($'000) |
|---|---|---|---|---|
| REVENUES | | | | |
| Power recovery | $ 768,079 | $ - | $ - | $ 768,079 |
| Distribution sales | 152,392 | - | - | 152,392 |
| Other revenue | 32,319 | - | (16,641) | 15,677 |
| TOTAL REVENUES | 952,790 | - | (16,641) | 936,149 |
| EXPENSES | | | | |
| Purchased power | 768,079 | - | - | 768,079 |
| Operating costs | 99,751 | 49 | (15,964) | 83,835 |
| Amortization/Depreciation | 37,098 | (181) | (22) | 36,895 |
| OTHER | | | | |
| Financing costs | 15,672 | - | - | 15,672 |
| PILS | 6,750 | (13) | - | 6,737 |
| TOTAL EXPENSE | **927,350** | **(145)** | **(15,987)** | **911,218** |
| **NET INCOME** | **25,440** | **145** | **(655)** | **24,930** |

The following table provides a reconciliation of Capital Assets as reported in the 2013 Audited Financial Statement and the information on the Historical Year (2013) that is provided in this Application.

[1] Net book value for capital assets and depreciation are different between CGAAP and MIFRS due to different capitalization policies between CGAAP and MIFRS prior to January 1, 2012. Capitalization policies under both accounting standards have been aligned starting January 1, 2012.
[2] For the purposes of this rate application, and in accordance with Ontario Energy Board policies, all revenue and expenses associated with Conservation and Demand Management ("CDM") has been excluded from the costs and revenues in this rate application. In addition, revenues and expenses related to other non-utility operations, such as rental of properties not in rate base, have also been excluded.
[3] For financial statement purposes interest earned (Account 4405) is an offset to interest expense (and in other revenue for regulatory accounting) and certain short-term interest is recorded as an operating expense.
[4] Remove Non-Utility Assets
[5] Adjustment includes reclassification differences between CGAAP and MIFRS between Properties, plant and equipment, Intangible, Investment properties and deferred income

1 **Table 2 – Capital Assets**
2

| | CGAAP Audited 2013 ($'000) | MIFRS Adjustment (1) (5) ($'000) | Unregulated Business (2) ($'000) | 2013 Regulated Balances ($'000) |
|---|---|---|---|---|
| Property, plant and equipment | $ 651,577 | $ 60,328 | $ (2,362) | **$ 709,543** |
| Intangible assets | 44,733 | (1,124) | - | **43,609** |
| Investment properties | - | 2,143 | - | **2,143** |
| Deferred income | - | (62,091) | - | **(62,091)** |
| TOTAL | **$ 696,310** | **$ 59,204** | **$ (2,362)** | **$ 753,152** |

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## RECONCILLIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICTION

The 2014 Reconciliation of Audited Financial Statements will be filed as Attachment A-4(H) when available.

# ANNUAL REPORT AND MANAGEMENT DISCUSSION AND ANALYSIS

Hydro Ottawa Holding Inc.'s (i.e. Hydro Ottawa Limited's parent company) Annual Report and Management's Discussion and Analysis for 2013 can be found in the subsequent attachment, A-4(C).

Hydro Ottawa Holding Inc.

# 2013 Annual Report

Cover Photo:
Hydro Ottawa Apprentice Powerline Maintainers get hands-on training along Fernbank Road near Terry Fox Drive in Kanata.

Credit: Leon T. Switzer/Front Page Media Group

# Our Mission

Hydro Ottawa's mission is to create long-term value for our shareholder, benefiting our customers and the communities we serve.

Hydro Ottawa is both a community asset and an investment for our shareholder, the City of Ottawa. As a community asset, our goal is to provide effective, efficient and reliable service to our customers, and to be a strong strategic partner for our city, helping to deliver on its economic development and environmental agendas. As an investment, our goal is to provide stable, reliable and growing returns to our shareholder.

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# Company Profile

Hydro Ottawa Holding Inc. (Hydro Ottawa) is 100 percent owned by the City of Ottawa. It is a private company, registered under the *Ontario Business Corporations Act*, and overseen by an independent board of Directors consisting of 11 members appointed by City Council. The core businesses of the Corporation are electricity distribution, renewable energy generation and related services. In 2013, Hydro Ottawa owned and operated two subsidiary companies.

## Hydro Ottawa Limited

Hydro Ottawa Limited is a regulated electricity distribution company operating in the City of Ottawa and the Village of Casselman. As the third largest municipally owned electrical utility in Ontario, Hydro Ottawa Limited maintains one of the safest, most reliable and cost-effective electricity distribution systems in the province, and serves over 315,000 residential and commercial customers across a service area of 1,100 square kilometres. As a condition of its distribution license, the company is required to meet conservation and demand management targets established by the Ontario Energy Board. Hydro Ottawa Limited added approximately 5,400 new customers to its distribution system in 2013, an increase of 1.7 percent, while the volume of electricity delivered through its distribution network decreased by approximately 0.7 percent over the prior year. The company's capital assets grew by $71 million, or 11.4 percent.

## Energy Ottawa Inc.

Energy Ottawa is the largest municipally owned producer of green power in Ontario, and a provider of commercial energy management services. It owns and operates six run-of-the-river hydroelectric generation plants at Chaudière Falls in the city's core and holds interests in two landfill gas-to-energy joint ventures that convert millions of tonnes of previously flared-off methane gas into renewable energy at the Trail Road landfill site in Ottawa and the Laflèche landfill site in Moose Creek, Ontario. In total, this represents a generation capacity of more than 48 megawatts annually, which is enough to power 40,000 homes.

# Message to Our Shareholder

On behalf of management and the Board of Directors of both Hydro Ottawa Holding Inc. and Hydro Ottawa Limited, and our more than 650 dedicated employees — we are very pleased to provide this 2013 Annual Report to our shareholder, the City of Ottawa.

Jim Durrell, C.M.
Chair, Board of Directors

Bryce Conrad
President and
Chief Executive Officer

This report marks the second year of reporting against our *2012–2016 Strategic Direction*, which was endorsed by our shareholder in June 2012. Hydro Ottawa's mission over the term of that five-year plan is to deliver value, both as a community asset providing essential services to our customers, and as an investment for the City of Ottawa, our shareholder. With that mission in mind, our goal is two-fold: to continue to fulfil our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the over 315,000 homes and businesses that rely on us every day; and to ensure a more sustainable energy future for our community.

Hydro Ottawa continued to provide value to our shareholder in 2013. We advanced key elements of our business strategy, while once again achieving strong financial results that exceeded our targets for the year. This reflects our focus on the business priorities that have driven our success to date — an unwavering commitment to financial strength, customer value, organizational effectiveness, and corporate citizenship.

In the area of financial strength, Hydro Ottawa's 2013 net income of $32.1 million surpassed the strategic plan projection by $4.1 million, resulting in $19.3 million in dividends to the City of Ottawa. With strong performance in both 2012 and 2013, Hydro Ottawa has delivered $37.9 million of the $90 million dividend commitment set out in the *2012–2016 Strategic Direction*. Based on this record of performance and prudent management of business risks, Hydro Ottawa continued to maintain its "A" credit rating with a "Stable" trend in 2013.

Hydro Ottawa's improved financial performance for 2013 was achieved in large part through better cost controls and enhanced revenues in our renewable energy generation business. Revenues from renewable generation for 2013 were $21 million, a 91 percent increase over 2012, and Hydro Ottawa's hydroelectric generation capacity grew to 48 megawatts largely due to the acquisition of three hydroelectric plants at Chaudière Falls in 2012.

While Hydro Ottawa Limited, our regulated electricity distribution company, contributed 80 percent of our 2013 net income, it did not match its 2012 performance. Both demand for electricity and distribution revenue dropped in 2013, while costs increased.

Revenue growth in the electricity distribution business is not expected to keep pace with cost increases arising from customer growth, contractual and inflationary pressures, as well as changing regulatory requirements. Productivity improvement is a must to partially offset rising costs, and enhanced revenue growth from our renewable generation business will be critical to increasing shareholder value. That is why Hydro Ottawa pursued the expansion of its renewable generation capacity at Chaudière Falls in 2013. We are pleased to report that we were awarded a 40-year power purchase agreement by the Ontario Power Authority. This will see the construction of a new 29-megawatt generation facility, which will increase our hydroelectric generation capacity by over 50 percent. Construction is to commence in 2015.

Our *2012–2016 Strategic Direction* calls for a continued focus on enhancing customer value and that is why working to keep distribution rates stable for the more than 315,000 homes and businesses we serve remains a priority. While the overall customer bill increased in 2013, the approved distribution rate increase for the Hydro Ottawa portion was 1.08 percent effective January 1, 2013. We are pleased that we have been able to keep this portion of the bill very stable over the past several years through effective cost control and efficient operations.

We are also investing in service reliability at unprecedented levels. Like all utilities in Ontario, Hydro Ottawa must replace aging distribution system equipment at an accelerated pace. We are investing more than half a billion dollars over the course of our 2012–2016 plan to improve system reliability and reduce the occurrence of interruptions caused by aging and defective equipment.

In 2013, Hydro Ottawa continued to experience reliability challenges due to bad weather and increasing failure rates for aging distribution assets. A concerted effort was made to reverse this trend and 2013 was another record year for distribution system investments. Our overall investment in electricity distribution assets was over $131 million, including the new $25 million Terry Fox station to better serve the growing needs of customers in Kanata and Stittsville.

Achieving our goals for customer and shareholder value requires a high performance workforce, and efficient and effective operations. At Hydro Ottawa, we strive for performance excellence in every area of our operations.

In light of shifting demographic trends, anticipated retirements and changing skill requirements, we continued to plan and prepare both for management succession and continuity of skilled trades and technical capacity to ensure a prepared and sustainable workforce over the next five to ten years. Key initiatives in this regard included the continuation of our skilled trades apprenticeship programs, our engineering internship program and our leadership development programs, the expansion of our Algonquin College Powerline Technician Diploma Program partnership, and the development of our Diversity Plan.

Hydro Ottawa also continued to be a responsible and engaged corporate citizen. In 2013, we partnered with Christie Lake Kids to establish the Hydro Ottawa Sustainable Youth Leadership Centre. We were also honoured with the United Way Community Builder Award for *Best Community Campaign* for our 2012 efforts and raised a record $228,415 in 2013. Whether by helping our customers conserve energy, educating over 17,000 local elementary students about electricity safety and conservation, or providing more than $139,000 in financial assistance to front-line agencies that serve people who are homeless or at risk of being homeless through our Brighter Tomorrow's Fund, Hydro Ottawa was there.

We also reached beyond our own community on two occasions last year to lend a helping hand when our neighbours in the Peterborough and Toronto areas and much of eastern and central Ontario were without power. It was a moving reminder that our employees are dedicated not only to service, but also to giving back to their community and their neighbours — and occasionally those neighbours a little further afield.

As a result of the company's achievements, Hydro Ottawa was recognized once again in 2013 by a number of awards including among others, for the fifth year in a row as one of the National Capital Region's Top Employers, for the third year in a row as one of Canada's Greenest Employers, for Innovation in HR Practices for our Retiree and Older Worker Engagement Strategy, and for our Hydro Ottawa Safe Supervisor Program.

We are proud of the company's performance in 2013 and of the many contributions we continued to make to the well-being of our community. This is a testament to the hard work and dedication of our employees — the cornerstone of our success. We look forward to advancing our *2012–2016 Strategic Direction* and continuing to deliver value to our shareholder, our customers and the communities we serve.

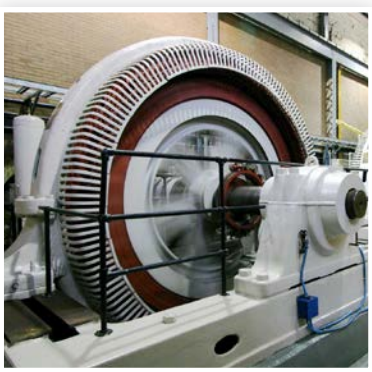
Sincerely,

Jim Durrell, C.M.
Chair, Board of Directors

Bryce Conrad
President and Chief Executive Officer

# Financial Highlights

| (in thousands of Canadian dollars) | 2013 | 2012 |
|---|---|---|
| **Operations** | | |
| Distribution revenue | 152,392 | 151,936 |
| Generation revenue | 21,047 | 11,009 |
| EBITDA | 96,925 | 87,752 |
| Net income | 32,142 | 30,989 |
| Dividend (paid in the following year) | 19,300 | 18,600 |
| **Balance Sheet** | | |
| Total assets | 1,008,006 | 925,901 |
| Capital assets | 791,782 | 721,527 |
| Long-term debt | 400,413 | 251,459 |
| Shareholder's equity | 384,153 | 367,718 |
| **Cash Flows** | | |
| Operating | 49,430 | 80,804 |
| Investing | (112,184) | (142,727) |
| Financing | 131,258 | (18,290) |



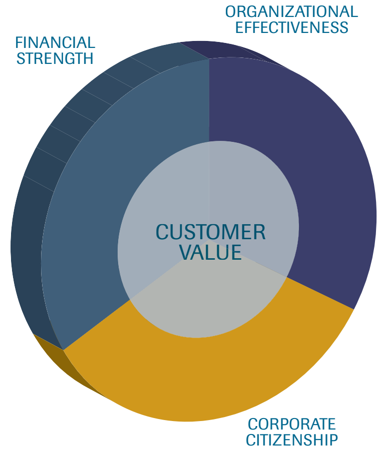

# Progress Against Plan

Hydro Ottawa's 2013 Annual Report is the second to report against the company's *2012–2016 Strategic Direction: Creating Long-Term Value*.

The aim of the Strategic Direction is to move the company from 'good to great', leveraging our position as a leading and trusted service provider to become one of Canada's most successful integrated utilities.

This strategy is built on the company's strengths and achievements, and responds to a changing environment that presents significant opportunities for Hydro Ottawa and the community we serve.

To ensure we take full advantage of those opportunities, Hydro Ottawa is focused on the fundamentals of leading performance: Financial Strength, Customer Value, Organizational Effectiveness, and Corporate Citizenship. These four Key Areas of Focus guide our business strategy and form the basis of our annual reporting in the pages that follow.




One of our Key Areas of Focus — Customer Value — takes on central importance under the company's five-year plan. The essence of Hydro Ottawa's business strategy is to put the customer at the centre of everything we do.

## FOUR KEY AREAS OF FOCUS

### Financial Strength

STRATEGIC OBJECTIVE

We will create sustainable growth in our business and our earnings

By improving productivity and pursuing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people

### Customer Value

STRATEGIC OBJECTIVE

We will deliver value across the entire customer experience

By providing reliable, responsive and innovative services at competitive rates

### Organizational Effectiveness

STRATEGIC OBJECTIVE

We will achieve performance excellence

By cultivating a culture of innovation and continuous improvement

### Corporate Citizenship

STRATEGIC OBJECTIVE

We will contribute to the well-being of the community

By acting at all times as a responsible and engaged corporate citizen

# Financial Strength

Strategic Objective: We will create sustainable growth in our business and our earnings by improving productivity and pursing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people.

Our commitment is to provide sustained shareholder value now and in the future.

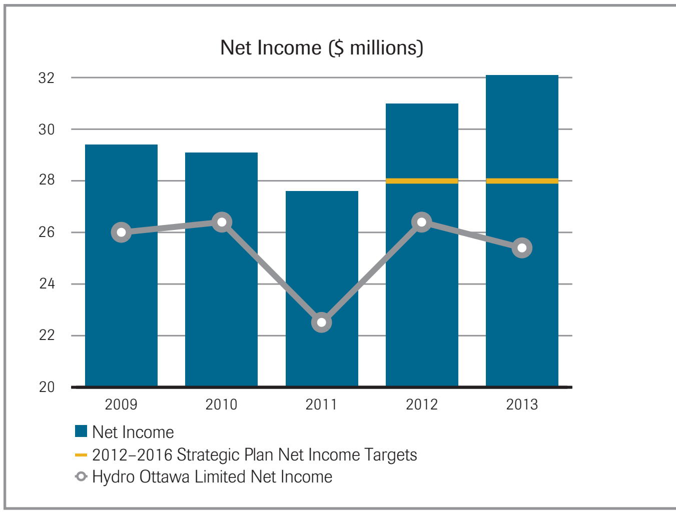
For a second consecutive year, Hydro Ottawa exceeded its financial targets as set out in our *2012–2016 Strategic Direction*. This was due in large part to better cost control and strong performance in our renewable energy generation business line that has enhanced the company's ability to fulfil our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the more than 315,000 homes and businesses that rely on us every day.

## We exceeded our financial targets

Growth in generation revenue and a focus on cost containment took Hydro Ottawa's 2013 net income to $32.1 million, exceeding the target forecast in the *2012–2016 Strategic Direction* by $4.1 million. Cumulative net income for 2012 and 2013, the first two years of our Strategic Direction, has exceeded target by $7.1 million.

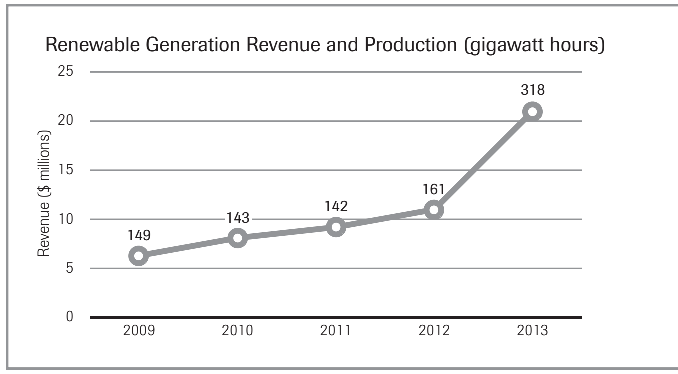
While our regulated local distribution company, Hydro Ottawa Limited, contributed 80 percent of our 2013 net income, it did not match its 2012 performance — both demand for electricity and distribution revenue dropped in 2013, while costs increased.

In order to manage these pressures, Hydro Ottawa kept its focus on cost control and productivity, and continued to closely monitor revenues and expenses. One important indicator of productivity is operating cost per customer. Each year the Ontario Energy Board (OEB) compares the operating costs per customer of all Ontario electricity distributors. In the OEB's most recent survey, Hydro Ottawa ranked 19th out of 73 electricity distribution companies in terms of lowest costs per customer.




**$32.1 million** in net income

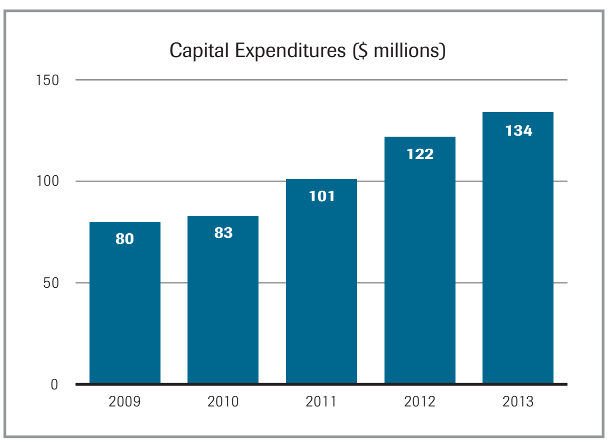
Hydro Ottawa's renewable energy generation business line became a greater source of revenues for the company in 2013 as a result of the full year of operations of the three hydroelectric plants at Chaudière Falls, acquired in November 2012, and the landfill gas-to-energy facility at Moose Creek, which commenced commercial operations on January 25, 2013. Revenues from renewable energy generation for 2013 were $21 million, a 91 percent increase over 2012, and Hydro Ottawa's hydroelectric generation capacity grew to 48 megawatts in total.



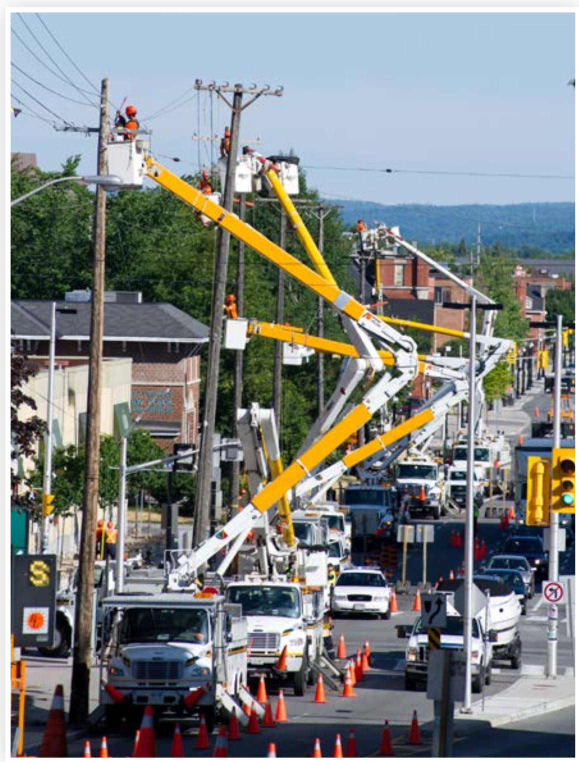

## Electricity generation revenue increased by **91 percent**

## We delivered our largest capital program to date

In 2013, Hydro Ottawa invested $134 million in our electricity distribution system and generation assets – part of our plan to make significant investments over the course of our *2012–2016 Strategic Direction* to maintain and enhance reliability, and to address aging infrastructure and system growth.




## **$134 million** capital program



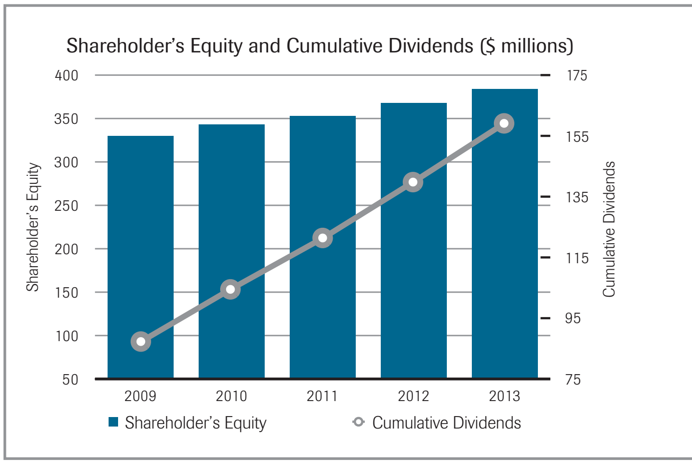
## Shareholder value increased by 13 percent

Hydro Ottawa continued to provide excellent value to its shareholder in 2013, with a return on equity of 8.6 percent. Total shareholder value — including dividends paid and earnings retained with the company — increased 13 percent during the year.

Since 2005, Hydro Ottawa has delivered $159.2 million in dividends to the City of Ottawa, including $19.3 million arising from 2013 results.

With strong performance in both 2012 and 2013, Hydro Ottawa has delivered $37.9 million of the $90 million dividend commitment set out in the *2012–2016 Strategic Direction*.

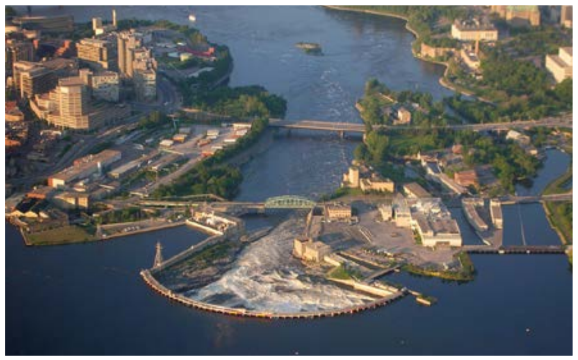
Based on this record of strong operational performance and prudent management of business risks, Hydro Ottawa continued to maintain its "A" credit rating with a "Stable" trend in 2013, and was able to issue long-term debt of $150 million to fund our capital programs and the purchase of the three hydroelectric plants at Chaudière Falls.




**$19.3 million** in dividends to the City of Ottawa

## We continued to pursue business growth

To enhance the company's ability to respond to changing needs and expectations, and to ensure long-term financial sustainability, Hydro Ottawa kept its focus on business growth opportunities. In 2013, Hydro Ottawa pursued the expansion of its renewable generation capacity at Chaudière Falls, and early in 2014, was awarded a 40-year power purchase agreement by the Ontario Power Authority. This will see the construction of a new 29-megawatt generation facility, which will increase our hydroelectric generation capacity by over 50 percent. Construction is to commence in 2015.



# Customer Value

Strategic Objective: We will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates.

The essence of Hydro Ottawa's business strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations – for quality service, cleaner energy, and help in controlling their energy consumption and electricity costs – is the key to success in an evolving energy landscape.

We strive to deliver a reliable product, while keeping our service efficient and friendly, and our costs as low as possible.

## Feedback from our customers continued to show we're on the right track


90 percent customer satisfaction rate

Overall customer satisfaction remained strong at 90 percent, and customer complaint escalations continued to trend downwards.

## We kept our focus on improving the customer's experience

Hydro Ottawa's innovative "Go Paperless" tree planting campaign in 2013 to promote customer self-serve and paperless billing and payment options resonated with customers; by year end, more than 104,000 customers were subscribed to MyHydroLink, while more than 66,000 customers had signed up for E-Billing. It also earned us the Communications Excellence Award from the Electricity Distributors' Association.

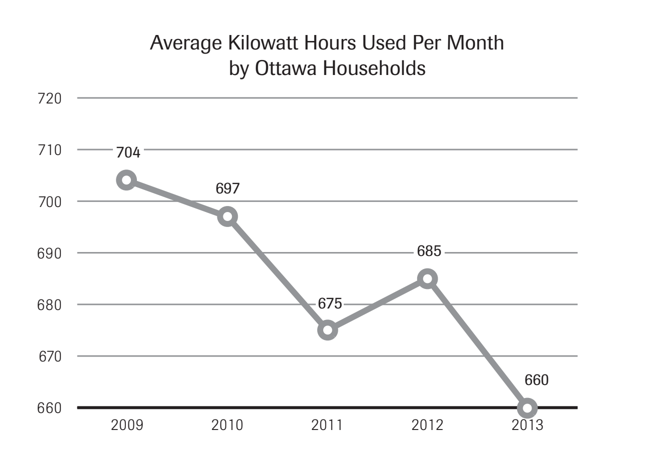
We continued to support our customers and other stakeholders on a variety of social media platforms including Twitter, Facebook, YouTube and LinkedIn. Our Twitter followers more than doubled in 2013 to 4,987.


14,414 customers registered for E-Billing as a result of our "Go Paperless" campaign

## We continued to help people conserve and control their electricity costs

Hydro Ottawa continued to be a leader in promoting energy conservation in our community, helping residents and businesses use our product efficiently and wisely. In 2013, our Pit Crew took to residential streets with free In-Home Displays and at year-end, more than 32,600 households were participating in the *peaksaver* PLUS® program.

It was also an excellent year for the Small Business Lighting program with 1,100 small businesses taking advantage of professionally installed energy efficient lighting. Another 780 larger commercial customers took advantage of our retrofit program to upgrade to much more efficient technologies.




40 Million kWh saved from our residential, small business and large commercial conservation programs, in addition to peak demand savings of 27MWs — enough electricity to power 4,000 homes for a year

## We re-invested in our electricity distribution system

Like most utilities in Ontario, Hydro Ottawa faces a need to replace aging distribution system equipment at an accelerated pace. Our plan is to continue to make significant investments of more than half a billion dollars over the course of our *2012–2016 Strategic Direction* to achieve the maximum benefit for our customers and reduce the occurrence of interruptions caused by defective equipment.

Hydro Ottawa continued to experience reliability performance challenges due to episodes of bad weather as well as increasing failure rates for aging distribution assets. A concerted effort was made to reverse this trend and 2013 was another record year for distribution system investments. Our overall investment in asset management projects was over $131 million, with a particular focus on areas with reliability issues, new station capacity, plant relocation, system expansion, and small residential and commercial infill.

Significant milestones in 2013 included energizing the new Terry Fox station to better serve customers in Kanata and Stittsville, expansion of the Fallowfield station for the growing community of Barrhaven, and extensive work to replace aging infrastructure including poles, underground cables, transformers and switchgear, and line extensions throughout our service territory.

New $25 million Terry Fox Station in Kanata

## Record year for distribution system investments: $131 million to address reliability, aging infrastructure and growth

# Distribution rates remained stable

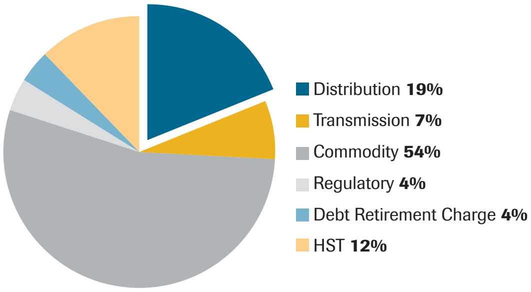
Hydro Ottawa's electricity distribution rates are set through open public hearings by the Ontario Energy Board (OEB), Ontario's electricity and natural gas regulator, which regulates the sector and receives policy direction from the Government of Ontario. The OEB approves rates for the distribution of electricity by utilities such as Hydro Ottawa with the goal of protecting the interests of consumers with respect to prices while ensuring that the electrical service provided by utilities is adequate, safe and reliable.

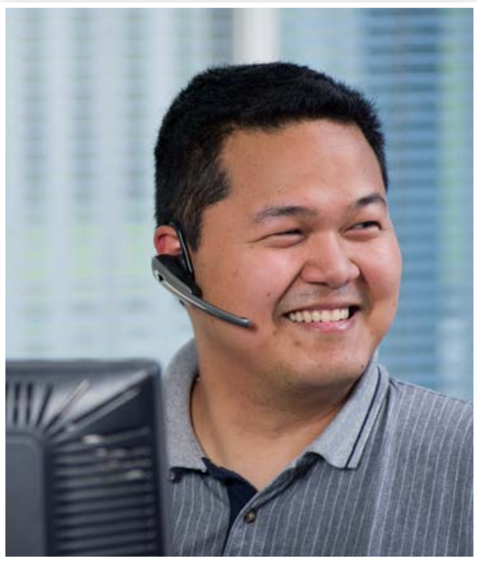
In 2013, Hydro Ottawa's distribution rates made up less than 20 percent of the customer's total electricity bill. The remaining 80 percent consists of pass-through charges that Hydro Ottawa collects for others, with no markup, including the cost of the electricity commodity.

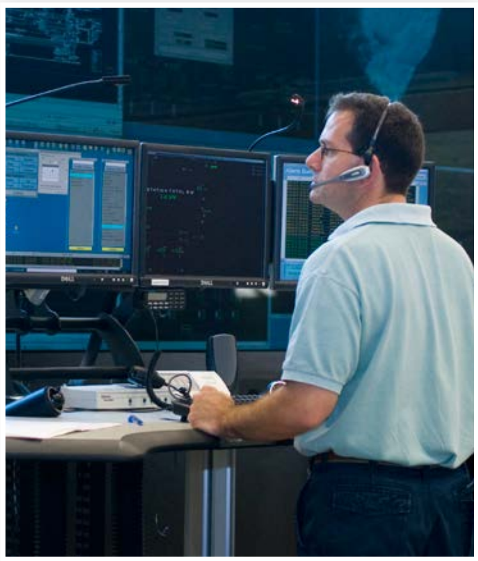
Hydro Ottawa's distribution rates ensure there are sufficient revenues to maintain a reliable electricity distribution system and provide high quality service.

While the overall customer bill increased in 2013, the approved distribution rate increase for the Hydro Ottawa portion was 1.08 percent effective January 1, 2013.

Typical Residential Monthly Bill with TOU
November 1, 2013 (with average usage of 800 kWh)





# Organizational Effectiveness

Strategic Objective: We will achieve performance excellence by cultivating a culture of innovation and continuous improvement.

Achieving our goals for customer and shareholder value requires a high performance workforce, and efficient and effective operations. At Hydro Ottawa, we strive for performance excellence in every area of our operations.

## Our performance continued to be recognized

Our efforts to build a top-performing organization were recognized once again in 2013

- For the fifth year in a row as one of the National Capital Region's Top Employers
- For the fourth consecutive year as an Achievers 50 Most Engaged Workplaces in Canada
- For the third year in a row as one of Canada's Greenest Employers
- Minister's Award for Apprenticeship Training
- Infrastructure Health and Safety Association President's Awards for 250,000, 500,000, 750,000 and 1,000,000 hours worked without a new lost time injury

Winner of the Electricity Human Resources Canada Employer's Award for Innovation in HR Practices for our Retiree and Older Worker Engagement Strategy

# Maintaining a healthy and safe work environment remained a top priority

Maintaining a healthy and safe work environment is a fundamental commitment to our employees. In 2013, Hydro Ottawa provided an average of more than 23 hours of safe work practices training per employee, focusing on higher risk trade employees, who received an average of 47 hours per employee. Our integrated Occupational Health, Safety and Environment management system continues to be certified to the internationally-recognized standards of OHSAS 18001 and ISO 14001.


Canadian Society of Safety Engineering Local Chapter and National Achievement Award for Hydro Ottawa's Safe Supervisor Program

Infrastructure Health & Safety Association™


**1,000,000 hours** worked without a new lost time injury

## We kept our focus on ensuring a prepared and sustainable workforce

In light of shifting demographic trends, anticipated retirements and changing skill requirements, we continued to plan and prepare both for management succession and continuity of skilled trades and technical capacity to ensure a prepared and sustainable workforce over the next five to ten years.

- Our leadership development program, offered in partnership with the MEARIE Group and the Schulich School of Business, York University, graduated 22 participating Hydro Ottawa leaders with a Masters Certificate in Energy Sector Leadership
- We developed our Diversity Plan to create and support a talented workforce that is reflective of the diversity in the communities we serve
- We expanded our Algonquin College Powerline Technician Diploma Program partnership through a double intake of students in 2013 and graduated 17 students from the first program cohort
- Our five Apprenticeship Programs continued to grow – 13 new apprentices were hired in 2013, bringing the total to 36 apprentices, representing 21 percent of our trades workforce
- Our Engineering Intern Program continued to create a talent pool with three interns receiving their P.Eng. designation for a total of 10 to date, and two program alumni promoted to supervisory levels
- Our Summer and Co-op Student Programs continued to be a vital part of our talent supply strategies – providing meaningful opportunities to young workers
- Our Retiree and Older Worker Engagement Strategy, branded as '*Prime Time*' via an all-employee survey, has been key to engaging workers and managing knowledge transfer

HydroOttawa PRIME TIME

**21 percent** of our trades workforce is now made up of apprentices hired through our five Apprenticeship Programs

# We continued to look for ways to improve our operations

A number of productivity improvements were implemented in 2013 with a continued focus on the capital project execution process. Through more efficient use and scheduling of internal crews and external contractors, we were able to complete our largest capital program to date.

We revitalized our Employee Reward and Recognition framework to emphasize performance and introduced the CEO's Award for Productivity and Innovation.

As part of our strategy to improve the efficiency and effectiveness of our operations, we advanced our Real Estate Rationalization Plan. The plan involves the sale of three of our existing facilities that are nearing end of useful life and require major capital investments in the next several years, and the construction of two combined facilities in the east and south ends of the city. In 2013, Hydro Ottawa concluded the acquisition of two new properties: one is near Hunt Club Road and Highway 417 and the other near Fallowfield Road and Highway 416. The Request for Qualifications for the design and build phase was also completed, together with the appointment of a Fairness Commissioner. When fully implemented, the plan is expected to deliver savings of $3 million annually through a combination of cost reductions and productivity improvements. It will also enhance service through more strategically located and better-equipped facilities, and help to reduce the environmental impact of our operations.

# Corporate Citizenship

Strategic Objective: We will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen.

At Hydro Ottawa, we seek to contribute to positive outcomes in our community and beyond.

## We continued to give where we live

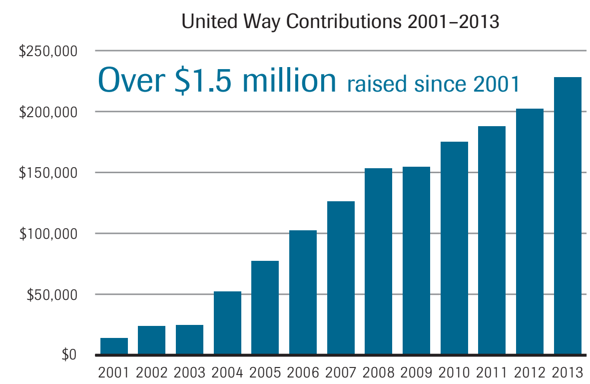
As a community company that delivers essential services to Ottawa residents, contributing to the well-being of our community has always been a part of Hydro Ottawa's core mandate. In 2013, we continued to be active in our community. We partnered with Christie Lake Kids to establish the Hydro Ottawa Sustainable Youth Leadership Centre, which provides a unique opportunity for disadvantaged youths to learn experientially about alternative energy, while building leadership skills. We were honoured with the United Way Community Builder Award for *Best Community Campaign* for our 2012 efforts and raised a record $228,415 in 2013. Whether by educating 17,635 children and youths about electricity safety and conservation, providing $139,946 in financial assistance to front-line agencies that serve people who are homeless or at risk of being homeless through our Brighter Tomorrows Fund, or providing $187,912 to struggling customers under the Low-Income Energy Assistance Program, Hydro Ottawa was there.

900 children with disabilities enjoyed exclusive access to the Gloucester Fair, thanks to Hydro Ottawa employee volunteers

**17,635 students** trained about electricity safety and conservation in area schools

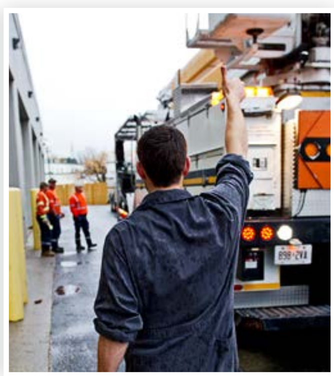

$139,946 in financial assistance to front-line agencies that serve people who are homeless or at risk of being homeless.

$228,415 raised for United Way Ottawa from employee donations and corporate matching




## We assisted those in need outside our community

Our employees are always willing to lend a helping hand to those in need. During the spring of 2013, tens of thousands of customers in Peterborough and the surrounding area were without power due to wind and freezing rain downing power lines. Hydro Ottawa responded immediately to requests for help in restoring power and repairing broken poles. In December 2013, the Toronto area and much of eastern and central Ontario experienced a significant ice storm where hundreds of thousands of customers lost power. Without hesitation, our employees volunteered to give up their holidays with family and loved ones to help restore power to residents in the hard hit communities of Picton, Brampton and Toronto.

THANK YOU HYDRO OTTAWA

*Your help was appreciated during Ice Storm 2013.*

The impact from the 2013 ice storm was devastating and affected 70,000 Brampton customers leaving them without power. Hydro One Brampton would like to thank Hydro Ottawa who worked alongside our crews day and night, and away from their families, to restore power to our customers.

Through hazardous conditions and extreme temperatures, we managed to restore most of our customers' power before the holidays allowing them to celebrate Christmas with their families and friends. As a team we were able to restore power to our customers safely and quickly.

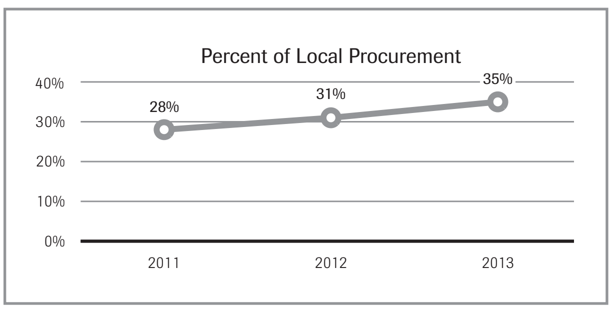
*Thank you for lending a hand.*

hydro one Brampton

## We kept our focus on being green

2013 Canada's Greenest Employers

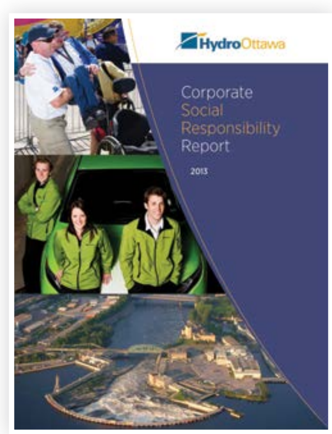
Given the inextricable link between energy and the environment, Hydro Ottawa's approach to corporate citizenship includes a strong focus on environmental sustainability. In 2013, we continued to practice what we preach by carefully managing our own impacts on the environment. We added a second electric vehicle to our fleet and swapped in 36 flex-fuel vehicles, and maintained a high rate of non-hazardous waste diversion at 91 percent. We also completed the installation of building automated systems in 52 of our substations, and continued to green our supply chain and procurement processes by purchasing 35 percent of our goods and services from local suppliers. And for the third year in a row, Hydro Ottawa was recognized as one of Canada's Greenest Employers for incorporating environmental values into our corporate culture.


**91 percent** non-hazardous waste diverted from landfill

## And we continued to walk the talk

At Hydro Ottawa, we believe that good governance is the glue that holds together responsible business practices. By making governance a core focus over the past several years, we have established leading practices for a company of our size and mandate. Accordingly, in 2013 we refreshed our Code of Business Conduct to provide greater clarity and guidance to employees and board members in making the right decisions. In addition, we produced our inaugural Corporate Social Responsibility Report to demonstrate our commitment and leadership in this area and share our progress with our stakeholders.



# Management's Discussion and Analysis

The Management's Discussion and Analysis ['MD&A'] is intended to provide a narrative review of Hydro Ottawa Holding Inc.'s operational performance and financial position, and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the year ended December 31, 2013. The consolidated financial statements are prepared in accordance with pre-changeover Canadian generally accepted accounting principles ['pre-changeover Canadian GAAP'], including accounting principles prescribed by the Ontario Energy Board ['OEB'] in the Accounting Procedures Handbook, and are expressed in thousands of Canadian dollars.

The MD&A contains forward-looking statements, including, but not limited to, statements as to future operating results and plans. These statements reflect management's expectations as of the date of release. The impacts of risks and uncertainties may cause actual results, performance or achievements to differ materially from those projected here.

## Business of Hydro Ottawa Holding Inc.

Hydro Ottawa Holding Inc. ['Hydro Ottawa' or 'the Corporation'] was incorporated on October 3, 2000 under the *Business Corporations Act* (Ontario) as a for-profit holding company. Hydro Ottawa is wholly owned by the City of Ottawa ['the Shareholder'] and governed by an independent Board of Directors appointed by the Shareholder.

The Corporation's core businesses are electricity distribution, renewable energy generation and related services. Hydro Ottawa owns and operates two subsidiary companies, as follows:

**Hydro Ottawa Limited:** The core and by far the largest business of the Corporation is the distribution of electricity by its largest subsidiary, Hydro Ottawa Limited, which accounts for approximately 88 percent of the Corporation's capital assets and 90 percent of revenues. Hydro Ottawa Limited is a regulated electricity local distribution company ['LDC'] that owns and operates distribution infrastructure in the City of Ottawa and the Village of Casselman. Hydro Ottawa Limited is the largest LDC in eastern Ontario and the third largest municipally owned LDC in the province of Ontario. Hydro Ottawa Limited delivers electricity reliably and safely to approximately 315,000 residential and commercial customers across a service area of approximately 1,100 square kilometres. As a condition of its distribution licence, Hydro Ottawa Limited is required to meet conservation and demand management targets established by the OEB. Hydro Ottawa Limited receives power from the provincial electricity grid and embedded generators and distributes it across a network comprising 85 distribution stations, 169 station class transformers, 2,800 kilometres of underground cable, 2,900 kilometres of overhead lines, 35,600 distribution transformers and 48,000 hydro poles. Hydro Ottawa Limited added 5,400 net new customers to its distribution system in 2013, an increase of 1.7 percent.

**Energy Ottawa Inc. (Energy Ottawa):** A generator of renewable energy and provider of commercial energy management services, Energy Ottawa is the largest municipally owned producer of green power in Ontario. Energy Ottawa now owns and operates six run-of-the-river hydroelectric generation plants at Chaudière Falls. Energy Ottawa also holds interests in the following entities:

PowerTrail Inc. ['PowerTrail'] is a 60 percent owned joint venture that operates a generation plant and gas collection system at the Trail Road landfill site in Ottawa, Ontario.

Moose Creek Energy LP ['Moose Creek LP'] is a 50.1 percent owned joint venture that operates a generation plant and gas collection system at the Laflèche landfill site in Moose Creek, Ontario.

Chaudiere Water Power Inc. ['CWPI'] is a 66.66 percent owned joint venture that operates the Chaudière Dam facilities on the Ottawa River.

Energy Ottawa's green energy production now exceeds 48 MW annually, which is enough to power 40,000 homes. On February 7, 2014, Energy Ottawa's subsidiary Chaudiere Hydro L.P., was granted a 40-year Hydroelectric Standard Offer Program – Municipal Stream Contract ['HESOP Contract'] by the Ontario Power Authority ['OPA'] to produce renewable waterpower. As a result of this contract, Chaudiere Hydro L.P. will expand its generation facilities increasing Energy Ottawa's total capacity from 38 megawatts to 58 megawatts ['Chaudière expansion']. The Chaudière expansion will require a major investment, and have a significant impact on operations in the coming years. The anticipated commercial operation date is in the fourth quarter of 2017.

# Vision and Strategy

## OUR VISION

Hydro Ottawa's vision is to be a leading and trusted integrated utility services Corporation. This vision is built upon the objectives that were set out for the Corporation at its inception – to increase the value of the Corporation for its Shareholder, to deliver efficient and effective service to our customers, and to grow competitive businesses that maximize the value of our existing assets and core competencies.

The goal of Hydro Ottawa's *2012–2016 Strategic Direction* is to move the Corporation from 'good to great', leveraging our position as a leading and trusted service provider to become one of Canada's most successful integrated utilities.

### LEADING

For Hydro Ottawa, leading means consistently being among the top performers in the business, in every critical area of our operations; and being regarded as a credible and trusted voice in our industry, helping to shape policy, regulatory and operational responses to the critical issues of the day.

As our industry evolves in response to customer needs and technological and policy change, our goal is to ensure Hydro Ottawa continues to be a leader in this shifting strategic context, becoming one of the most successful utility companies in Canada.

TRUSTED

Trust is fundamental to Hydro Ottawa's success; a continuing belief among our stakeholders that we will deliver on our mission, reliably, in a transparent and accountable fashion.

We are a Corporation with very deep roots in our community, established through more than 100 years of providing an essential service to homes and businesses. Through an independent third party survey conducted in 2013, Hydro Ottawa scored higher results than National and Ontario industry comparables when customers were asked to rate their satisfaction with items such as:

- provides consistent, reliable energy;
- quickly handles outages;
- provides good value for money;
- operates a cost effective hydroelectric system;
- deals professionally with customer problems;
- works with customers to keep their energy costs affordable;
- proactive in communicating changes;
- quickly deals with issues that affect customers;
- adapts well to changes in customer's expectations; and
- overall provides excellent quality services.

We are proud of our legacy and continue to seek out ways to be of service to our customers.

In the years to come, we will continue to demonstrate that we have the strength and ability to deliver on our mandate, coupled with a commitment to transparency, accountability, and the well-being of our community.

INTEGRATED

Hydro Ottawa's strategic vision involves realizing synergies and economies of scale in 'close to the customer' utility services, to create savings, and additional value for the Shareholder and enhanced service to customers.

## OUR STRATEGY

The essence of Hydro Ottawa's strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations for service quality, cleaner energy, and greater control over the management of energy costs will be key to Hydro Ottawa's continued success in an evolving landscape. The customer value we provide up to and beyond the meter will drive all critical areas of performance-our financial strength and business growth, our operational efficiency and effectiveness, and our contributions to the well-being of our community.

To enhance our ability to respond to customer needs and expectations, and ensure long-term financial sustainability, Hydro Ottawa will also maintain a focus on strategic business growth within our core areas of strength. Our growth agenda involves three basic components:

- achieving economies of scale by expanding our electricity distribution business beyond its current service territory, and leveraging our core systems to support other utility services;
- increasing the supply of clean energy for customers and earnings for our Shareholder by expanding our renewable generation; and
- bringing innovative solutions to energy-conscious consumers and businesses, by growing our energy management expertise.

To achieve our strategy, the plan is structured around four critical areas of performance that have driven our success to date; our four Key Areas of Focus:

- Customer Value: We will deliver value across the entire customer experience;
- Financial Strength: We will create sustainable growth in our business and our earnings;
- Organizational Effectiveness: We will achieve performance excellence; and
- Corporate Citizenship: We will contribute to the well being of the community.

These four key areas of focus will continue to guide our activities throughout the current plan.

We have made significant strides on the growth agenda by increasing the supply of clean energy with the following projects:

On November 20, 2012, Chaudiere Hydro L.P. completed the purchase of three additional run-of-the-river hydroelectric plants at Chaudière Falls from Domtar Inc. Energy Ottawa's hydroelectric generating capacity has more than doubled to 38 megawatts with this purchase. In addition, the Chaudière Falls site is one of the largest remaining hydroelectric sites available in Ontario.

On January 25, 2013, the landfill gas collection plant at the Laflèche landfill site in Moose Creek, Ontario commenced commercial operations.

On February 7, 2014, Chaudiere Hydro L.P. was granted a 40-year HESOP Contract by the OPA to produce renewable waterpower. As a result of this contract, Chaudiere Hydro L.P. will expand its generation facilities increasing Energy Ottawa's total capacity from 38 megawatts to 58 megawatts. The anticipated commercial operation date is in the fourth quarter of 2017.

Hydro Ottawa continues to pursue solar energy projects, including those through a partnership with the City of Ottawa.

# Electricity Distribution — Industry Overview

## THE ROLE OF THE LOCAL DISTRIBUTION COMPANY

Ontario's LDCs take power from the high-voltage transmission grid, reduce the electricity voltage to a lower level [50,000 volts and under], and provide this electricity to customers; homes, businesses, institutions and industry. They also provide energy conservation services to their customers, as a condition of their distribution licenses issued by their regulator, the OEB.

The functions carried out by Ontario's LDCs include the following:

- Plan: Review performance and trending, project consumer demand growth, develop capital and maintenance plans;
- Design: Apply standards and rigor to projects and retrofits and execute plan;
- Build: Bring the conceptual design to construction;
- Operate: 24/7 operations;
- Maintain: Manage physical assets;
- Restore: Outage management, customer communications;
- Meter: Measure the customer's consumption;
- Bill: Obtain all the usage information and send the bill to the customer;
- Settle: Act as the billing agent for other organizations in Ontario's electricity system;
- Collect: Manage payment collection;
- Conserve: Promote conservation and demand management programs; and
- Customer Care: Manage the relationship with customers.

## REGULATORY ENVIRONMENT

Hydro Ottawa and its subsidiaries operate within the framework of the *Electricity Act, 1998* ['Electricity Act'] and the *Ontario Energy Board Act, 1998*.

Hydro Ottawa Limited, as an electricity distributor, is both licensed and regulated by the OEB. Hydro Ottawa Holding Inc. and Energy Ottawa also have restrictions on business activities because they are affiliates to a distributor that is owned indirectly by a municipal corporation. On November 12, 2010, Hydro Ottawa Limited's Distribution Licence was revised to reflect its additional mandate to achieve Conservation and Demand Management ['CDM'] targets.

The legal and policy framework for the Corporation's businesses is set mainly by the Government of Ontario, which passes legislation and regulations that govern the energy sector in the province. The Ministry of Energy works to develop the electricity generation, transmission and other energy related facilities in Ontario. The Ministry of Energy also has legislative responsibility for several agencies, including the Independent Electricity System Operator ['IESO'], the OEB and the OPA. The government restructured Ontario's electricity industry in 1998, and within the new structure, utilities provide service and build and maintain infrastructure to meet or exceed regulated standards, while earning a regulated return on invested capital. The OEB implements and oversees this framework, ensuring that market participants in the natural gas and electricity sectors comply with their regulatory obligations.

As an LDC, Hydro Ottawa Limited is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credits ratings. The OEB regulates the province's electricity sector and, in keeping with the *Ontario Energy Board Act, 1998*, has the authority and power to approve and fix all rates for the transmission and distribution of electricity in the province.

The OEB must set or approve all rates charged by Hydro Ottawa Limited, and establishes standards of service and conduct that must be followed as a condition of being licensed to distribute electricity. Energy Ottawa and its affiliates are also licensed by the OEB as an electricity retailer and generator.

The permitted business activities of Hydro Ottawa Limited were expanded as a result of the *Green Energy and Green Economy Act, 2009* ['Green Energy Act'] to include the ownership and operation of generation and energy storage facilities under established criteria. Existing permitted activities include distributing electricity, load management, the promotion of electricity conservation and the efficient use of electricity and cleaner energy sources.

The Green Energy Act requires all distributors to file plans with the OEB on facilitating renewable energy generation and implementing a smart grid. It also amended the mandate of the OEB, expanding its objectives to include the promotion of CDM, facilitating the implementation of a smart grid and promoting the use and generation of electricity from renewable energy sources. The Corporation filed a Green Energy Act plan with its 2012 Cost-of-Service application.

The Electricity Act establishes the structure of the electricity industry and the roles and responsibilities of parties such as the IESO, Electrical Safety Authority ['ESA'], OPA and the Smart Meter Entity ['SME']. The Electricity Act further establishes rights and obligations for distributors. For instance, distributors are obligated to connect any building that lies along their distribution systems upon request and access to its system must be non-discriminatory. The Green Energy Act establishes mandatory timelines and information requirements for each step of a process established for the connection of generation facilities that sell electricity through the distribution grid.

The Ontario electricity commodity market is open to competition at both the wholesale and retail levels. Since 1999, electricity distributors have been purchasing their electricity from the wholesale market overseen by the IESO and recovering costs of electricity in accordance with procedures mandated by the OEB. At the wholesale level, generators can bid into the electricity market overseen by the IESO or enter into a contract with the OPA. At the retail level, consumers have the choice of purchasing the electricity commodity through a contract with a licensed electricity retailer or through a licensed distributor, such as Hydro Ottawa Limited, as part of a standard supply service ['SSS'].

Under SSS, the commodity is provided to customers on a pass-through basis such that commodity revenues match the cost. Residential and small commercial customers receive the SSS through a regulated price plan ['tiered'] or Time-of-Use ['TOU'], under which the OEB sets the commodity rates for the province twice per year, in May and November, based on a forecast of the commodity costs. Differences between the forecast and actual costs are tracked by the OEB in a variance account until the balance is cleared through future regulated commodity rates. Other customers pay for the commodity based on the provincial spot market price or through the terms of a retail contract.

Regardless of whether customers have signed a contract with a retailer, or are supplied through the SSS, Hydro Ottawa Limited continues to be responsible for the delivery of the electricity through its distribution system to all customers within the licensed service area.

In April 2012, the Ontario Minister of Energy established the Ontario Distribution Sector Review Panel to provide expert advice to the government on how to improve efficiencies in the sector, with the aim of reducing the financial cost of electricity distribution for electricity consumers. The Panel's report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First* was published in December 2012. Based on a thorough review of the sector, the Panel proposed a new model for electricity distribution in Ontario aimed at creating robust, efficient and well-resourced utilities that will reduce costs to the consumer and support continued economic growth, largely through the consolidation of LDCs into larger regional utilities. Hydro Ottawa is well positioned to respond to opportunities involving regional consolidation where there is a clear benefit to our customers and our Shareholder.

## DETERMINING DISTRIBUTION RATES

Ontario's electricity distribution companies, such as Hydro Ottawa Limited, recover their costs from customers through electricity distribution rates, including the costs to:

- design, build and maintain overhead and underground distribution lines, poles, stations and local transformers;
- operate local distribution systems, including smart meters; and
- provide customer service and emergency response.

Before LDCs can make any changes to their rates, they are required to seek approval from the OEB through a rate application. The OEB follows a multi-year process to set electricity distribution rates. The process is designed to encourage distribution companies to maximize their efficiency while generating the revenue required to reliably deliver electricity to consumers.

Under this model, a Cost-of-Service review is used to establish rates every fourth year [a 'rebasing'], based on the utility's costs to provide the service as determined through an open process before the OEB. This is followed by three years of rate setting under the Incentive Regulation Mechanism ['IRM']. During this three-year period, distributors file an application before the OEB, and rates are adjusted by an inflationary factor minus a productivity factor. This encourages management of the distribution company to maximize the efficiency and productivity of their business, by putting a cap on the distributor's rates. An 'incremental capital module', designed to accommodate significant and special capital needs, can also be applied for during the IRM term. A distribution company can apply for a Cost-of-Service review more often than every fourth year, but it must clearly demonstrate why an IRM adjustment would not provide sufficient resources to manage its business during the IRM period.

In 2011, the OEB initiated a review of the 3rd Generation IRM regulatory model for electricity distributors in Ontario, as part of a broader review of the regulatory framework for electricity in the province. Over the past five years of operating under the 3rd Generation IRM, electricity distributors have raised a number of concerns with the model, including a concern that it did not provide adequate recovery for capital expenditures in the intervening years between rebasing. In the fall 2012, the OEB announced a new policy framework for regulation of the electricity industry in Ontario [*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012]. Recognizing that the capital investment needs of LDCs vary over time, the new framework identified three rate-setting models from which LDCs will be able to choose to set their rates:

- 4th Generation Incentive Rate-setting [suitable for most distributors];
- Custom Incentive Rate-setting [suitable for those distributors with large or highly variable capital requirements]; and
- Annual Incentive Rate-setting Index [suitable for distributors with limited incremental capital requirements].

The OEB believes these models will provide choices suitable for distributors with varying capital requirements, addressing the issues raised by electricity distributors regarding recovery of capital expenditures, while allowing greater focus by the electric distributors on customer value and service. During 2013, the details of each of the regulatory models was developed with input from working groups comprised of electricity distributor staff, ratepayer groups and OEB staff. In November 2013, the OEB issued its final report on the details of 4th Generation Incentive Rate-setting and the Annual Incentive Rate-setting Index. Hydro Ottawa was actively engaged in the policy-making process through working groups and in other ways, which influenced the final design of the regulatory models. With the final details determined, electricity distributors can file applications under one of the three new models for 2015 rates.

Hydro Ottawa's rates for 2013 were established by means of the 3rd Generation Incentive rate-setting Index. Under this method, Hydro Ottawa's rates were adjusted, commencing January 1, 2013, by an inflationary adjustment of 1.08 percent increase. This inflationary adjustment was determined by the OEB as appropriate for electric distributors for 2013.

Costs and rates vary from distributor to distributor depending on factors such as the age and condition of assets, geographic terrain and distance, and population density and growth. The proportion of residential to commercial and industrial consumers can also contribute to cost differences between distribution companies.

Electricity bills include charges for the commodity, wholesale market services, transmission services, distribution services, debt retirement, and harmonized sales tax. Revenues from all of these charges, except distribution services, are collected from customers on a pass-through basis. Any differences between costs and revenues collected for these pass-through charges are tracked as a regulatory asset or liability, to be cleared through rates in a subsequent period. Distribution services revenue, which represents only about 20 percent of the bill, is retained by the LDC. The OEB-approved distribution rates include a fixed charge and a variable charge based on electricity consumption or peak demand.

Each year the OEB compares the operating costs per customer of all Ontario distributors. In the *2012 Yearbook of Electricity Distributors* [August 2013], Hydro Ottawa ranked in the top quartile of distributors in terms of lowest costs per customer [19th out of 73 electricity distributors].

## Selected Consolidated Financial Results

The selected consolidated financial results of the Corporation presented below should be viewed in conjunction with the audited consolidated financial statements for the year ended December 31, 2013.

## CONSOLIDATED STATEMENT OF INCOME [SUMMARY]

| (in thousands of Canadian dollars) | 2013 | 2012 | Change |
|---|---|---|---|
| Revenues | | | |
| Power recovery | 768,079 | 709,935 | 58,144 |
| Distribution sales and other revenue | 208,288 | 190,840 | 17,448 |
| | 976,367 | 900,775 | 75,592 |
| Expenses | | | |
| Purchased power | 765,151 | 707,552 | 57,599 |
| Operating costs | 114,291 | 105,471 | 8,820 |
| | 879,442 | 813,023 | 66,419 |
| EBITDA | 96,925 | 87,752 | 9,173 |
| Depreciation and amortization | 40,322 | 37,121 | 3,201 |
| Other expenses and recoveries | 14,645 | 10,422 | 4,223 |
| Payments in lieu of corporate income taxes | 9,410 | 8,928 | 482 |
| | 64,377 | 56,471 | 7,906 |
| Non-controlling interest | (406) | (292) | (114) |
| Net income and comprehensive income | 32,142 | 30,989 | 1,153 |

Net income increased by approximately $1.2 million [4 percent].The increase in net income is largely attributable to the growth in revenues resulting from the acquisition of generation assets at Chaudière Falls from Domtar Inc. in late 2012, the addition of a sixth generating engine at the PowerTrail landfill gas to energy plant, and the start of commercial operations at the Moose Creek landfill gas to energy plant in early 2013.

## REVENUES

Revenues are earned from electricity distribution, sales of generated power, energy management services, the CDM program, and sundry activities.

The largest component in Hydro Ottawa's total revenues is the cost of power recovered from the customer through provincially established rates. The cost of power is a flow through amount, which poses limited risk to Hydro Ottawa's financial performance either positively or negatively. Hydro Ottawa Limited's power recovery increased by $58.1 million [8 percent], mainly due to increases in commodity and global adjustment rates included in purchased power costs.

Revenues, excluding power recovery, increased $17.4 million [9 percent] from 2012. Electricity distribution revenue is reflective of OEB approved distribution rates and the amount of electricity consumed. Revenue from distribution sales increased $0.4 million [0.3 percent] from 2012 as a result of new rates established by means of the 3rd Generation Incentive rate-setting index. Both CDM program revenues and revenues from other sundry activities increased $3.5 million respectively over the prior year as business has increased. Energy Ottawa's electricity generation revenues increased by $10.0 million over the prior year mainly due to new revenue as a result of the acquisition of generation assets at Chaudière Falls from Domtar Inc., the addition of a sixth generating engine at the PowerTrail landfill gas to energy plant, and the start of commercial operations at the Moose Creek landfill gas to energy plant in early 2013. Energy Ottawa's commercial energy management services revenues were in line with the prior year.

## EXPENSES

Purchased power costs represent the cost of electricity delivered to customers within Hydro Ottawa Limited's distribution service territory. These costs consist of the commodity, wholesale market service charges, transmission charges and the global adjustment levied by the IESO, net of energy generated by Energy Ottawa and supplied to Hydro Ottawa Limited as an embedded generator within Hydro Ottawa Limited's service territory. The cost of purchased power increased by $57.6 million [8 percent], due mainly to increased commodity and global adjustment rates as noted above. The global adjustment accounts for differences between the market price and the rates paid to regulated and contracted generators and for CDM programs. When the spot market price of electricity is lower, the global adjustment is higher in order to cover the additional costs of energy contracts and other regulated generation.

Operating costs in the current year of $114.3 million increased by $8.8 million over 2012 due in large part to compensation costs which have increased over the prior year by approximately $6.4 million. The increase in compensation costs is due to increased number of employees as a result of the Chaudiere Hydro L.P. acquisition on November 20, 2012 as well as negotiated and inflationary increases. CDM program costs have also increased over the prior year by $3 million in conjunction with the increase in program revenues.

## DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses increased by $3.2 million, primarily due to the acquisition of generation assets at Chaudière Falls from Domtar Inc., the addition of a sixth generating engine at the PowerTrail landfill gas to energy plant, and the start of commercial operations and thus depreciation of the Moose Creek landfill gas to energy plant in early 2013. Also contributing to the increase are acquisitions and improvements to information systems and a global increase of investments in the electricity distribution infrastructure of the Corporation.

PAYMENTS IN LIEU OF CORPORATE TAXES ['PILS']

Hydro Ottawa Limited is considered to be a Municipal Electric Utility ['MEU'] for purposes of the PILs regime contained in the *Electricity Act, 1998*, since all of its share capital is indirectly owned by the City of Ottawa and not more than 10 percent of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The Electricity Act provides that a MEU that is exempt from tax under the *Income Tax Act* (Canada) ['ITA'] and *Taxation Act, 2007* (Ontario) ['TAO'] is required to make, for each taxation year, a PILs payment in an amount approximating the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

The Corporation and Energy Ottawa are also MEUs. PowerTrail and CWPI are taxable under the ITA and TAO, as less than 90 percent of their share capital is owned by the City of Ottawa.

Moose Creek LP and Chaudiere Hydro L.P. are not taxable entities for federal and provincial income tax purposes. Tax on Moose Creek LP and Chaudiere Hydro L.P.'s net income (loss) is borne by the individual partners through the allocation of taxable income.

The Corporation's effective tax rate increased from 22.2 percent in 2012 to 22.4 percent in 2013. The year-over-year increase is a result of impacts of permanent and temporary differences between the accounting and tax basis of assets and liabilities.

## CONSOLIDATED BALANCE SHEET [SUMMARY]

| (in thousands of Canadian dollars) | 2013 | 2012 | Change |
|---|---|---|---|
| Current assets | 183,147 | 172,075 | 11,072 |
| Non-current assets | 824,859 | 753,826 | 71,033 |
| Total assets | 1,008,006 | 925,901 | 82,105 |
| Current liabilities | 161,689 | 234,195 | (72,506) |
| Non-current liabilities | 462,164 | 323,988 | 138,176 |
| Total liabilities | 623,853 | 558,183 | 65,670 |
| Shareholder's equity | 384,153 | 367,718 | 16,435 |
| Liabilities and shareholder's equity | 1,008,006 | 925,901 | 82,105 |

### ASSETS

Total assets increased by approximately $82.1 million during the year. This increase is largely attributable to property, plant and equipment and intangible assets, which have increased by $70.3 million. This is a result of our continuing investment in electrical distribution and generation infrastructure. In addition, accounts receivable and unbilled revenue have increased by $11.5 million due in large part to the global adjustment amount included in unbilled revenue.

### LIABILITIES

Total liabilities increased by $65.7 million in 2013. This change is largely attributable to the issuance of Senior Unsecured Debentures in the amount of $150 million discussed below under the Statement of Cash Flows [Summary], offset by a $68.5 million decrease in bank indebtedness and a $10.2 million decrease in regulatory liabilities, primarily attributable to variances associated with the electricity and global adjustment costs.

## STATEMENT OF CASH FLOWS [SUMMARY]

| (in thousands of Canadian dollars) | 2013 | 2012 |
|---|---|---|
| Cash (bank indebtedness), beginning of year | (77,357) | 2,856 |
| Cash provided by Operating Activities | 49,430 | 80,804 |
| Cash used in Investing Activities | (112,184) | (142,727) |
| Cash provided by (used in) Financing Activities | 131,258 | (18,290) |
| Bank indebtedness, end of year | (8,853) | (77,357) |

### CASH PROVIDED BY OPERATING ACTIVITIES

Cash generated by operating activities provided approximately $31 million less cash flow than in 2012. The majority of the decrease arises from less cash flow being generated from working capital, primarily due to the timing of settlement within the regulatory accounts as well as an increase in the global adjustment amount included in unbilled revenue.

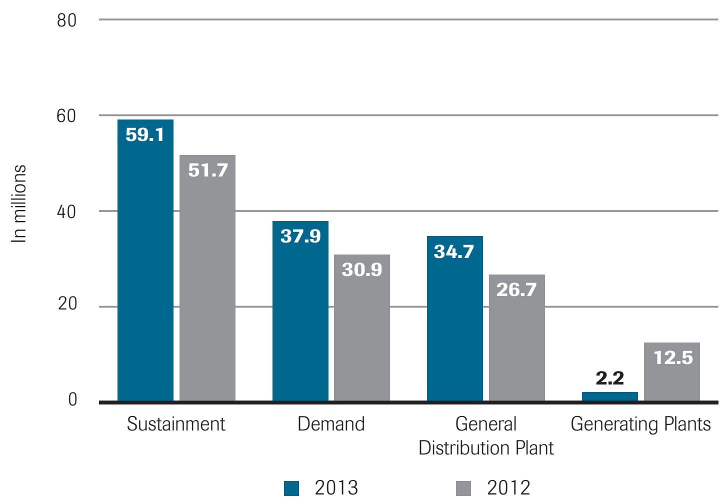
### CASH USED IN INVESTING ACTIVITIES

The total investment in property, plant and equipment and intangible assets, net of contributions in aid of construction in 2013 is approximately $112 million. Capital investments in 2013 included approximately $59 million on sustainment capital to replace aging infrastructure and to modify the existing distribution system; $38 million on demand projects [less contributed capital of $22 million], which includes third-party driven growth projects such as new residential or commercial installations, and municipal improvement projects including the City of Ottawa's Light Rail Transit project; $35 million on general plant items including Information Technology infrastructure, land purchases for new facilities, fleet, and other sundry items; and $2 million in generating plants.

Investment in the Hydro Ottawa Limited electricity distribution system continues to be robust. In 2013, 1,087 new poles, 543 overhead transformers, and 233 km of overhead cables were installed. Over 250 demand capital projects were initiated, including the addition of 5,388 new residential and 1,084 new commercial connections.

Investments in generation operations during 2013 saw a large decrease from the prior year. In 2012 the Corporation made major investments, which included the $46.3 million purchase of three additional run-of-the-river hydroelectric plants at Chaudière Falls from Domtar Inc., and $10.6 million on construction costs related to the new Moose Creek landfill gas collection plant and utilization system that was completed in early 2013.

The following chart shows the year over year capital investments, excluding the acquisition of assets from Domtar Inc. on November 20, 2012.




### CASH PROVIDED BY FINANCING ACTIVITIES

Dividends were paid to the Shareholder in 2013 in accordance with the approved dividend policy. The 2013 payment totalled $18.6 million based on 2012 results, and the 2012 payment totalled $16.6 million based on 2011 results.

On May 14, 2013, the Corporation issued $150 million in Senior Unsecured Debentures. The debentures bear interest at a rate of 3.991 percent per annum, payable semi-annually in arrears in equal instalments on November 14 and May 14, and is due on May 14, 2043.

## LIQUIDITY AND CAPITAL RESOURCES

The Corporation's primary sources of liquidity and capital resources are derived from operating activities, banking facilities, and proceeds from bond issuances as and when required. Liquidity and capital resource requirements are primarily for capital expenditures to maintain the Hydro Ottawa Limited electricity distribution system, cost of power, interest expense and prudential requirements.

On July 15, 2013, the Corporation renewed its credit facility for $193.5 million. The Corporation may use up to $75 million of the facility for general operating requirements and annual capital expenditures. In addition, a $100 million two-year revolving credit line remains available for larger capital expenditures and acquisitions. Capital expenditure requirements in excess of this, if any, will be funded through future bond issuances.

As at December 31, 2013, the Corporation had drawn $16 million in standby letters of credit and $5 million in short term borrowings against its credit facility. The remaining facility is adequate to support the short-term working capital deficit experienced each month to settle the IESO costs of power invoice in advance of receiving payment from customers. The Corporation will continue to invest in its distribution system and expects to renew the $200 million bond maturing in February 2015. This will enable the Corporation to maintain its appropriate liquidity position.

PowerTrail maintains a separate credit facility with a Canadian Chartered bank. The facility consists of $0.2 million in standby letters of credit. As at December 31, 2013, $0.1 million in standby letters of credit were drawn against this credit facility.

CWPI also maintains a credit facility consisting of a $0.5 million operating credit line secured by the principals of CWPI. The operating credit line is repayable on demand and bears interest at the Bank of Canada's prime lending rate per annum with interest payable monthly. The facility also contains customary covenants and events of default. As at December 31, 2013, CWPI had not drawn this operating line.

## CREDIT RATINGS

As at December 31, 2013, the Corporation's bonds are rated as follows:

| Rating Agency | Rating |
|---|---|
| Standard & Poor's Rating Services Inc. | A ('stable') |
| Dominion Bond Rating Service Inc. | A ('stable') |

During the past year, both the Dominion Bond Rating Service ['DBRS'] and Standard & Poor's Rating Services Inc. ['S&P'] reaffirmed Hydro Ottawa Holdings Inc.'s rating at 'A' with a stable trend. Once again, both rating agencies noted the Corporation's strong competitive position and a recession resistant customer base promoting an excellent business risk profile.

Hydro Ottawa's strong credit rating over the past several years is a direct result of its conservative financial policies, strong operational performance and low business risk.

The Corporation's bonds carry covenants normally associated with this type of debt [see Notes 14 and 15 of the consolidated financial statements for further details]. The Corporation is in compliance with these covenants as at December 31, 2013.

# Accounting Estimates and Policies

## SIGNIFICANT ACCOUNTING ESTIMATES

The preparation of consolidated financial statements, in conformity with pre-changeover Canadian GAAP, requires management to make estimates and assumptions that affect the reported amounts of consolidated revenues, expenses, assets, liabilities, and the disclosure of commitments and contingencies at the date of the consolidated financial statements.

These estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Because they involve varying degrees of judgment and uncertainty, the amounts currently reported in the financial statements could prove to be inaccurate in the future.

The following accounting estimates require management's judgments and assumptions in preparing financial statements and, as such, are considered to be critical. References to the associated note in the consolidated financial statements are provided in brackets:

- Useful lives of property, plant and equipment and intangible assets [Note 2(j) and (k)]
- Unbilled revenue [Note 2(g)(iii)]
- Regulatory assets and liabilities [Note 6]
- Employee future benefits [Note 13]
- Payments in lieu of corporate income taxes [Note 21]

## CHANGES IN ACCOUNTING POLICIES – FUTURE

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to International Financial Reporting Standards ['IFRS'] effective January 1, 2011. While the Corporation is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board ['IASB']. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 – Regulatory Deferred Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted. The Corporation will adopt IFRS and early adopt IFRS 14 on January 1, 2015.

# Critical Non-Capital Resources and Internal Processes

## CRITICAL NON-CAPITAL RESOURCES

The Corporation employs over 650 people with Hydro Ottawa Limited accounting for over 90 percent of this workforce.

Over the next five years, 156 employees of Hydro Ottawa will be eligible to retire with an unreduced pension. Almost 60 percent are trades and technical employees; the other 40 percent are management, administrative, professional, and clerical employees. This reflects a broader trend of workforce demographics seen by utilities in Ontario and across Canada.

In preparation for these retirements, Hydro Ottawa has a comprehensive and integrated talent management strategy to ensure a sustainable and prepared workforce. This includes:

- Extensive in-house apprenticeship programs, and an engineering intern training and development program, to ensure the availability of qualified journeypersons and professional engineers;
- A succession planning and management program and training and development program to ensure that there are qualified employees in the talent pipeline for key positions;
- A proactive approach to knowledge management and knowledge transfer for key positions, including an older worker and retiree engagement strategy so that work is seamlessly transitioned from our veteran workforce to the next generations;
- A Diversity Plan to create and support a talented workforce that is reflective of the diversity in the communities we serve; and
- Partnerships with industry and educational institutions to support the implementation of the talent management strategy. These include, most notably, collaborations with Algonquin College to deliver the College's new Powerline Technician diploma program, and with Carleton University's Sustainable and Renewable Energy Engineering Department for the establishment of a smart grid laboratory to foster innovative research on electrical power systems and promote the training of engineers in the smart grid environment.

On November 20, 2012, with the acquisition of assets from Domtar Inc., over 20 individuals who were previously employed by Domtar Inc. became employees of Chaudiere Hydro L.P. and CWPI. As a result of this transaction, the Corporation established a defined benefit pension plan for these employees. A Retirement Committee has been created to undertake the management, operation and administration of the pension plan; this Committee through the Governance and Management Resources Committee reports to the Hydro Ottawa Holding Inc. Board of Directors.

## INTERNAL PROCESSES

Various technologies and processes have been introduced to enhance sustainability and better manage electrical distribution assets and improve customer service, including increasing the automation and reliability of the network through faster restoration times. Hydro Ottawa believes a commitment to sustainability is important not only because it benefits the environment, but also because it improves the Corporation's business.

With the successful completion of the Province's Smart Meter and Time-of-Use rate programs in 2011, in 2013 the Corporation continued to focus on leveraging customer access to their account information through customer self-serve options not available prior to the Smart Metering initiative. These options result in improved customer satisfaction, fewer complaints and improved efficiencies.

By year end 2013 over 104,000 customers [33 percent of all customers] had subscribed to *MyHydroLink*, a web-based customer portal that provides a number of self-service options. Over 66,000 customers have opted to receive their Hydro Ottawa bill electronically, and over 63,000 customers have subscribed to an automated payment process which is more convenient for them and more efficient for the utility.

Customer use of Hydro Ottawa's leading mobile web offering continued to increase in popularity in 2013. This mobile service features many customer account information options along with access to Hydro Ottawa's award winning Outage Communications system. Hydro Ottawa Mobile is available to customers with a smart phone such as an iPhone, Android device or BlackBerry.

In 2013 Hydro Ottawa continued to deploy a Remote Disconnect/Reconnect feature that allows electrical service to be interrupted and restored to a customer's premise remotely by Hydro Ottawa staff. This will provide more efficient service by reducing the number of truck-rolls required to respond to non-payment situations. Over 8,400 meters are now equipped with this feature.

Hydro Ottawa Limited also continues to maintain certification to several international standards, including ISO 9001 Quality Management System, ISO 14001 Environmental Management System and OHSAS 18001 Occupational Health and Safety Management System. Internal and external third-party audits are conducted annually to confirm and maintain certification and to attain re-registration as required by the standards.

A key and significant upgrade to the Customer Information System ['CIS'] which began in 2011 has been completed and deployed in early 2014. In conjunction with this upgrade, Hydro Ottawa converted all residential and small commercial customers to a monthly billing cycle, in place of the bi-monthly cycle.

In 2013 Hydro Ottawa completed its most extensive Customer Market Research which enabled the development of a series of customer persona profiles. This foundational research will be utilized in the development of Hydro Ottawa's Customer Experience Strategic Plan and is being applied in the deployment of several initiatives throughout the Corporation.

The Corporation places significant emphasis on cost containment and productivity improvements in order to enhance financial strength and operational performance. The OEB sets productivity improvement targets for electricity distributors as part of its Incentive Regulation Mechanism, and the Corporation pursues corporate-wide efficiencies in addition to those targets. In 2013 Hydro Ottawa launched a corporate-wide team to develop a five-year strategy to help the entire Corporation prioritize and put into place plans for productivity improvements. This team was tasked with identifying new initiatives for 2014 which will have a notable and positive impact on productivity. These initiatives include the deployment of an Asset Optimization Tool and a Mobile Workforce Management Tool. Coincident with the development the five-year strategy, will be the development of a scorecard to monitor and report on overall productivity of the Corporation.

## Risks and Uncertainties

The ability to manage and mitigate risk, to maintain flexibility, and to respond effectively to changes in our business environment is critical to the Corporation's continued success.

The Corporation's Enterprise Risk Management ['ERM'] system establishes the framework to help the Corporation track and respond to risks and opportunities impacting strategic direction and business activities, in a consistent and integrated manner across the enterprise. A multi-year Business Planning cycle, with annual updates, enables continuous review of assumptions and the state of the market in which the Corporation operates.

Hydro Ottawa continues to monitor and manage traditional risks and sources of risk that are structural within the industry and the regulated environment. It is possible; however, that some of these risks could adversely impact Hydro Ottawa's results and objectives. These include but are not restricted to: the weather; the policy and regulatory environment; the state of the economy and macro-economic trends; government policies relating to the production and procurement of renewable and clean energy as well as carbon emissions and conservation; labour force demographics, with a particular emphasis on the renewal of human resources in the trades; and the impact of fiscal policies on customers. In addition, the evolution of the industry presents new and emerging risks that need to be managed effectively.

The emerging as well as the traditional risks are discussed below.

### POLICY AND REGULATORY ENVIRONMENT

Political uncertainty in the province of Ontario could affect opportunities for growth, in both electricity distribution [e.g. potential consolidation and integration of local distribution companies] and electricity generation [e.g. rates for new power purchase agreements; approval of new Feed-In Tariff projects].

Hydro Ottawa's businesses operate in a regulated environment. Business performance could be adversely affected by significant policy and regulatory changes, including but not limited to changes in rate regulation, policies relating to the production, procurement, pricing or sale of renewable and clean energy, carbon emissions, CDM, the consolidation of electrical utilities, or restrictions on utility service provision.

The OEB approves local electricity distribution rates based on projected load growth and consumption levels. Hydro Ottawa sought and obtained OEB approval for a rebasing of its distribution rates, which went into effect on January 1, 2012, with OEB-approved incentive regulation applications thereafter. If actual experience varies from the projections, the Corporation's net income could be affected. Hydro Ottawa's distribution revenue will decline if CDM forecasts are exceeded. While the OEB has recognized the need to compensate for such lost revenue, the Lost Revenue Adjustment Mechanism instituted by the OEB may not adequately compensate the Corporation for such lost revenue.

The ability to maintain and operate the electrical distribution system reliably and safely depends on sufficient funding and the OEB allowing recovery of capital expenditures on distribution infrastructure repair and replacement.

## ECONOMY

The state of the local and national economy could have a significant impact on the Corporation's business performance, through factors such as interest rates, inflation, customer credit risk, weakening demand for electricity and/or value-added services, and availability of market capital to fund growth. The economic climate could also have an effect on the stability and performance of some of Hydro Ottawa's key business partners.

## CREDIT RATINGS

Significant future changes in business or financial risks could affect the Corporation's existing credit rating of [A/Stable].

## DEPENDENCE ON PARTNERS

Current and future growth opportunities may depend upon the presence of willing partners, capable of performing to long-term expectations. The absence of municipalities willing to partner on utility service delivery, or of willing partners for mergers and acquisitions, or the underperformance of key business partners, could have a negative impact on Hydro Ottawa's ability to meet its growth objectives.

## PENSION PLANS

The Corporation provides a defined benefit pension plan for the majority of its employees, through the Ontario Municipal Employees Retirement System ['OMERS']. As OMERS is a multi-employer, contributory, defined benefit pension plan, it is not practicable to determine the Corporation's portion of pension obligations or the fair value of plan assets. OMERS' future funding shortfalls and net losses, if any, may entail temporary contribution increases from both members and employers.

Hydro Ottawa has recently established a defined benefit pension plan for employees of Chaudiere Hydro L.P. and participating employers, with appropriate financial and investment procedures and oversight, as required by law. Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that pension plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets.

## TECHNOLOGY INFRASTRUCTURE

The Corporation's business performance is dependent upon complex technology systems, including administrative information technology, customer information and billing systems, advanced metering, and operational technologies such as geographic information systems, system control and outage management systems. Increasing automation, the integration of systems, and extensive use of common technology in facilitating such integration and connectivity present emerging risks that the Corporation must manage effectively. The failure of one or more of these key systems, or a failure of the Corporation to plan effectively for future technology needs or transition effectively to new technology systems could adversely impact the Corporation's business operations.

### CYBER SECURITY

The Corporation's reliance on information systems and expanded data transmission and exchange networks, in conjunction with the growing extent of systems and data integration within the electricity sector, increases its exposure to information security threats, including cyber security risks. A security breach, data corruption or system failure at a shared resource or common service provider, could put Hydro Ottawa's information systems and information assets at risk.

### TIME-OF-USE TECHNOLOGY

Given the number of devices, systems and web interfaces involved in the smart meter – TOU billing process, as well as the number of external and internal service providers engaged, risks arising from the reliability and performance of any single component of this integrated network or of the system as a whole could lead to a disruption of the meter-to-cash cycle.

## CUSTOMER, MEDIA PERCEPTIONS

Electrical utilities across Ontario are confronted with risks arising from negative customer and media perceptions, driven by rising electricity prices and inconsistent service levels, including reported billing inaccuracies. With Hydro Ottawa's cutover in early 2014 to a new customer care and billing system, and the phased transition of its customers to monthly billing, these risks could become more prominent.

## LABOUR FORCE DEMOGRAPHICS

Across the electricity sector, retirements are outpacing new entrants to the workforce, which could have an adverse impact on the ability of the Corporation to build a sustainable workforce and achieve its business objectives. Hydro Ottawa's investments in apprenticeship, succession planning and retiree engagement programs are designed to manage risks relating to workforce demographics.

### WEATHER

Severe weather can significantly impact financial results. Storms increase capital and maintenance costs to repair or replace damaged equipment and infrastructure, to ensure the continuing reliability of the electricity distribution system. Weather fluctuations also influence distribution revenues, which tend to increase with severe weather and decrease with moderate weather, and renewable energy production, which depends upon factors such as water flows [hydroelectric], and sun [solar].

## Outlook

Subject to the risks and uncertainties discussed in this document, Hydro Ottawa will continue to provide efficient, reliable electricity distribution services to customers at a competitive cost, generate green power, and provide energy services and conservation expertise while maintaining sustainable earnings. The Corporation will achieve this by continuing to invest in core distribution assets, improving productivity and pursuing business growth opportunities that leverage corporate strengths.

The Corporation also continues to actively pursue opportunities for expansion in non-regulated business lines in accordance with the endorsed strategy, as evidenced by the acquisition of the run-of-the-river generation assets, the completion of a second landfill gas collection plant and the upcoming expansion of generation facilities at Chaudière Falls.

# Consolidated Financial Statements

December 31, 2013

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**Report of Management**

Management is responsible for the integrity of the financial data reported by Hydro Ottawa Holding Inc. ['the Corporation']. Fulfilling this responsibility requires the preparation and presentation of consolidated financial statements using management's best judgment and estimates in accordance with Canadian generally accepted accounting principles, applied on a basis consistent with the preceding year.

Management maintains appropriate systems of internal control and corporate-wide policies and procedures, which provide reasonable assurance that the Corporation's assets are safeguarded and that financial records are relevant and reliable.

The Board of Directors, through the Audit Committee, ensures that management fulfills its responsibility for financial reporting and internal control. The Audit Committee consists of outside directors and at regular meetings reviews audit, internal control and financial reporting matters with management and external auditors. The Audit Committee has reviewed the consolidated financial statements and submitted its report to the Board of Directors.

On behalf of Management,

Bryce Conrad
President and Chief Executive Officer

Geoff Simpson
Chief Financial Officer

# INDEPENDENT AUDITORS' REPORT

To the Shareholder of
**Hydro Ottawa Holding Inc.**

We have audited the accompanying consolidated financial statements of **Hydro Ottawa Holding Inc.**, which comprise the consolidated balance sheet as at December 31, 2013, and the consolidated statements of income, comprehensive income and retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's responsibility for the consolidated financial statements**

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Hydro Ottawa Holding Inc.** as at December 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ottawa, Canada,
April 3, 2014.

Chartered Accountants
Licensed Public Accountants

## Hydro Ottawa Holding Inc.

Consolidated Statement of Income, Comprehensive Income and Retained Earnings
Year ended December 31
[in thousands of Canadian dollars]

| | 2013 | 2012 |
|---|---|---|
| **Revenue** | | |
| Power recovery [Note 24] | **$ 768,079** | $ 709,935 |
| Distribution sales [Note 24] | **152,392** | 151,936 |
| Generation revenue | **21,047** | 11,009 |
| Other revenue [Note 24] | **34,849** | 27,895 |
| | **976,367** | 900,775 |
| **Expenses** | | |
| Purchased power | **765,151** | 707,552 |
| Operating costs [Note 24] | **114,291** | 105,471 |
| Depreciation | **31,891** | 30,449 |
| Amortization | **8,431** | 6,672 |
| | **919,764** | 850,144 |
| **Income before other expenses (recoveries) and payments in lieu of corporate income taxes** | **56,603** | 50,631 |
| Financing costs [Note 20] | **14,645** | 11,101 |
| Recovery of regulatory asset write-down [Note 6] | **-** | (679) |
| | **14,645** | 10,422 |
| **Income before payments in lieu of corporate income taxes** | **41,958** | 40,209 |
| **Payments in lieu of corporate income taxes [Note 21]** | **9,410** | 8,928 |
| **Net income and comprehensive income** | **32,548** | 31,281 |
| **Attributable to non-controlling interest [Note 17]** | **406** | 292 |
| **Attributable to equity shareholder** | **32,142** | 30,989 |
| **Retained earnings, beginning of year** | **138,242** | 123,853 |
| **Dividends declared and paid [Note 16]** | **(18,600)** | (16,600) |
| **Recovery of refundable dividend taxes paid [Note 16]** | **1,489** | - |
| **Retained earnings, end of year** | **$ 153,273** | $ 138,242 |

*The accompanying notes are an integral part of these consolidated financial statements*

# Hydro Ottawa Holding Inc.

Consolidated Balance Sheet
As at December 31
[in thousands of Canadian dollars]

| | 2013 | 2012 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Accounts receivable [Notes 4 and 24] | **$ 70,276** | $ 75,408 |
| Payments in lieu of corporate income taxes receivable | **2,372** | 1,482 |
| Unbilled revenue [Note 5] | **106,551** | 89,935 |
| Prepaids | **3,099** | 2,653 |
| Regulatory assets [Note 6] | **31** | 1,969 |
| Future income tax assets [Note 21] | **818** | 628 |
| | **183,147** | 172,075 |
| **Non-current assets** | | |
| Regulatory assets [Note 6] | **12,441** | 7,603 |
| Property, plant and equipment [Note 7] | **725,656** | 669,740 |
| Intangible assets [Note 8] | **66,126** | 51,787 |
| Future income tax assets [Note 21] | **19,947** | 24,222 |
| Retirement benefit asset [Note 13] | **689** | 474 |
| **Total assets** | **1,008,006** | 925,901 |
| | | |
| **Liabilities and shareholder's equity** | | |
| **Current liabilities** | | |
| Bank indebtedness [Note 9] | **8,853** | 77,357 |
| Accounts payable and accrued liabilities [Notes 10 and 24] | **132,348** | 132,791 |
| Payments in lieu of corporate income taxes payable | **157** | 702 |
| Regulatory liabilities [Note 6] | **19,173** | 22,097 |
| Notes payable [Note 14] | **340** | 620 |
| Regulatory liability for future income tax assets [Note 21] | **818** | 628 |
| | **161,689** | 234,195 |
| **Non-current liabilities** | | |
| Regulatory liabilities [Note 6] | **12,915** | 20,144 |
| Regulatory liability for future income tax assets [Note 21] | **19,893** | 24,165 |
| Employee future benefits [Note 13] | **9,065** | 10,780 |
| Notes payable [Note 14] | **400,413** | 251,459 |
| Future income tax liabilities [Note 21] | **6,464** | 5,179 |
| Other liabilities [Note 11] | **13,414** | 12,261 |
| | **623,853** | 558,183 |
| **Shareholder's equity** | | |
| Share capital [Note 16] | **228,453** | 228,453 |
| Retained earnings | **153,273** | 138,242 |
| Non-controlling interest [Note 17] | **2,427** | 1,023 |
| | **384,153** | 367,718 |
| **Total liabilities and shareholder's equity** | **$ 1,008,006** | $ 925,901 |

**Contingent liabilities and commitments [Notes 22 and 23]**

ON BEHALF OF THE BOARD:

Marion Harvey

Director

Director

*The accompanying notes are an integral part of these consolidated financial statements*

## Hydro Ottawa Holding Inc.

Consolidated Statement of Cash Flows
Year ended December 31
[in thousands of Canadian dollars]

| | 2013 | 2012 |
|---|---|---|
| **Net inflow (outflow) of cash related to the following activities:** | | |
| **Operating** | | |
| Net income and comprehensive income | **$ 32,548** | $ 31,281 |
| Items not affecting cash | | |
| Depreciation | **31,891** | 30,449 |
| Amortization | **8,431** | 6,672 |
| Loss on disposal of property, plant and equipment | **1,083** | 1,779 |
| Allowance for funds used during construction [Notes 7 and 8] | **(2,411)** | (2,056) |
| Future payments in lieu of corporate income taxes | **1,288** | 671 |
| Amortization of debt-issuance costs | **237** | 225 |
| Employee future benefits [Notes 6 and 13] | **107** | 188 |
| Change in retirement benefit asset [Note 13] | **(215)** | 7 |
| Changes in non-cash working capital and other operating balances | | |
| Decrease (increase) in accounts receivable | **5,132** | (9,833) |
| Increase in unbilled revenue | **(16,616)** | (2,680) |
| Increase in prepaids [Note 18] | **(446)** | (742) |
| (Increase) decrease in regulatory assets, net of liabilities [Notes 6 and 13] | **(14,949)** | 13,456 |
| Increase in accounts payable and accrued liabilities [Notes 7, 8 and 13] | **3,296** | 6,280 |
| Increase in payments in lieu of corporate income taxes receivable/payable [Note 16] | **54** | 5,107 |
| | **49,430** | 80,804 |
| **Investing** | | |
| Acquisition of property, plant and equipment [Notes 7 and 18] | **(112,299)** | (107,695) |
| Acquisition of intangible assets [Notes 8 and 18] | **(23,069)** | (10,929) |
| Proceeds from disposal of property, plant and equipment | **1,765** | 45 |
| Acquisition of assets from Domtar Inc. [Note 18] | **-** | (46,339) |
| Contributions in aid of construction [Note 7] | **21,419** | 22,191 |
| | **(112,184)** | (142,727) |
| **Financing** | | |
| Proceeds from bond issuance, net of debt-issuance costs [Note 14] | **148,857** | - |
| Increase (decrease) in customer deposits [Notes 10 and 11] | **435** | (1,375) |
| Dividends paid [Note 16] | **(18,600)** | (16,600) |
| Repayment of notes payable [Note 14] | **(420)** | (300) |
| Repayable grant [Note 7] | **(12)** | (15) |
| Contributed capital from non-controlling interest [Note 17] | **998** | - |
| | **131,258** | (18,290) |
| **Net change in cash** | **68,504** | (80,213) |
| **(Bank indebtedness) cash, beginning of year** | **(77,357)** | 2,856 |
| **Bank indebtedness, end of year** | **$ (8,853)** | $ (77,357) |
| **Supplemental cash flow information** | | |
| Interest paid | **$ 16,864** | $ 12,723 |
| Payments in lieu of corporate income taxes paid, net of refunds | **$ 7,858** | $ 3,199 |

*The accompanying notes are an integral part of these consolidated financial statements*

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

## 1. DESCRIPTION OF BUSINESS

**Hydro Ottawa Holding Inc.** ['Hydro Ottawa' or the 'Corporation'] was incorporated on October 3, 2000 pursuant to the *Business Corporations Act (Ontario)* as mandated by the Ontario government's *Electricity Act, 1998*. The Corporation is wholly owned by the City of Ottawa [the 'Shareholder']. The Corporation owns 100% of Hydro Ottawa Limited, Energy Ottawa Inc. ['Energy Ottawa'] and Telecom Ottawa Holding Inc. ['TOHI'], which does not maintain active operations.

**Hydro Ottawa Limited** is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Village of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, Hydro Ottawa Limited invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services and for debt retirement.

**Energy Ottawa** is a power generation company that generates renewable energy. Energy Ottawa also offers a range of expert energy management and procurement services to large energy-consuming organizations and companies. Energy Ottawa holds interests in the following entities:

- Chaudiere Hydro L.P. was formed on June 22, 2012 and is over 99.99% owned by Energy Ottawa and less than 0.01% owned by Chaudiere Hydro Inc. ['Chaudiere Hydro GP']. Chaudiere Hydro L.P. was formed to own and operate three hydroelectric generation plants and related assets purchased from Domtar Inc. on November 20, 2012 as described in Note 18 of these consolidated financial statements. Chaudiere Hydro GP is wholly owned by Energy Ottawa and was incorporated on June 18, 2012 to act as the general partner of Chaudiere Hydro L.P.

- Moose Creek Energy LP ['Moose Creek LP'] is a 50.10% owned joint venture formed on April 15, 2011 to facilitate the construction and operation of a generation plant and gas collection system at the Laflèche landfill site in Moose Creek, Ontario. Moose Creek Energy Inc., a 50.00% owned joint venture incorporated on March 2, 2011, is the general partner of Moose Creek LP. Commercial operations of Moose Creek LP commenced on January 25, 2013.

- PowerTrail Inc. ['PowerTrail'] is a 60.00% owned joint venture incorporated on August 10, 2005 to construct and operate a generation plant and gas collection system at the Trail Road landfill site in Ottawa, Ontario.

- Chaudiere Water Power Inc. ['CWPI'] is a 66.67% owned joint venture [as of November 20, 2012; 28.33% previously], incorporated on April 30, 1981 to act as an agent for the three principals of CWPI with a mandate to operate the Chaudière Dam facilities on the Ottawa River. The facilities are not owned by CWPI; they are jointly owned by the principals. In accordance with the shareholders agreement, all costs incurred by CWPI in relation to the facilities are fully reimbursed in accordance with each principal's ownership percentage.

## 2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ['pre-changeover Canadian GAAP'], including principles prescribed by the Ontario Energy Board ['OEB'] in the *Accounting Procedures Handbook* ['AP Handbook']. In the opinion of management, all adjustments necessary for fair presentation are reflected in the consolidated financial statements. The consolidated financial statements reflect the significant accounting policies summarized below.

### (a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its subsidiaries: Hydro Ottawa Limited, Telecom Ottawa Holding Inc., and Energy Ottawa, which includes the accounts of PowerTrail, Moose Creek LP, Chaudiere Hydro L.P., Chaudiere Hydro GP and CWPI [as of November 20, 2012]. All intercompany balances and transactions have been eliminated in these consolidated financial statements.

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (b) Consolidation of variable interest entities

The Corporation consolidates variable interest entities ['VIEs'] in which the Corporation is the primary beneficiary, as described in pre-changeover Canadian GAAP Accounting Guideline 15 – *Consolidation of Variable Interest Entities* ['AcG-15']. Upon the application of AcG-15, the initial equity investment at risk was not sufficient to permit PowerTrail or Moose Creek LP to finance their activities without additional subordinated financial support from its equity owners and, as such, PowerTrail and Moose Creek LP are consolidated in the consolidated financial statements of Energy Ottawa and ultimately, the Corporation.

As of November 20, 2012, Energy Ottawa became the primary beneficiary of CWPI due to an increase in effective share ownership from 28.33% to 66.66% as a result of the acquisition of assets described in Note 18 of these consolidated financial statements. CWPI was therefore consolidated by Energy Ottawa under AcG-15 as of this date. Prior to November 20, 2012, Energy Ottawa accounted for its 28.33% interest as a joint venture using proportionate consolidation and accounted for the costs incurred by CWPI as operating or capital expenditures, based on the nature of the costs.

The VIEs have non-controlling interests which are reported separately as part of equity.

### (c) Investment in joint venture

The Corporation holds a 50.00% interest in Moose Creek GP, the general partner of Moose Creek LP. As general partner, Moose Creek GP has the full and exclusive right, power and authority to manage, control, administer and operate the business and affairs regarding the undertaking and business of Moose Creek LP. The other 50.00% is owned by Integrated Gas Recovery Services Inc. ['IGRS'] of Thorold, Ontario. While the Corporation accounts for its interest in Moose Creek GP using proportionate consolidation, Moose Creek GP does not contain significant assets, liabilities, revenue or expenses.

### (d) Acquisition of assets and business combinations

The Corporation evaluates the integrated set of activities [inputs, processes, outputs] associated with an acquired asset group to determine whether it meets the definition of a business as prescribed by Section 1582 Business Combinations under pre-changeover Canadian GAAP. The consideration for an acquisition is measured at the aggregate of the fair values, at the date of exchange, of the assets transferred and the liabilities incurred to former owners of the acquired business in exchange for control of the acquired business. If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Corporation will report in its consolidated financial statements provisional amounts for the items for which the accounting is incomplete. Within one year, the Corporation will retrospectively adjust the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date and, if known, would have affected the measurement of the amounts recognized as of that date.

Transaction costs with respect to a business combination are expensed as incurred and included in general and administrative expenses as part of operating costs.

## Hydro Ottawa Holding Inc.

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

### 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

#### (e) Measurement uncertainty

The preparation of consolidated financial statements in conformity with pre-changeover Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Accounts receivable and unbilled revenue are reported net of an appropriate allowance for unrecoverable amounts. Other significant estimates are used in determining the useful lives and asset impairments of long-lived assets, payments in lieu of corporate income taxes, employee future benefits, the retirement benefit asset, certain accruals, as well as the fair value of assets and liabilities acquired.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these consolidated financial statements, including changes as a result of future decisions made by the OEB or the provincial government. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies.

#### (f) Regulation

Hydro Ottawa Limited is regulated by the OEB under the authority of the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfil obligations to connect and service customers.

Hydro Ottawa Limited operates under an incentive regulation mechanism ['IRM'] prescribed by the OEB. Under an IRM, a distributor first sets base rates through a cost-of-service application every four years. This application determines the appropriate revenue requirement to recover approved costs, and provides a rate of return on a deemed capital structure applied to approved rate base assets. For subsequent years in which no cost-of-service application is filed, rates are adjusted by an inflation factor less a productivity factor.

Hydro Ottawa Limited applies for distribution rates based on estimated costs of service. Once the rate is approved, it is not adjusted as a result of actual costs of service being different from those which were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates. The OEB has the general power to include or exclude costs and revenue in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company.

Hydro Ottawa Limited continues to assess the likelihood of recovery of all regulatory assets subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, the Corporation will recognize the provision in operating costs for the period.

The following regulatory treatments have resulted in accounting treatments that differ from pre-changeover Canadian GAAP for enterprises operating in a non-regulated environment:

(i) Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers for electricity services and the costs that Hydro Ottawa Limited incurs to purchase these services.

Hydro Ottawa Limited accrues interest on the regulatory asset and liability balances as directed by the OEB.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (f) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after the reporting period. All other regulatory asset and liability balances are classified as long-term on the consolidated balance sheet.

Regulatory balances are comprised principally of the following:

- Regulatory asset/liability refund account ['RARA' / 'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.

- Settlement variances relate primarily to the charges Hydro Ottawa Limited incurred for transmission services, the commodity, wholesale market operations and the global adjustment that were not settled with customers during the period. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time and they are reported at year end dates in accordance with rules prescribed by the OEB.

- Deferred smart meter costs represent the differences between the amounts funded through rates for smart meters and actual program costs. Program costs include operating, maintenance, depreciation and administrative expenses directly related to smart meters, a return on smart meter assets, and the net book value of conventional meters removed upon the installation of smart meters.

- Other Post Employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to post-retirement benefits relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

Other regulatory variances and deferred costs:

- The OEB allows electricity distributors to record in a deferral account the difference between low voltage charges paid to Hydro One Networks Inc. and those charged to customers.

- The OEB allows electricity distributors to record in a deferral account the net cost of providing retailer billing services and transaction request services.

- The OEB approved a deferral account for distributors to record one-time administrative incremental International Financial Reporting Standards ['IFRS'] transition costs, which were not already approved and included for recovery in distribution rates.

- In its Guidelines released June 16, 2009, the OEB created four new deferral accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid. These deferral accounts were authorized to be used to record qualifying incremental capital investments or operating, maintenance and administrative expenses.

**Hydro Ottawa Holding Inc.**

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**2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]**

**(f) Regulation [continued]**

(i) Regulatory assets and liabilities [continued]

- In its Guidelines released January 5, 2012, the OEB required Hydro Ottawa Limited to record the difference between the actual authorized Conservation and Demand Management ['CDM'] activities and activities included in Hydro Ottawa Limited's load forecast. This variance is recorded in the Lost Revenue Adjustment Mechanism variance account.

- The OEB directed distributors to record the input tax credit savings arising from the elimination of the provincial sales tax and implementation of the harmonized sales tax on July 1, 2010 in a separate account. The OEB concluded that fifty percent of the balances should be returned to the ratepayers for the period up to the rebasing date, which for Hydro Ottawa Limited was January 1, 2012.

(ii) Contributions in aid of construction

Contributions in aid of construction received from outside sources are used to finance additions to property, plant and equipment. According to the AP Handbook, contributions in aid of construction are treated as a reduction to property, plant and equipment and are depreciated at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

(iii) Allowance for funds used during construction ['AFUDC']

An allowance for the cost of funds used during the construction period has been applied to major capital and development projects.

(iv) Payments in lieu of corporate income taxes ['PILs']

Hydro Ottawa Limited is considered to be a Municipal Electric Utility ['MEU'] for purposes of the PILs regime contained in the *Electricity Act, 1998*, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the *Income Tax Act (Canada)* ['ITA'] and the *Taxation Act, Ontario* ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

Hydro Ottawa Limited follows the liability method for recording income taxes in accordance with pre-changeover Canadian GAAP recommendations. Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The AP Handbook provides for the recovery of PILs by Hydro Ottawa Limited through annual distribution rate adjustments as approved by the OEB. Hydro Ottawa Limited recognizes regulatory liabilities and assets for the amounts of future income taxes expected to be refunded to or recovered from customers in future electricity rates.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (f) Regulation [continued]

(iv) Payments in lieu of corporate income taxes ['PILs'] [continued]

The Corporation, Energy Ottawa, Chaudiere Hydro GP and Telecom Ottawa Holding Inc. are also MEUs that account for PILs using the liability method.

PowerTrail and CWPI are taxable under the ITA and TAO as less than 90% of each corporation's share capital is owned by the City of Ottawa. Corporate income taxes are accounted for using the liability method as described above.

Moose Creek LP and Chaudiere Hydro L.P. are not taxable entities for federal and provincial income tax purposes. Tax on the net income (loss) is borne by the individual partners through the allocation of taxable income.

### (g) Revenue recognition

The Corporation recognizes revenue when persuasive evidence of an arrangement exists, services have been delivered, the price has been fixed or is determinable and collection is reasonably assured.

(i) Distribution sales

The Corporation charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Corporation to recover its prudently incurred costs and earn a fair return on invested capital. Distribution sales are recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates.

(ii) Power recovery

Power recovery revenue represents the pass-through of the cost of power to the consumer as purchased by the Corporation and is recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system.

(iii) Unbilled revenue

Unbilled revenue represents an estimate of the electricity consumed by customers that has not yet been billed at year end.

(iv) Generation revenues

Generation revenue is recorded on the basis of regular meter readings.

**Hydro Ottawa Holding Inc.**

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## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (g) Revenue recognition [continued]

(v) Other revenue

Other revenue related to the provision of services is recognized as services are rendered. Other revenue includes contract revenue, commercial services revenue and conservation and demand management ['CDM'] revenue.

Contract revenue and commercial services revenue are accounted for using the percentage-of-completion method, whereby revenue and the corresponding costs are recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident. CDM revenue stems from the delivery of provincial government programs that promote conservation and is recognized on a cost-recovery basis.

### (h) Bank indebtedness

Bank indebtedness includes short-term advances and/or bankers' acceptances with a maturity date of three months or less, and outstanding cheques.

### (i) Financial instruments

All financial instruments are initially recorded at fair value, unless fair value cannot be reliably determined. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties. The subsequent measurement of each financial instrument depends on the classification elected by the Corporation.

The Corporation classifies and measures its financial instruments as follows:

- Cash is classified as held-for-trading and is measured at fair value.

- Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value with the exception of related party transactions which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, *Related Party Transactions*. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

- Bank indebtedness, accounts payable and accrued liabilities, customer deposits and notes payable are classified as other financial liabilities and are initially measured at their fair value with the exception of related party transactions which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, *Related Party Transactions*. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

## Hydro Ottawa Holding Inc.

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### 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

#### (j) Property, plant and equipment

Property, plant and equipment consist principally of electricity distribution infrastructure, generating plant and equipment, buildings and fixtures, land, reservoirs, dams and waterways, furniture and equipment, and assets under construction. Property, plant and equipment acquired in a business combination are initially recorded at their acquisition date fair values.

Spare parts and standby equipment, which are expected to be used during more than one year, are considered to be assets under construction, and are depreciated only once they are put into service.

Property, plant and equipment are recorded at cost and include directly attributable contracted services, materials, labour, engineering costs, overheads and AFUDC. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions in aid of construction received are treated as a contra account to property, plant and equipment. The amount is depreciated by a charge to accumulated depreciation and a reduction in depreciation expense at an equivalent rate to that used for the depreciation of the related asset.

Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is increased, reliability is improved above original design standards or if operating costs are reduced by a substantial and quantifiable amount.

Depreciation is recorded on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for property, plant and equipment classes are as follows:

| | |
|---|---|
| Buildings and fixtures | 20 to 100 years |
| Furniture and equipment | 5 to 10 years |
| Rolling stock | 7 to 15 years |
| Electricity distribution infrastructure | 10 to 60 years |
| Generating plant and equipment | 3 to 50 years |
| Reservoirs, dams and waterways | 75 to 125 years |

Assets under construction, land, spare parts and standby equipment are not subject to depreciation.

The Corporation reviews its property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Corporation will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Corporation's primary measure of fair value is based on discounted cash flows.

#### (k) Intangible assets

Intangible assets include land rights, a power purchase agreement, line connection contributions, computer software, water rights and computer software under development.

## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (k) Intangible assets [continued]

Intangible assets with finite lives are recorded at cost and amortized on a straight-line basis over the estimated service life of the related asset. Intangible assets acquired in a business combination are initially recorded at their acquisition date fair values.

Estimated service lives for intangible assets with finite lives are as follows:

| | |
|---|---|
| Land rights | 50 years |
| Power purchase agreement | 7 years |
| Line connection contributions | 45 years |
| Computer software | 5 to 10 years |

Water rights with respect to the Chaudière Dam on the Ottawa River, which has an indefinite useful life, and computer software under development are not subject to amortization.

The Corporation reviews its intangible assets subject to amortization for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Corporation will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Corporation's primary measure of fair value is based on discounted cash flows.

The Corporation reviews its intangible assets not subject to amortization annually for the possibility of impairment. Through this process, the assessment of indefinite life is reviewed to determine whether the indefinite life continues to be supportable. If not, the change in useful life from indefinite to finite is made on a prospective basis.

### (l) Asset retirement obligations

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of a liability for an asset retirement obligation is recognized in the period during which it is incurred if a reasonable estimate can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows are reflected in the liability. The liability is adjusted for an annual accretion charged to operating costs. A gain or loss may be incurred upon settlement of the liability.

### (m) Employee future benefits

#### (i) Pension plans

The Corporation provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

**Hydro Ottawa Holding Inc.**

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## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (m) Employee future benefits [continued]

#### (i) Pension plans [continued]

Although the plan is a defined benefit plan, sufficient information is not available to the Corporation to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the fund. As a result, the Corporation accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs.

Chaudiere Hydro L.P. is the sponsoring employer of the Pension Plan for Employees of Chaudiere Hydro L.P. and Participating Employers ['Chaudiere Pension Plan' or 'CHPP'] effective November 20, 2012 and is accounted for as follows:

- CHPP assets are assets that are held by an insurance corporation and are measured at fair value, which is based on published market mid-price information in the case of quoted securities.

- Accrued benefit obligations of the CHPP are determined based on the expected future benefit payments discounted using market interest rates on high-quality debt instruments that match the timing and amount of expected benefit payments.

- The cost of pension earned by employees is actuarially determined using the projected benefit method prorated on services, and management's best estimate of expected plan investment performance, salary escalation, retirement ages, life expectancy and health care costs.

- The actuarial gains and losses arising on the plan assets and defined benefit obligation are recognized into income in the year in which they occur using the immediate recognition approach.

- Past service costs are included in the cost of the CHPP for the year when they arise.

Since the CHPP is funded, the fair value of the Chaudiere Pension Plan assets is offset against the accrued benefit obligation. The net amount is included in the retirement benefit asset or retirement benefit liability.

#### (ii) Employee future benefits other than pension plans

Employee future benefits other than pensions provided by the Corporation include medical, dental and life insurance benefits, accumulated sick leave credits and a retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The accrued benefit obligation and current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are recognized in income immediately, however for Hydro Ottawa Limited, these amounts are deferred as a regulatory asset or liability as permitted by the OEB.

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
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## 2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

### (n) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

### (o) Leases

At the inception of a lease, or an arrangement that contains a lease, the Corporation evaluates whether the lease should be classified as a capital lease or an operating lease. Leases that transfer substantially all the risks and rewards incidental to ownership of the related asset are classified as capital leases. All other leases are classified as operating leases. Classification is reassessed if the terms of the lease are changed.

Upon evaluation, all of the Corporation's leases are classified as operating leases.

### (p) Debt-issuance costs

The Corporation incurred debt issuance costs that were external, direct and incremental in nature arising from its debenture offerings and credit facility restructuring. Debt issuance costs are netted against the proceeds of debt and amortized using the effective yield method. Credit facility restructuring costs are amortized over the initial term of the revolving term credit facility.

## 3. FUTURE CHANGES IN ACCOUNTING POLICIES

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to IFRS effective January 1, 2011. While the Corporation is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board [‘IASB’]. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 - Regulatory Deferred Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted. The Corporation will adopt IFRS and early adopt IFRS 14 on January 1, 2015.

**Hydro Ottawa Holding Inc.**

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## 4. ACCOUNTS RECEIVABLE

| | 2013 | 2012 |
|---|---|---|
| Electricity receivables, net of allowance for doubtful accounts of $1,919 [2012 – $1,411] | $ 52,125 | $ 52,449 |
| Other receivables, net of allowance for doubtful accounts of $66 [2012 – $139] | 11,954 | 17,159 |
| Amounts due from related parties [Note 24] | 6,197 | 5,800 |
| | $ 70,276 | $ 75,408 |

## 5. UNBILLED REVENUE

| | 2013 | 2012 |
|---|---|---|
| Unbilled revenue | $ 106,757 | $ 90,003 |
| Less allowance for doubtful accounts | (206) | (68) |
| | $ 106,551 | $ 89,935 |

## 6. REGULATORY ASSETS AND LIABILITIES

The Corporation files a rate application to settle its regulatory assets and liabilities as required. The time period for settlement is determined by the OEB based on the magnitude of the balances to be cleared.

Information about the Corporation's regulatory assets and liabilities is as follows:

| | 2013 | 2012 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred smart meter costs | $ - | $ 1,939 |
| OPEB deferral account [Note 13] | 3,109 | 4,977 |
| Settlement variances | 5,527 | - |
| RARA | 475 | 253 |
| Other | 3,361 | 2,403 |
| | 12,472 | 9,572 |
| Less current portion | (31) | (1,969) |
| Total non-current regulatory assets | $ 12,441 | $ 7,603 |

## Hydro Ottawa Holding Inc.

Notes to the Consolidated Financial Statements
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### 6. REGULATORY ASSETS AND LIABILITIES [CONTINUED]

| | **2013** | 2012 |
|---|---|---|
| **Regulatory liabilities** | | |
| Settlement variances | **$ 27,374** | $ 39,917 |
| Deferred smart meter costs | **1,045** | - |
| RLRA | **2,002** | 678 |
| Other | **1,667** | 1,646 |
| | **32,088** | 42,241 |
| Less current portion | **(19,173)** | (22,097) |
| Total non-current regulatory liabilities | **$ 12,915** | $ 20,144 |

#### (a) Regulatory asset/liability refund accounts

The RARA/RLRA is the net aggregate of all regulatory assets and liabilities which have been approved for recovery or disposition and includes accrued interest costs up to December 31, 2013 of $178 [2012 – interest cost of $107] less amounts already settled through distribution rates.

On December 5, 2013, the OEB approved the disposition of regulatory liabilities of $19,173, consisting of settlement variances and low voltage variance account accumulated up to December 31, 2012. The December 5, 2013 approved disposition will be transferred to RLRA on January 1, 2014, which is when this disposition is effective in rates.

#### (b) Settlement variances

Settlement variances include accrued interest costs of $284 [2012 – $458].

#### (c) Other

Other variance and deferred costs include accrued interest earned of $34 [2012 –- $13].

#### (d) Income before PILs

In the absence of rate regulation, the income before PILs for the year ended December 31, 2013 would be lower by $13,052 [2012 – higher by $12,305].

#### (e) Recovery of regulatory asset write-down

In 2013, the Corporation recorded a recovery of regulatory asset write-down of nil [2012 – $679].

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
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## 7. PROPERTY, PLANT AND EQUIPMENT

| | | 2013 | |
|---|---|---|---|
| | **Cost** | **Accumulated depreciation** | **Net book value** |
| Land | **$ 31,252** | **$ -** | **$ 31,252** |
| Buildings and fixtures | **87,132** | **22,206** | **64,926** |
| Furniture and equipment | **18,121** | **11,904** | **6,217** |
| Rolling stock | **24,754** | **15,455** | **9,299** |
| Electricity distribution infrastructure | **1,131,820** | **437,739** | **694,081** |
| Generating plant and equipment | **56,445** | **14,559** | **41,886** |
| Reservoirs, dams and waterways | **19,293** | **222** | **19,071** |
| Assets under construction | **44,861** | **-** | **44,861** |
| | **1,413,678** | **502,085** | **911,593** |
| Contributions in aid of construction | **(234,318)** | **(48,381)** | **(185,937)** |
| | **$ 1,179,360** | **$ 453,704** | **$ 725,656** |

| | | 2012 | |
|---|---|---|---|
| | Cost | Accumulated depreciation | Net book value |
| Land | $ 11,639 | $ - | $ 11,639 |
| Buildings and fixtures | 78,076 | 20,135 | 57,941 |
| Furniture and equipment | 20,945 | 15,152 | 5,793 |
| Rolling stock | 23,708 | 15,648 | 8,060 |
| Electricity distribution infrastructure | 1,045,845 | 414,664 | 631,181 |
| Generating plant and equipment | 43,912 | 12,361 | 31,551 |
| Reservoirs, dams and waterways | 19,144 | 112 | 19,032 |
| Assets under construction | 74,698 | - | 74,698 |
| | 1,317,967 | 478,072 | 839,895 |
| Contributions in aid of construction | (214,046) | (43,891) | (170,155) |
| | $ 1,103,921 | $ 434,181 | $ 669,740 |

During the year, the Corporation capitalized an AFUDC of $1,330 [2012 – $1,751] to property, plant and equipment and credited financing costs [Note 20]. The average annual interest rate for 2013 was 4.5% [2012 – 4.8%].

The Corporation entered into significant non-cash transactions that have been excluded from the consolidated statement of cash flows. These transactions were related to property, plant and equipment additions of $11,485 [2012 – $12,859], of which $11,485 [2012 –- $11,674] represent amounts included in accounts payable and accrued liabilities and nil [2012 – $1,185] in construction holdbacks, also included in accounts payable and accrued liabilities as at December 31, 2013.

## Hydro Ottawa Holding Inc.

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### 7. PROPERTY, PLANT AND EQUIPMENT [CONTINUED]

In 2005, Energy Ottawa entered into an agreement with the Federal Government's Department of Natural Resources whereby project funding of up to $220 was provided to Energy Ottawa to field trial a mini hydro turbine developed by the Canada Centre for Mineral and Energy Technology ['CANMET'] Small Hydro Program. Under the terms of the agreement, an amount of $150 of the funding received was repayable at a rate of 2.5% of revenue received from the project, over a maximum period of 10 years. As at December 31, 2013, the unamortized balance of the non-repayable funding received of $41 [2012 – $44] is included in contributions in aid of construction. The current portion of the remaining repayable balance amounts to $12 [2012 – $12] and is included in accounts payable and accrued liabilities, while the long-term portion in the amount of $29 [2012 – $41] is included in other liabilities.

### 8. INTANGIBLE ASSETS

| | 2012 | Acquisitions | Retirements | 2013 |
|---|---|---|---|---|
| **Cost** | | | | |
| Land rights | $ 3,135 | **$ 2** | **$ -** | **$ 3,137** |
| Power purchase agreement | 4,578 | **-** | **-** | **4,578** |
| Line connection contributions | 3,614 | **354** | **-** | **3,968** |
| Computer software | 64,073 | **2,167** | **(5,265)** | **60,975** |
| Water rights | 16,941 | **-** | **-** | **16,941** |
| Computer software under development | 13,690 | **20,246** | **-** | **33,936** |
| | $ 106,031 | **$ 22,769** | **$ (5,265)** | **$ 123,535** |

| | 2012 | Amortization | Retirements | 2013 |
|---|---|---|---|---|
| **Accumulated amortization** | | | | |
| Land rights | $ 1,310 | **$ 49** | **$ -** | **$ 1,359** |
| Power purchase agreement | 81 | **700** | **-** | **781** |
| Line connection contributions | 974 | **70** | **-** | **1,044** |
| Computer software | 51,879 | **7,611** | **(5,265)** | **54,225** |
| | $ 54,244 | **$ 8,430** | **$ (5,265)** | **$ 57,409** |

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| **Net book value as at December 31, 2013** | | | |
| Land rights | **$ 3,137** | **$ 1,359** | **$ 1,778** |
| Power purchase agreement | **4,578** | **781** | **3,797** |
| Line connection contributions | **3,968** | **1,044** | **2,924** |
| Computer software | **60,975** | **54,225** | **6,750** |
| Water rights | **16,941** | **-** | **16,941** |
| Computer software under development | **33,936** | **-** | **33,936** |
| | **$ 123,535** | **$ 57,409** | **$ 66,126** |

**Hydro Ottawa Holding Inc.**

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## 8. INTANGIBLE ASSETS [CONTINUED]

| | 2011 | Acquisitions | Retirements | 2012 |
|---|---|---|---|---|
| Cost | | | | |
| Land rights | $ 3,125 | $ 10 | $ - | $ 3,135 |
| Power purchase agreement | - | 4,578 | - | 4,578 |
| Line connection contributions | 3,583 | 31 | - | 3,614 |
| Computer software | 61,493 | 2,580 | - | 64,073 |
| Water rights | - | 16,941 | - | 16,941 |
| Computer software under development | 3,801 | 9,889 | - | 13,690 |
| | $ 72,002 | $ 34,029 | $ - | $ 106,031 |

| | 2011 | Amortization | Retirements | 2012 |
|---|---|---|---|---|
| Accumulated amortization | | | | |
| Land rights | $ 1,261 | $ 49 | $ - | $ 1,310 |
| Power purchase agreement | - | 81 | - | 81 |
| Line connection contributions | 910 | 64 | - | 974 |
| Computer software | 45,401 | 6,478 | - | 51,879 |
| | $ 47,572 | $ 6,672 | $ - | $ 54,244 |

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Net book value as at December 31, 2012 | | | |
| Land rights | $ 3,135 | $ 1,310 | $ 1,825 |
| Power purchase agreement | 4,578 | 81 | 4,497 |
| Line connection contributions | 3,583 | 974 | 2,609 |
| Computer software | 64,073 | 51,879 | 12,194 |
| Water rights | 16,941 | - | 16,941 |
| Computer software under development | 13,721 | - | 13,721 |
| | $ 106,031 | $ 54,244 | $ 51,787 |

Water rights and the power purchase agreement were acquired from Domtar Inc. November 20, 2012 [Note 18].

During the year, the Corporation capitalized an AFUDC of $1,081 [2012 – $305] to intangible assets and credited financing costs [Note 20]. The average annual interest rate for 2013 was 4.5% [2012 – 4.8%].

There was no impairment of intangible assets for the years ended December 31, 2013 and 2012.

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## 8. INTANGIBLE ASSETS [CONTINUED]

The Corporation entered into significant non-cash transactions that have been excluded from the consolidated statement of cash flows. These transactions were related to intangible asset additions of $729 [2012 – $2,119], which represent amounts included in accounts payable and accrued liabilities at year end.

## 9. CREDIT FACILITY

During the year, the Corporation renewed its credit facility for a revised amount of $193,500 [2012 – $193,650]. The facility is now structured into four types of credit availability and consists of a $75,000 [2012 – $75,000] 364-day revolving operating line which matures on August 2, 2014, a $100,000 [2012 – $100,000] revolving line to fund capital expenditures and growth opportunities which matures on August 2, 2015, a $17,500 [2012– $17,500] line to fund letters of credit and other guarantees and a $1,000 [2012 – $1,000] commercial card facility. The revolving operating line can be used by way of direct advances and/or bankers' acceptances. This credit facility contains customary covenants and events of default including a covenant to maintain the consolidated tangible net worth in excess of $175,000 at all times. It also requires the debt to capitalization ratio to be at or below 75% on a consolidated basis. The Corporation has cancelled its $150 corporate Visa facility which existed in the previous year.

As at December 31, 2013, the Corporation had drawn $4,950 in direct advances against the operating line, and nil against the capital line [2012 – $60,000 in bankers' acceptances against the operating line and $14,000 in bankers' acceptances against the capital line]. The facility allows for continuous renewal of operating and capital bankers' acceptances with maturities of 7 to 180 days. The Corporation has also drawn $16,000 [2012 – $16,000] against its facilities in standby letters of credit.

On October 12, 2013, PowerTrail renewed its existing credit facility for $200 [2012 - $200] in standby letters of credit to the Ontario Power Authority ['OPA'] for another year. The facility contains customary covenants and events of default, including a covenant to maintain a tangible net worth of $1,000. As at December 31, 2013, PowerTrail had drawn an amount of $133 [2012 – $133] in standby letters of credit against this facility.

CWPI maintains a credit facility consisting of a $500 [2012 - $500] operating credit line secured by the three principals of CWPI. The operating credit line is repayable on demand, bears interest at the Bank of Canada's prime lending rate with interest payable monthly. The facility also contains customary covenants and events of default. As at December 31, 2013, CWPI had not drawn this operating line [2012 – $19].

## 10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| | **2013** | 2012 |
|---|---|---|
| Purchased power payable | **$ 67,033** | $ 62,813 |
| Trade accounts payable and accrued liabilities | **43,377** | 45,569 |
| Customer deposits | **14,307** | 15,174 |
| Customer credit balances | **7,363** | 9,146 |
| Due to related parties [Note 24] | **268** | 89 |
| | **$ 132,348** | $ 132,791 |

## Hydro Ottawa Holding Inc.

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### 11. OTHER LIABILITIES

| | 2013 | 2012 |
|---|---|---|
| Non-current customer deposits | **$ 13,085** | $ 11,782 |
| Non-current repayable grant [Note 7] | **29** | 41 |
| Asset retirement obligations [Note 12] | **300** | 438 |
| | **$ 13,414** | $ 12,261 |

### 12. ASSET RETIREMENT OBLIGATIONS

| | 2013 | 2012 |
|---|---|---|
| Balance, beginning of year | **$ 438** | $ 627 |
| Liabilities settled during the year | **(141)** | (203) |
| Accretion expense | **26** | 19 |
| Revisions in estimated cash flows | **(23)** | (5) |
| | **$ 300** | $ 438 |

As at December 31, 2013, the Corporation estimates an asset retirement obligation ['ARO'] of $300 [2012 – $438] related to the removal and destruction of polychlorinated biphenyls ['PCBs'] in distribution transformers and other clean-up related to PCBs. The ARO is calculated using an estimated undiscounted cash flow over two years [2012 – one year] totalling $357 [2012 – $498] and a discount rate of 5.3% [2012 – 5.3%]. No assets have been legally restricted for settlement of the liability.

### 13. EMPLOYEE FUTURE BENEFITS

#### (a) Pension plans

The Corporation contributes to two defined benefit plans covering substantially all of its employees.

The Corporation's participating employer contributions under OMERS for the year ended December 31, 2013 amounted to $5,939 [2012 – $5,008].

Effective November 20, 2012, the Corporation provides retirement benefits to certain employees who transferred to the Corporation from Domtar Inc. Consequently, the Corporation created the Chaudiere Pension Plan on this date. In accordance with the Purchase Agreement as described in Note 18, Domtar Inc. has agreed to fund the actuarial plan obligations relating to the transferred employees as at November 20, 2012. However, the physical transfer of plan assets from Domtar Inc.'s pension plan to the CHPP is not legally permitted to occur until the pending registration with the Financial Services Commission of Ontario is complete. The Corporation retains all risks and rewards of the plan assets awaiting to be transferred to CHPP and remains liable for the benefits accruing to its members from November 20, 2012 and onward.

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## 13. EMPLOYEE FUTURE BENEFITS [CONTINUED]

### (a) Pension plan [continued]

Information about the Chaudiere Hydro Pension Plan is as follows:

(i) Accrued benefit obligation

| | 2013 | 2012 |
|---|---|---|
| Balance, beginning of period | **$ 3,573** | $ 3,538 |
| Current service cost | **264** | 19 |
| Interest cost on accrued benefit obligation | **151** | 16 |
| Benefit payments and administrative expenses | **(102)** | - |
| Actuarial gains | **(293)** | - |
| Balance, end of period | **$ 3,593** | $ 3,573 |

(ii) Plan assets

| | 2013 | 2012 |
|---|---|---|
| Fair value, beginning of period | **$ 4,047** | $ 4,019 |
| Actual return on plan assets | **48** | 21 |
| Employer contributions | **190** | - |
| Benefit payments and administrative expenses | **(102)** | - |
| Employee contributions | **99** | 7 |
| Fair value, end of period | **$ 4,282** | $ 4,047 |

(iii) Funded status

| | 2013 | 2012 |
|---|---|---|
| Retirement benefit asset, beginning of period | **$ 474** | $ 481 |
| Change in retirement benefit asset | **215** | (7) |
| Retirement benefit asset, end of period | **$ 689** | $ 474 |

**Hydro Ottawa Holding Inc.**

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## 13. EMPLOYEE FUTURE BENEFITS [CONTINUED]

### (a) Pension plan [continued]

No valuation allowance has been recorded by the Corporation as at December 31, 2013 or December 31, 2012 with respect to the retirement benefit asset.

Employee future benefits under the CHPP are calculated using an annual compensation rate increase of 2.0% [2012 – 2.0%], an expected return on plan assets of 4.8% [2012 – 4.7%] and a discount rate of 4.8% [4.0%] to calculate the liabilities.

### (b) Employee future benefits other than pension plans

Employee future benefits are calculated using an annual compensation rate increase ranging from 2% to 3.1% [2012 – 2% to 3.1%] and a discount rate of 4.8% [2012 – ranging from 3.8% to 4.6%] to calculate the liabilities. The valuations also includes several other economic and demographic assumptions including mortality rates. The mortality assumption at December 31, 2013 has been updated resulting in an actuarial remeasurement of employee future benefits. The mortality assumption is now based on the most recent Canadian Pensioners Mortality information published by the Canadian Institute of Actuaries in July 2013.

Information about the Corporation's employee future benefits other than pension plans is as follows:

| | 2013 | | |
|---|---|---|---|
| | **Accumulated liability** | **Expense for the year** | **Benefits paid** |
| Life, medical and dental insurance | **$ 5,650** | **$ 564** | **$ 434** |
| Retirement grant provision | **927** | **83** | **21** |
| Sick leave | **5** | **-** | **-** |
| | **6,582** | **647** | **455** |
| Accrued benefit obligation | **9,691** | | |
| Deferred actuarial loss | **$ (3,109)** | | |

| | 2012 | | |
|---|---|---|---|
| | Accumulated liability | Expense for the year | Benefits paid |
| Life, medical and dental insurance | $ 5,605 | $ 612 | $ 510 |
| Retirement grant provision | 865 | 80 | 32 |
| Sick leave | 5 | - | - |
| | 6,475 | 692 | 542 |
| Accrued benefit obligation | 11,452 | | |
| Deferred actuarial loss | $ (4,977) | | |

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### 13. EMPLOYEE FUTURE BENEFITS [CONTINUED]

#### (b) Employee future benefits other than pension plans [continued]

An actuarial extrapolation was performed as at December 31, 2013. As a result of this exercise, the Corporation decreased the projected benefit obligation by $1,761 [2012 – increased by $1,509].

The current liability portion of the accrued employee future benefits included in other accounts payable and accrued liabilities amounts to $626 [2012 – $672] and the non-current portion was $9,065 [2012 – $10,780].

### 14. NOTES PAYABLE

| | **2013** | 2012 |
|---|---|---|
| 4.930% senior unsecured debentures, Series 2005-1, due on February 9, 2015 | **$ 199,762** | $ 199,548 |
| 4.968% senior unsecured debentures, Series 2006-1, due on December 19, 2036 | **49,762** | 49,751 |
| 3.991% senior unsecured debentures, Series 2013-1, due on May 14, 2043 | **148,869** | - |
| IGRS promissory note | **2,360** | 2,780 |
| | **400,753** | 252,079 |
| Less current portion of IGRS promissory note | **(340)** | (620) |
| | **$ 400,413** | $ 251,459 |

On February 9, 2005, the Corporation issued $200,000 in 4.930% senior unsecured debentures, Series 2005-1, due on February 9, 2015. The debentures bear interest at a rate of 4.930% per annum, payable semi-annually in arrears in equal instalments on February 9 and August 9, which commenced August 9, 2005.

On December 20, 2006, the Corporation issued $50,000 in 4.968% senior unsecured debentures, Series 2006-1, due on December 19, 2036. The debentures bear interest at a rate of 4.968% per annum, payable semi-annually in arrears in equal instalments on June 19 and December 19, which commenced June 19, 2007.

On May 14, 2013, the Corporation issued $150,000 in 3.991% senior unsecured debentures, Series 2013-1, due on May 14, 2043. The debentures bear interest at a rate of 3.991% per annum, payable semi-annually in arrears in equal instalments on November 14 and May 14, which commenced November 14, 2013.

Each of the above debentures were purchased at 100% of their principal amount and are carried net of the related debt issuance costs which are amortized over the initial term of the debenture. Each debenture contains customary covenants and events of default, including a covenant to ensure that the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. Interest payments on these debentures over the next five years will be $18,331 in 2014, $13,401 in 2015 and $8,471 in 2016, 2017 and 2018.

The IGRS promissory note was issued by PowerTrail to fund the construction of the gas collection and generation plant at the Trail Road landfill site. Pursuant to the Shareholders' Agreement dated November 3, 2005, among Energy Ottawa, IGRS and PowerTrail, the note is unsecured, non-interest bearing, subject to certain conditions and has no set terms of repayment. During the year, PowerTrail made $420 [2012 – $300] in repayments to IGRS and intends to repay an additional $340 on this note in 2014. Management of IGRS has confirmed that it does not intend to call the remaining $2,020 in 2014.

## Hydro Ottawa Holding Inc.

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### 15. CAPITAL DISCLOSURES

The Corporation's main objectives when managing capital are to:

- Ensure continued access to funding to maintain and improve the operations and infrastructure of the Corporation;
- Ensure compliance with covenants related to the credit facilities and senior unsecured debentures; and
- Align Hydro Ottawa Limited's capital structure with the debt-to-equity structure recommended by the OEB.

The Corporation's capital consists of the following:

| | **2013** | 2012 |
|---|---|---|
| Bank indebtedness | **$ 8,853** | $ 77,357 |
| Notes payable | **400,753** | 252,079 |
| Total debt | **409,606** | 329,436 |
| Shareholder's equity | **381,726** | 366,695 |
| Total capital | **$ 791,332** | $ 696,131 |
| Debt capitalization ratio | **52 %** | 47 % |

The Corporation is in compliance with all financial covenants and limitations associated with its credit facilities and its long-term debt.

Hydro Ottawa Limited is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Corporation's actual capital structure may differ from the OEB deemed structure.

The Corporation met its capital management objectives, which have not changed during the year.

### 16. SHARE CAPITAL

#### (a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share
Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting fourth preferred shares [10 votes per share], redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares
Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holders of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

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### 16. SHARE CAPITAL [CONTINUED]

#### (b) Issued

| | **2013** | 2012 |
|---|---|---|
| 214,901,003 Class A common shares | **$ 228,453** | $ 228,453 |

Any invitation to the public to subscribe for shares of the Corporation is prohibited by shareholder resolution.

Shareholder resolution directs the Corporation to target dividends at the greater of 60% of its annual consolidated net income or $14,000, provided that the Corporation is in compliance with the *Business Corporations Act (Ontario)* and relevant OEB guidelines, is not in breach of any covenants on its senior unsecured debentures or credit facility obligations, and does not negatively impact its credit rating as a result of the dividend payment.

On April 4, 2013, the Board of Directors declared an $18,600 dividend to the City of Ottawa, which was paid on April 10, 2013 [2012 – April 3, the Board of Directors declared a $16,600 dividend to the City of Ottawa, which was paid on April 5, 2012].

On May 1, 2008, TOHI sold the shares of both its subsidiaries creating a balance in its refundable dividend tax on hand ['RDTOH'] account. On December 5, 2013, TOHI paid an intercompany dividend to the Corporation to recover its RDTOH balance. This amount is included in payments in lieu of corporate income taxes receivable on the consolidated balance sheet at year end and has been removed from the change in payments in lieu of corporate taxes receivable/payable on the statement of cash flows.

### 17. NON-CONTROLLING INTEREST

The non-controlling interest as at December 31, 2013 represents the sum of:

- IGRS non-controlling interest [40%] in the net assets of PowerTrail;
- IGRS and Moose Creek GP's combined non-controlling interest [49.90%] [2012 – 49.95%] in the net assets of Moose Creek LP; and
- Hydro Québec's non-controlling interest [33.33%] in the net assets of CWPI [effective November 20, 2012].

During 2013, Moose Creek LP issued 1,002,000 Class A units and 998,000 Class B units to its limited partners [Energy Ottawa and IGRS] at a price of one dollar per unit, respectively. These issuances were made to fund the completion of Moose Creek LP's gas collection and generation plant and to provide sufficient working capital during the initial stage of operations.

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### 18. ACQUISITION OF ASSETS

On November 20, 2012, the Corporation, through its subsidiary Chaudiere Hydro L.P., completed an acquisition of generation assets from Domtar Inc. in exchange for $46,339 in cash through an Agreement of Purchase and Sale ['Purchase Agreement']. Identifiable assets acquired included three hydro-electric generation plants, the tangible and intangible assets related thereto and all of Domtar Inc.'s 38.33% interest in the CWPI joint venture. The acquisition of assets was accounted for as an acquisition of a business under Section 1582 Business Combinations of pre-changeover Canadian GAAP. The acquisition has brought the Corporation recurring revenue through a long-term power purchase agreement with Hydro Québec. As part of this transaction, a small group of employees previously employed by Domtar Inc. were transferred to the Corporation.

The following table summarizes the fair values of the assets acquired as part of the transaction with Domtar Inc.:

| | Acquisition date fair value |
|---|---|
| Land | $ 6,256 |
| Buildings and fixtures | 1,900 |
| Generating plant and equipment | 8,494 |
| Reservoirs, dams and waterways | 8,050 |
| Power purchase agreement | 4,578 |
| Water rights | 16,941 |
| Prepaids | 62 |
| Retirement benefit asset | 481 |
| Accounts payable and accrued liabilities | (163) |
| Employee future benefits | (260) |
| Total cash paid for net assets acquired | $ 46,339 |

The amounts above relating to prepaids, accounts payable and accrued liabilities and employee future benefits were removed from their respective operating line items in the consolidated statement of cash flows as they did not arise in the ordinary course of business.

The Corporation incurred transaction costs relating to the acquisition of $1,492 which were expensed in operating costs in the previous year. In addition, $313 of operating costs relating to repairs and maintenance were expensed in the previous year as they did not meet the criteria of an asset. From the date of acquisition to December 31, 2012, the assets acquired contributed $1,011 of revenue and $204 of net income. As the Corporation did not have access to the financial information of Domtar Inc., it was not possible to determine the revenue, income or loss the Corporation would have realized had the acquisition occurred on January 1, 2012.

The acquisition of Domtar Inc.'s shares in CWPI increased the Corporation's total effective common share interest in CWPI from 28.33% to 66.67%. Consequently, the Corporation was required to consolidate CWPI as of the acquisition date in accordance with AcG-15. The impact on the Corporation's net assets upon consolidation was not significant.

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### 18. ACQUISITION OF ASSETS [CONTINUED]

Due to the timing of this acquisition, the retirement benefit asset and employee future benefits were provisional and subject to change. Measurement was finalized in 2013 and no significant adjustments were necessary. Moreover, in 2013, reclass adjustments totaling $1,400 were made out of generating plant and equipment and into buildings and fixtures to more accurately portray the componentization of the assets acquired. As a result, the fixed asset information presented for comparative year purposes has been reclassified to conform to such presentation adopted for the current year.

### 19. FINANCIAL INSTRUMENTS

#### (a) Carrying values

The Corporation's financial instruments consist of cash, accounts receivable, unbilled revenue, bank indebtedness, accounts payable and accrued liabilities, customer deposits and notes payable. The only financial instrument recorded at fair value is bank indebtedness and it is classified as level 1 in the pre-changeover Canadian GAAP Section 3862 fair value hierarchy. The carrying values of the Corporation's remaining financial instruments, except for notes payable, approximate fair value because of the short maturity of these instruments.

The Corporation has estimated the fair value of the senior unsecured debentures notes payable as at December 31, 2013 as amounting to $414,176 [2012 – $264,955]. The fair value has been determined based on discounting all future payments of interest and the principal repayments on February 9, 2015, December 19, 2036 and May 14, 2043 at the estimated interest rate of 4.0% [2012 – 4.0%] that would be available to the Corporation on December 31, 2013.

The Corporation cannot determine the fair value of the IGRS promissory note as the amount is non-interest bearing and has no specific repayment terms other than as agreed upon from time to time between Energy Ottawa and IGRS.

#### (b) Risk factors

In the normal course of business, the Corporation is exposed to market risk, credit risk and liquidity risk. The Corporation’s risk exposure and strategies to mitigate these risks are noted below.

(i) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risk: interest rate risk, currency risk and other price risk such as equity risk.

The Corporation is exposed to interest rate risk on its borrowings. The Corporation mitigates exposure to interest rate risk by issuing long-term fixed interest rate debt. Under the Corporation’s credit facility, any advances on its operating line expose it to fluctuations in short-term interest rates related to prime rate loans and bankers' acceptances. In addition, the fees payable on bankers' acceptances via the operating and capital lines are based on a margin determined by reference to the Corporation's credit rating.

As at December 31, 2013, the Corporation has nil [2012 – $60,000] of outstanding bankers' acceptances on its operating line. Borrowing requirements on this line are typically for a short duration as advances serve to bridge gaps between the cash outflow related to Hydro Ottawa Limited's monthly power bill and the inflows related to the settlements with customers and, as such, there is limited exposure to interest rate risk.

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**19. FINANCIAL INSTRUMENTS [CONTINUED]**

**(b) Risk factors [continued]**

(i) Market risk [continued]

As at December 31, 2013, the Corporation has nil [2012 – $14,000] of outstanding bankers' acceptances on its capital line. Borrowing requirements on this line are typically for a short duration as advances serve to bridge gaps between the cash outflow related to significant business development acquisitions and the inflows related to the issuance of additional long-term fixed rate debt to finance such acquisitions. Consequently, there is limited exposure to interest rate risk.

As at December 31, 2013, the Corporation has limited exposure to fluctuations in foreign currency exchange rates. The Corporation does purchase a small proportion of goods and services which are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

As at December 31, 2013, the Corporation has not entered into any hedging transactions or derivative contracts.

(ii) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss. Concentration of credit risk associated with accounts receivable and unbilled revenue is limited due to the large number of customers the Corporation services. Hydro Ottawa Limited has approximately 315,000 customers, the majority of which are residential. As a result, the Corporation did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

Hydro Ottawa Limited performs ongoing credit evaluations of its customers and requires collateral to support customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB legislation. Effective October 2010, the OEB instituted changes to the Distribution System Code requirements for residential security deposits. Security deposits on hand must be applied to active residential accounts in arrears prior to the customer entering into a payment arrangement, rather than as a deposit to be applied to the final bill. Further, additional amendments prohibit Hydro Ottawa Limited from collecting deposits from low income residential customers. Management has concluded that residential security deposits are no longer as effective for mitigating credit risk. Effective January 1, 2011, Hydro Ottawa Limited ceased collecting residential security deposits, and began refunding all residential deposits on hand. Hydro Ottawa Limited continues to hold collateral to support customer accounts receivable on non-residential accounts. As at December 31, 2013, the Corporation held security deposits related to power recovery and distribution sales in the amount of $14,514 [2012 – $12,882].

Energy Ottawa and its subsidiaries limit credit risk by dealing with customers that are considered to be of high credit quality.

The Corporation monitors and limits its exposure to credit risk on a continuous basis.

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### 19. FINANCIAL INSTRUMENTS [CONTINUED]

#### (b) Risk factors [continued]

(ii) Credit risk [continued]

The carrying amount of accounts receivable and unbilled revenue is reduced by an allowance for doubtful accounts based on the credit risk applicable to particular customers and historical and other information. The Corporation records an allowance for doubtful accounts when the recoverability of an amount becomes doubtful. The amount of the related impairment loss is recognized in income in the period during which such assessment is made. When the receivable amount is deemed to be uncollectible, it is written off and the allowance for doubtful accounts is adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of operating costs in the consolidated statement of income, comprehensive income and retained earnings. As at December 31, 2013, the allowance for doubtful accounts was $2,191 [2012 – $1,618] and there have been no significant fluctuations in the allowance during the year.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

| | **2013** | 2012 |
|---|---|---|
| Accounts receivable | **$ 72,261** | $ 76,958 |
| Total unbilled revenue | **106,757** | 90,003 |
| Less allowance for doubtful accounts | **(2,191)** | (1,618) |
| | **176,827** | 165,343 |
| Of which: | | |
| Outstanding for 30 days or less | **64,637** | 69,595 |
| Outstanding for more than 30 days but not more than 120 days | **5,665** | 5,845 |
| Outstanding for 120 days or more | **1,959** | 1,518 |
| Unbilled revenue | **106,757** | 90,003 |
| Less allowance for doubtful accounts | **(2,191)** | (1,618) |
| | **$ 176,827** | $ 165,343 |

As at December 31, 2013, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties and approximately 10% [2012 – 10%] of the Corporation's accounts receivable was aged more than 30 days. The Corporation's maximum exposure to credit risk is equal to the carrying value of accounts receivable and unbilled revenue less customer deposits held.

(iii) Liquidity risk

Liquidity risk is the risk that the Corporation will not meet its financial obligations as they come due. The Corporation regularly monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and capital investment requirements. The Corporation achieves this objective by ensuring that sufficient facilities, as described in Note 9, are maintained to meet obligations as they come due while minimizing standby fees and interest.

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## 19. FINANCIAL INSTRUMENTS [CONTINUED]

### (b) Risk factors [continued]

(iii) Liquidity risk [continued]

Liquidity risks associated with financial commitments are as follows:

| | 2013 | | |
|---|---|---|---|
| | **Due within 1 year** | **Due between 1 year and 5 years** | **Due after 5 years** |
| Bank indebtedness | **8,853** | **$ -** | **$ -** |
| Accounts payable and accrued liabilities | **132,348** | **-** | **-** |
| Notes payable | | | |
| 4.930% senior unsecured debentures, Series 2005-1 | **-** | **199,762** | **-** |
| 4.968% senior unsecured debentures, Series 2006-1 | **-** | **-** | **49,762** |
| 3.991% senior unsecured debentures, Series 2013-1 | **-** | **-** | **148,869** |
| IGRS promissory note | **340** | **2,020** | **-** |
| | **$ 141,541** | **$ 201,782** | **$ 198,631** |

## 20. FINANCING COSTS

| | **2013** | 2012 |
|---|---|---|
| Interest on notes payable | **$ 16,404** | $ 12,593 |
| Short-term interest and fees, net of interest income | **652** | 564 |
| Less AFUDC | **(2,411)** | (2,056) |
| | **$ 14,645** | $ 11,101 |

## Hydro Ottawa Holding Inc.

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### 21. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:

| | **2013** | 2012 |
|---|---|---|
| Federal and Ontario statutory income tax rate | **26.50 %** | 26.50 % |
| Income before provision for PILs | **$ 41,958** | $ 40,209 |
| Provision for PILs at statutory rate | **$ 11,119** | $ 10,655 |
| Increase (decrease) resulting from: | | |
| Permanent differences | **1,093** | 952 |
| Impact of changes to expected future tax rates on opening temporary differences | **-** | (636) |
| Regulatory offset to temporary differences and changes in future tax rates | **(3,001)** | (996) |
| Future tax benefit recognized on actuarial gains (losses) recorded in OPEB deferral account | **495** | (1,319) |
| Prior year adjustments | **(58)** | 412 |
| Tax credits | **(162)** | (249) |
| Change in valuation allowance | **42** | 19 |
| Other | **(118)** | 90 |
| | **$ 9,410** | $ 8,928 |
| Effective income tax rate | **22.43 %** | 22.20 % |

The Corporation as a rate-regulated enterprise is required to recognize future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Provision for PILs consists of the following:

| | **2013** | 2012 |
|---|---|---|
| Current PILs corporate income tax provision | **$ 8,126** | $ 8,257 |
| Future PILs corporate income tax provision | | |
| Future income tax provision before regulatory adjustment | **5,367** | 1,632 |
| Regulatory adjustment for the recovery of future income tax provision | **(4,083)** | (961) |
| | **$ 9,410** | $ 8,928 |

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

## 21. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES [CONTINUED]

The Corporation's future income tax assets and liabilities are presented on the consolidated balance sheet as follows:

| | **2013** | 2012 |
|---|---|---|
| **Assets** | | |
| Future income tax assets, current | **$ 818** | $ 628 |
| Future income tax assets, non-current | **19,947** | 24,222 |
| | **20,765** | 24,850 |
| **Liabilities** | | |
| Future income tax liabilities, non-current | **(6,464)** | (5,179) |
| | **$ 14,301** | $ 19,671 |

Significant components of the Corporation's future income tax assets and liabilities are as follows:

| | **2013** | 2012 |
|---|---|---|
| Property, plant and equipment and intangible assets | **$ 9,844** | $ 14,295 |
| Employee future benefits | **3,354** | 3,990 |
| Non-capital loss carryforwards | **697** | 909 |
| Other temporary differences | **406** | 477 |
| | **$ 14,301** | $ 19,671 |

The Corporation's regulatory liabilities for the amounts of future income taxes expected to be refunded to customers in future electricity rates are presented on the consolidated balance sheet as follows:

| | **2013** | 2012 |
|---|---|---|
| Regulatory liability for future income tax assets, current | **$ 818** | $ 628 |
| Regulatory liability for future income tax assets, non-current | **19,893** | 24,165 |
| | **$ 20,711** | $ 24,793 |

The Corporation did not have any unused non-capital tax losses at December 31, 2013 or December 31, 2012. At December 31, 2013, the Corporation had capital losses of $700 [December 31, 2012 – $700] which have not been recognized in the consolidated financial statements.

As at December 31, 2013, Energy Ottawa had corporate minimum tax ['CMT'] carryforwards of nil [2012 – $190].

As at December 31, 2013, PowerTrail had non-capital tax loss carryforwards of $2,627 [2012 – $3,392]. These losses expire between 2026 and 2030.

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

## 22. CONTINGENT LIABILITIES

Purchasers of electricity in Ontario, including Hydro Ottawa Limited, through the Independent Electricity System Operator ['IESO'], are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Corporation fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2013, the Corporation had drawn standby letters of credit in the amount of $16,000 [2012 – $16,000] against its credit facility to cover its prudential support obligation.

The Corporation participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Corporation is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

In December 2012, Hydro Ottawa Limited was charged with five charges under the Occupational Health and Safety Act with respect to an incident occurring on March 22, 2012, which resulted in the fatality of an employee of a third party subcontractor. No charges have been or can be brought against directors, officers or employees arising from this incident. The maximum fine for each count is $500. Hydro Ottawa Limited, through external counsel, is defending the charges. At this time, it is not possible to quantify the effect, if any, of these charges on these consolidated financial statements.

Various lawsuits have been filed against the Corporation for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Corporation’s insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

## 23. COMMITMENTS

Hydro Ottawa Limited has $40,714 in total open commitments, of which $32,312 are for 2014, $6,806 for 2015, $1,552 for 2016, $44 for 2017 and nil for 2018. This includes commitments relating to a customer information system services agreement, construction projects, spare parts and standby equipment and overhead and underground services.

PowerTrail is committed, under a Gas Utilization License of Occupation Agreement with the City of Ottawa, to provide a 5.5% royalty of its gross annual receipts derived from the sale of electricity associated with the use of gas from the Trail Road landfill site through 2024. In exchange, the City of Ottawa provides facilities for the collection and use of gas generated by the Trail Road landfill site.

Moose Creek LP is committed, under a Gas Utilization and Lease Agreement with a third party, to provide a royalty on its gross generation revenues ranging from 4% to 12% through 2033. These royalties are based on certain annual net generation thresholds as defined within the agreement and in 2013 was 6% [2012 – N/A as operations had not yet commenced]. In exchange, the third party provides the use of land for the collection and use of gas generated by the Laflèche landfill site.

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

### 23. COMMITMENTS [CONTINUED]

The operating lease obligations of the Corporation are as follows:

| | | |
|---|---|---|
| 2014 | $ | 101 |
| 2015 | | 133 |
| 2016 | | 126 |
| 2017 | | 118 |
| 2018 | | 114 |
| Thereafter | | 1,566 |
| | $ | 2,158 |

### 24. RELATED PARTY TRANSACTIONS

The following table provides the transactions entered into with related parties as well as outstanding balances at year end. These transactions occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties. Trade amounts due from and to related parties are non-interest bearing, result from normal operations and are due within one year.

| | 2013 Transactions during the year | | 2013 Balances at year end | |
|---|---|---|---|---|
| | **Sales to related parties** | **Purchases from related parties** | **Due from related parties** | **Due to related parties** |
| **City of Ottawa** | | | | |
| Electricity [1] | **$ 33,852** | **$ -** | **$ -** | **$ -** |
| Commercial energy services [2] | **3,584** | **-** | **-** | **-** |
| Other services [2] | **7,684** | **-** | **-** | **-** |
| Fuel, permits and other services [3] | **-** | **1,183** | **-** | **-** |
| Property taxes [3] | **-** | **2,053** | **-** | **-** |
| Royalties [3] | **-** | **176** | **-** | **-** |
| Conservation and demand management initiatives[3] | **-** | **57** | **-** | **-** |
| Accounts receivable | **-** | **-** | **6,197** | **-** |
| Accounts payable and accrued liabilities | **-** | **-** | **-** | **268** |
| | **$ 45,120** | **$ 3,469** | **$ 6,197** | **$ 268** |

[1] Included in power recovery and distribution sales revenue
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

### 24. RELATED PARTY TRANSACTIONS [CONTINUED]

| | 2012 Transactions during the year | | 2012 Balances at year end | |
|---|---|---|---|---|
| | Sales to related parties | Purchases from related parties | Due from related parties | Due to related parties |
| City of Ottawa | | | | |
| Electricity [1] | $ 33,995 | $ - | $ - | $ - |
| Commercial energy services [2] | 3,370 | - | - | - |
| Other services [2] | 4,017 | - | - | - |
| Fuel, permits and other services [3] | - | 730 | - | - |
| Property taxes [3] | - | 1,849 | - | - |
| Royalties [3] | - | 165 | - | - |
| Conservation and demand management initiatives [3] | - | 254 | - | - |
| Accounts receivable | - | - | 5,800 | - |
| Accounts payable and accrued liabilities | - | - | - | 89 |
| | $ 41,382 | $ 2,998 | $ 5,800 | $ 89 |
| CWPI [January 1, 2012 - November 19, 2012] | | | | |
| Prepaids | $ - | $ 15 | $ - | $ - |
| Operating and maintenance expenses [3] | - | 359 | - | - |
| Property, plant and equipment | - | 11 | - | - |
| | $ - | $ 385 | $ - | $ - |
| Total | $ 41,382 | $ 3,383 | $ 5,800 | $ 89 |

[1] Included in power recovery and distribution sales revenue
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs

### 25. SUBSEQUENT EVENTS

On February 7, 2014, Energy Ottawa's subsidiary Chaudiere Hydro L.P., was granted a forty year Hydroelectric Standard Offer Program – Municipal Stream Contract ['HESOP Contract'] by the OPA to produce renewable waterpower. As a result of this contract, Chaudiere Hydro L.P. will expand its generation facilities increasing Energy Ottawa's total capacity from 38 megawatts to 58 megawatts [‘Chaudiere expansion’]. The Chaudiere expansion will require a significant investment, and have a significant impact on the operations of this entity in the coming years. The anticipated commercial operation date is in the fourth quarter of 2017.

**Hydro Ottawa Holding Inc.**

Notes to the Consolidated Financial Statements
December 31, 2013
[in thousands of Canadian dollars]

## 26. COMPARATIVE FIGURES

In certain instances, the 2012 information presented for comparative purposes has been reclassified to conform to the consolidated financial statement presentation adopted for the current year.

# Statement of Executive Compensation

The Governance and Management Resources Committee of the Board, made up entirely of independent directors, is responsible for developing and recommending the approval of the compensation framework for the Corporation and each of its subsidiaries.

In developing the compensation framework, the Governance and Management Resources Committee is guided by two principles: the need to provide a total compensation package that will attract and retain qualified and experienced executives, and linking compensation to performance.

Executive compensation is reviewed by the Governance and Management Resources Committee and approved by the Board of Directors. In making its recommendations to the Board, the Committee examines the responsibilities and performance of individual executives, and considers the recommendations of the President and Chief Executive Officer.

In an effort to attract and retain qualified and experienced executives, the Corporation aims to offer a total compensation package that is competitive with other organizations of a similar size and scope. Executive compensation is reviewed on an annual basis and compared to market data, with the assistance of independent consultants, every two to three years to ensure competitiveness. In line with best practices for the sector, as identified by the Ontario Minister of Energy's Agency Review Panel in 2007, Hydro Ottawa applies a 50/50 weighting of market data from public and private comparators. The industry component of the market comparator group has a strong sector affiliation [e.g. Transportation and Utilities sector], and is assessed by revenue levels to ensure comparability.

Total cash compensation for Executives consists of two components*: base salary and an at risk performance incentive. Total cash compensation is benchmarked to companies of comparable size and scope in both the Ontario and national markets, with the target for total cash compensation set at the 50th percentile, or midpoint, of the market.

The at risk performance incentive component is paid on an annual basis, and is expressed as a percentage of base salary. It is designed to retain and motivate executives, to reward them for their performance during the preceding year, and to ensure alignment with shareholder objectives. Payments are based on the achievement of corporate and division objectives, both financial and non-financial, which are established each year by the Board of Directors. Non-financial targets are designed to achieve continuous improvement in relation to a number of strategic objectives including, but not limited to, customer service, operational and organizational efficiency and effectiveness, and service reliability.

Executives participate in a benefits program, which includes extended health care, dental care, basic and optional life insurance, and short-term and long-term disability insurance. This same program is available to all management group employees of the Corporation.

Executives also participate in the OMERS pension plan. This plan is a multi-employer, contributory, defined benefit pension plan established by the Province for employees of municipalities, local boards and school boards in Ontario. Pension benefits are determined by a formula based on the highest consecutive five-year average of contributory earnings and years of service. Pension benefits are indexed to increases in the Consumer Price Index subject to an annual maximum of 6 percent. Both participating employers and participating employees are required to make equal contributions to the plan based on the participating employees' contributory earnings. Earnings for pension purposes are capped based on recent plan changes.

*The total cash compensation for the President and Chief Executive Officer consists of a base salary only.

## SUMMARY OF COMPENSATION

Officers of the Corporation

| NAME AND PRINCIPAL POSITION[1] | YEAR | BASE SALARY ($)[2] | AT RISK PERFORMANCE INCENTIVE ($)[3] | OTHER COMPENSATION ($)[4] |
|---|---|---|---|---|
| Bryce Conrad<br>President and Chief Executive Officer | 2013<br>2012<br>2011 | $354,579<br>$344,230<br>$112,500[5] | N/A<br>N/A<br>N/A | $35,240<br>$15,734<br>$4,557 |
| Geoff Simpson<br>Chief Financial Officer | 2013 | $63,301[6] | N/A | $3,362 |
| Norm Fraser<br>Chief Operating Officer –<br>Distribution and Customer Service | 2013<br>2012<br>2011 | $216,082<br>$215,919<br>$211,346 | $73,900<br>$67,367<br>$89,629 | $8,894<br>$8,714<br>$9,058 |
| Gregory Clarke<br>Chief Operating Officer – Generation | 2013<br>2012<br>2011 | $175,116<br>$174,984<br>$171,256 | $59,890<br>$52,535<br>$75,064 | $8,687<br>$9,550<br>$8,545 |

1 Officers whose earnings are reported are those who occupied the position at December 31, 2013

2 Amounts shown in this column have been rounded to the nearest dollar

3 Amounts shown in this column reflect the at risk performance incentive for the executive in respect of the achievement of the performance objectives for the previous financial year, paid in the reporting year

4 Amounts in this column include Board approved discretionary payments such as payment of earned and unused vacation credits, car allowance, computer allowance and employer's share of basic life insurance premiums

5 Mr. Conrad assumed the position on August 15, 2011. Had Mr. Conrad been employed for the entire year, his base salary would have been $325,000

6 Mr. Simpson assumed the position on August 6, 2013. Had Mr. Simpson been employed in this position for the entire year, his base salary would have been $172,500

# Corporate Governance

Hydro Ottawa is committed to establishing and maintaining leading governance practices for a company of its size and mandate. Because governance standards and best practices are always evolving, the company seeks to continuously improve its governance practices.

Hydro Ottawa Holding Inc. is a private company, incorporated under the *Business Corporations Act* (Ontario). At the same time, the company is wholly owned by the City of Ottawa and fulfills a public mandate, and is therefore mindful of its responsibility to be accountable both to its shareholder and the public. The company's governance practices are guided not simply by legal obligations, but by best business practices and standards established by independent agencies.

While Hydro Ottawa is not a reporting issuer under the Securities Act and is therefore not subject to governance standards that apply to publicly-traded companies, the company is guided by these standards and seeks to meet or exceed them. In addition, Hydro Ottawa regularly compares its governance practices to those of private and public sector organizations, and to standards set by agencies such as the Canadian Securities Administrators and the Ontario Securities Commission.

## Governance Structure

Accountability for the effective oversight of the Corporation and its subsidiaries rests with an eleven-member Board of Directors, which provides direction to the Corporation on behalf of the shareholder, the City of Ottawa. The Board provides leadership for the company within a framework of effective controls that enables risks to be assessed and managed, and is responsible for supervising the management of the business and affairs of the company and its subsidiaries. In carrying out its oversight function, the Board of Directors is guided by a Shareholder Declaration issued by Ottawa City Council and revised from time to time. The company's Code of Business Conduct, its Director Conflict of Interest and Conduct Guidelines and a Related Party Transaction Disclosure Policy and Process also govern the actions of the Board.

In 2006, a separate Board of Directors was established to oversee the operations of Hydro Ottawa Limited, in accordance with the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board. The powers and functions of that Board are set out in a Shareholder Declaration issued by the Hydro Ottawa Holding Inc. Board of Directors. A majority of the members of both Boards are independent of management and the shareholder.

On a day-to-day basis, the Corporation is led by an Executive Management Team, comprising the Corporation's President and Chief Executive Officer, the Chief Financial Officer and the senior executives of the subsidiaries and critical functional areas. This team oversees the alignment of business practices and strategies with the goals of the Corporation, and drives performance by managing risks and opportunities. The Executive Management Team is accountable to the Corporation's Board of Directors through the President and Chief Executive Officer.

## Key Governance Processes and Controls

Hydro Ottawa has established a number of leading governance processes and controls to assist the Board and executive management in carrying out their oversight functions.

**Risk Management:** An extensive, corporate-wide risk management system has been established to track indicative and predictive measures of risk. Risk assessments are included with regular reporting to the Board on all areas of the Corporation's operations.

**Internal Audit:** Hydro Ottawa conducts a rigorous internal audit program to verify controls and maximize business efficiency and effectiveness. A number of business processes and functions are audited annually based on an audit plan approved by the Board. The use of experienced auditors both internal and external to the Corporation ensures rigour and objectivity.

**Business Continuity Plans:** Plans are in place to ensure the continuance of critical operations in the event of a major emergency such as a pandemic, and to return the Corporation to normal operations as quickly as possible after such an event. They include detailed strategies for the re-assignment of resources to critical processes, and redundant supply arrangements with critical external suppliers.

## Appointments to the Board of Directors

The governance structure for the Corporation (Hydro Ottawa Holding Inc.) and its subsidiaries (Hydro Ottawa Limited and Energy Ottawa Inc.) includes two boards of directors – the Hydro Ottawa Holding Inc. Board and the Hydro Ottawa Limited Board.

In accordance with the terms of the Shareholder Declaration, the City of Ottawa appoints all Directors to the Boards except the President and Chief Executive Officer. In doing so, the City considers candidates recommended by the Nominating Committee of the Board of Hydro Ottawa Holding Inc., but is not obliged to select these candidates. The Nominating Committee is assisted by outside consultants in its search for candidates for appointment to the Boards.

As set out in the Shareholder Declaration, all candidates for appointment to the Boards must meet certain requirements, including demonstrated integrity and high ethical standards, relevant career experience and expertise, and an understanding of the role of Hydro Ottawa both as a service to local ratepayers and an asset of taxpayers.

In addition, the nomination and selection process is designed to maintain a Board that includes the following overarching competencies among one or more directors: strong business background including competitive business experience and strategic planning; a strong financial background including financial accreditation and public or private market financing experience; industry sector experience in the areas of business of the subsidiary companies; board experience; and merger and acquisition experience.

# Committees

The following committees were created to help the Boards of Directors carry out their duties. The committees meet regularly and provide feedback on their discussions to their respective Boards.

## HYDRO OTTAWA HOLDING INC.

**Audit:** The Audit Committee reviews financial statements, accounting practices and policies, auditing processes and the results of internal and external audits and related matters. It also oversees financial risk management and assesses internal controls. In 2009, the committee was consolidated with the Audit Committee of Hydro Ottawa Limited to improve the efficiency of committee oversight. Its membership includes representatives of the Board of Directors of Hydro Ottawa Limited.

**Governance and Management Resources:** The Governance and Management Resources Committee reviews the Corporation's governance structures and practices to ensure that the Board of Directors can fulfill its mandate. It reviews management resources and compensation practices to ensure systems are in place to attract, retain and motivate qualified management employees. It also reviews and assesses the performance of the President and Chief Executive Officer, oversees the Board Assessment process, and monitors compliance with codes of conduct. Its membership includes representatives of the Board of Directors of Hydro Ottawa Limited.

**Investment Review:** The Investment Review Committee, created by the Board of Directors effective April 2010, is responsible for assisting management and the Board of Directors in the review and pursuit of business development, acquisition and investment opportunities. In carrying out these functions, the Committee focuses on the consistency of opportunities with strategic plans and investment guidelines, the maximization of shareholder value and the management of risk.

**Nominating:** The Nominating Committee, with the assistance of outside consultants, identifies and evaluates potential candidates for appointment as Directors. The Nominating Committee makes recommendations to the shareholder [represented by Ottawa City Council] for the appointment of directors.

**Strategic Initiatives Oversight:** The Strategic Initiatives Oversight Committee, created by the Board of Directors effective November 2013, is responsible for assisting the Board of Directors in guiding management and providing support and focus for large-scale capital project efforts as identified by the Board from time to time.

# Board and Committee Meeting Attendance

The following tables illustrate the attendance of members at meetings of the Boards of Directors and their committees.

## HYDRO OTTAWA HOLDING INC.

| DIRECTOR | BOARD MEETINGS | COMMITTEE MEETINGS |
|---|---|---|
| Pierre Richard* (Outgoing Chair) | 2/2 | 7/7 |
| Bryce Conrad (President and CEO) | 6/6 | N/A |
| Jim Durrell (Incoming Chair) | 6/6 | 7/8 |
| Dale Craig*** | 2/3 | 1/1 |
| Manon Harvey | 6/6 | 7/7 |
| Peter Hume | 5/6 | 1/1 |
| Douglas McLarty | 6/6 | 5/5 |
| Maria McRae | 5/6 | 1/1 |
| Ford Ralph | 6/6 | 7/7 |
| Jim Watson | 3/6 | 3/3 |
| Ken Wigglesworth | 6/6 | 7/7 |
| Carole Workman | 6/6 | 4/4 |

## HYDRO OTTAWA LIMITED

| DIRECTOR | BOARD MEETINGS | COMMITTEE MEETINGS |
|---|---|---|
| Pierre Richard* (Outgoing Chair) | 2/2 | N/A |
| George Anderson* | 2/2 | 2/2 |
| Bryce Conrad (President and CEO) | 6/6 | N/A |
| Jim Durrell** (Incoming Chair) | 4/4 | N/A |
| Manon Harvey | 6/6 | N/A |
| Kalai Kalaichelvan** | 4/4 | 2/2 |
| Bob Monette | 3/6 | N/A |
| Phil Murray | 6/6 | 4/4 |
| Zaina Sovani | 5/6 | 5/5 |

* Depicts outgoing Board members who departed in June 2013
** Depicts incoming Board members effective July 2013
*** Depicts incoming Board members effective October 2013

# Members of the Board of Directors

## Hydro Ottawa Holding Inc.*


Jim Durrell, C.M. (Chair)


Bryce Conrad


Dale Craig


Manon Harvey


Councillor Peter Hume


Douglas McLarty


Councillor Maria McRae


Ford Ralph


Mayor Jim Watson


Ken Wigglesworth


Carole Workman

## Hydro Ottawa Limited*


Jim Durrell, C.M. (Chair)


Bryce Conrad


Manon Harvey


Kalai Kalaichelvan


Councillor Bob Monette


Phil Murray


Zaina Sovani

* As at December 31, 2013.

Note: George Anderson served on the Hydro Ottawa Limited Board of Directors from September 12, 2007 to June 30, 2013. Pierre Richard was first appointed to the Hydro Ottawa Holding Inc. Advisory Board on January 17, 2002, and was appointed to the Hydro Ottawa Holding Inc. Board of Directors on November 1, 2004, where he served as Chair until his departure in June 2013. Pierre was also appointed to the Hydro Ottawa Limited Board of Directors on July 1, 2006, and served as Chair from that time onwards. We wish to convey our sincere appreciation to both of these individuals for their dedicated service.

# Glossary of Terms

## Electricity Industry

IESO The Independent Electricity System Operator is responsible for day-to-day operation of Ontario's electrical system. It operates the wholesale electricity market, forecasting demand and ensuring an adequate supply to meet that demand.

MDM/R The Meter Data Management and Repository system stores and manages consumption data received from Smart Meters, enabling Time-of-Use billing as part of the provincial Smart Meter Initiative.

OEB The Ontario Energy Board regulates the provincial electricity and natural gas industries in the public interest.

OPA The Ontario Power Authority is responsible for ensuring an adequate long-term supply of electricity for Ontario. It creates and implements conservation and demand management programs, ensures adequate investment in new supply infrastructure, performs long-term electricity system planning, and facilitates the development of a more sustainable and competitive electricity system.

Smart Meters Smart Meters measure and store data about when customers use electricity as the foundation for Time-of-Use billing.

TOU A Time-of-Use rate structure charges customers higher rates for electricity used during peak times of the day and lower rates for off-peak usage.

## Internal Systems and Processes

GIS Geographic information systems capture, store, analyze, and display geographically referenced spatial information.

OMS The Outage Management System, when integrated with the GIS (see above) results in a single computerized map of the electricity distribution system to facilitate system planning and outage response.

SCADA Supervisory control and data acquisition refers to large-scale measurement and control systems used to monitor power generation and other distribution processes.

## Financial Reporting

AcSB Accounting Standards Board is an independent body with the authority to develop and establish standards and guidance governing financial accounting and reporting in Canada.

CPA Canada Chartered Professional Accountants Canada represents the CPA profession nationally. It supports the setting of accounting, auditing and assurance standards for business, not-for-profit organizations and government, and issues guidance on control and governance.

Pre-changeover Canadian GAAP Pre-changeover Canadian Generally Accepted Accounting Principles are the common set of accounting principles, standards and procedures companies use to prepare their financial statements in Canada before the introduction of IFRS.

IFRS International Financial Reporting Standards are standards and interpretations adopted by the International Accounting Standards Board (IASB). Hydro Ottawa will be required to report under IFRS rather than pre-changeover Canadian GAAP (see above) on January 1, 2015.

## Earnings

There are a number of different ways of looking at how much a company earns. The most common is "net income", but other measurements, such as EBITDA, can be useful in judging the company's ability to borrow and to expand its business.

EBITDA Earnings Before Interest, Taxes, Depreciation and Amortization is a measure of financial health that helps to show how much money a company generates to pay for its obligations (such as interest on money borrowed and taxes) and fund its future growth (through depreciation and amortization).

Net Income Net income is a company's total earnings (or profit). It is determined by subtracting expenses and losses from revenues and gains during the period.

## Cash Sources and Uses

Operating Operating activities primarily measure the cash-generating abilities of Hydro Ottawa's core operations rather than its ability to raise capital or purchase assets.

Investing Investing activities relate to Hydro Ottawa's purchases or sales of capital assets (assets that appear on the balance sheet and have a useful life of more than one year). Capital assets include property, plant and equipment, and intangible assets.

Financing Financing activities result in changes in the size and composition of the Company's equity capital and borrowings. A major source of cash from financing activities is the money received from long-term bond issuances.

**Hydro Ottawa** @hydroottawa 3h
Very nice. RT @judithregion3: just saw hydro Ottawa going down our road. thank you to all the hydro workers helping us this weekend ^mb
Expand

**Hydro Ottawa** @hydroottawa 4h
Proud of our crews, who had a busy weekend restoring 15K people in Peterborough area affected by last Friday's storm. ow.ly/i/1TvRE

**Hydro Ottawa** @hydroottawa 4h
Nice! RT @markjhaug: SHOUT OUT to Hydro Ottawa for driving 9 trucks and people down to help @Pto_Canada #blessyou pic.twitter.com/9J2D76JpbT
View photo

**Hydro Ottawa** @hydroottawa 4h
RT @caltek79: Drove past 12+ Hydro Ottawa vehicles heading west on Fleming Drive. Help has arrived for those still without power. #onstorm

Hydro Ottawa
Holding Inc.

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# RATING AGENCY REPORTS

Attachment A-4(D) is the current "Rating Report" for Hydro Ottawa Holding Inc. issued in May 2014 by Dominion Bond Rating Service.

Attachment A-4(E) is the current "Rating Report" for Hydro Ottawa Holding Inc. issued in December 2014 by Standard & Poor's.

**Rating Report**

**Report Date:**
May 12, 2014

**Previous Report:**
May 21, 2013

*Insight beyond the rating.*

# Hydro Ottawa Holding Inc.


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**The Company**

Hydro Ottawa Holding Inc. is a holding company that wholly owns the following subsidiaries: (1) Hydro Ottawa Limited (the LDC), a regulated electricity distributor (Hydro Ottawa's primary business); (2) Energy Ottawa Inc., a non-regulated power generation company also involved in energy management services; and (3) Telecom Ottawa Holding Inc.

Hydro Ottawa Holding Inc. is wholly owned by the City of Ottawa.

## Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Senior Unsecured Debt | A | Confirmed | Stable |
| Issuer Rating | A | Confirmed | Stable |

## Rating Update

DBRS has confirmed the Issuer Rating and the Senior Unsecured Debt rating of Hydro Ottawa Holding Inc. (Hydro Ottawa or the Company) at "A," both with Stable trends. The ratings reflect the Company's reasonable financial risk profile as well as the low business risk associated with its regulated electricity distribution business. However, DBRS is concerned over rising earnings and cash flows contributed from the higher risk non-regulated segment. Hydro Ottawa's business risk profile could be negatively affected should non-regulated earnings exceed the 20% threshold for the current rating category (18.4% of 2013 EBIT).

Hydro Ottawa's business risk profile of "A" is supported by the reasonable regulatory framework in Ontario and the relatively stable earnings and cash flows from the Company's regulated operations (approximately 82% of 2013 EBIT). Hydro Ottawa currently operates under the 3rd Generation Incentive Rate Mechanism (IRM) but is expected to transition to 4th Generation Incentive Rate-setting (IR) or to Custom IR under the Ontario Energy Board's (OEB) Renewed Regulatory Framework. DBRS views the regulatory risk under the renewed framework as modestly higher than under IRM as the longer minimum term (four plus years versus three years) could potentially result in greater regulatory lag. This risk is partially mitigated by the ability of Hydro Ottawa to initiate a regulatory review if actual return on equity (ROE) is 300 basis points (bps) below the approved ROE.

Hydro Ottawa's exposure to non-regulated earnings increased significantly in 2013, following the acquisition of three hydroelectric plants and a further 38.3% interest in the Ring Dam at Chaudière Falls (total Hydro Ottawa ownership: 67%) in late 2012. Earnings and cash flows from this segment are considered more volatile because of the greater associated volume risk. Commodity price risk for the Company is minimal as it has been mitigated through long-term fixed-price contracts with a creditworthy counterparty. However, increasing exposure to non-regulated operations remains a concern.

Hydro Ottawa's financial risk profile is in the "A" rating range, supported by a reasonable balance sheet and strong credit metrics. All three of the Company's key ratios weakened slightly in 2013 as a result of a considerable increase in debt to $410 million from $329 million in 2012. Although the Company's debt-to-capital ratio may further deteriorate during this period of high capex in order to enhance the reliability of the system and expand generation capacity at Chaudière Falls (see DBRS press release, DBRS Comments on Hydro Ottawa's Expansion at Chaudière Falls, dated March 7, 2014), DBRS expects Hydro Ottawa to continue to have reasonable financial flexibility for the current rating category going forward.

## Rating Considerations

**Strengths**
(1) Stability from regulated business
(2) Strong franchise area
(3) Long-term contracts in non-regulated generation

**Challenges**
(1) Higher risk non-regulated business
(2) Large capital expenditures
(3) Unable to access equity markets

## Financial Information

| **Hydro Ottawa Holding Inc.** | **For the year ended December 31** | | | | |
|---|---|---|---|---|---|
| (CA$ millions) | **2013** | **2012** | **2011** | **2010** | **2009** |
| Total debt | 410 | 329 | 252 | 252 | 252 |
| Total debt in capital structure (1) | 51.6% | 47.3% | 41.7% | 42.4% | 43.4% |
| Cash flow/Total debt (1) | 17.8% | 21.0% | 29.1% | 28.5% | 28.2% |
| EBIT gross interest coverage (times) (1) | 3.52 | 4.16 | 3.85 | 4.49 | 4.51 |
| Net income before extraordinary items | 33 | 32 | 29 | 30 | 29 |
| Cash flow from operations | 73 | 69 | 73 | 72 | 71 |

(1) Includes operating leases.

**Hydro Ottawa Holding Inc.**

**Report Date:**
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## Rating Considerations Details

**Strengths**

(1) **Stability from regulated business.** Approximately 82% of the Company's EBIT is contributed by its low-risk regulated distribution business, which operates under a reasonable regulatory framework. Earnings and cash flows have also been relatively stable, underpinned by a reasonable allowed ROE (9.42% for 2013) and full and timely recovery of purchased power costs.

(2) **Strong franchise.** Hydro Ottawa is one of the largest municipally owned local distribution companies in Ontario, serving the densely populated areas within the City of Ottawa and the Village of Casselman. The majority of Hydro Ottawa's electricity sales are to residential customers, the federal government, and the municipalities, universities, schools and hospitals (MUSH) sector, which have relatively stable year-over-year demand as they are less sensitive to economic cycles.

(3) **Long-term contracts for non-regulated power generation.** Although Hydro Ottawa's non-regulated power generation business provides opportunities for earnings growth, it also entails higher business risk than the regulated distribution business. However, commodity price risk is mitigated by long-term contracts with creditworthy counterparties, such as the Ontario Power Authority (rated A (high)).

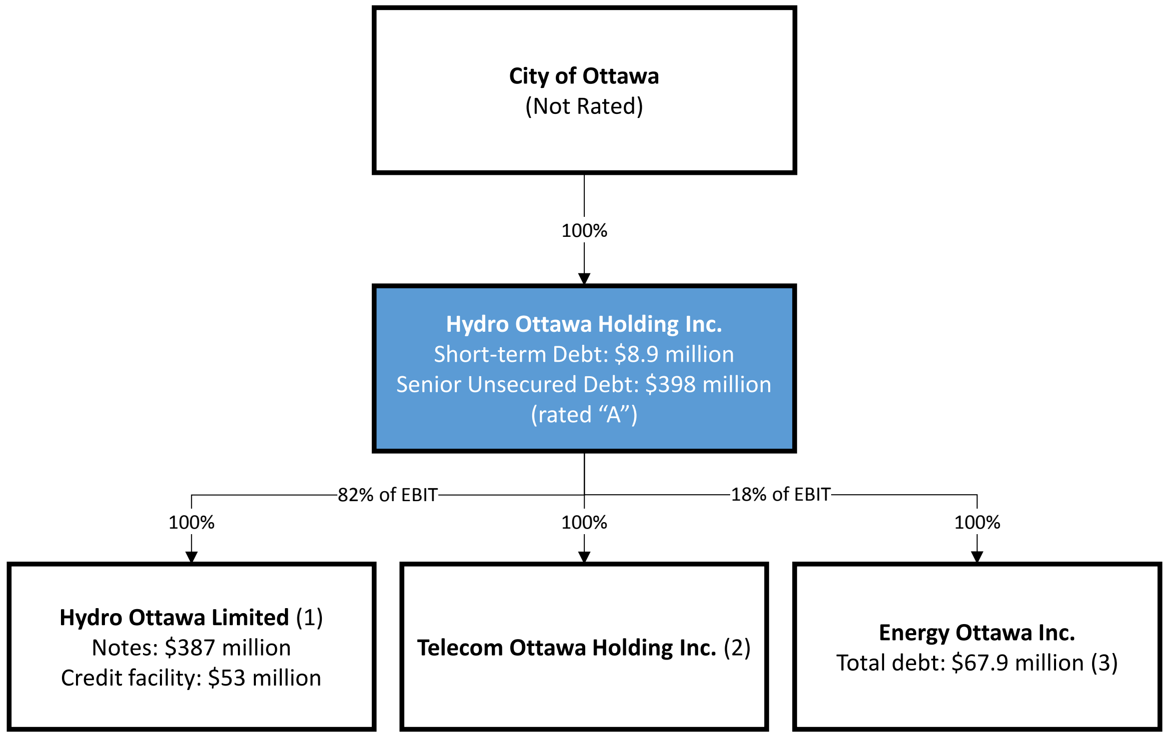
**Challenges**

(1) **Increasing exposure to higher risk non-regulated business.** DBRS considers the non-regulated business as higher risk than Hydro Ottawa's core regulated electricity distribution business. This is largely due to the greater volume risk associated with non-regulated operations. Although commodity price risk has been mitigated through long-term contracts, increasing exposure to the non-regulated segment could result in greater volatility in the Company's earnings and cash flows going forward.

(2) **Large capital expenditures.** The company is in the midst of major capex programs to 1) enhance the reliability of the system and meet growing demographic demands and 2) to construct a new 29-megawatt (MW) facility at Chaudière Falls. This is expected to result in the Company continuing to generate free cash flow deficits over the medium term.

(3) **No access to the equity markets.** Hydro Ottawa's ownership structure (100% owned by the City of Ottawa) limits its ability to directly access the equity markets. As a result, Hydro Ottawa's cash flow deficits are being financed largely through its revolving credit facilities and debt issuances.

## Corporate Structure




(1) The debt at Hydro Ottawa Limited is owed to Hydro Ottawa Holding Inc., mostly in the form of promissory notes.
(2) Telecom Ottawa Holding Inc. does not maintain active operations.
(3) $65.6 million was owed to Hydro Ottawa Holding Inc., and $2.4 million (non-interest bearing) was owed to Integrated Gas Recovery Services Inc.

**Hydro Ottawa Holding Inc.**

**Report Date:**
May 12, 2014

## Earnings and Outlook

| (Consolidated) | For the year ended December 31 | | | | |
|---|---|---|---|---|---|
| (CA$ millions) | **2013** | **2012** | **2011** | **2010** | **2009** |
| Net revenues | 976.4 | 900.8 | 840.1 | 799.6 | 754.7 |
| Net sales | 211.2 | 193.2 | 179.6 | 179.1 | 170.5 |
| EBITDA | 98.0 | 89.5 | 93.9 | 100.9 | 98.7 |
| EBIT | 57.7 | 52.4 | 48.5 | 56.5 | 56.7 |
| Gross interest expense | 16.4 | 12.6 | 12.6 | 12.6 | 12.6 |
| Net income before non-recurring items | 32.9 | 31.6 | 29.1 | 29.9 | 29.3 |
| Reported net income | 32.1 | 31.0 | 26.3 | 31.2 | 29.4 |
| Return on equity | 8.8% | 8.8% | 8.4% | 8.9% | 9.0% |
| | | | | | |
| Regulated rate base | 669 | 669 | 546 | 546 | 546 |
| Approved regulated return on equity | 9.42% | 9.42% | 8.57% | 8.57% | 8.57% |
| Actual regulated return on equity | 9.44% | 10.19% | 9.08% | 10.33% | 10.70% |

| **EBIT by subsidiary (estimate)** | | | | | |
|---|---|---|---|---|---|
| (CA$ millions) | **2013** | **2012** | **2011** | **2010** | **2009** |
| Hydro Ottawa Limited | 47.9 | 48.0 | 53.0 | 53.6 | 48.5 |
| Energy Ottawa Inc. | 10.8 | 4.7 | 5.7 | 4.1 | 4.9 |
| Telecom Ottawa Holdings Inc. | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 |
| | 58.7 | 52.7 | 58.7 | 57.9 | 53.7 |
| Hydro Ottawa Holdings Inc. (non-cons.) | (1.0) | (0.3) | (2.7) | (1.2) | (2.7) |
| Hydro Ottawa Holdings Inc. (consolidated) | 57.7 | 52.4 | 56.0 | 56.7 | 51.1 |

**2013 Summary**

- Hydro Ottawa's earnings improved modestly over 2013 as a result of stronger results from its non-regulated operations. Earnings from the regulated electricity distribution segment were largely in line with 2012 earnings.
- Non-regulated earnings at Energy Ottawa Inc. benefitted from commercial operations commencing at a landfill gas-to-energy plant at the Laflèche landfill, and from a full year's impact of acquiring the three hydro-electric plants operating at Chaudière Falls from Domtar Inc.
- Net income increased as a result of higher earnings from non-regulated operations, offset by increased interest expenses from larger consolidated debt.
- As a result, non-regulated operations increased to 18.4% of EBIT from 9.0% in 2012.

**2014 Outlook**

- Hydro Ottawa's earnings are expected to be slightly more volatile as a result of the Company's greater exposure to non-regulated operations.
- Earnings from the non-regulated generation business are typically more volatile as this sector is subject to greater volume risk.
- The regulated distribution business is expected to continue to provide relatively stable earnings.
- Going forward, DBRS expects the distribution segment to continue to contribute at least 80% of Hydro Ottawa's earnings. However, should non-regulated earnings exceed the 20% threshold for the current rating category, the Company's business risk profile could be negatively affected.

**Hydro Ottawa Holding Inc.**

**Report Date:**
May 12, 2014

## Financial Profile

| (Consolidated)<br>(CA$ millions) | For the year ended December 31<br>2013 | <br>2012 | <br>2011 | <br>2010 | <br>2009 |
|---|---|---|---|---|---|
| Net income before non-recurring items | 32.9 | 31.6 | 29.1 | 29.9 | 29.3 |
| Depreciation & amortization | 40.3 | 37.1 | 45.4 | 44.4 | 42.0 |
| Deferred income taxes and other | (0.3) | 0.5 | (1.1) | (2.0) | 0.2 |
| **Cash flow from operations** | 73.0 | 69.2 | 73.5 | 72.2 | 71.5 |
| Dividends paid | (18.6) | (16.6) | (17.5) | (17.6) | (17.2) |
| Capital expenditures | (113.9) | (96.4) | (78.0) | (60.7) | (59.0) |
| **Free cash flow (bef. working cap. changes)** | (59.6) | (43.8) | (22.0) | (6.1) | (4.7) |
| Changes in working capital | (23.5) | 11.6 | 26.0 | (2.1) | (16.2) |
| **Net free cash flow** | (83.1) | (32.2) | 4.0 | (8.1) | (20.9) |
| Acquisitions & long-term investments | 0.0 | (46.3) | 0.0 | 0.0 | 0.0 |
| Net equity change | 1.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Net debt change (2) | 71.1 | 2.6 | (0.2) | 0.2 | 0.0 |
| Other financing | 2.2 | (1.3) | (0.9) | 4.4 | 2.8 |
| **Change in cash** (2) | (8.9) | (77.4) | 2.9 | (3.5) | (18.2) |
| | | | | | |
| Total debt | 410 | 329 | 252 | 252 | 252 |
| Total debt in capital structure (1) | 51.6% | 47.3% | 41.7% | 42.4% | 43.4% |
| Cash flow/Total debt (1) | 17.8% | 21.0% | 29.1% | 28.5% | 28.2% |
| EBIT gross interest coverage (times) (1) | 3.52 | 4.16 | 3.85 | 4.49 | 4.51 |
| Dividend payout ratio | 56.5% | 52.5% | 60.1% | 58.9% | 58.6% |

(1) Includes operating leases. (2) Adjusted for bank indebtedness.

**2013 Summary**

- Hydro Ottawa's credit metrics weakened as a result of the higher debt level in 2013. However, the Company's key ratios remain commensurate with the current rating.
- Cash flow from operations improved as a result of stronger earnings in the unregulated business.
- Dividends of $18.6 million were in line with the Company's dividend policy. Hydro Ottawa pays dividends equal to the greater of $14 million or 60% of the previous year's net income.
- The Company generated a significant negative free cash flow largely because of the high level of capex needed in the regulated distribution business to sustain the reliability of the system. This deficit was largely funded through incremental debt.

**2014 Outlook**

- DBRS expects cash flow from operations to be slightly more volatile as a result of the Company's greater exposure to non-regulated operations.
- DBRS anticipates elevated capex in 2014 as the Company continues to invest in renewing the infrastructure of the distribution system and begins construction on the new facility at Chaudière Falls.
- Free cash flow deficits are expected to persist over the medium term during this period of high capex. Free cash flow is also restricted by the Company's dividend policy. DBRS expects Hydro Ottawa to fund these deficits in a prudent manner in order to maintain key credit metrics in line with the current rating category.

# Liquidity, Bank Lines and Long-Term Debt Maturities

## Liquidity

**Credit facilities as at Dec. 31, 2013**

| (CA$ millions) | Amount | Drawn | Available | Expiry |
|---|---|---|---|---|
| 364-day revolving operating credit line | 75.00 | 4.95 | 70.05 | 02-Aug-14 |
| Revolving credit line | 100.00 | - | 100.00 | 02-Aug-15 |
| Letters of credit and other guarantees | 17.50 | 16.00 | 1.50 | |
| Commercial card facility | 1.00 | - | 1.00 | |
| **Total consolidated credit facilities** | **193.50** | **20.95** | **172.55** | |

- Hydro Ottawa's liquidity remained reasonable, reflecting stable cash flows and available credit facilities.
- DBRS believes that the Company's liquidity is sufficient to finance its capex and working capital needs.
- Hydro Ottawa renewed its credit facility in 2013, cancelling its $0.15 million corporate Visa facility. The current facility is made up of the following four types of credit availability:
  - $75 million 364-day revolving operating line.
  - $100 million two-year revolving line to fund capex and growth opportunities.
  - $17.5 million line to fund letters of credit and other guarantees.
  - $1 million commercial card facility.
- The credit facility contains customary covenants and events of default, including a covenant to maintain the consolidated tangible net worth in excess of $175 million at all times. It also requires the debt-to-capitalization ratio to be at or below 75% on a consolidated basis.

## Long-Term Debt

**Long-Term Debt Maturity as at Dec. 31, 2013**

| (CA$ millions) | Amount | Rate | Maturity |
|---|---|---|---|
| Senior Unsecured Debentures, Series 2005-1 | 199.76 | 4.9% | Feb. 2015 |
| Senior Unsecured Debentures, Series 2006-1 | 49.76 | 5.0% | Dec. 2036 |
| Senior Unsecured Debentures, Series 2013-1 | 148.87 | 4.0% | May 2043 |
| **Total** | **398.39** | | |

- On May 14, 2013, Hydro Ottawa issued $150 million of Senior Unsecured Debentures (Series 2013-1 debentures) maturing on May 14, 2043, with an interest rate of 3.991% per annum. The net proceeds from the Series 2013-1 debentures were used to refinance its credit facilities and for general corporate purposes, including capex requirements.
- The trust indenture contains the following covenants for the Series 2005, Series 2006, and Series 2013 debentures:
  - Any additional indebtedness is subject to a 75% capitalization ratio test.
  - Negative pledge clause.
  - Restrictions on asset sales and amalgamations.
- An Integrated Gas Recovery Services Inc. (IGRS) promissory note of $3.1 million was issued by PowerTrail Inc. to fund the construction of the gas collection and generation plant at the Trail Road landfill site. The note is unsecured and non-interest bearing. Hydro Ottawa repaid $0.42 million in 2013 and intends to pay an additional $0.34 million in 2014. IGRS does not intend to call the remaining $2.02 million this year.
- DBRS expects re-financing risk on the Company's Series 2005-1 debentures maturing in 2015 to be manageable.

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## Regulation

- Hydro Ottawa Limited (the LDC; a regulated subsidiary of Hydro Ottawa) is regulated by the OEB under *the Ontario Electricity Act, 1998.*
- The LDC currently operates under the 3rd Generation IRM framework and is subject to a formula price cap that allows for an annual increase in distribution rates based on inflation less a productivity factor, which can be reset annually.
- Under the IRM framework, if the LDC's actual rate of ROE is 300 bps above or below the allowed ROE, the OEB will undertake a review, and earnings above 300 bps may be shared with customers.
- The IRM framework also allows the Company to file under the Incremental Capital Module (ICM) during the IRM period if the capex was material and determined to be necessary and prudently spent.
- The LDC is allowed to fully recover its purchased power costs (except doubtful accounts on power cost, which are manageable) in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario.
- Additionally, the LDC is allowed to file a Cost of Service (COS) application, which is expected every four years.
- In the rebasing year, subject to the OEB's approval, the LDC could be allowed to add prudently incurred capex that was already spent during the IRM period to its rate base. The Company last rebased in 2012.
- Beginning in January 2012, the OEB approved the following: ROE at 9.42%, deemed equity at 40% (both of which are reasonable), and the rate base of $669 million. The OEB also allowed the LDC to invest appropriate capital amounts.
- In August 2013, the LDC filed an IRM application for 2014 electricity distribution rates, effective for January 1, 2014. The LDC proposed 2014 rates to be adjusted by a price cap adjustment and to include rate riders for deferral/variance account disposition, and for the derecognition of assets in the transition to IFRS.
- In December 2013, the OEB approved a price cap adjustment of 1.4%, which includes an inflation factor of 1.7% less a productivity factor of 0% and a stretch factor of 0.3%. DBRS views the price cap adjustment as reasonable. The OEB also approved the LDC's request for the disposition of certain deferral/variance accounts over a one-year period from January 1, 2014, to December 31, 2014. However, the OEB did not approve the creation of a new variance account for the purpose of recording the costs of assets derecognized following the change in accounting standards.
- The regulatory framework for electricity distribution companies in Ontario will change from the current IRM framework to the Renewed Regulatory Framework. DBRS expects the LDC to either transition to 4th Generation IR following the next rebasing year (expected to be in 2016) or apply for the Custom IR framework.
- The chart below reflects DBRS's assessment of the current regulatory environment for Hydro Ottawa based on DBRS's methodology.

| Criteria | Score | Analysis |
|---|---|---|
| (1) Deemed Equity | Excellent<br>Good<br>**Satisfactory**<br>Below Average<br>Poor | The OEB allows the LDC to have a deemed equity of 40%, which is consistent with the other electricity distribution companies in Ontario. As a result of the need to maintain the regulatory capital structure, Hydro Ottawa's leverage has been in line with the "A" rating range. |
| (2) Allowed ROE | Excellent<br>**Good**<br>Satisfactory<br>Below Average<br>Poor | The LDC has an allowed ROE of 9.42% for 2014. The difference in ROE between Hydro Ottawa and other distribution companies is mainly due to the timing of the regulatory filings and the interest environment prevalent at that time. |

| | | |
|---|---|---|
| (3) Energy Cost Recovery | **Excellent**<br>Good<br>Satisfactory<br>Below Average<br>Poor | There is no power price risk for Hydro Ottawa Limited as it is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to rate payers at rates set by the OEB, and Hydro Ottawa Limited collects the payments from its customers on a monthly basis. |
| (4) Capital Cost Recovery | Excellent<br>**Good**<br>Satisfactory<br>Below Average<br>Poor | Under IRM, Some capital costs are pre-approved at the time of the COS application. Subsequent capital spending after the base year will not be approved until the next rate application and approval of the rate base. If incremental capital costs are significant, non-discretionary and prudent, Hydro Ottawa can file under ICM to request for the recovery of the costs. |
| (5) COS Versus IRM | Excellent<br>Good<br>**Satisfactory**<br>Below Average<br>Poor | Hydro Ottawa is regulated under an IRM framework, with three years in between the COS rebasing year. Hydro Ottawa rebased in 2012 and was allowed to recover prudently spent capex from 2008 to 2011. In 2013, Hydro Ottawa returned to the IRM. During the IRM period, Hydro Ottawa can also file under the ICM if there are significant, non-discretionary and prudent incremental capital needs between rebasing years. DBRS notes that efficiency targets have been reasonable for Hydro Ottawa. Going forward, DBRS expects the Company to remain on IRM for the remaining term and rebase under 4th Generation IR, or apply for Custom IR under the Renewed Regulatory Framework. |
| (6) Political Interference | Excellent<br>Good<br>Satisfactory<br>**Below Average**<br>Poor | The government of Ontario plays a significant role in the electricity sector in Ontario, given that the majority of the utilities are government owned (Hydro Ottawa is owned by the City of Ottawa). Further, stakeholders, such as the Ontario Power Authority (rated A (high)) and the Independent Electricity System Operator, are also government owned. As a result, the government has direct and indirect influence in Ontario's electricity industry. |
| (7) Retail Rate | Excellent<br>Good<br>**Satisfactory**<br>Below Average<br>Poor | The cost of power in Hydro Ottawa's service territory is set by the OEB. On average, electricity prices for Hydro Ottawa's residential customers are around 13.5 cents per kilowatt hour. This is comparable with other service territories in Ontario. |
| (8) Stranded Cost Recovery | Excellent<br>**Good**<br>Satisfactory<br>Below Average<br>Poor | Minimal stranded costs exist in the Ontario market. DBRS notes that the recovery of the costs is also subject to some regulatory lag. Although stranded costs have been fully recovered in the past years, assets could potentially be written down if the OEB does not approve the recovery of the costs. |

| | | |
|---|---|---|
| (9) Rate Freeze | Excellent<br>Good<br>**Satisfactory**<br>Below Average<br>Poor | Distribution rates were frozen for a short time in the early 2000s, but this did not have a material impact on Hydro Ottawa's financial profile. Since distribution costs represent approximately 20% of a customer's overall electricity bill, an increase in rates would have a greater nominal impact on customers' bills. This could increase the risk of potential rate freezes. |
| (10) Market Structure (Deregulation) | Excellent<br>**Satisfactory**<br>Poor | Following the restructuring of Ontario Hydro in 1999, Ontario's electricity market became partially deregulated, specifically for the generation segment. Distribution (including Hydro Ottawa) and transmission remains fully regulated under the OEB. DBRS notes that no single utility in Ontario is fully integrated. |

**Hydro Ottawa Holding Inc.**

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**Hydro Ottawa Holding Inc.**

| **Balance Sheet (CA$ millions)** | **Dec. 31** | **Dec. 31** | **Dec. 31** | | **Dec. 31** | **Dec. 31** | **Dec. 31** |
|---|---|---|---|---|---|---|---|
| **Assets** | **2013** | **2012** | **2011** | **Liabilities & Equity** | **2013** | **2012** | **2011** |
| Cash & equivalents | 0 | 0 | 3 | S.T. borrowings | 9 | 77 | 0 |
| Accounts receivable | 70 | 75 | 65 | Accounts payable | 132 | 133 | 123 |
| Inventories | 0 | 0 | 0 | Current portion L.T.D. | 0 | 1 | 0 |
| Prepaid expenses & other | 113 | 97 | 99 | Other current liab. | 20 | 23 | 11 |
| **Total Current Assets** | 183 | 172 | 167 | **Total Current Liab.** | 162 | 234 | 134 |
| Net fixed assets | 726 | 670 | 589 | Long-term debt | 400 | 251 | 252 |
| Future income tax assets | 20 | 24 | 25 | Provisions | 9 | 11 | 9 |
| Goodwill & intangibles | 66 | 52 | 25 | Deferred income taxes | 6 | 5 | 4 |
| Investments & others | 13 | 8 | 9 | Other L.T. liab. | 46 | 56 | 61 |
| | | | | Shareholders' equity | 384 | 368 | 353 |
| **Total Assets** | 1,008 | 926 | 814 | **Total Liab. & SE** | 1,008 | 926 | 814 |

| **Balance Sheet & Liquidity & Capital Ratios** | **For the year ended December 31** 2013 | **2012** | **2011** | **2010** | **2009** |
|---|---|---|---|---|---|
| Current ratio | 1.13 | 0.73 | 1.25 | 1.45 | 1.35 |
| Total debt in capital structure | 51.6% | 47.3% | 41.7% | 42.3% | 43.2% |
| Total debt in capital structure (1) | 51.6% | 47.3% | 41.7% | 42.4% | 43.4% |
| Cash flow/Total debt | 17.8% | 21.0% | 29.1% | 28.6% | 28.4% |
| Cash flow/Total debt (1) | 17.8% | 21.0% | 29.1% | 28.5% | 28.2% |
| (Cash flow-dividends)/Capex (times) | 0.48 | 0.55 | 0.72 | 0.90 | 0.92 |
| Dividend payout ratio | 56.5% | 52.5% | 60.1% | 58.9% | 58.6% |
| **Coverage Ratios (times)** | | | | | |
| EBIT gross interest coverage | 3.52 | 4.16 | 3.86 | 4.49 | 4.52 |
| EBIT interest coverage (1) | 3.52 | 4.16 | 3.85 | 4.49 | 4.51 |
| EBITDA gross interest coverage | 5.97 | 7.11 | 7.47 | 8.02 | 7.86 |
| Fixed-charge coverage | 3.52 | 4.16 | 3.86 | 4.49 | 4.52 |
| **Profitability Ratios** | | | | | |
| EBITDA margin | 46.4% | 46.3% | 52.3% | 56.3% | 57.9% |
| EBIT margin | 27.3% | 27.1% | 27.0% | 31.5% | 33.3% |
| Profit margin | 15.6% | 16.4% | 16.2% | 16.7% | 17.2% |
| Return on equity | 8.8% | 8.8% | 8.4% | 8.9% | 9.0% |
| Return on capital | 5.8% | 6.0% | 6.2% | 6.4% | 6.4% |

(1) Includes operating leases.

**Hydro Ottawa Holding Inc.**

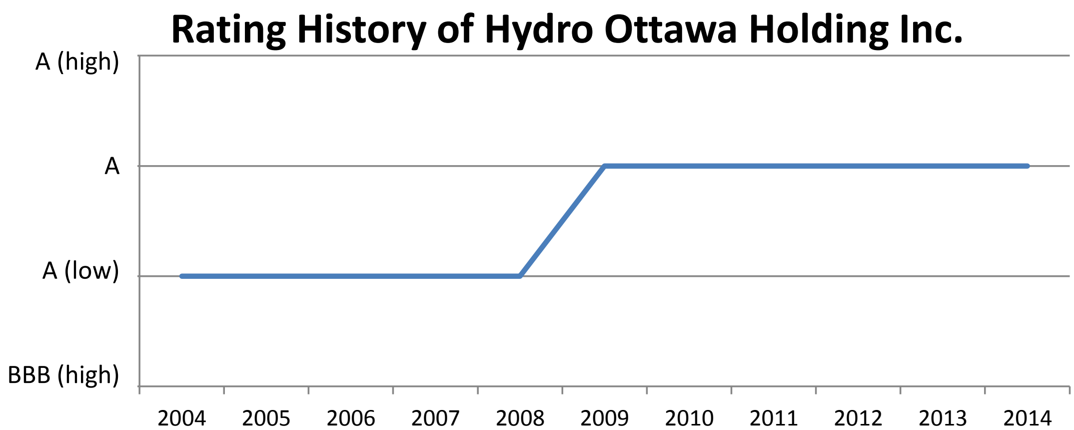
**Report Date:**
May 12, 2014

# Rating

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Senior Unsecured Debt | A | Confirmed | Stable |
| Issuer Rating | A | Confirmed | Stable |

# Rating History

| | Current | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|---|
| Senior Unsecured Debt | A | A | A | A | A | A |
| Issuer Rating | A | A | A | NR | NR | NR |




Note:
All figures are in Canadian dollars unless otherwise noted.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

# Research

Summary:

# Hydro Ottawa Holding Inc.

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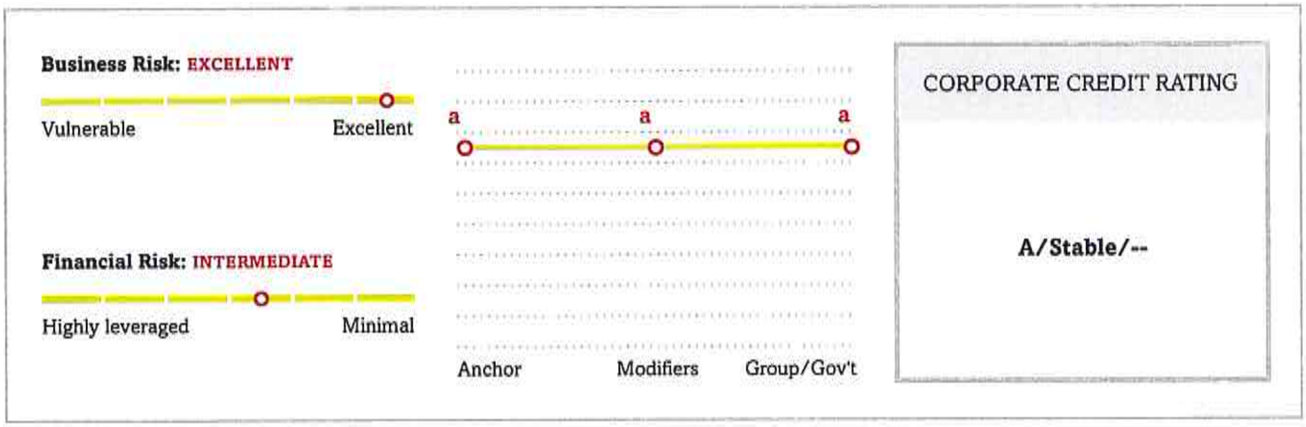
Summary:

# Hydro Ottawa Holding Inc.




## Rationale

| Business Risk: Excellent | Financial Risk: Intermediate |
|---|---|
| • A relatively transparent and predictable regulatory regime<br>• Passed-through commodity costs<br>• The ability to recover all prudently spent fixed and variable operating costs<br>• A well-diversified local economy<br>• Expansion in unregulated operations (hydroelectric power generation) increases business risk | • Stable, regulated cash flow<br>• Large upcoming capital program, especially with the Chaudière Falls expansion project<br>• Volume risk and volatility in cash flows associated with unregulated hydroelectric power generation<br>• "Low" likelihood of extraordinary support from its municipal government shareholder |

**Outlook: Stable**

The stable outlook reflects Standard & Poor's Ratings Services' expectation that Hydro Ottawa Holdings Inc. (HOHI) will continue to generate stable and predictable cash flow from its regulated electricity distribution business during our two-year outlook horizon. In addition, we expect the company will continue to focus on its regulated operations and remain contained in its unregulated power business.

### Downside Scenario

Although we do not expect a downgrade during the outlook horizon, we could lower the rating on HOHI if the company continues to expand its unregulated power business, resulting in 20% or higher of unregulated EBITDA in proportion to regulated EBITDA, increasing HOHI's overall business risk. We expect HOHI to continue focusing on its regulated electricity distribution operations. In addition, any material adverse regulatory decisions, substantial delays or additional capital required for the new Chaudière Falls project, or other changes that we believe might lead to significant and sustained increase in leverage resulting in deterioration of adjusted funds from operations (AFFO)-to-debt below 13% could lead to a downgrade. In the event of a cash flow shortfall, we expect the company to decrease its capital spending or suspend dividend payments to preserve credit metrics.

### Upside Scenario

An upgrade would require HOHI to demonstrate sustainable long-term financial growth or to improve its financial position, resulting in AFFO-to-debt of 23%-25%. However, we believe this is highly unlikely, given the company's heavy capital spending in the next few years.

## Standard & Poor's Base-Case Scenario

HOHI is an Ontario-based local electricity distribution company operating in Ottawa. The rating's key driver continues to be the Ontario Energy Board's (OEB) regulatory framework and the utility's performance within it.

**Assumptions**

- The regulatory structure will be relatively stable, and HOHI will not experience any material, adverse regulatory decisions
- HOHI will continue to earn close to its allowed return on equity of 9.42% established in 2012 by the OEB based on its deemed capital structure
- Distribution rates for 2014 and 2015 will be set based on the fourth-generation incentive rate-making mechanism (IRM)
- The OEB has approved HOHI to raise its distribution rate by 1.40% (1.70% inflation rate, 0.30% stretch factor) for 2015
- HOHI will file for a cost-of-service application in 2015 to re-base its distribution rates using the new IRM from 2016 through 2020
- Capital expenditures of approximately C$100 million in each of 2015 and 2016 for the regulated electricity distribution business
- The Chaudière Falls expansion project will cost approximately C$160 million. There will be no material delay and cost overruns. The new facility will commission in late 2017 or early 2018. The cash flows and debt from this project are consolidated to those of HOHI

**Key Metrics**

| | 2013A | 2014E | 2015E |
|---|---|---|---|
| AFFO/debt | 17.2% | 14%-17% | 12%-14% |
| Debt-to-debt and equity | 52.3% | 53%-58% | 56%-61% |

AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

## Business Risk: Excellent

In our view, HOHI's business risk profile is "excellent," reflecting our assessment of the regulatory structure provided by the OEB. The OEB continues to provide a transparent, consistent, and independently operated regulatory framework that supports a stable and predictable cash flow model, which we view as a key credit strength. Historically, electricity rates are established under a cost-of-service framework, with rates for the subsequent three years under an IRM. In 2012, the OEB proposed additional alternatives to electricity rate setting. We expect HOHI will adapt the IRM method to reflect the revenue requirement based on the large multiyear capital programs the company is committed to in the next few years. HOHI's most recent cost-of-service hearing was in 2012; the next one and a rate base reset are scheduled in 2016. The regulatory framework also limits the utility's exposure to commodity risk and associated cash flow volatility because the tariff structure allows the cost of electricity to flow through directly to customers. The tariff structure also allows the utility operator to recover prudently spent operating costs, capital expenditures, or other unexpected material losses in a timely manner.

Further supporting the excellent business risk profile is HOHI's large and diverse customer base with no meaningful concentration risk. Residential customers account for approximately 80% of HOHI's customers and 55% of HOHI's distribution revenue. In our view, this customer profile is less sensitive to macroeconomic stress and business cycles. Nevertheless, the residential customer base has some sensitivity to volume fluctuations, primarily weather-driven, although we do not believe the fluctuations would pressure credit metrics for the rating. We do not expect HOHI's customer composition to change materially in the next two years.

Aside from the regulated electricity distribution business, HOHI also operates an unregulated power business via one of its subsidiaries, Energy Ottawa Inc.. Currently, the unregulated business accounts for approximately 15% of HOHI's consolidated EBITDA and revenue. We do not expect this to change in the next two years. However, when the Chaudière Falls expansion project commissions in late 2017 or early 2018, cash flow (EBITDA) contribution from the unregulated business could account for about 20% of HOHI's overall EBITDA.

We expect HOHI will not pursue further unregulated business and that the 20% unregulated EBITDA contribution will decrease gradually as HOHI's regulated business continues to grow. Therefore, we continue to use the low-volatility table for HOHI and to maintain its current business risk profile with the assumption that unregulated EBITDA will peak near 20% in 2018 when the Chaudière project commissions, and will gradually decrease.

## Financial Risk: Intermediate

Our view of HOHI's financial risk profile is "intermediate". We use the low-volatility table, reflecting the stability and predictability with regulated utilities and the supportive regulatory framework. We expect HOHI will continue generating stable cash flow, a key credit strength. It has large capital programs, including replacement of aging infrastructure and expansion of the Chaudière Falls renewable power generation in the next few years, and relies on the combination of internally generated funds and external debt to fund these capital expenditures.

HOHI plans to externally finance the Chaudière Falls expansion and we have consolidated the debt and cash flow from the project into the company per our ratios and adjustments criteria. Consolidating the cash flow from the Chaudière expansion project creates downward pressure on the credit metrics, especially the AFFO-to-debt ratio from 2015 to 2016 during the construction phase, when there will be no cash inflow from the project. During this period, we expect HOHI will maintain AFFO-to-debt in the 12%-14% range. We do not expect improvement to this ratio until late 2017 or early 2018 when the Chaudière plant commissions. For 2014, we expect AFFO-to-debt to be in the range of 14%-17% because much of the Chaudière expansion project capital spending is in 2015 and 2016.

Because the company is going through a capital-intensive period and we are consolidating the debt and cash flow from the Chaudière project into HOHI, we expect leverage to increase modestly in the next few years to about 63% debt-to-capital by 2018, slightly above the regulatory deemed capital structure of 60% debt-to-capital. However, we do not expect HOHI to deviate materially from the regulatory guideline. The dividend policy has been consistent, with dividends set at the greater of 60% of current year consolidated net income or C$14 million, and we expect this to remain the same.

## Liquidity: Adequate

HOHI's liquidity is "adequate," in our view. We expect that liquidity sources will be sufficient to cover uses more than 1.1x in the next six months. We expect that in the event of a 10% decline in earnings, the company's sources of funds would still exceed its uses. In our view, HOHI has sound relationships with its banks and generally prudent financial risk management.

| Principal Liquidity Sources | Principal Liquidity Uses |
|---|---|
| • Projected FFO of approximately C\$74 million-C\$77 million in 2015<br>• Undrawn committed credit facility of approximately C\$325 million in capacity, with C\$150 million expiring in August 2015 and C\$175 million expiring in 2017 | • Capital spending of approximately C\$140 million in 2015<br>• Cash dividends of approximately C\$18 million in 2015<br>• Debenture maturity of C\$200 million in February 2015 |

## Government Influence

We believe there is a "low" likelihood that the company's owner, the City of Ottawa, would provide timely and sufficient extraordinary support in the event of financial distress. We base this on our assessment that there is a "limited" link and "limited importance" role to HOHI's government owner, as our government-related entity criteria define these terms. We believe HOHI has a role of "limited importance" to Ottawa, given that the province has oversight of both electricity regulation and water licensing, not the city, and that a private enterprise could provide the utility's services. We believe there is a "limited" link between the utility and Ottawa, given our view that in a stress scenario, although the city might provide some temporary liquidity support, it is unlikely to support HOHI with taxpayer dollars in the long term.

## Ratings Score Snapshot

### Corporate Credit Rating

A/Stable/--

### Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

### Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

### Anchor: a

### Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

### Stand-alone credit profile : a

- **Likelihood of government support:** Low (no impact)

## Related Criteria And Research

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

**Business And Financial Risk Matrix**

| | Financial Risk Profile | | | | | |
|---|---|---|---|---|---|---|
| **Business Risk Profile** | Minimal | Modest | **Intermediate** | Significant | Aggressive | Highly leveraged |
| **Excellent** | aaa/aa+ | aa | **a+/a** | a- | bbb | bbb-/bb+ |
| Strong | aa/aa- | a+/a | a-/bbb+ | bbb | bb+ | bb |
| Satisfactory | a/a- | bbb+ | bbb/bbb- | bbb-/bb+ | bb | b+ |
| Fair | bbb/bbb- | bbb- | bb+ | bb | bb- | b |
| Weak | bb+ | bb+ | bb | bb- | b+ | b/b- |
| Vulnerable | bb- | bb- | bb-/b+ | b+ | b | b- |

# PROSPECTUS FOR PLANNED AND RECENT SHARE ISSUES

Hydro Ottawa Limited's sole shareholder is Hydro Ottawa Holding Inc. (the "Holding Company"). The Holding Company is 100% owned by the City of Ottawa (the "City"). There are no plans for additional share issues to the City or otherwise.

# ACCOUNTING ORDERS

Hydro Ottawa Limited confirms that it has complied with the Uniform System of Accounts ("USoA") as set out in the OEB's Accounting Procedures Handbook ("APH"), and with the following utility-specific accounting orders:

- Sub-Accounts to Account 1508 – Other Regulatory Assets, effective January 1, 2012, relating to OPEB Deferral Account[1]
- Account 1555 - Smart Meter Capital and Recovery Offset Variance Account, Sub Account Stranded Meter Costs (EB-2011-0054 & EB-2007-0713)

[1] EB-2011-0054, Decision and Order (January 26, 2012)

# ACCOUNTING STANDARDS

In compliance with the Board's direction, Hydro Ottawa Limited ("Hydro Ottawa") filed its 2012 Cost of Service Application on June 17, 2011 using modified International Financial Reporting Standards ("MIFRS") as the accounting basis, and adopted MIFRS for regulatory accounting and reporting purposes on January 1, 2012 with a January 1, 2011 transition date. Consequently, all International Financial Reporting Standards ("IFRS") conversion issues were dealt with in that rate application. At the time of filing, it was anticipated that external financial reporting would align with regulatory reporting, however a late deferral was issued by the Canadian Accounting Standards Board ("AcSB") and Hydro Ottawa decided to defer adoption.

Hydro Ottawa continues to report under MIFRS to the Board while providing reconciliation to its audited financial statements, prepared in accordance with Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ("CGAAP"). To limit the differences caused by the different accounting basis, Hydro Ottawa has sought to align its CGAAP accounting policies with IFRS requirements wherever possible as of January 1, 2012. Nonetheless, a difference in the effective implementation dates gave rise to a $ 502k difference in the carrying values of certain Property, Plant and Equipment for CGAAP and MIFRS reporting purposes. Consequently, Hydro Ottawa recorded a one-time adjustment to align MIFRS and CGAAP. For more information, refer to Exhibit B, Tab 2, Schedule 1.

Originally, IFRS did not contain a standard governing rate-regulated activities ("RRA"), which led to numerous deferrals issued by AcSB. Hydro Ottawa continued to report under CGAAP during this time as it was believed that if an interim standard was issued on RRA, it would only be applicable to first time adopters. On January 30, 2014, the IASB issued interim standard *IFRS 14 - Regulatory Deferred Accounts* ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted therefore Hydro Ottawa adopted IFRS and early adopted IFRS 14 on January 1, 2015.

Under IFRS, Hydro Ottawa is required to present one year of comparative information in its first set of IFRS financial statements. The first day of the comparative year is referred to as the “transition date” and the first day of the year in which the utility has chosen to adopt IFRS for financial reporting purposes is referred to as the “changeover date”. For Hydro Ottawa, the transition date was January 1, 2014, and the changeover date was January 1, 2015.

# CONFIRMATION OF ACCOUNTING TREATMENT FOR LDC OWNED GENERATION

Hydro Ottawa Limited confirms that the accounting for non-utility businesses has been segregated from its rate-regulated activities.

# MATERIALITY THRESHOLD

Section 2.4.5 of the Chapter 2 Filing Requirements for Transmission and Distribution Applications, issued by the Ontario Energy Board (the "Board") on July 14, 2014 require that *"The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold."*

For a utility the size of Hydro Ottawa Limited ("Hydro Ottawa"), the default materiality threshold is defined as 0.5% of the distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. Hydro Ottawa's base revenue requirement for 2016 is $177M so the default materiality threshold would be $880k. In this application, Hydro Ottawa has generally explained variances based on a threshold of $750k.

Hydro Ottawa notes that the $880K materiality threshold will apply to Hydro Ottawa for any future Z factor application unless its distribution revenue requirement exceeds $200 million for that year in which case its materiality threshold would be $1 million.

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, as amended;

**AND IN THE MATTER OF** an Application by Hydro Ottawa Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges effective January 1, 2016 to December 31, 2020

## APPLICATION & APPROVALS SOUGHT

The Applicant, Hydro Ottawa Limited (herein referred to as "the Applicant", "Hydro Ottawa", "HOL", "the Company, or "the Utility") is a corporation incorporated pursuant to the *Business Corporations Act* (Ontario) and is licensed by the Ontario Energy Board (the "Board") pursuant to distribution license (ED-2002-0556) to distribute electricity to customers residing within the City of Ottawa and Village of Casselman.

Hydro Ottawa hereby applies to the Board pursuant to section 78 of the Ontario Energy Board Act 1998 (the "OEB Act") and pursuant to the Custom Incentive Regulation ("Custom IR") rate setting method outlined in the Report of the Board: *Renewed Regulatory Framework for Electricity Distributors*: A Performance Based Approach dated October 18, 2012 ("the RRFE") for an Order or Orders approving:

a) Final distribution rates effective January 1, 2016 determined from a service revenue requirement of $187,269,000 as set out in Exhibit F-1-1;
b) Custom IR rate-setting model wherein Hydro Ottawa's capital requirements are recovered on a five year forecasted cost of service basis and its operations, maintenance and administrative ("OM&A") requirements are recovered pursuant to an "I-X" formula and the model includes a Y factor and an earnings sharing mechanism as set out in Exhibit A-2-1;
c) Final electricity distribution rates for the years commencing January 1, 2017, January 1, 2018, (collectively the Future Test Years), determined in accordance with Hydro Ottawa's forecast revenue requirements of $197,235,000 for 2017

and $208,120,000 for 2018 and to be adjusted for the years commencing January 1, 2019 and January 1, 2020 determined in accordance with Hydro Ottawa's forecast revenue requirements of $217,816,000 and $224,430,000 as adjustments to reflect updated inflation and cost of capital parameters; and

d) all specific other relief sought as set out below.

This Application is prepared pursuant to the requirements set out in:

a) Filing Requirements for Electricity Transmission and Distribution Companies' Cost of Service Rate Applications, Based on a Forward Test Year – of the Board's *Filing Requirements for Transmission and Distribution Applications* dated July, 2014 (the "Filing Requirements"); and
b) Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach as issued by the OEB on October 18, 2012 pursuant to the proceedings initiated by EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004 (the "RRFE Report").

This application is supported by written evidence as enumerated in Exhibit A-2-6. Hydro Ottawa may amend or supplement this written evidence prior to or during the course of the Board's hearing of the Application or the rendering of its final decision.

Hydro Ottawa accordingly proposes the following title for the proceeding that is commenced by this Application:

Hydro Ottawa Limited
2016-2020 Electricity Distribution Rates.

Hydro Ottawa requests that this application be disposed of by way of a written and oral hearing but recognizes that the Board may choose a different process as deemed appropriate.

Hydro Ottawa requests that the OEB make its Rate Order(s) emanating from the current proceeding effective January 1, 2016. In the event that the OEB's Decision with Reasons and Rate Order(s) cannot be delivered until after December 1, 2015, then Hydro Ottawa requests that the Board grant an Order making its current distribution rates and charges interim effective January 1, 2016 and establish an account allowing Hydro Ottawa to recover any differences between the interim rate and the approved rates as determined by the OEB in its final Decision and Order.

The Tariff of Rates and Charges proposed in this application is set out in Exhibit H-10. In this application Hydro Ottawa provides evidence to support all rates and charges for the 2016 Test year as well as evidence to support all rates and charges resulting from its proposed Custom IR rate setting model.

**Specific Relief Requested**

Hydro Ottawa accordingly applies to the Board for the following Order or Orders:

a) Approval of 2016-2018 revenue requirement and 2019-2020 distribution revenue requirement as adjusted as proposed in Exhibit F-1-1 including;
    i. Rate base and capital expenditures as set out in B-1;
    ii. Working capital allowance as set out in B-3-1;
    iii. Cost of capital and debt to fund rate base as set out in Exhibit E-1-1
    iv. Revenue Offset forecasts as set out in Exhibit C-2;
    v. Operations, maintenance and administrative expenses set out in Exhibit D-1-2;
    vi. Depreciation expenses as set out in Exhibit D-3-1;
    vii. Payment in lieu of taxes as set out in Exhibit D-4-1;

b) Approval of 2016-2018 electricity distribution rates and charges as proposed in Exhibit H-10 and 2019-2020 distribution rates and charges as adjusted;
c) Approvals related to deferral and variance accounts as proposed in Exhibit I including;

i. to dispose of balances in existing deferral and variance accounts as at December 31, 2014 as set out in Exhibit I-8-1;
ii. Approval for the continuation of existing deferral and variance accounts as set out in Exhibit 1-8-1;
iii. Approval of six new deferral and variance accounts as proposed in Exhibit I-1-2:
    i. Y Factor Deferral and Variance account to record costs to be recovered from the construction of Hydro Ottawa's new head office and operations buildings;
    ii. Proceeds of Sale of Existing Facilities to capture the after tax gain/loss from the sale of Hydro Ottawa current facilities;
    iii. Energy East – Trans Canada Pipeline – Hydro Ottawa requests a sub-account be added to US ofA 1508 Other Regulatory Assets deferral account to capture costs associated with consultations regarding the TransCanada Pipeline Limited's Proposed Energy East Pipeline Project;
    iv. Monthly Billing – Hydro Ottawa requests a deferral account to record costs associated with the transition to monthly billing per EB-2014-0198;
    v. Loss on Disposal of Fixed Assets
    vi. Earnings Sharing Mechanisms to record earnings to be shared above prescribed threshold.

d) Approval of a rate adjustment process to be initiated in 2017 to set final rates for 2019 and 2020 as discussed in Exhibit A-2-1;
e) Approval for the inclusion of a transformer substation called South28 Substation with assets that operate above 50kV form part of the Hydro Ottawa distribution system.
f) Approval of other items or amounts that may be requested by the Applicant in the course of the proceeding and such other relief or entitlements as the OEB may grant.

Hydro Ottawa requests, pursuant to subsection 17(1) of the Statutory Powers Procedure Act, that the Board give reasons in writing for its final decision and order(s) in this proceeding.

The names of Hydro Ottawa's authorized representative and its legal counsel, with their contact information, are set out below and in the evidence that is filed with the Application. Hydro Ottawa requests that all documents issued or filed in connection with this proceeding be served on its authorized representative and its legal counsel.

Authorized Representative:

Geoff Simpson
Chief Financial Officer
Hydro Ottawa Limited

3025 Albion Road North
P.O. Box 8700
Ottawa, Ontario
K1G 3S4

Telephone: 613-738-5499 ext. 7606
E-mail: RegulatoryAffairs@HydroOttawa.com

Counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Brookfield Place
181 Bay Street, Suite 1800
P.O. Box 754

Telephone: 416-865-7742
E-mail: fcass@airdberlis.com

**Dated at Ottawa, Ontario, this 29th Day of April, 2015.**

Applicant Hydro Ottawa Limited ("Hydro Ottawa")

3025 Albion Road North, PO Box 8700
Ottawa, Ontario
K1G 3S4

Signed by:

Geoff Simpson
Chief Financial Officer
Hydro Ottawa Limited

## Appendix to Application

| | |
|---|---|
| Title of Proceeding: | an Application by Hydro Ottawa Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges effective January 1, 2016 to December 31, 2020 |
| Applicant's Name: | Hydro Ottawa Limited ("Hydro Ottawa" or "HOL") |
| Applicant's Address: | 3025 Albion Road North<br>P.O. Box 8700<br>Ottawa, Ontario<br>K1G 3S4<br>RegulatoryAffairs@HydroOttawa.com |
| Applicant's Counsel: | Mr. Frederick D. Cass |
| Counsel's Contact Information: | Mr. Fred D. Cass<br>Aird & Berlis LLP<br>Brookfield Place<br>181 Bay Street, Suite 1800<br>P.O. Box 754<br><br>Telephone: 416-865-7742<br>E-mail: fcass@airdberlis.com |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

**Date: April 29, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **GENERAL** | | | |
| Ch 1 p3 & 4 | Confidential Information - Practice Direction has been followed | N/A | No confidential information filed |
| 2 & 3 | In advance of scheduled application - meet threshold established in Board letter (April 20, 2010) | N/A | Early rebasing not sought |
| 3 | Align rate year with fiscal year - request for proposed alignment | N/A | Rate and fiscal year aligned as of 2012 |
| 4 | Text searchable and bookmarked PDF documents | Yes | |
| *Accounting Standards and Modified IFRS Applications* | | | |
| 6 | State accounting standard(s) used in historical, bridge and test years | Yes | A-4-7 |
| 6 | Summary of changes to accounting policies and quantification of revenue requirement impact (Appendix 2-Y) | N/A | Addressed in previous rebasing application (EB-2011-0054). |
| 7 | Identify all material changes, quantify and explain the changes in the adoption of IFRS, if none state that and explain why it would not be material | Yes | B-2-1 |
| *Performance Evaluation* | | | |
| 8 | Discuss performance for each of the Board's performance outcomes over the last five years, and current performance | Yes | A-2-2; B-1-2; D-1-5 |
| 8 | Discuss how self-assessment has informed the utility's business plan and the application, and what measures are planned to achieve continuous improvement | Yes | A-2-2; B-1-2; D-1-5 |
| **EXHIBIT A - ADMINISTRATIVE DOCUMENTS** | | | |
| *Alignment With the RRFE* | | | |
| 9 & 10 | Overall business strategy past and expected performance including narrative of how they align with the four objectives of the RRFE | Yes | A-1-1 |
| *Executive Summary* | | | |
| 10 | Revenue Requirement - service RR, increase from previously approved, main drivers | Yes | A-2-1 |
| 10 | Budgeting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards | Yes | A-2-1 |
| 10 | Load Forecast Summary - load and customer growth, change in kWh and customer numbers, methodology description | Yes | A-2-1 |
| 10 &11 | Rate Base and Capital Plan - major drivers of DSP, rate base for test year, change from last approved, capex for test year, change from last approved, costs for any REG-related capital investments | Yes | A-2-1 |
| 11 | OM&A for test year and change from last approved, summary of drivers, inflation assumed, total compensation for test year and change from last approved. | Yes | A-2-1 |
| 11 | Statement regarding use of Board's cost of capital parameters; summary of any deviations | Yes | A-2-1 |
| 11 | Cost Allocation & Rate Design - summary of any deviations from Board methodologies, significant changes and summary of proposed mitigation plans | Yes | A-2-1 |
| 11 | Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested | Yes | A-2-1 |
| 11 | Bill Impacts - total impacts ($ and %)for all classes for typical customers | Yes | A-2-1 |
| *Customer Engagement* | | | |
| 11 & 12 | Overview of customer engagement activities; description of plans and how customer needs have been reflected in the application. | Yes | A-3-1; Attachment A-3(A) |
| 12 | Discuss how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates | Yes | A-3-1; Attachment A-3(A) |
| 12 | Discuss any feedback provided by customers and how the feedback shaped the final application | Yes | A-3-1; Attachment A-3(A) |
| 12 | Reference any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities | Yes | A-3-1; Attachment A-3(A) |
| 12 | Explanation if no customer engagement done and whether any is planned for the future | N/A | |
| 12 | Complete Appendix 2-AC Customer Engagement Activities Summary | N/A | Included in A-3-1 |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

Date: April 29, 2015

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| *Financial Information* | | | |
| 12 & 40 | Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals) | Yes | A-4-1 |
| 12 | Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed | Yes | A-4-2 |
| 13 | Annual Report and MD&A for most recent year of parent company, if applicable | Yes | A-4-3 |
| 13 | Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances | Yes | A-4-4; A-4-5 |
| 13 | Any change in tax status | N/A | No change in tax status |
| 13 | Existing accounting orders and departures from USoA including references to the accounting orders | Yes | A-4-6 |
| 13 | Accounting Standards used for financial statements and when adopted | Yes | A-4-6 |
| 13 | Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities | Yes | A-4-7 |
| *Materiality Thresholds* | | | |
| 13 & 14 | Materiality threshold; additional details beyond the threshold if necessary | Yes | A-5-1 |
| *Administration* | | | |
| Ch 1 p2 | | | |
| 14 | Table of Contents | Yes | A-6-3 |
| 14 | Primary contact information (name, address, phone, fax, email) | Yes | A-6-5 |
| 14 | Identification of legal (or other) representation | Yes | A-6-5 |
| 14 | Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers | Yes | A-6-5 |
| 14 | Statement of who will be affected by application | Yes | A-6-5 |
| 14 | Bill impacts - distribution only impacts for 800 kWh residential and 2000 kWh GS<50 (sub-total A of Appendix 2-W) | Yes | A-6-5 |
| 14 | Form of hearing requested and why | Yes | A-6-1 |
| 14 | Requested effective date | Yes | A-6-1 |
| 14 | List of approvals requested (and relevant section of legislation), including accounting orders | Yes | A-6-1 |
| 14 | Statement identifying all deviations from Filing Requirements | Yes | A-6-6 |
| 15 | Statement identifying and describing any changes to methodologies used vs previous applications | Yes | A-6-8 |
| 15 | Identification of Board Directives from previous Board Decisions, and how addressed | Yes | A-6-9 |
| 15 | Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service as a result of application | Yes | A-6-10 |
| 15 | Description of Operating Environment (including map, list of neighbouring utilities) | Yes | A-7-1 |
| 15 | Identification of embedded and/or host distributors | Yes | A-7-1 |
| 15 | Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the Board as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application | Yes | A-7-1 |
| 15, 16 & 17 | Corporate Governance: Number of Directors on Board, number of independent directors, how independent judgement is facilitated<br>- Board Mandate; Schedule of Board Meetings<br>- Orientation and Continuing Education for directors<br>- Ethical Business Conduct - written code where available<br>- Process for Nomination of Directors<br>- Committees - function and charter for each committee<br>- Audit Committee - number of independent members, whether members are financially literate | Yes | A-8-1 |
| 17 | Responses to matters raised in letters of comment filed | N/A | To be submitted after application filed |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

Filing Requirement Page # Reference

Date: April 29, 2015

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT B - RATE BASE** | | | |
| *Overview* | | | |
| 17 | Completed Fixed Asset Continuity Schedule (Appendix 2-BA) | Yes | B-1-1 |
| 17 & 18 | Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actuals, bridge and test year forecast) | Yes | B-1-1 |
| 18 | Continuity statements (year end balance, including interest during construction and overheads).<br>Year over year variance analysis; explanation where variance greater than materiality threshold<br>Hist. Brd-Approved vs Hist. Actual<br>Hist. Act. Vs previous Hist. Act.<br>Bridge vs. Test | Yes | B-1-1; B-1-2 |
| 18 & 19 | Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (eg. WIP, ARO, smart meter balances). Reconciliation must be between YE 2014 and YE 2015 net book value balances reported on Appendix 2-BA and balances included in rate base calculation | Yes | B-1-1 |
| *Gross Assets - PP&E and Accumulated Depreciation* | | | |
| 19 | Breakdown by function and by major plant account; description of major plant items for test year | Yes | B-2-1 |
| 19 | Summary of approved and actual costs for any ICM(s) approved in previous IRM applications | Yes | B-2-1 |
| 19 & 40 | Continuity statements must reconcile to calculated depreciation expenses and presented by asset account | Yes | B-2-1 |
| *Allowance for Working Capital* | | | |
| 19 | Working Capital - 13% allowance or Lead/Lag Study or Previous Board Direction | Yes | B-3-1 |
| 20 | Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. Should include SME charge. | Yes | B-3-1; Attachment B-3(A) |
| 20 | Lead/Lag Study - leads and lags measured in days, dollar-weighted | Yes | A-6-9 |
| *Treatment of Stranded Assets Related to Smart Meter Deployment* | | | |
| 20 & 21 | Stranded Meters - if the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved, a proposal for a Stranded Meter Rate Rider must be made<br>Explanation for approaches that are not the Board approach<br>Completed Appendix 2-S. | Yes | B-4-1 |
| *Planning* | | | |
| 22 | As applicable - file evidence that demonstrates that regional issues have been appropriately considered and where applicable addressed in developing the applicant's proposed capital expenditure plan. As part of its planning an applicant should consider municipal planning, including any plans for expansion of boundaries from a regional perspective to demonstrate the most cost effective solutions are being considered. | Yes | B-1-2 section 3.1.9; Attachment B-1(A) |
| *Capital Expenditures/Distribution System Plan* | | | |
| 23 | DSP filed as a stand-alone document | Yes | B-1-2 |
| Ch 5 p9 | Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table | Yes | B-1-2 section 1.0 |
| Ch 5 p9-10 | Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | Yes | B-1-2 section 1.1 |
| Ch 5 p10-11 | Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter | Yes | B-1-2 section 1.2; |
| Ch 5 p11 | Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | Yes | B-1-2 section 1.3 |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| Ch5 p12 | Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments | Yes | B-1-2 section 2.1 |
| Ch5 p12 | Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | Yes | B-1-2 section 2.1 |
| Ch 5 p13 | Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | Yes | B-1-2 section 2.2 |
| Ch 5 p13-14 | Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | Yes | B-1-2 section 2.3 |
| Ch 5 p14-15 | Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category<br>- list, description and total capital cost of material capital expenditures sorted by category (table recommended)<br>- information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate)<br>- description of customer engagement<br>- Dx expectations of system development over next 5 years<br>- list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended) | Yes | B-1-2 section 3.1 |
| Ch 5 p15 | Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments | Yes | B-1-2 section 3.2 |
| Ch 5 p16 | System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints | Yes | B-1-2 section 3.3 |
| Ch 5 p16-18<br>Ch 2 p23 | Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year<br>Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB | Yes | B-1-2 section 3.4; Appendix 2-AB also available in B-5-1 |
| Ch5 p19 | Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment | Yes | B-1-2 section 3.5.1 |
| Ch 5 p19-25 | Material Investments - For each project that meets materiality threshold set in Ch 2 p10<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | Yes | B-1-2 section 3.5.2 |
| 23 & 24 | Capital Expenditures - completed Appendix 2-AA showing capex on a project specific basis for 4 historical years, bridge and test; explanation of variances, accounting treatment for projects with life cycle greater than one year | Yes | B-5-1 |
| 24 | Non-distribution activities - capital expenditures and reconciliation to total capital budget | Yes | A-6-7 |
| 7 & 24 | Capitalization policy, changes to capitalization since previous rebasing - explanations must be provided. The changes must be identified and the causes of the changes must also be identified. | Yes | B-5-2; B-5-3 |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| 24 | Capitalization of overhead - Completed Appendix 2-D regarding overhead costs on self-constructed assets Burden rates must be identified; changes from last rebasing must be identified; LDC must identify burden rates prior to and after the change | Yes | B-5-3 |
| *Costs of Eligible Investments for Connection of Qualifying Generation Facilities* | | | |
| 25 | For Eligible Investments - proposal to divide costs per O.Reg. 330/09 | N/A | Not applicable to Hydro Ottawa |
| 25 | Where applicable, file a draft accounting order to establish variance account tracking IESO payment revenues against actual spending | N/A | Not applicable to Hydro Ottawa |
| 25 | As Applicable appendices 2-FA through 2-FC must be filed identifying eligible investments, as applicable | N/A | Not applicable to Hydro Ottawa |
| 25 | Ensure that Capital Costs of the Distributor are entered into the Rate Base for the Test Year | N/A | Not applicable to Hydro Ottawa |
| *New Policy Options for the Funding of Capital* | | | |
| 25 | Policy Options - can propose an approach for the funding of capital based on the proposed policy options | N/A | Not applicable to Hydro Ottaawa |
| *Addition of ICM Assets to Rate Base* | | | |
| 25 & 26 | Distributor with previously approved ICM(s) - schedule of ICM amounts, variances and explanation | N/A | Not applicable to Hydro Ottawa |
| 26 | Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue | N/A | Not applicable to Hydro Ottawa |
| *Service Quality and Reliability* | | | |
| 26 | 5 historical years of ESQRs, explanation for any under-performance and actions taken | Yes | B-5-4 |
| 26 | 5 historical years of SAIDI and SAIFI - for all interruptions and all interruptions excluding loss of supply, explanation for any under-performance and actions taken | Yes | B-5-4 |
| 26 | Completed Appendix 2-G | Yes | B-5-4 |
| **EXHIBIT C - OPERATING REVENUE** | | | |
| *Load and Revenue Forecasts* | | | |
| 27 & 30 | Customer, volume and revenue forecast methodologies and data | Yes | C-1-1; Attachment C-1(A); Appendix 2-IA |
| 27 | Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts | Yes | C-1-1; Attachment C-1(A) |
| 27 | Completed Appendix 2-IA | Yes | C-1-3; Appendix 2-IA |
| 28 | Regression Model - rationale for choice, regression statistics, explanation for any unintuitive relationships, explanation of modeling approaches and alternative models tested, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, explanation of any constructed variables; data used in load forecast must be provided in Excel format, including derivation of constructed variables | Yes | C-1-3; Appendix 2-IA; Exhibit C-1-1,Attachment C-1(A) |
| 29 | NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations | Yes | C-1(A) Itron Report |
| 29 & 30 | CDM Adjustment - 2014 and 2015 CDM reductions must take into account 2011 - 2013 CDM program results reported by OPA. CDM adjustment should take into account historical CDM results factored into base load forecast before CDM adjustment | Yes | Appendix 2-I |
| 29 | CDM savings for 2015 LRAMVA balance and adjustment to 2015 load forecast; data by customer class | Yes | C-1-1 |
| 29 & 30 | Completed Appendix 2-I, or alternative with explanation | Yes | C-1-1; Appendix 2-I |
| *Accuracy of Load Forecast and Variance Analyses* | | | |
| 30 | Schedule of volumes, revenues, customer/connection count by class and total system load: 5 years historical, Board approved, 5 years historical weather normalized, bridge year and test year. | Yes | Appendix 2-V |
| 30 | Customer count increases or decreases for test year - explanation by class; confirmation of year end or average format | Yes | Appendix 2-V |
| 31 | Explanation for any changes in definition or composition of class | N/A | no class changes |
| 31 | Weather normalized average consumption per customer for historical 5 years, bridge and test | Yes | Attachment C-1(A) |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| 31 | Explanation of net change in average consumption from last Board approved, and actual historical, bridge and test - for each rate class | Yes | C-1-2 |
| 31 | Details of development of billed kW | Yes | C-1-2 |
| 31 | Revenues on existing and proposed rates for the test year | Yes | H-1-1 |
| 31 | Variance analysis of volumes, revenues, customer/connection count and total system load:<br>Historical Board approved vs Historical Actual (and Historical Actual weather normalized)<br>Year over year historical weather normalized variance, weather normalized bridge, test year | Yes | C-1-2; Appendix 2-IA |
| 31 | Data used to determine forecast should be filed as live Excel spreadsheet | Yes | C-1 (C) Itron's Load Forecast |
| *Other Revenue* | | | |
| 31 | Breakdown of other distribution revenue accounts; completed Appendix 2-H | Yes | C-2-1; Appendix 2-H |
| 31 | Variance analysis - year over year, historical, bridge and test | Yes | C-2-1 |
| 31 | Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges | Yes | C-2-2; H-7-1 |
| 31 | Revenue from affiliate transactions, shared services, corporate cost allocation | Yes | C-2-1. D-2-1 |
| **EXHIBIT D - OPERATING COSTS** | | | |
| *Overview* | | | |
| 33 | Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes | Yes | D-1-1 |
| *Summary and Cost Driver Tables* | | | |
| 33 | Summary of recoverable OM&A expenses; Appendix 2-JA | Yes | D-1-2; Appendix 2-JA |
| 33 | OM&A cost drivers; Appendix 2-JB | Yes | D-1-3; Appendix 2-JB |
| 33 | Recoverable OM&A Cost per customer and per FTE; Appendix 2-L | Yes | D-1-2; Appendix 2-L |
| 33 | Identification of change in OM&A in test year in relation to change in capitalized overhead. | N/A | No change to capitalized policy |
| 33 | OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D | Yes | D-1-3; Appendix 2-D |
| *Program Delivery Costs with Variance Analysis* | | | |
| 33 &34 | Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last Board approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why. | Yes | D-1-3; Appendix 2-JC |
| 34 | For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives | Yes | D-1-3 |
| 34 | Employee Compensation - completed Appendix 2-K | Yes | D-1-8 |
| 34 | Description of compensation strategy | Yes | D-1-8 |
| 34 & 35 | Explanation for material changes to head count and compensation: year over year variances, inflation, plans for new employees, details on collective agreements, basis for performance pay, filing of any relevant studies | Yes | D-1-8 |
| 35 | Details of employee benefit programs including pensions for last Board approved, historical, bridge and test; must agree with tax section | Yes | D-1-8 |
| 35 | Most recent actuarial report on employee benefits, pension and OPEBs | Yes | Attachment D-1(B); D-1-8 |
| 35 | Identification of all shared services among affiliates and parent company | Yes | D-2-1 |
| 35 | Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review | Yes | D-2-1 |
| 36 | Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue | Yes | D-2-1 |
| 36 | Identification of any Board of Director costs for affiliates included in LDC costs | Yes | D-2-1 |
| 36 | Shared Service and Corporate Cost Variance analysis - test year vs last Board approved and most recent actual | Yes | D-2-1 |

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|---|---|---|---|
| **36** | Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance) | **Yes** | D-2-2; Attachment D-2(A) |
| **36** | Explanation for procurements above materiality threshold without competitive tender | **Yes** | D-2-2; Attachment D-2(A) |
| **36** | Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years) | **Yes** | D-2-3 |
| **37** | Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application, proposed recovery (ie amortized?). Completed Appendix 2-M | **Yes** | D-2-4 |
| **37** | LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes | **Yes** | D-2-5 |
| **37** | Statement whether test year revenue requirement includes legacy low income energy assistance programs. If yes, identify programs | **Yes** | D-2-5 |
| **38** | Charitable Donations - amounts paid from last Board approved up to test year | **Yes** | D-2-6 |
| **38** | Detailed information for any proposal to recover charitable donations (outside of assistance for payment of electricity bills) | **Yes** | D-2-6 |
| **38** | Any non-recoverable contributions identified and removed from revenue requirement. Confirm that no political contributions have been included for recovery | **Yes** | D-2-7 |
| *Depreciation, Amortization and Depletion* | | | |
| **38** | Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report | **N/A** | |
| **18 & 38** | Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must agree to accumulated depreciation in Appendix 2-BA under rate base. | **Yes** | D-3-1 |
| **38** | Identify any Asset Retirement Obligations and associated depreciation | **Yes** | D-3-1 |
| **38 & 39** | May propose an approach that differs from Board's general policy of capital additions attracting six months of depreciation expense when they enter service in the test year, based on the Board's proposed new policy options for the Board's consideration | **Yes** | D-3-1 |
| **39** | Identify historical depreciation practice and proposal for test year. Variances from half year rule must be documented and with supporting rationale | **Yes** | D-3-1 |
| **39** | Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS | **Yes** | D-3-1 |
| **39** | Explanation of any deviations from the practice of significant parts or components of PP&E being depreciated separately | **N/A** | |
| **39 & Appendices** | Regulatory Accounting changes for depreciation<br>- use of Kinectrics study or another study to justify changes in useful life<br>- list detailing all asset service lives tied to USoA, detail differences in TUL from Kinetrics and explain differences outside of minimum and maximum TUL range from Kinectrics<br>- Appendix 2-BB<br>- recalculation to determine average remaining service life of opening balance on date of making depreciation changes<br>- If further depreciation expense policy changes or changes in asset service lives are made they must be identified and provide a detailed explanation of the changes<br>-File applicable depreciation appendices as provided in Chapter 2 MIFRS Appendices (Appendix 2-CA to 2-CI) | **N/A** | This was addressed by HOL as part of last rebasing application (EB-2011-0054) and no material changes have since been made to depreciation and capitalization. |
| *PILs and Property Taxes* | | | |
| **40** | Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years | **Yes** | D-4-1; Attachments D-4(C) through D-4(L) |
| **40** | Supporting schedules and calculations identifying reconciling items | **N/A** | N/A |
| **40** | Most recent federal and provincial tax returns | **Yes** | D-4-1; Attachments D-4(A) and D-4(D) |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| 12 & 40 | Financial Statements included with tax returns if different from those filed with application | N/A | |
| 40 | Calculation of Tax Credits | Yes | D-4-1 |
| 40 | Supporting schedules, calculations and explanations for other additions and deductions | Yes | D-4-1 |
| 40 | Explanation of how property tax amounts are derived | N/A | N/A |
| 40 & 41 | Exclude from regulatory tax calculation any non-recoverable or disallowed expenses | Yes | D-4-1 |
| 41 | Completion of Integrity checks listed on p.41; statement confirming completion | Yes | D-4-1 |
| *Conservation and Demand Management* | | | |
| 43 | LRAM and LRAMVA - disposition of balance(s) for any pre-2011 and 2011-2014 account balances<br>- statement indicating use of most recent input assumptions when calculating lost revenue<br>- statement indicating reliance on most recent CDM evaluation report from OPA; copy of report<br>- Tables for each rate class showing lost revenue by year<br>- lost revenue calculations - energy savings by class and Board approved variable charge<br>- statement that indicates if carrying charges are requested<br>- Third party report for any Board-approved programs | Yes | D-5-1; D-5-2 |
| **EXHIBIT E - COST OF CAPITAL AND CAPITAL STRUCTURE** | | | |
| *Capital Structure* | | | |
| 44 | Statement that LDC adopting Board's guidelines for cost of capital and confirming updates will be done. Alternatively - utility specific cost of capital with supporting evidence | Yes | E-1-1 |
| 4 & 44 Appendices | Completed Appendix 2-OA for last Board approved and test year; total capitalization (debt and equity) must equate to total rate base | Yes | E-1-1, Appendix 2-OA |
| 44 | Completed Appendix 2-OB for historical, bridge and test years | Yes | E-1-1, Appendix 2-OB |
| 44 | Explanation for any changes in capital structure | N/A | Not applicable to HOL |
| 44 | Calculation of cost for each capital component | N/A | E-1-1 |
| 44 | Profit or loss on redemption of debt | N/A | E-1-1 |
| 45 | Copies of promissory notes or other debt arrangements with affiliates | Yes | Attachments E-1(A) through E-1(F) |
| 45 | Explanation of debt rate for each existing debt instrument | Yes | E-1-1 |
| 45 | Forecast of new debt in bridge and test year - details including estimate of rate | Yes | E-1-1 |
| *Not-for-Profit Corporations* | | | |
| 45 | Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves | N/A | Not applicable to HOL |
| 45 | Detailed calculation for its test year revenue requirement based on its Reserve Requirement | N/A | Not applicable to HOL |
| 45 | The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve | N/A | Not applicable to HOL |
| 46 | Description of the governance of the not-for-profit corporation<br>-policy on Reserve Requirement<br>-roles and responsibilities of the Board of Directors and management with regards to the need for types of reserves<br>-authorization and approval process for access and use<br>-investment objectives and policies for the reserve funds<br>-reporting requirements and monitoring | N/A | Not applicable to HOL |
| 46 | If there are approved reserves from previous Board decisions provide the following:<br>-any changes to the reserve policies and rationale for the changes since last CoS<br>-limits of any capital and/or operating reserves as approved by the Board and identify decisions<br>-current balances of any established capital and/or operating reserves<br>-list withdrawals from capital and operating reserves, identify amounts and purpose of withdrawal<br>-if limits on capital and operating reserves achieved provide a proposal for utilization of amounts<br>-if limits on reserves not achieved provide rationale and the detail for its forecast of the Reserve Requirement for the test year | N/A | Not applicable to HOL |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **EXHIBIT F - REVENUE DEFICIENCY/SUFFICIENCY** | | | |
| 47 | Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter and other DVA balances). | Yes | F-1-1, F-1(A), F-1(B), F-1(C), F-1(D), F-1(E) |
| 47 | Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers | Yes | F-1-1 |
| 47 | Impacts of any changes in methodologies to deficiency/sufficiency | N/A | Calculation has remained the same |
| *Revenue Requirement Work Form* | | | |
| 48 | RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits | Yes | Attachments F-1(A), F-1(B), F-1(C), F-1(D), F-1(E) |
| **EXHIBIT G - COST ALLOCATION** | | | |
| *Cost Allocation Study Requirements* | | | |
| 48 | Completed cost allocation study reflecting test year loads and costs. Excel version of 2015 cost allocation model (updated load profiles or scaled version of HONI CAIF). Appendix 2-P completed as well. | Yes | G-1-1; Attachment G-1(A); Appendix 2-P |
| 48 | Description of weighting factors, and rationale for use of default values (if applicable) | Yes | G-1-1; Attachment G-1(A) |
| 48 | Hard copy of sheets I-6, I-8, O-1 and O-2 (first page) | Yes | G-1-1; Attachments G-1(B), G-1(C), G-1(D), G-1(E), G-1(F) |
| 49 | Host Distributor - evidence of consultation with embedded Dx<br>- Statement regarding embedded Dx support for approach to allocation of costs<br>- If embedded Dx is separate class - class in cost allocation study and Appendix 2-P<br>- If new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and Appendix 2-P<br>- If embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. LDC may choose to file Appendix 2-Q. | N/A | HOL does not have any embedded distributors in its service territory |
| *Unmetered Load* | | | |
| 50 | Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges | N/A | See G-1-2 |
| 50 | New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS | N/A | See G-1-2 |
| *Class Revenue Requirements and Revenue to Cost Ratios* | | | |
| 51 | Completed Appendix 2-P; supporting information for any proposal to re-balance rates | Yes | Appendix 2-P |
| 52 | Proposal to re-balance to bring R:C ratio within Board policy ranges; any proposal to for further re-balancing beyond test year. | Yes | G-3-1 |
| 52 | If Cost Allocation Model other than Board model used - exclude LV, exclude DVA such as smart meters | Yes | G-3-1 |
| **EXHIBIT H - RATE DESIGN** | | | |
| 52 | Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places | Yes | H-1-1 |
| 53 | Current and Proposed F/V proportion with explanation for any changes | Yes | H-1-1 |
| 53 | Table comparing current and proposed fixed charge with floor and ceiling from cost allocation study. Explanation for Monthly Fixed Charge(s) that exceed the ceiling; analysis must be net of adders and riders | Yes | H-1-1 |
| 53 | Policy Options - can propose fixed monthly charge based on the proposed policy options | Yes | H-2-1 |
| 53 | Explanation of the method used to design the fixed charge for distribution service (if applicable) | Yes | H-2-1 |
| *RTSRs and Other Charges* | | | |

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| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| 53 | Retail Transmission Service Rate Work Form - PDF and Excel | Yes | H-3-1; Attachment H-3(A); Live Excel filed as well |
| 53 | RTSR information must be consistent with working capital allowance calculation | Yes | H-3-1 |
| 54 | If proposing changes to Retail Service Charge - evidence of consultation and notice | Yes | H-4-1 |
| 54 | Wholesale Market Service Rate - reflect $0.0057 in application or justify otherwise | Yes | H-5-1 |
| 54 & 55 | Smart Metering Charge - reflect $0.79 in application for Residential and GS<50 | Yes | H-6-1 |
| 55 | Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges | Yes | H-7-1; Attachment H-7(A) |
| 55 | Identify any rates and charges in Conditions of Service that do not appear on tariff sheet<br>Explain nature of costs, schedule outlining revenues 2010-2013, bridge and test<br>Whether these charges are included on tariff sheet | Yes | H-7-2 |
| 55 | Ensure revenue from SSCs corresponds with Operating Revenue evidence | Yes | C-2,2; H-7-1; |
| 55 | Can propose activities or initiatives that will reduce cost of transition to monthly billing | N/A | Transitioned to monthly billing March, 2014 |
| 56 | Forecast of LV cost, sum of host distributors charges | Yes | H-8-1 |
| 56 | Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes | Yes | H-8-1 |
| 56 | Support for forecast LV, e.g. Hydro One Sub-Transmission charges | Yes | H-8-1 |
| 56 | Allocation of LV cost to customer classes (typically proportional to Tx connection revenue) | Yes | H-8-1 |
| 56 | Proposed LV rates by customer class | Yes | H-8-1 |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

Date: April 29, 2015

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| *Loss Factors* | | | |
| 56 | Proposed SFLF and Total Loss Factor for test year | Yes | H-9-1; Appendix 2-R |
| 56 | Statement as to whether LDC is embedded including whether fully or partially | Yes | H-9-1 |
| 56 | Study of losses if required by previous decision | N/A | Not applicable to HOL |
| 56 | 3-5 years of historical loss factor data - Completed Appendix 2-R | Yes | H-9-1, Appendix 2-R |
| 56 | Explanation of losses >5% | N/A | Not applicable to HOL |
| 56 | If proposed loss factor >5%, action plan to reduce losses going forward | Yes | Not applicable to HOL |
| 56 | Explanation of SFLF if not standard | N/A | Not applicable to HOL |
| *Rates and Bill Impacts* | | | |
| 57 | Current Tariff of Rates and Charges | Yes | H-10-1; Attachment H-10(A) |
| 57 | Proposed Tariff of Rates - Appendix 2-Z | Yes | H-10-1; Appendix 2-V |
| 57 | Explanation of changes to terms and conditions of service if changes affect application of rates | N/A | Not applicable to HOL |
| 57 | Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement | Yes | Appendix 2-V |
| 57 | Completed Appendix 2-V (Revenue Reconciliation) | Yes | H-11-1; Appendix 2-V |
| 57 | Bill Impacts - completed Appendix 2-W for all classes for representative samples of end-users. Must provide residential 800 kWh and GS<50 2,000 kWh.<br>Commodity and regulatory charges held constant | Yes | H-12-1; Appendix 2-W |
| 58 & 59 | Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation | N/A | None over 10% |
| 59 | Rate Harmonization Plans, if applicable - including impact analysis | N/A | Not applicable to HOL |
| **EXHIBIT I - DEFERRAL AND VARIANCE ACCOUNTS** | | | |
| 59 | List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH | Yes | I-1-1 |
| 59 | Completed DVA continuity schedule for period following last disposition to present - Excel format | Yes | Attachment I-8(A); filed as separate live Excel as well |
| 59 | Interest rates applied to calculate carrying charges (month or quarter) | Yes | I-1-1 |
| 59 | Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS | Yes | I-1-1 |
| 60 | Identification of Group 2 accounts that will continue/discontinue going forward, with explanation | Yes | I-1-1 |
| 60 | Statement as to any new accounts, and justification. | Yes | I-1-2 |
| 60 | Statement whether any adjustments made to DVA balances previously approved by Board on final basis; explanation, amount of adjustment and supporting documents | Yes | I-1-1 |
| 60 | Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity. | Yes | I-1-1 |
| 60 | Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated. | Yes | I-1-1 |
| 60 | If not addressed previously, disposition of Account 1592 - Completed Appendix 2-TA | N/A | Addressed in previous rebasing application (ED-2011-0054) |
| 61 | If not addressed previously, disposition of Account 1592 sub-account HST/OVAT ITC - analysis that supports conformity with Dec 2010 APH FAQ (particularly #4)<br>Applicant must state the period that the account covers (i.e. Jul 1-2010 up to start of new rate year (year of rebasing)) | Yes | I-3-1 |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

Date: April 29, 2015

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **61 & 62** | Request for disposition of Account 1508 sub-account IFRS transition costs<br>- completed Appendix 2-U<br>- statement whether any one time IFRS transition costs are embedded in 2015 revenue requirement, where and why it is embedded, and the quantum<br>- explanation for each category of cost recorded in 1508 sub-account, how it meets criteria of one time IFRS admin incremental costs<br>- explanation for material variances in Account 1508 sub-account IFRS Transition Costs Variance<br>- statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case | **Yes** | I-4-1; Appendix 2-U |
| **62 & 63** | 1575 IFRS-CGAAP PP&E account<br>- Account 1575 and 1576 can't be used interchangeably<br>- breakdown of balance, Appendix 2-EA<br>- listing and quantification of drivers<br>- a breakdown for quantification of any accounting changes arising from IFRS in relation to PP&E<br>- volumetric rate rider to clear 1575;<br>- rate of return component is to be applied to 1575 but not recorded in 1575<br>- statement confirming no carrying charges applied to 1575<br>- explanation for the basis of the proposed disposition period to clear Account 1575 rate rider<br>- show the balance in DVA continuity schedule | **N/A** | This was addressed by HOL as part of last rebasing application (EB-2011-0054) and no material changes have since been made to depreciation and capitalization. |
| **63, 64 & 65** | Changes to depreciation and capitalization in 2012 or 2013 - 1576 IFRS-CGAAP PP&E account<br>- Appendix 2-BA must not be adjusted for 1576<br>- breakdown of balance related to 1576, Appendix 2-EB or 2-EC<br>- volumetric rate rider to clear 1576;<br>- rate of return component is to be applied to 1576 but not recorded in 1576<br>- statement confirming no carrying charges applied to 1576<br>- explanation for the basis of the proposed disposition period to clear Account 1576 rate rider<br>- show the balance in DVA continuity schedule | **N/A** | This was addressed by HOL as part of last rebasing application (EB-2011-0054) and no material changes have since been made to depreciation and capitalization. |
| **65** | Retail Service Charges - material balance in 1518 or 1548<br>- confirm variances are incremental costs of providing retail services<br>- identify drivers<br>- provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year<br>- state whether Article 490 of APH has been followed; explanation if not followed | **Yes** | I-7-1 |
| **65** | Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed | **Yes** | I-7-1 |
| **5 & 65** | Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why<br>Proposal for disposition of deferral accounts for renewable generation connection and smart grid as set out in FR "Distribution System Plans - Filing Under Deemed Conditions of Licence" | **Yes** | I-8-1 |
| **59 & 65** | Statement whether DVA balances before forecasted interest match the last AFS | **Yes** | I-8-1 |
| **65** | Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account.<br>Provide explanations even if such variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings | **Yes** | I-8-1 |

# 2015 Cost of Service Checklist

## HYDRO OTTAWA LIMITED

## EB-2015-0004

**Date: April 29, 2015**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **66** | Show relevant calculations: rationale for allocation of each account, proposed billing determinants and length of disposition period. | **Yes** | I-8-1 |
| **66** | If applicant is proposing to allocate an account which the Board has not established an approved allocator for the applicant must:<br>-propose and allocator based on the cost driver(s)<br>-propose the charge type (fixed or variable) for recovery purposes<br>-include this in the continuity schedule | **N/A** | HOL is not proposing to establish non-approved allocators |
| **66** | Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation. | **Yes** | I-8-1 |
| **66** | Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO. | **Yes** | I-8-1 |
| **66** | Establish separate rate riders to recover the balance of account 1589. Distributors who serve class A customers per O.Reg 429/04 must propose an appropriate allocation for their recovery of the global adjustment variance balance based on their settlement process with the IESO. | **Yes** | I-8-1 |
| **66** | New DVA - must meet causation, materiality, prudence criteria; include draft accounting order | **Yes** | I-1-2 |
| | **TOTAL "NO"** | **0** | |

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# ABBREVIATIONS AND DEFINED TERMS

## 1.0 ABBREVIATIONS

"2012 AMP" – Hydro Ottawa 2012 Asset Management Plan
"2GIRM" – Second Generation Incentive Regulation Mechanism
"3GIRM" – Third Generation Incentive Regulation Mechanism
"4GIRM" – Fourth Generation Incentive Regulation Mechanism
"AFUDC" – Allowance for funds used during construction
"AMCD" – Advanced Metering Communications Device
"AMI MT" – Advanced Metering Infrastructure Management Tool
"AMI" – Advanced Metering Infrastructure
"AMP" – Arrears Management Plan
"APH" – Accounting Procedures Handbook
"ARC" – Affiliate Relationships Code for Electricity Transmitters and Distributors
"ARO" – Asset Retirement Obligation
"BA" – Bankers' Acceptance
"Billing Practices Report" – Draft Report of the Board, Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance (EB-2014-0198) issued September 18, 2014
"Board Filing Requirements" – Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued July 18, 2014
"Board" – the Ontario Energy Board"
"BOMA" – Building Owners and Managers Association
"BRR" – Base Revenue Requirement
"C&M" – Construction and Maintenance division
"CAFM" – Computer Aid Facilities Management
"Canadian AcSB" – Canadian Accounting Standards Board
"CAPEX" – Capital Expenditures
"CC&B" – Customer Care & Billing
"CCA" – Capital Cost Allowance

"CDD" – Cooling Degree Days

"CDM" – Conservation and Demand Management

"CEA" – Canadian Electricity Association

"CEC" – Cumulative Eligible Capital

"CGAPP" – Canadian Generally Accepted Accounting Principles

"CICA" – Canadian Institute of Chartered Accountants

"CIO" – Chief Information Officer

"CIP" – Construction-Work-in-Progress

"CIS" – Customer Information System

"City" – the City of Ottawa

"CLD" – Coalition of Large Distributors

"COO" – Chief Operating Officer

"COS" – Cost of Service

"Cost Allocation Report" – Report of the Board, Review of Electricity Distribution Cost Allocation Policy, issued March 31, 2011

"Cost Allocation Report" – Staff Report to the Board, Implementation of the Revisions to the Board's Electricity Distributor Cost Allocation Policy (EB-2010-0219) issued August 4, 2011

"CPI" – Consumer Price Index

"CRTC" – Canadian Radio-television and Telecommunications Commission

"CSA" – Canadian Standards Association

"CSSP" – Customer Service Strategy Plan

"CVR" – Conservation Voltage Reduction

"D&T" – Deloitte and Touche

"DAM" – Distribution Asset Management division

"DBA" – Data Base Administrator

"DRC" – Debt Retirement Charge

"DSC" – Distribution System Code

"DRRM" – Distribution Reliability Response Maintainer

"EBT" – Electronic Business Transactions

"ECE" – Eligible Capital Expenditure

"EDA" – Electricity Distributors Association

"EDDVAR Report" – Electricity Distributors' Deferral and Variance Account Review Initiative – Report of the Board (EB-2008-0046) issued July 31, 2009

"EDR" – Electricity Distribution Rate

"EI" – Employment Insurance

"EIT" – Engineer in Training

"Emp" – Employment

"EMT" – Executive Management Team

"Energy Ottawa" – Energy Ottawa Inc.

"ENV" – Environment

"ERM" – Enterprise Risk Management

"ESA" – Electrical Safety Authority

"ESQR" – Electricity Service Quality Requirement

"FCI" – Fault Circuit Indicator

"FIT" – Feed in Tariff

"FMV" – Fair Market Value

"FTE" – Full time equivalent

"GA" – Global Adjustment

"GDP" – Gross Domestic Product

"GEA" – Green Energy and Green Economy Act (Ontario), 2009

"GHG" – Greenhouse Gas

"GIS" – Geographic Information System

"GPS" – Geographic Positioning System

"GRM" – Geographic Resource Management

"GS >50kW" – General Service with average monthly demand greater than 50 kilowatts

"GS <50kW" – General Service with average monthly demand less than 50 kilowatts

"GST" – Goods and Service Tax

"H&S" – Health and Safety

"HDD" – Heating Degree Days

"Holding Company" – Hydro Ottawa Holding Inc.

"HR" – Human Resources

"HST" – Harmonized Sales Tax

"Hydro One" – Hydro One Networks Inc.

"Hydro Ottawa" – Hydro Ottawa Limited

"IAS 16" – IAS 16 Property, Plant and Equipment

"IAS 19" – IAS 19 Employee Benefits

"IAS 23" – IAS 23 Borrowing Costs

"IAS" – International Accounting Standard

"IASB" – International Accounting Standards Board

"IBEW" – International Brotherhood of Electrical Workers

"IESO" – Independent Electricity System Operator

"IFRS" – International Financial Reporting Standards

"IGRS" – Integrated Gas Recovery Services Inc.

"IM/IT" – Information Management and Information Technology

"IPSP" – Integrated Power System Plan

"IRM" – Incentive Regulation Mechanism

"IS&T" – Information Services and Technology

"ISO" – International Organization for Standardization

"IT" – Information Technology

"ITC" – Input Tax Credit

"IVR" – Interactive Voice Recording

"JDE" – J.D. Edwards

"Kinectrics" – Kinectrics Inc.

"KPI" – Key Performance Indicators

"kW" – Kilowatt

"kWhs" – Kilowatt hours

"LAC" – Locate Alliance Consortium

"LCBF" – Long Canada Bond Forecast

"LCT" – Large Corporation Tax

"LDC" – Local Distribution Company

"LEAP" – Low-Income Energy Assistance Program

"LEAP Report" – Report of the Board, Low-Income Energy Assistance Program (EB-2008-0150) issued March 10, 2009

"LRAM" – Lost Revenue Adjustment Mechanism

"LRT" – Light Rail Transit Line

"LTLT" – Longer Term Load Transfer

"LV" – Low Voltage

"MAPE" – Mean Absolute Percentage Error

"MDM/R" – Meter Data Management/Repository

"MEARIE" – Municipal Electric Association Reciprocal Insurance Exchange

"MER" – Metering and Electricity Revenue

"MEUs" – Municipally Owned Hydro-Electric Utilities

"MicroFIT" – Micro Feed in Tariff

"MIFRS" – Modified International Financial Reporting Standards

"MOE" – Ministry of Energy

"MOL" – Ministry of Labour

"MSC" – Monthly Service Charge

"MSP" – Meter Service Provider

"MTS" – Municipal Transformer Station

"MUSH" – Municipalities, Universities, Schools and Hospitals

"MW" – Megawatt

"MWh" – Megawatt hour

"NBV" – Net Book Value

"New Policy Options for the Funding of Capital Investments" – Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219) issued September 18, 2014

"NManEmp" – Non-Manufacturing Employment

"non RPP" – Non Regulated Price Plan

"NPV" – Net Present Value

"O&M" – Operations and Maintenance

"ODI" – Oracle Data Integrator

"OEA" – Ontario Energy Association

"OEFC" – Ontario Electricity Financial Corporation

"OH&S" – Occupational Health, Safety and Environment

"OHSAS" – Occupational Health and Safety Assessment Series

"OM&A" – Operations, Maintenance and Administration

"OMERS" – Ontario Municipal Employees Retirement System

"OMS" – Outage Management System

"OP" – Operational Technologies

"OPA" – Ontario Power Authority

"OPC" – Ontario Price Credit

"ORCGA" – Ontario Regional Common Ground Alliance

"PARs" – Production Action Reports

"PBR" – Performance Based Regulation

"PC" – Personal Computer

"PCBs" – Polychlorinated Biphenyls

"PEG" – Pacific Economics Group

"PILC" – Paper Insulated Lead Cable

"PILs" – Payments in Lieu of Taxes

"PLM" – Power line Maintainer

"PM" – Project Manager

"PMP" – Program Management Plan

"PP&E" – Property, plant and equipment

"PSWHA" – Public Service Works on Highways Act

"PTO" – Power Take Off

"PUC" – Paid-up Capital

"QA" – Quality Assurance

"QC" – Quality Control

"Rate Design Report" – Draft Report of the Board, Rate Design for Electricity Distributors (EB-2012-0410) issued March 31, 2014

"RCVA" – Retail Cost Variance Account

"Region" – Regional Municipality of Ottawa-Carleton

"Reliability Measures and Targets Paper" – Staff Discussion Paper, Electricity System Reliability Measures and Targets (EB-2014-0189) issued July 15, 2014
"Revenue Decoupling Report" – Staff Report to the Board, Distribution Revenue Decoupling (EB-2010-0060) issued January 18, 2011
"RFP" – Request for Proposal
"ROE" – Return on Equity
"RPI" – Real Personal Income
"RPP" – Regulated Price Plan
"RRFE Report" – Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, issued October 18, 2012
"RRFE" – Renewed Regulatory Framework for Electricity Distributors
"RRR" – Reporting and Record Keeping Requirements
"RRWF" – Revenue Requirement Work Form
"RSC" – Retail Settlement Code
"RSVA" – Retail Settlement Variance Account
"RTU" – Remote Terminal Unit
"SAIDI" – System Average Interruption Duration Index
"SAIFI" – System Average Interruption Frequency Index"
"SAN" – Storage Area Network
"SCADA" – Supervisory Control and Data Acquisition
"SLAs" – Service Level Agreements
"SM" – Smart Meter
"SMC" – Smart Metering Charge
"SME" – Smart Meter Entity
"SMI" – Smart Meter Initiative
"SOA" – System of Accounts
"SOM" – Switching Optimization Module
"SPC" – Special Purpose Charge
"SPL" – SPL WorldGroup Inc.
"SQI" – Service Quality Indicator
"SSM" – Shared Savings Mechanism

"STRs" – Service transaction requests
"TDRP" – Total Demand Response Initiative
"THESL" – Toronto Hydro Electric System Limited
"TOC" – Transformer Ownership Credit
"TOU" – Time of Use
"UCC" – Undepreciated Capital Cost
"USL" – Unmetered Scattered Load
"USofA" – Uniform System of Accounts
"VEE" – Validation, Editing and Estimation
"WCA" – Working Capital Allowance
"WMP" – Wholesale Market Participant
"WSCP" – Work-order Supply Chain Process
"WSIB" – Workplace Safety and Insurance Board
"XLPE" – Crosslink Polyethylene

## 2.0 DEFINED TERMS

'Historical Years' means 2012, 2013, 2014
"Most recent Board Approved Test Year 2012
'Bridge Year' means 2015
'Test Year' means 2016

'Capital expenditure' is the amount spent on a capital project/program in a given year.
'Capital additions' are the amounts that are capitalized for the project/program in a given year and are equal to the sum of the capital expenditures in the year plus the construction work in progress from the previous year minus the construction work in progress for the given year minus any deletions in the year.

# NOTICE OF APPLICATION

Pursuant to the OEB's filing requirements set out in Chapter 2 Filing Requirements for Electricity Distribution Rate Applications dated July 18, 2014 this schedule provides the following administrative information:

1. Notice of Application, including:
    a. Statement of who will be affected by this application;
    b. Summary of Bill Impacts
    c. Publication information;
    d. Contact Information; and
    e. Internet address for viewing the application.

## 1.0 NOTICE OF APPLICATION

### a) Affected Customers

Hydro Ottawa Limited has approximately 315,000 distribution customers across its service territories that will be affected by this rate application. More information regarding Hydro Ottawa's customer base is available in the Executive Summary to this application available in Exhibit A, Tab 2, Schedule 1 and Hydro Ottawa's Customer Engagement evidence provided in Exhibit A, Tab 3, Schedule 1.

### b) Summary of Bill Impacts

Table 1 below provides a high level summary of distribution bill impacts for a typical residential customer using 800kWh per month and for a General Service <50kW customer using 2000kWh per month. Hydro Ottawa proposes to include in its Notice of Application a summary of bill impact information that will be published pursuant to OEB directions or as set out below.

**Table 1 – Bill Impacts Summary**

| Residential (800kWh) | | | | | |
|---|---|---|---|---|---|
| **Distribution Bill** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Total ($)** | $2.66 | $1.44 | $1.29 | $0.90 | $0.47 |
| **Total Bill (% ∆ )** | 1.84% | 1.06% | 0.93% | 0.65% | 0.34% |
| **General Service <50kW (2000kWh)** | | | | | |
| **Distribution Bill** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Total ($)** | $65.95 | $70.55 | $74.85 | $78.95 | $81.60 |
| **Total Bill (% ∆ )** | 2.11% | 1.41% | 1.30% | 1.22% | 0.78% |

**c) Publication Information**

Hydro Ottawa proposes to publish a notice of this application in the Ottawa Citizen and LeDroit newspapers and post a copy of the application on Hydro Ottawa's website www.hydroottawa.com . LeDroit is a daily newspaper serving the French speaking communities in the Ottawa Gatineau area. The Ottawa Citizen is a daily newspaper serving the Ottawa area. Both LeDroit and the Ottawa Citizen have a paid circulation of approximately 30,669 and 94,449 respectfully. Hydro Ottawa choose these publications due to their significant reach into the French and English speaking communities within the city of Ottawa and the village of Cassleman.

**d) Contact Information**

The names and contact information of Hydro Ottawa Limited's authorized representative and legal counsel for this Custom IR application to the Board are:

a. Authorized Representative

Mr. Geoff Simpson
Chief Financial Officer
Hydro Ottawa Limited

3025 Albion Road North
P.O. Box 8700
Ottawa, Ontario
K1G 3S4

Telephone: 613-738-5499 ext. 7606
E-mail: RegulatoryAffairs@HydroOttawa.com

b. Counsel

Mr. Fred D. Cass
Aird & Berlis LLP

Brookfield Place
181 Bay Street, Suite 1800
P.O. Box 754

Telephone: 416-865-7742
E-mail: fcass@airdberlis.com

**e) Internet address for viewing the application**

This application and related documents are available for viewing on Hydro Ottawa's website, www.hydroottawa.com . Additionally, Hydro Ottawa's Communications Team will be communicating via twitter and Facebook through the company's official handles, respectively "@hydroottawa" and "Hydro Ottawa".

# COMPLIANCE WITH THE OEB'S FILING REQUIREMENTS

Hydro Ottawa's Custom IR Application is guided by the requirements set out in Chapters 2 and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications Issued July 18, 2014 ("the filing requirements") as well as the requirements set by the Board in the Renewed Regulatory Framework for Electricity Distributors ("RRFE"). See Exhibit A-6-2 for a checklist that relates Hydro Ottawa's exhibits and evidence to the OEB's filing requirements and RRFE requirements.

# MATERIALITY THRESHOLD AND ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

## 1.0 HYDRO OTTAWA'S MATERIALITY THRESHOLD

Pursuant to section 3.2.2.2 of the Filing Requirements, Hydro Ottawa's materiality threshold is $880K based on a distribution revenue requirement of $177 million for 2016. Hydro Ottawa has adopted a $750K materiality threshold for the purposes of this application.

## 2.0 ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

Hydro Ottawa confirms that it has segregated the business activities of its non-utility business from its rate-regulated business.

# CHANGES TO METHODOLOGIES USED IN PREVIOUS APPLICATIONS

Since Hydro Ottawa's last rebasing in 2011 (EB-2011-0054) Hydro Ottawa has made changes to the Accounting standard used for financial reporting purposes. Specifically, Hydro Ottawa has completed the transition to International Financial Reporting Standards ("IFRS") for financial reporting. This transition became effective January 1, 2015.

# OEB DIRECTIVES FROM PREVIOUS BOARD DECISIONS AND/OR ORDERS

Below is a summary of previous OEB directives and a description of how such directives are addressed by Hydro Ottawa in the current application.

a) In Decision EB-2011-0054 the OEB directed Hydro Ottawa to prepare a new lead-lag study to be filed in its next cost of service application to reflect the move to monthly billing at the end of 2013. Hydro Ottawa is not filing a new lead lag study in the context of the current proceeding due to insufficient monthly billing data available to support reliable findings. Hydro Ottawa expects to be in a position to provide a new lead/lag study in Q3 of 2015.

b) In EB-2012-0383 the Board indicated that unmetered load (kW) and consumption (kWh) data should ultimately be used to update load profile data for the purpose of the distributor's next cost allocation filing with the Board, which occurs during the distributor's next cost of service application to the Board. As noted in Exhibit G-1-2, Hydro Ottawa is aware of a study being undertaken by Navigant Consulting Limited ("Navigant") and related working group activities examining unmetered loads as initiated by the Ontario Energy Board (OEB) pursuant to the proceeding EB-2012-0383 Review of Cost Allocation Policy for Unmetered Loads. Based on the record of the proceeding, the Navigant study and a revised cost allocation model are expected to be completed prior to the 2016 Board filing requirements release. Should the cost allocation model be updated with the 2016 filing requirements, Hydro Ottawa intends to review the model for any material impacts to the Company's current proposed cost to revenue allocation ratios.

# CONDITIONS OF SERVICE

Hydro Ottawa recently updated its Conditions of Service ("COS"), Version 5, which is available on its website under Rates and Conditions at the following link: https://hydroottawa.com/about/policies/conditions-of-service/. This current version went into effect April 1, 2015. On this same date, a confirmation letter was sent to the Board.

In alignment with the customer value objective of the RRFE, over the course of 2014 Hydro Ottawa engaged key internal and external stakeholders to assess the effectiveness of Hydro Ottawa's COS from the perspective of stakeholders. These groups included residential and business customers, developers, city planners, city councillors and internal employees. Feedback sessions were led by professional facilitator Janet Leblanc and Associates Inc. Further details on this customer engagement initiative and the associated outcomes are provided in Exhibit A-3, Section 2.1.4.

In follow-up to several recommendations identified through the customer engagement process, Hydro Ottawa secured the professional services of The Masha Krupp Translation Group Ltd to edit the document for consistency and conciseness. A second phase to the document enhancement plan will render a copy of Hydro Ottawa's Conditions of Service in web content for easy access and search ability (Q2/Q3 2015). This phase will utilize a third-party editor to improve the document's navigability, accessibility, and flow.

Ultimately Hydro Ottawa anticipates that its new version of Conditions of Service will improve the customer experience when accessing information on Hydro Ottawa services.

## 1.0 REVISION HIGHLIGHTS

In addition to updating COS V5 to reflect current regulatory and business requirements, the following key changes were made:

- Section 1.6 updated and expanded customer rights and responsibilities with regard to maintenance of their own equipment and lead times for service isolation requests;
- Section 2.3.2.12 updated power outage reporting procedures;
- Section 2.3.7.2 updated to advise that a fee will be charged when Hydro Ottawa must manually read an interval meter, due to an outstanding, inoperable phone line;
- Section 2.4.3 revised requirement for residential security deposits;
- Section 2.4.3.4 added provision of a third-party guarantor, in lieu of a deposit;
- Section 2.4.4 added billing and payment process for generation accounts;
- Section 2.4.4.5 notes the phasing out of the transformer ownership credit for customer-owned transformers;
- Section 2.4.6.7 added conditions under which credit balances on accounts may be transferred
- Section 2.4.6.8 added process for generator payments;
- Section 2.4.7 added a new section dedicated to Eligible Low-Income Consumers and the low-income energy assistance provisions and qualifications;
- Section 3.1.1.3 removed provision that ownership of underground secondary service conductors would be transferred at no cost;
- Section 3.1.3.7 added provision that Hydro Ottawa will extend the overhead distribution system to provide for a single standard, 1-phase, secondary residential service within its service area;
- Section 3.5 removed mandatory Micro-FIT insurance provision;
- Section 3.9.1 revised temporary underground service requirement from 400-A to “up to 400 A;
- Section 4.0 revised, added and removed numerous Definitions;

- Appendix B – added provision of a 25-year revenue horizon for some MUSH projects;
- Appendix D - revised account set up information requirements; and
- Appendix G – added more exceptions to current technical standards and related business processes.

# APPLICANT OVERVIEW

Hydro Ottawa Limited ("Hydro Ottawa") was created in November 2000 following the amalgamation of the municipalities of the former Region of Ottawa-Carleton. Hydro Ottawa acquired the assets of Casselman Hydro Inc. in April 2002, and therefore, as Attachment A-7(A) reveals, the Hydro Ottawa service territory also includes the Village of Casselman. The Village of Casselman and the City of Ottawa are separated by the territory of Hydro One Networks Inc. ("Hydro One").

Hydro Ottawa is one of 73 distinct local distribution companies ("LDCs") in Ontario regulated by the Ontario Energy Board. While all of these operate under the same fundamental direction from the Board, each is confronted with their own unique qualities. Hydro Ottawa's foremost distinctiveness is its physical size; with a service territory made up of 650 $km^2$ rural area and 454 $km^2$ of urban area, its total service area of 1,104 $km^2$ makes it the fifth physically largest in the province. For context, Hydro Ottawa's service territory is geographically larger than the combined service territories of Toronto Hydro-Electric System Limited ("THESL") and Horizon Utilities Corporation ("Horizon").

With roughly 315,000 customers within its service territory, it is also one of the largest LDCs in the province in terms of customer count, with only PowerStream Inc., Toronto Hydro and Hydro One surpassing Hydro Ottawa with regard to number of customers.

Hydro Ottawa's service territory is a geographically diverse area, with significant population dispersion. The Hydro Ottawa service territory sits at the convergence of three major rivers: the Ottawa River, the Gatineau River and the Rideau River. The Ottawa River functions as the northern border of Hydro Ottawa's service territory, beyond being the province of Quebec. Hydro Ottawa is otherwise completely surrounded by the service territory of Hydro One. The Rideau Canal, which by-passes unnavigable sections of the Rideau River, winds itself through Hydro Ottawa's service territory. Around the main urban area of the city of Ottawa is an extensive greenbelt comprised of mostly forest, farmland and marshland. Outside of the greenbelt, there are a number of rapidly expanding suburban communities. These distinct geographical features present Hydro Ottawa with unique circumstances in terms of response time and ultimately, operating costs. For more information regarding the unique features of Hydro Ottawa's serving territory refer to Hydro Ottawa's Executive Summary available in A-2-1. A map of Hydro Ottawa Limited's service territory is available in Exhibit A-7-1, Attachment A.

**Host Distributor vs. Embedded**

Hydro Ottawa's service area is surrounded by the service area of Hydro One Network Inc. ("Hydro One"). Hydro Ottawa accordingly contains no licensed distributors embedded in its service area. Hydro Ottawa's load is primarily delivered through transmission connection points; however, there are a number of delivery points embedded in the Hydro One distribution system, primarily in rural areas.

**High Voltage Distribution Assets**

The following list of substations in Table 1 includes all of Hydro Ottawa's assets that operate at or above 50kV and form part of the distribution system. Table 1 was filed in Exhibit A1-4-1 of EB-2011-0054 and approved pursuant to a settlement agreement filed with the Board November 1, 2011. The approvals extended to the Cyrville and Ellwood substations as well as the expanded capacity at Fallowfield DS and the Terry Fox substation.

**Table 1 – Transformer Substations above 50 kW[1]**

| Transformer Substations above 50 kV and Part of Hydro Ottawa's Distribution System | |
|---|---|
| Epworth DS | Marchwood MS |
| Merivale DS | Bridlewood MS(27.6kV) |
| Manordale DS | Bridlewood MS (8kV) |
| Centrepointe DS | Kanata MTS |
| Uplands MS (27.6kV) | Cyrville MS |

[1] DS means distribution station, MS means municipal station, MTS means municipal transformer station. This terminology is historical, often based on past ownership arrangements.

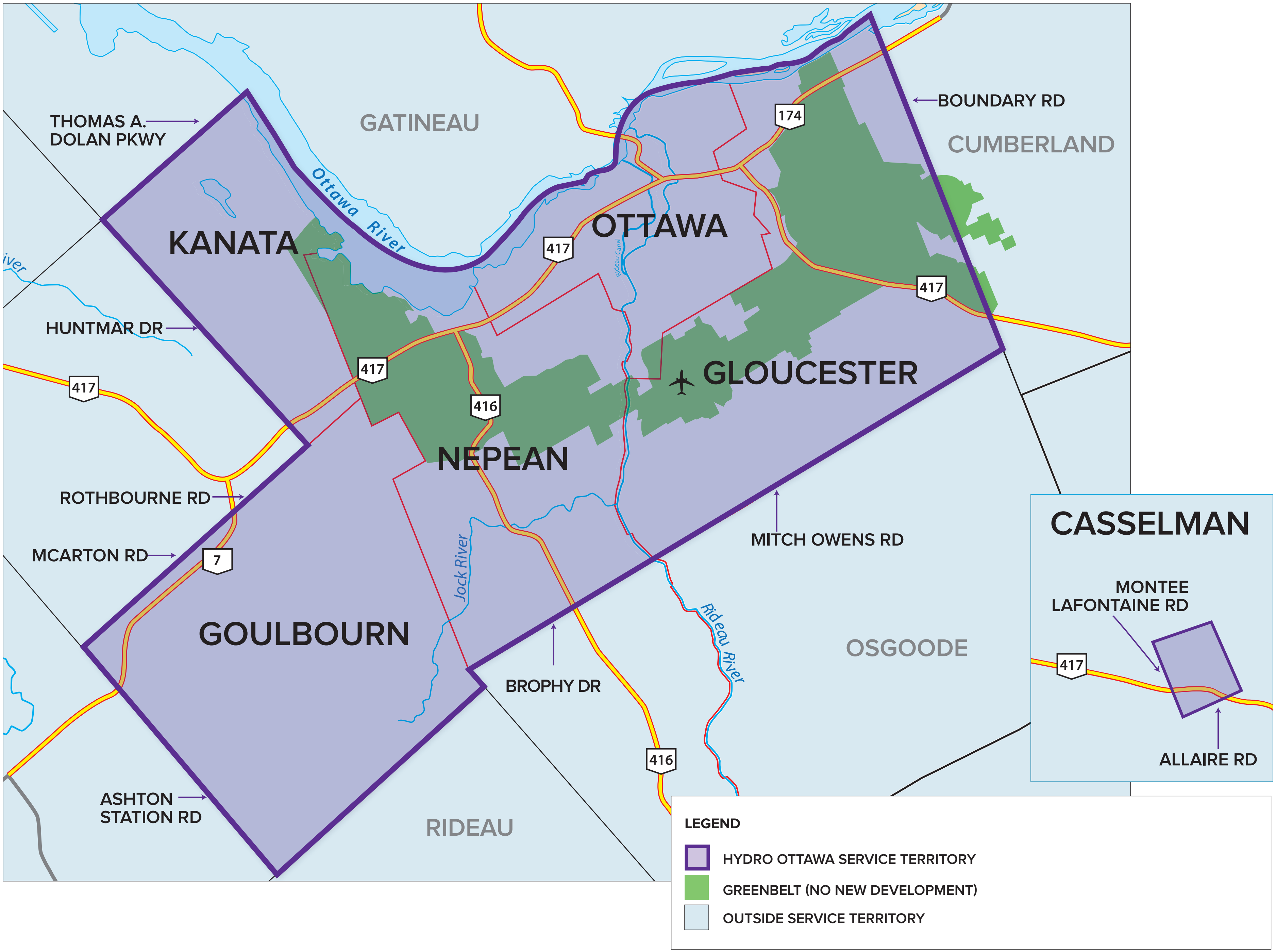
| | |
|---|---|
| Limebank MS | Ellwood MS |
| Moulton MS | Fallowfield DS |
| | Richmond South DS |
| | Terry Fox DS |

Table 2 shows the transformer stations which Hydro Ottawa plans to add assets above 50kV over the period of 2015-2020.

**Table 2 – Transformer Substations above 50 kV to be added**

| **Transformer Substations with assets being added above 50 kV and Part of Hydro Ottawa's Distribution System** | |
|---|---|
| **Station Name** | **Planned In Service Date** |
| South 28kV Substation (yet to be named) | 2020 |

Hydro Ottawa is therefore seeking approval from the Board that this substation form part of Hydro Ottawa's distribution system, and that the amount be included in rate base. Exhibit A-6-1 includes the specific request for approvals pertaining to the South 28kV substation. Hydro Ottawa records these stations per the Uniform System of Accounts as Account 1815 Transformer Station Equipment - Normally Primary above 50 kV.



GATINEAU
CUMBERLAND
BOUNDARY RD
THOMAS A.
DOLAN PKWY
Ottawa River
KANATA
OTTAWA
GLOUCESTER
NEPEAN
GOULBOURN
HUNTMAR DR
ROTHBOURNE RD
MCARTON RD
ASHTON
STATION RD
BROPHY DR
MITCH OWENS RD
OSGOODE
RIDEAU
Jock River
Rideau River
174
417
416
7
CASSELMAN
MONTEE
LAFONTAINE RD
ALLAIRE RD
LEGEND
HYDRO OTTAWA SERVICE TERRITORY
GREENBELT (NO NEW DEVELOPMENT)
OUTSIDE SERVICE TERRITORY

# CORPORATE GOVERNANCE

Pursuant to section 2.4.8 of the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rates Applications (July 18, 2014) (hereinafter "the filing requirements"), Hydro Ottawa Limited herein provides information regarding the corporate and utility organizational structure, and corporate governance practices. This schedule includes the following attachments:

- Attachment A-8 (A) – Shareholder Declaration – Hydro Ottawa Holding Inc.
- Attachment A-8 (B) – Shareholder Declaration – Hydro Ottawa Limited
- Attachment A-8 (C) – Charter of the Hydro Ottawa Holding Inc. Board of Directors
- Attachment A-8 (D) – Charter of the Hydro Ottawa Limited Board of Directors
- Attachment A-8 (E)- Charter of the Nominating Committee
- Attachment A-8 (F) – Charter of the Audit Committee
- Attachment A-8 (G) – Charter of the Governance and Management Resources Committee
- Attachment A-8 (H) – Charter of the Investment Review Committee
- Attachment A-8 (I) – Charter of the Strategic Initiatives and Oversight Committee
- Attachment A-8 (J) – 2014 Meeting Schedule - Hydro Ottawa Holding Inc. Board, its committees, and its subsidiary board, Hydro Ottawa Limited Board
- Attachment A-8 (K) - Director Orientation and Continuing Education Policy and Process
- Attachment A-8 (L) – Code of Business Conduct
- Attachment A-8 (M) – Director Conflict of Interest and Conduct Guidelines
- Attachment A-8 (N) – Related Party Transaction Disclosure Policy and Process
- Attachment A-8 (O) – Business Conduct Hotline Brochure

## 1.0 CORPORATE AND UTILITY ORGANIZATIONAL STRUCTURE

Hydro Ottawa Holding Inc. (HOHI / Hydro Ottawa / the Corporation) was created as a result of the Electricity Act, 1998, which required all hydro utilities to operate as business corporations. Under this structure, HOHI is a for-profit company that continues to be wholly owned by the City of Ottawa, and is governed by an independent Board of Directors appointed by its shareholder. The core businesses of the Corporation are electricity distribution, renewable energy generation and related services. In 2014, HOHI owned and operated two subsidiary companies: Hydro Ottawa Limited, a regulated distribution company operating in the City of Ottawa and the Village of Casselman; and Energy Ottawa Inc., the largest municipally-owned producer of green power in Ontario and a provider of commercial energy management services.

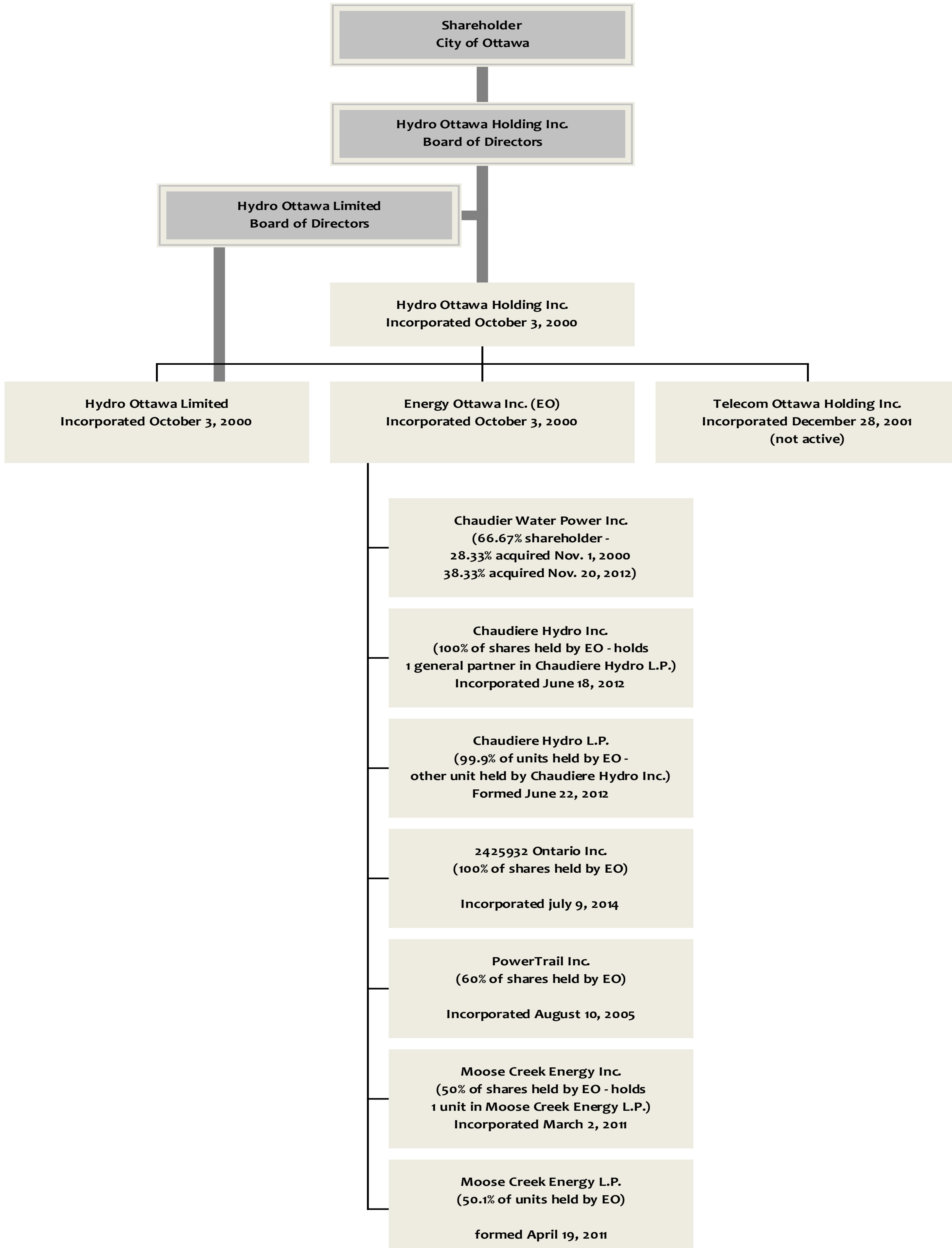
### 1.1 Current Governance Structure

Accountability for the effective oversight of Hydro Ottawa Holding Inc. (the Corporation) and its wholly-owned subsidiaries (Hydro Ottawa Limited and Energy Ottawa Inc.) rests with an eleven-member Hydro Ottawa Holding Inc. (HOHI) Board of Directors, which provides direction to the Corporation on behalf of the shareholder, the City of Ottawa. The HOHI Board provides leadership within a framework of effective controls that enables risks to be assessed and managed, and is responsible for supervising the management of the business and affairs of the Corporation and its wholly-owned subsidiaries. In carrying out its oversight function, the HOHI Board of Directors is guided by a Shareholder Declaration issued by Ottawa City Council (Attachment A-8 (A)) and revised from time to time. The Corporation's Code of Business Conduct (Attachment A-8 (L)), its Director Conflict of Interest and Conduct Guidelines (Attachment A-8 (M)) and a Related Party Transaction Disclosure Policy and Process (Attachment A-8 (N)) also govern the actions of the HOHI Board.

In 2006, a separate subsidiary Board of Directors was established to oversee the operations of Hydro Ottawa Limited (HOL), in accordance with the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board. The powers and functions of that Board are set out in a Shareholder Declaration issued by the Hydro Ottawa Holding Inc. Board of Directors (Attachment A-8 (B)). The chart shown below depicts the relationship between the various corporate entities.

The composition of the utility company board, HOL, includes three members, two of whom also serve on the parent board (Hydro Ottawa Holding Inc. - HOHI), and one who is a member of the management of HOL but who is not employed by an affiliate of HOL. The members include the HOHI Board Chair, the President and Chief Executive Officer of HOHI and HOL, and the Chief Operating Officer – Distribution and Customer Service, HOL.

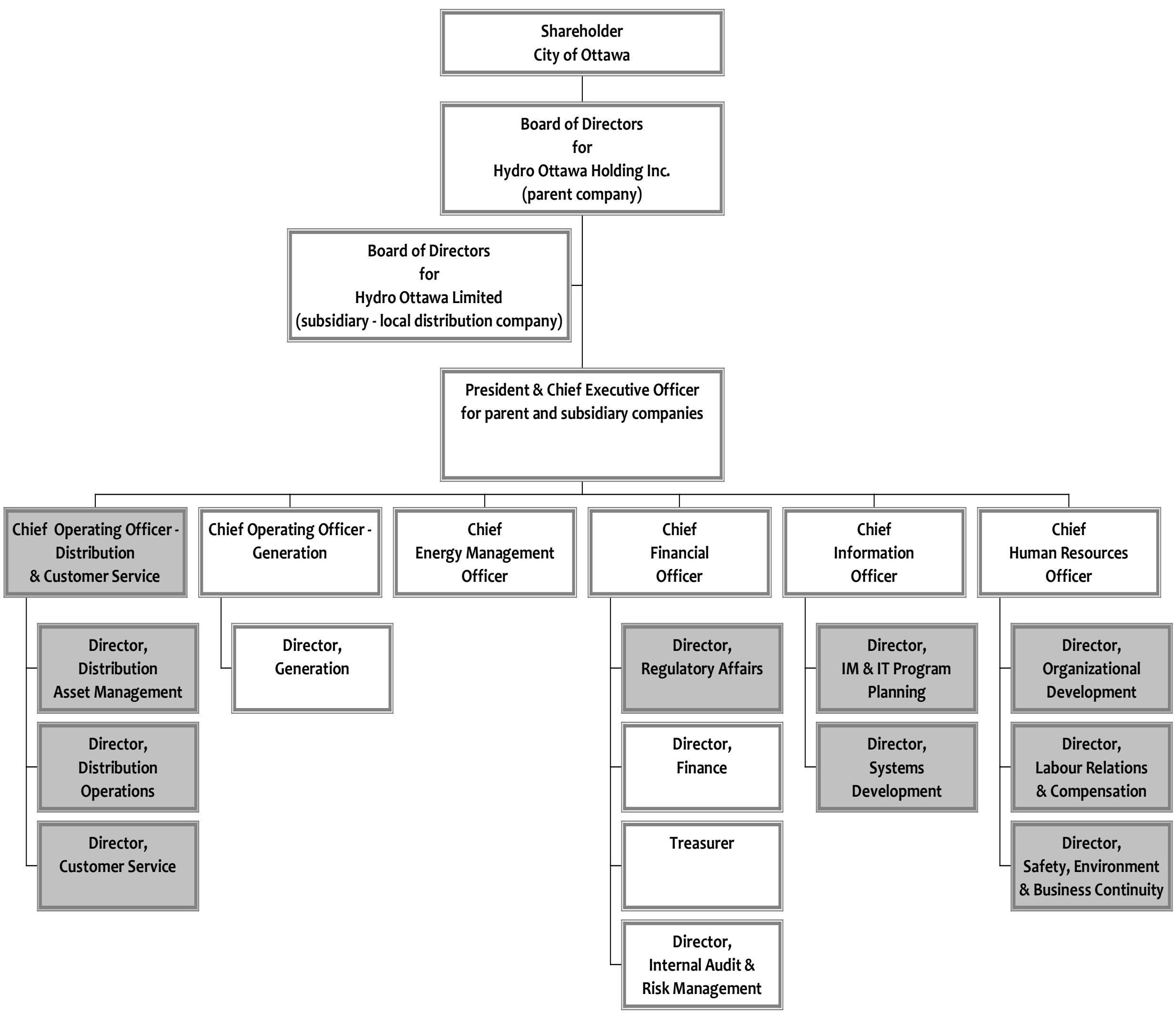
## Figure 1 - Corporate Entities Relationship Chart



## 1.2 Executive Management Team and Reporting Relationship between Utility Management and Parent Company Officials

On a day-to-day basis, the Corporation is led by an Executive Management Team, comprising the Corporation's President and Chief Executive Officer, the Chief Financial Officer and the senior executives of the subsidiaries and critical functional areas. This team oversees the alignment of business practices and strategies with the goals of the Corporation, and drives performance by managing risks and opportunities. The Executive Management Team is accountable to the Corporation's Board of Directors through the President and Chief Executive Officer. The chart shown below depicts the relationship between utility management (shaded boxes) and parent company officials.

**Figure 2 – Utility Management and Parent Company Relationship**



## 2.0 CORPORATE GOVERNANCE PRACTICES

### 2.1 Board of Directors

a. The composition of the parent board, Hydro Ottawa Holding Inc. (HOHI), includes eleven members, eight of whom are independent of management and the sole shareholder, the City of Ottawa.

   The composition of the subsidiary board, Hydro Ottawa Limited (HOL), includes three members: the Chair of the HOHI Board; the President and Chief Executive Officer of HOHI and HOL; and the Chief Operating Officer – Distribution and Customer Service, HOL. One of the three members, the Chief Operating Officer – Distribution and Customer Service, HOL, is independent from any affiliate as required by the provisions of subsection 2.1.3 of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters.

   The number and proportion of independent directors on the HOL Board is set out in Section 2 of its charter (Attachment A-8 (D)), which requires that one third of the Board, shall at all times, be independent of any affiliate.

b. To facilitate its exercise of independent judgement in carrying out its responsibilities,
   i. the parent board, the HOHI Board, is comprised of a majority of independent directors;
   ii. the subsidiary board, the HOL Board, has met its charter requirements to have one third of the Board independent of any affiliate;
   iii. a number of internal policies and processes are in place to address related party transactions (see Attachment A-8 (N) – Related Party Transaction Disclosure Policy and Process) including among other things,
      - an agenda item at each meeting of the boards and committees that requires Board members to make declarations of interest

and to disclose any transactions in which they could have an interest but also to disclose any entities in which they have come to have a financial interest that could be involved in transactions with HOHI or its wholly-owned subsidiary companies;

- an annual disclosure to the Governance and Management Resources Committee of related party transactions involving directors of Hydro Ottawa Holding Inc. and its wholly-owned subsidiary companies; and
- an annual disclosure to the shareholder, through the City Manager, of related party transactions involving directors of Hydro Ottawa Holding Inc. and its wholly-owned subsidiary companies, including certification of compliance with the restrictions contained in the Shareholder Declaration relating to restrictions on payments to directors, their family members and entities in which directors have a substantive ownership interest;

iv. the Audit Committee is comprised solely of independent directors, both the internal and external auditors attend the Audit Committee meetings, and the Audit Committee has a closed session with the external auditors at every meeting;

v. the parent (HOHI) and subsidiary (HOL) Boards receive regular briefings on a variety of strategic issues; and

vi. the parent (HOHI) and subsidiary (HOL) Boards conduct a periodic self-evaluation to assess the performance and effectiveness of the boards, board committees, the board and committee chairs. All information supplied by members of the boards is kept confidential and is not accessible by members of management of the Corporation. All results of the assessment process are reported out to the Board on a confidential basis without attribution.

## 2.2 Board Mandate

As part of its commitment to implementing good governance practices consistent with a corporation of its size and nature of business activities, Hydro Ottawa Holding Inc., including its wholly-owned subsidiary companies, Hydro Ottawa Limited and Energy Ottawa Inc., is committed to regularly assessing its practices to ensure that this continues to be the case.

With respect to board mandates, the Governance and Management Resources Committee of the parent board, Hydro Ottawa Holding Inc., has been assigned the responsibility to maintain charters for the boards and committees, including for the Hydro Ottawa Limited Board, and annually reviews roles, responsibilities and terms of reference to ensure that they are consistent with good governance practices for a corporation of Hydro Ottawa's size and mandate.

The written mandate of the Hydro Ottawa Limited Board of Directors is set out in its charter appended at Attachment A-8 (D).

## 2.3 Board Meetings

A schedule of the 2014 meetings of the parent board, Hydro Ottawa Holding Inc., its committees, and its subsidiary board, Hydro Ottawa Limited, is appended at Attachment A-8 (J).

## 2.4 Orientation and Continuing Education

As part of its commitment to implementing good governance practices consistent with a corporation of its size and nature of business activities, Hydro Ottawa Holding Inc. (HOHI), including its wholly-owned subsidiary companies Hydro Ottawa Limited and Energy Ottawa Inc., is committed to ensuring that members of the Board of Directors receive both an initial orientation and on-going education that will assist them in undertaking their roles as directors of the corporation and its subsidiaries.

To this end, the HOHI Board has put in place a Director Orientation and Continuing Education Policy and Process (see Attachment A-8 (K)), and has assigned responsibility to the Governance and Management Resources Committee for ensuring that appropriate and relevant practices are in place for board director orientation and continuing education. The Corporation encourages board directors to participate in external professional development education programs to assist in the execution of their roles as board directors, and also funds the participation of one board director per year for a recognized director education program providing board director certification.

### 2.5 Ethical Business Conduct

The Corporation's Code of Business Conduct (Attachment A-8 (L)), its Director Conflict of Interest and Conduct Guidelines (Attachment A-8 (M)) and a Related Party Transaction Disclosure Policy and Process (Attachment A-8 (N)) govern the actions of the parent board, Hydro Ottawa Holding Inc. (HOHI), and its subsidiary board, Hydro Ottawa Limited (HOL). Moreover, the charters of the HOHI Board (Attachment A-8 (C)), the Governance and Management Resources Committee (Attachment A-8 (G)), and the HOL Board (Attachment A-8 (D)) each include specific provisions as these relate to Code of Conduct and Compliance.

In accordance with their charter requirements, the Governance and Management Resources Committee (GMRC), and the HOHI and HOL Boards, annually receive a report confirming that directors, members of management and those in key financial positions have signed an attestation acknowledging acceptance of the company's Code of Business Conduct.

Additionally, the Corporation has established a Business Conduct Hotline (see Attachment A-8 (O)), a third party service that allows employees and Board members to anonymously report any concerns they might have related to perceived improper activities in the workplace and/or non-compliance with the Code of Business Conduct, or even suggestions for improvement. The Audit Committee of the HOHI Board receives annual Business Conduct Hotline updates and more frequent reports if a serious complaint is received.

### 2.6 Nomination of Directors

In accordance with the requirements of the Shareholder Declaration for the parent board, Hydro Ottawa Holding Inc. (Attachment A-8 (A)), the City of Ottawa, the sole shareholder, appoints all directors to the Boards of HOHI and its wholly-owned subsidiaries, including Hydro Ottawa Limited, except for the President and Chief Executive Officer. In doing so, the City considers candidates recommended by the Nominating Committee of the HOHI Board (see charter at Attachment A-8 (E), but is not obliged to select these candidates. The Nominating Committee is assisted by outside consultants in its search for candidates for appointment to the Boards.

As set out in the Shareholder Declaration, all candidates for appointment to the boards must meet certain requirements, including demonstrated integrity and high ethical standards, relevant career experience and expertise, and an understanding of Hydro Ottawa both as a service to local ratepayers and an asset of taxpayers.

In addition, the nomination and selection process is designed to maintain boards that includes the following overarching competencies among one or more directors: strong business background including competitive business experience and strategic planning; a strong financial background including financial accreditation and public or private market financing experience; industry sector experience in the areas of business of the subsidiary companies; board experience; and merger and acquisition experience.

In 2014, the *Institute on Governance* assisted with the process of identifying and evaluating potential candidates. The process used by the *Institute on Governance* to source qualified candidates for the Nominating Committee's consideration was designed to target recruitment priorities identified by the Governance and

Management Resources Committee as part of its annual review of the board competency profile. It included:

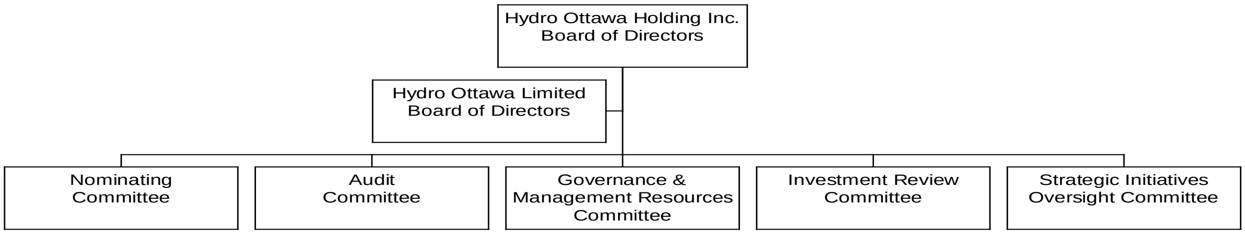
- A recruitment posting on the Hydro Ottawa website;
- A review of the Institute of Corporate Directors Register;
- A search of the Canadian Board Diversity Council database;
- A recruitment posting that connected with the Canadian Bar Association Women's Lawyer Forum;
- A review of the Women's Law Association of Ontario member directory;
- A search of Lexpert's database of law firms to identify local organizations that have individuals with legal expertise and M&A expertise; and
- Submission of the Recruitment Posting link to a contact at the Association of Power Producers of Ontario for display on their employment opportunities page.

The *Institute on Governance* assessed applications against the selection criteria set out in the Shareholder Declaration as well as the recruitment priorities identified for 2014, and then provided the Nominating Committee a report including a candidate listing, biographies and a summary competency assessment for each potential candidate.

As per usual practice, the Nominating Committee then met to discuss the candidate listing provided by the *Institute on Governance,* giving consideration to the recruitment priorities identified through the board profile review conducted earlier in the year. Following its deliberation, the Nominating Committee resolved to recommend candidates for appointments to the Boards to the shareholder, and the recommended candidate names were included as part of Hydro Ottawa's AGM report to City Council for its meeting of June 25, 2014.

## 2.7 Board Committees

The following five committees have been created to assist the parent board (HOHI) and its subsidiary board, Hydro Ottawa Limited, in carrying out their duties.




**Nominating:** The Nominating Committee, with the assistance of outside consultants, identifies and evaluates potential candidates for appointment as board directors. The Nominating Committee makes recommendations to the shareholder (represented by Ottawa City Council) for the appointment of board directors. The Committee charter is appended at Attachment A-8 (E).

**Audit:** The Audit Committee reviews financial statements, accounting practices and policies, auditing processes and the results of internal and external audits and related matters. It also oversees financial risk management and assesses internal controls. The Committee charter is appended at Attachment A-8 (F).

The Audit Committee is comprised solely of independent directors. Financial expertise is one of the overarching competencies for all board directors, and all Audit Committee directors are financially literate. In addition, both the internal and external auditors attend the Audit Committee meetings, and the Audit Committee has a closed session with the external auditors at every meeting.

**Governance and Management Resources:** The Governance and Management Resources Committee reviews the Corporation's governance structures and practices to ensure that the Board of Directors can fulfill its mandate. It reviews management resources and compensation practices to ensure systems are in place to attract, retain and motivate qualified management employees. It also reviews and assesses the performance of the President and Chief Executive Officer, oversees the Board Assessment process, and monitors compliance with codes of conduct. The Committee charter is appended at Attachment A-8 (G).

**Investment Review:** The Investment Review Committee, created by the Board of Directors effective April 2010, is responsible for assisting management and the Board of Directors in the review and pursuit of business development, acquisition and investment opportunities. In carrying out these functions, the Committee focuses on the consistency of opportunities with strategic plans and investment guidelines, the maximization of shareholder value and the management of risk. The Committee charter is appended at Attachment A-8 (H).

**Strategic Initiatives Oversight:** The Strategic Initiatives Oversight Committee, created by the Board of Directors effective November 2013, is responsible for assisting the Board of Directors in guiding management and providing support and focus for large-scale capital project efforts as identified by the Board from time to time. The Committee charter is appended at Attachment A-8 (I).

**SHAREHOLDER DECLARATION** dated the 25th day of June 2014.

BY: **CITY OF OTTAWA**
Being the sole shareholder of Hydro Ottawa Holding Inc.

**WHEREAS** subsection 108(2) of the *Ontario Business Corporations Act* permits all of the shareholders of a corporation to enter into a unanimous shareholder agreement;

**AND WHEREAS** pursuant to subsection 108(3) of such Act, a written declaration by a sole shareholder of a corporation that restricts in whole or in part the powers of the directors to manage or supervise the management of the business and affairs of the corporation is deemed to be a unanimous shareholder agreement;

**AND WHEREAS** pursuant to subsection 108(5) of such Act, to the extent that a unanimous shareholder agreement restricts the discretion or powers of the directors of a corporation to manage or supervise the management of the business and affairs of a corporation, a shareholder who is a party to the unanimous shareholder agreement assumes such powers and the related duties and liabilities and the directors are thereby relieved of their duties and liabilities;

**AND WHEREAS** the City of Ottawa is the sole owner of all the issued and outstanding shares of Hydro Ottawa Holding Inc./Société de Portefeuille d'Hydro Ottawa Inc. and desires to make this Declaration with the intent that to the extent that it restricts the discretion and powers of the directors of Hydro Ottawa Holding Inc./Société de Portefeuille d'Hydro Ottawa Inc., it shall constitute a unanimous shareholder agreement with respect to only those restrictions;

**AND WHEREAS** the City of Ottawa wishes that the shareholder declaration show that it is an objective of Hydro Ottawa Holding Inc. and its Subsidiary Hydro Ottawa Limited to have electricity customers in the whole of the geographic area of the City of Ottawa receive electricity distribution services from Hydro Ottawa Limited;

**AND WHEREAS** the City of Ottawa wishes to establish certain principles of governance and other fundamental principles and policies relating to Hydro Ottawa Holding Inc./Société de Portefeuille d'Hydro Ottawa Inc. and its subsidiaries;

**NOW THEREFORE**, the City of Ottawa hereby declares as follows:

## ARTICLE I
## INTERPRETATION

### 1.1 Definitions

In this Declaration the following terms will have the meanings set out below:

**"Act"** means the Ontario *Business Corporations Act*, as now enacted or as the same may from time to time be amended, re-enacted or replaced;

**"Affiliate"** means a Body Corporate that is affiliated with Holdco as such relationship is defined in the Act;

**"Board"** means the board of directors of Holdco;

**"Body Corporate"** means a firm, partnership, unincorporated association, joint venture, corporation, bank, trust, pension fund, union, governmental agency, board, tribunal, ministry of commission or other legal entity of any kind whatsoever, but excludes an individual or natural person;

**"Business Day"** means a day, other than a Saturday or Sunday, on which the principal commercial banks located at Ottawa, Ontario are open for business during normal banking hours;

**"City"** means the City of Ottawa being the body corporate by which, on January 1, 2001, the inhabitants of the municipal areas, as defined in the *City of Ottawa Act, 1999*, are constituted as a body corporate as provided in subsection 2.(1) of such act;

**"Competitive Affiliates"** means Energy Ottawa Inc./Énergie Ottawa Inc. and Telecom Ottawa Holding Inc.;

**"External"** means, with respect to a member of the Board, (a) an individual who is not the Mayor (or his/her designee), a councillor or employee of the City; or (b) an individual who is not an officer or employee of Holdco or any Affiliate;

**"Holdco"** means Hydro Ottawa Holding Inc./Société de Portefeuille d'Hydro Ottawa Inc., a corporation incorporated under the Act;

**"Municipal Electric Utilities"** means collectively The Hydro-Electric Commission of the City of Ottawa, The Hydro-Electric Commission of the City of Nepean, The Hydro-Electric Commission of The City of Kanata, The Hydro-Electric Commission of the City of Gloucester and Goulbourn Hydro-Electric Commission;

**"Person"** means an individual, a natural person or a Body Corporate;

**"Regulator"** means the Ontario Energy Board, the Independent Electricity System Operator, the Ontario Power Authority or any other governmental or regulatory authority having jurisdiction over Holdco or a Subsidiary;

**"Subsidiary"** means, with respect to Holdco, each of the Utility Affiliate, the Competitive Affiliates and any body corporate of which more than 50% of its outstanding securities of any class carrying exercisable voting rights are beneficially owned, directly or indirectly, by Holdco, and includes any Body Corporate in like relation to a Subsidiary;

**"Third Party"** means a person who deals at arm's length (as interpreted by subsection 251 (1) of the *Income Tax Act* (Canada) with Holdco or a Subsidiary; and

**"Utility Affiliate"** means Hydro Ottawa Limited/Hydro Ottawa Limitée, a corporation incorporated under the Act.

1.2 Calculation of Time

In this Declaration, unless otherwise specified, time periods within or following which any payment is to be made or act is to be done shall be calculated by excluding the day on which the period commences and including the day which ends the period and by extending the period to the next Business Day following if the last day of the period is not a Business Day.

1.3 Regulatory Matters

In the event of any conflict between any approval or direction or other requirement of the City of Ottawa and Holdco or a Subsidiary under this Declaration and any decision, order or policy of any Regulator, the decision, order or policy of the Regulator shall govern and Holdco and the Subsidiaries will at all times comply with any decision, order or policy of the Regulator whether or not an approval or direction has first been given in respect thereof by the City of Ottawa under this Declaration. For greater certainty, Holdco and the Subsidiaries will not seek any order from any Regulator for any matter that would require the approval of the City of Ottawa under this Declaration without first giving notice of their intention to seek such an order to the City of Ottawa.

## ARTICLE 2
## BUSINESS OF HOLDCO

2.1 Permitted Business Activities

Subject to its compliance with the *Energy Competition Act, 1998*, Holdco, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) Transmitting and distributing electricity;

(b) providing the standard supply service of electricity to Persons connected to the distribution system of Holdco or a Subsidiary;

(c) owning, managing, operating and having an ownership interest in electricity generation facilities;

(d) providing meter installation, repair, calibration and reading services;

(e) providing energy-related products and services;

(f) providing services related to the promotion of energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources and services to assist the Government of Ontario in achieving its goals in electricity conservation;

(g) providing energy procurement and energy efficiency services;

(h) renting or selling hot water heaters;

(i) providing street lighting services;

(j) distributing gas or any other energy product which is carried through pipes or wires to the user;

(k) retailing electricity produced at a generating facility owned, operated or managed by a Subsidiary;

(l) participating in the retailing of electricity (other than as set out in paragraph (k) above) or gas on a basis that is limited to normal commercial risk and does not subject Holdco or a Subsidiary to risk created by variations in the market price of the commodity;

(m) using the real property that Holdco or a Subsidiary has the right to use for the purpose of providing telecommunications services, or entering into agreements with any Third Party, or Subsidiary, authorizing such Third Party or Subsidiary to use such real property for the purpose of providing telecommunications services;

(n) managing or operating on behalf of the City of Ottawa the provision of a public utility, water or sewage service;

(o) conducting business activities the principal purpose of which is to use more effectively the assets of a Subsidiary;any other business activities carried on by the Municipal Electric Utilities at the time the assets of the latter were transferred to Holdco and/or a Subsidiary, the principal purpose of which is to use more effectively the assets of Holdco or a Subsidiary; and

(p) subject to the restrictions set out in paragraph (l), any other business activities permitted, pursuant to provincial legislation, to be carried on by an electricity distributor or its affiliates where the voting securities carrying more than 50 per cent of the voting rights attached to the voting securities of the electricity distributor are owned directly or indirectly by a municipal corporation .

2.2 Other Business Activities with Prior Approval

Subject to compliance with the *Energy Competition Act, 1998,* and with the prior written approval of the City of Ottawa, Holdco, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) retailing electricity or gas on a basis which exposes Holdco or a Subsidiary to the risk of fluctuations in the market price of the commodity.

2.3 City of Ottawa Consent

The Board shall have the authority to prepare a business case for consideration by the City of Ottawa whether or not related to any business activity set out in section 2.2. hereof which business case shall include an assessment of whether or not the new business activity is financially viable or otherwise commercially prudent to be pursued by Holdco or a Subsidiary. Upon a review of the business case, the City of Ottawa shall advise Holdco in writing whether or not the new business activity may be pursued by Holdco or its Subsidiary.

2.4 Service Territory

Holdco shall have an objective of having electricity customers in the whole of the geographic area of the City of Ottawa receive electricity distribution services from its Subsidiary Hydro Ottawa Limited.

## ARTICLE 3
## OPERATION AND CONTROL

3.1 Number of Directors

Holdco shall be managed by the Board which shall be comprised of not less than five (5) and not more than eleven (11) directors, and which will consist of eleven (11) directors elected by the City of Ottawa, of whom:

(a) one (1) shall be the Mayor of the City of Ottawa or a member of the Council of the City of Ottawa designated by such Council in the event that such Mayor chooses not to act as a director;

(b) two other members of the Council of the City of Ottawa, until November 30, 2014 and shall be reduced to one other member of the Council of the City of Ottawa effective December 1, 2014;

(c) the Chair of the Board of Directors of Hydro Ottawa Limited (unless such office shall be held at the same time by the Chair of the Board);

(d) one shall be the President and Chief Executive Officer of Holdco; and

(e) the balance shall be External, one of whom shall become Chair of the Board.

Paragraph (c) shall be repealed effective December 1, 2014.

3.2 Governance Practices

The Board of Directors of Holdco shall prepare and make available to the City of Ottawa upon request a manual setting out its governance practices. The manual shall include a description of the roles and responsibilities of the Board of Directors, of the Chair of the Board of Directors, of individual directors and of the President and Chief Executive Officer.

3.3 Role of the Chair of the Board

The Chair of the Board of Directors shall carry out the following duties and responsibilities:

(a) provide leadership to the company and its Board of Directors;

(b) provide leadership in the good governance of the corporation;

(c) set the agenda for meetings of the Board of Directors;

(d) chair the meetings of the Board of Directors ;

(e) ensure that the Board of Directors and its committees work effectively in carrying out their responsibilities;

(f) attend to the assessment of the performance of the Board of Directors;

(g) facilitate the relationship between the Board of Directors and management;

(h) represent the company at meetings with the shareholder and to the public;

(i) attend to the evaluation of the performance of the President and Chief Executive Officer of Holdco;

(j) assist the President in the evaluation of the performance of senior management of Holdco and its subsidiaries and in the proper succession planning for the Senior Management;

(k) collaborate with the Shareholder to allow for the proper succession planning for the Board of Directors; and

(l) carry out such other functions and responsibilities as may be determined by the Board of Directors.

3.4 Committees

The Board may appoint one or more committees which shall have such powers as may be assigned by the Board. The Board may appoint additional members of a committee from outside the Board for their particular expertise, but a majority of the members of committees with responsibilities relating to the operations of Holdco shall be members of the Board.

3.5 Nominating Committee

The City of Ottawa shall consider candidates nominated by the Nominating Committee, being a Committee established to assist in the selection of directors of Holdco and its wholly-owned Subsidiaries, but shall not be obliged to select such candidates. It is expected that the Nominating Committee will develop a process to identify and evaluate potential Board candidates in order to recommend a slate of qualified candidates to the City of Ottawa The Nominating Committee shall utilize the services of a placement service to search for members of the Board.

3.6 Criteria For Selection of Directors

The process used by the Nominating Committee shall be designed to ensure that each director satisfies the following criteria:

(a) demonstrates integrity and high ethical standards;

(b) has career experience and expertise relevant to Holdco's business purposes, financial responsibilities and risk profile;

(c) demonstrates an appreciation of the fiduciary duties of a Director;

(d) demonstrates well-developed listening, communicating and influencing skills;

(e) demonstrates an interest in and a commitment to devote the time necessary so that the individual Directors can actively participate in Board and Committee discussions and debate;

(f) demonstrates an understanding of the role of Hydro Ottawa as a service to local ratepayers; and

(g) demonstrates an understanding of the role of Hydro Ottawa as an asset of taxpayers;

The process used by the Nominating Committee shall also be designed to maintain a Board having the following competencies among one or more directors:

(a) strong business background;

(b) strong financial background including financial accreditation;

(c) industry sector experience in the areas of business of the Subsidiary companies;

(d) strategic planning and corporate stewardship experience;

(e) competitive business experience;

(f) an awareness of the needs of the Corporation's customers;

(g) public or private market financing experience; and

(h) board experience.

3.7 Term of Office

The term of office for a director shall be:

(a) In the case of a director who is the Mayor of the City, or City Council's designee, as the case may be, for a term which ends on the earlier of: (i) the date on which the term of office of such Mayor ends; or (ii) the date on which his or her successor takes office;

(b) In the case of the director who is the President and Chief Executive Officer of Holdco, for so long as the director holds such office;

(c) In the case of members of the Council of the City of Ottawa other than the Mayor, for the balance of the term for which the member of Council has been elected and

(d) In the case of any other directors, for such terms, which will be staggered, as may, from time to time, be provided in the by-laws of Holdco.

Any director may stand for re-election to the Board at the expiry of his or her term, subject to any limitations as may, from time to time, be provided in the by-laws of Holdco.

3.8 Remuneration

The remuneration of the members of the Board or the board of directors of a Subsidiary for their respective services as directors will be as determined by the City of Ottawa from time to time. For greater certainty, only one annual stipend will be paid where an individual is a director of both Holdco and a Subsidiary. Notwithstanding the foregoing:

(a) the directors who are members of the Council of the City of Ottawa (including the Mayor) will receive no remuneration; and
(b) the President and Chief Executive Officer of Holdco will receive no remuneration in his or her capacity as director,

although the individuals described in paragraphs (a) and (b) will, along with all other directors, be reimbursed by Holdco for their out-of-pocket expenses upon presentation of supporting receipts therefor.

The Board of Directors shall review every other year the remuneration paid to members of the Board of Directors of Holdco and its Subsidiaries (including the Chair) and bring forward recommendations to the City of Ottawa for consideration in connection with the presentation of the financial statements for such year.

No amount shall be paid to the Chair, directors, members of their immediate families or entities in which they have a substantive ownership interest over and above the remuneration for directors determined by the City of Ottawa from time to time.

3.9 Vacancies

If a member of the Board ceases to be a director for any reason, the City of Ottawa will fill the vacancy created thereby as soon as reasonably possible having regard to the provisions of section 3.1. If a member of the board of directors of a Subsidiary ceases to be a director for any reason, Holdco will cause the vacancy to be filled by another director as soon as reasonably possible.

## ARTICLE 4
## SHAREHOLDER MATTERS

4.1 Shareholder Approval under the Act

In accordance with the provisions of the Act, Holdco will not, without the prior written approval of the City of Ottawa:

(a) amend its articles or make, amend or repeal any by-law;

(b) amalgamate (except for an amalgamation with one or more Subsidiaries), apply to continue as a body corporate under the laws of another jurisdiction, merge, consolidate or reorganize, or approve or effect any plan of arrangement, in each case whether statutory or otherwise;

(c) take or institute proceedings for any winding-up, arrangement, reorganization or dissolution;

(d) create new classes of shares or reorganize, consolidate, subdivide or otherwise change its outstanding securities;

(e) change its auditor;

(f) make any change to the number of directors comprising the Board; or

(g) enter into any other transaction or take any other action that requires shareholder approval pursuant to the Act.

4.2 Additional Matters Requiring Shareholder Consent

The powers of the Board, including without limitation any committee thereof, from time to time are hereby restricted, in part, such that Holdco shall not without the prior written approval of the City of Ottawa:

(a) make any change in the issued capital of Holdco;

(b) enter into any agreement or make any offer or grant any right capable of becoming an agreement to allot or issue any shares of Holdco;

(c) permit the ratio of consolidated funded obligations to total consolidated capitalization of Holdco to exceed 75 percent, as calculated in accordance with market standard practice for local distribution utilities in the Province of Ontario;

(d) make directly or indirectly loans or advances in excess of fifty thousand dollars ($50,000) to any Person, other than a Subsidiary;

(e) give security for or guarantee debts in excess of fifty thousand dollars ($50,000) of any Person, other than a Subsidiary;

(f) declare any dividend prior to consultation with the City or any dividend which is inconsistent with the dividend policy communicated, from time to time in writing, by the City of Ottawa to the Board;

(g) appoint any auditor to fill any vacancy in the position of auditor which may occur during a year;

(h) appoint any director to fill any vacancy in the position of director of the Board or director of the board of directors of Subsidiary directly or indirectly wholly owned by the City of Ottawa, as contemplated by section 3.5 hereof;

(j) establish any financial year end of Holdco which is not December 31; or

(k) sell or otherwise dispose of, by conveyance, transfer, lease, sale and leaseback or other transaction, ten percent (10%) or more of its assets or undertaking,

4.3 Liability of the City of Ottawa

In the exercise of the rights, duties and powers assumed and transferred under this Declaration, the City of Ottawa, as the sole shareholder of Holdco, shall be subject to the same obligations and liabilities to which the Board would otherwise have been subject if this Declaration had not been made and the Board is hereby wholly relieved of all powers, duties and liabilities as directors of Holdco to the extent that the City of Ottawa is subject thereto.

4.4 Residual Power of Boards

Without restricting the application of sections 4.1 and 4.2 hereof, the Board and the boards of directors of a Subsidiary shall have, subject to the Act and this Declaration, the full authority to manage the business and affairs of Holdco and a Subsidiary, respectively, including the authority to develop and recommend to the City of Ottawa decisions with respect to any of the matters specified in sections 4.1 and 4.2 hereof.

4.5 City of Ottawa Power to Consent

The rights, powers and duties vested in the City of Ottawa pursuant to the provisions of this Declaration shall be exercised by or pursuant to a resolution or by-law of the City of Ottawa.

## ARTICLE 5
## REPORTING TO CITY OF OTTAWA

5.1 Reports

Holdco will report to the City of Ottawa on any and all matters as requested by the City of Ottawa from time to time including reports relating to a Subsidiary. Without limiting the foregoing, Holdco shall provide, in a timely manner, to the City of Ottawa an annual financial report containing such financial and other information as the City of Ottawa may reasonably request and which information Holdco is legally entitled to provide. Holdco shall provide to the City of Ottawa a report of material facts and material changes as they occur and shall be guided by securities laws applicable to publicly traded corporations when assessing the extent and timing of such disclosure.

## ARTICLE 6
## GENERAL PROVISIONS

6.1 Reference on Certificates

Holdco shall cause a reference to this Declaration to be noted conspicuously on every share certificate issued by Holdco. Holdco shall cause each Subsidiary to ensure that a reference to the Declaration delivered to it pursuant to section 6.4 hereof is noted conspicuously on every share certificate issued by such Subsidiary.

6.2 Termination

This Declaration shall be effective as of the date hereof and shall continue in full force and effect until the City of Ottawa has given written notice to the Board of the revocation and termination of this Declaration.

6.3 Amendment of Declaration

This Declaration may be amended by the City of Ottawa from time to time as circumstances may require and the City of Ottawa will consult with the Board prior to completing any amendments and will promptly provide the Board with copies of such amendments.

6.4 Revocation of Previous Declarations

The Declaration dated June 29, 2006 passed by the City of Ottawa is hereby revoked and replaced by this Declaration.

6.5 Governing Law

This Declaration shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

6.6 Effective Date

This Declaration shall be effective as of and from July 1, 2014, except as otherwise expressly provided.

**IN WITNESS WHEREOF**, the City of Ottawa has executed this Declaration as a unanimous shareholder agreement pursuant to subsections 108(2) and 108(3) of the Act.

Approved for Execution

Per City Solicitor

**CITY OF OTTAWA**
Per:

By: ______________________

Name: Jim Watson
Title: Mayor

By: ______________________

Name: M. Rick O'Connor
Title: City Clerk and Solicitor

**SHAREHOLDER DECLARATION** dated the 28th day of August 2014.

BY: **HYDRO OTTAWA HOLDING INC./SOCIÉTÉ DE PORTEFEUILLE D'HYDRO OTTAWA INC.**
A corporation incorporated under
The laws of the Province of Ontario
**("Holdco").**

**WHEREAS** subsection 108(2) of the *Ontario Business Corporations Act* permits all of the shareholders of a corporation to enter into a unanimous shareholder agreement;

**AND WHEREAS** pursuant to subsection 108(3) of such Act, a written declaration by a sole shareholder of a corporation that restricts in whole or in part the powers of the directors to manage or supervise the management of the business and affairs of the corporation is deemed to be a unanimous shareholder agreement;

**AND WHEREAS** pursuant to subsection 108(5) of such Act, to the extent that a unanimous shareholder agreement restricts the discretion or powers of the directors of a corporation to manage or supervise the management of the business and affairs of a corporation, a shareholder who is a party to the unanimous shareholder agreement assumes such powers and the related duties and liabilities and the directors are thereby relieved of their duties and liabilities;

**AND WHEREAS** Holdco is the registered and beneficial owner of all the issued and outstanding shares of Hydro Ottawa Limited/Hydro Ottawa Limitée and desires to make this Declaration with the intent that to the extent that it restricts the discretion and powers of the directors of Hydro Ottawa Limited/Hydro Ottawa Limitée, it shall constitute a unanimous shareholder agreement with respect to only those restrictions;

**AND WHEREAS** Holdco, together with its subsidiaries Hydro Ottawa Limited/Hydro Ottawa Limitée and Energy Ottawa Inc./Énergie Ottawa Inc., are the successors to the businesses formerly carried on by the Municipal Electric Utilities (as herein defined);

**AND WHEREAS** Holdco wishes that this declaration show that it is an objective of Hydro Ottawa Limited to provide electricity distribution services to all customers in the geographic area of the City of Ottawa;

**AND WHEREAS** Holdco wishes to establish certain principles of governance and other fundamental principles and policies relating to Hydro Ottawa Limited/Hydro Ottawa Limitée and its subsidiaries;

**NOW THEREFORE**, Holdco hereby declares as follows:

## ARTICLE I
## INTERPRETATION

1.1 Definitions

In this Declaration the following terms will have the meanings set out below:

**"Act"** means the Ontario *Business Corporations Act*, as now enacted or as the same may from time to time be amended, re-enacted or replaced;

**"Affiliate"** means a Body Corporate that is affiliated with Hydro Ottawa Limited as such relationship is defined in the Act;

**"Board"** means the board of directors of Hydro Ottawa Limited;

**"Body Corporate"** means a firm, partnership, unincorporated association, joint venture, corporation, bank, trust, pension fund, union, governmental agency, board, tribunal, ministry of commission or other legal entity of any kind whatsoever, but excludes an individual or natural person;

**"Business Day"** means a day, other than a Saturday or Sunday, on which the principal commercial banks located at Ottawa, Ontario, are open for business during normal banking hours;

**"External"** means, with respect to a member of the Board, (a) an individual who is not the Mayor, a councillor or employee of the City; or (b) an individual who is not an officer and employee of Hydro Ottawa Limited or any Affiliate;

**"Hydro Ottawa Limited"** means Hydro Ottawa Limited/Hydro Ottawa Limitée, a corporation incorporated under the laws of Ontario;

**"Municipal Electric Utilities"** means collectively The Hydro-Electric Commission of the City of Ottawa, the Hydro-Electric Commission of the City of Nepean, The Hydro-Electric Commission of The City of Kanata, The Hydro-Electric Commission of the City of Gloucester and Goulbourn Hydro-Electric Commission;

**"Person"** means an individual, a natural person or a Body Corporate;

**"Regulator"** means the Ontario Energy Board, the Independent Electricity System Operator, the Ontario Power Authority or any other governmental or regulatory authority having jurisdiction over Hydro Ottawa Limited or a Subsidiary;

**"Subsidiary"** means, any body corporate, the incorporation of which has been approved by Holdco as contemplated by subsection 4.2(a) hereof, of which more than 50% of its outstanding securities of any class carrying exercisable voting rights are beneficially owned, directly or indirectly, by Hydro Ottawa Limited, and includes any Body Corporate in like relation to a Subsidiary;

**"Third Party"** means a person who deals at arm's length (as interpreted by subsection 251 (1) of the *Income Tax Act* (Canada) with Hydro Ottawa Limited;

1.2 Calculation of Time

In this Declaration, unless otherwise specified, time periods within or following which any payment is to be made or act is to be done shall be calculated by excluding the day on which the period commences and including the day which ends the period and by extending the period to the next Business Day following if the last day of the period is not a Business Day.

1.3 Regulatory Matters

In the event of any conflict between any approval or direction or other requirement of Holdco and Hydro Ottawa Limited or a Subsidiary under this Declaration and any decision, order or policy of any Regulator, the decision, order or policy of the Regulator shall govern and Hydro Ottawa Limited and a Subsidiary will at all times comply with any decision, order or policy of the Regulator whether or not an approval or direction has first been given in respect thereof by Holdco under this Declaration. For greater certainty, Hydro Ottawa Limited and a Subsidiary will not seek any order from any Regulator for any matter that would require the approval of Holdco under this Declaration without first giving notice of their intention to seek such an order to Holdco.

## ARTICLE 2
## BUSINESS OF HYDRO OTTAWA LIMITED

2.1 Permitted Business Activities

Subject to its compliance with the *Energy Competition Act,* 1998, Hydro Ottawa Limited, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) Transmitting and distributing electricity;

(b) providing the standard supply service of electricity to Persons connected to the distribution system of Hydro Ottawa Limited or a Subsidiary;

(c) providing meter installation, repair, calibration and reading services;

(d) providing services related to the promotion of energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources and services to assist the Government of Ontario in achieving its goals in electricity conservation

(e) providing street lighting services;

(f) managing or operating on behalf of the City of Ottawa the provision of a public utility, water or sewage service;

(g) using the real property that Hydro Ottawa Limited or a Subsidiary has the right to use for the purpose of providing telecommunications services for the purpose of electricity transmission or distribution, or entering into agreements with any Third Party, or Subsidiary, authorizing such Third Party or Subsidiary to use such real property for the purpose of providing telecommunications services for the purpose of electricity transmission or distribution;

(h) any other business activities carried on by the Municipal Electric Utilities at the time the assets of the latter were transferred to Hydro Ottawa Limited, the principal purpose of which is to use more effectively the assets of Hydro Ottawa Limited; and

(i) any other business activities permitted, pursuant to provincial legislation, to be carried on by an electricity distributor where the voting securities carrying more than 50 per cent of the voting rights attached to the voting securities of the electricity distributor are owned directly or indirectly by a municipal corporation.

2.2 Other Business Activities with Prior Approval

Subject to compliance with the *Energy Competition Act, 1998,* and with the prior written approval of Holdco, Hydro Ottawa Limited, either directly or through a Subsidiary, may engage in any of the following business activities:

(a) business activities which Hydro Ottawa Limited is not otherwise permitted to undertake which are not prohibited by section 71 of the *Ontario Energy Board Act, 1998.*

2.3 Holdco Consent

The Board shall have the authority to prepare a business case for consideration by Holdco related to any business activity set out in section 2.2. hereof which business case shall include an assessment of whether or not the new business activity is financially viable or otherwise commercially prudent to be pursued by Hydro Ottawa Limited or a Subsidiary. Upon a review of the business case, Holdco shall advise Hydro Ottawa Limited in writing whether or not the new business activity may be pursued by Hydro Ottawa Limited or its Subsidiary.

2.4 Service Territory

Hydro Ottawa Limited shall have an objective of providing electricity distribution services to all electricity customers in the geographic area of the City of Ottawa.

## ARTICLE 3
## OPERATION AND CONTROL

3.1 Number of Directors

Until November 30, 2014, Hydro Ottawa Limited shall be managed by the Board which shall be comprised of not less than five (5) and not more than seven (7) directors, and which initially will consist of seven (7) directors elected by Holdco, of whom:

(a) one (1) shall be the President and Chief Executive Officer of Holdco;

(b) one shall be a member of the Council of the City of Ottawa;

(c) one shall be the Chair of Holdco (unless such office shall be held at the same time by the Chair of the Board)_and

(d) the balance shall be External, one of whom may become Chair of the Board.

provided that one-third of the Board shall, at all times, be independent from any Affiliate as required by the provisions of subsection 2.1.3 of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters.

Effective December 1, 2014, Hydro Ottawa Limited shall be managed by the Board which shall be comprised of not less than two (2) and not more than three (3) directors, and which initially will consist of three (3) directors elected by Holdco, of whom:

(a) one shall be the President and Chief Executive Officer of Holdco;
(b) one shall be the Chair of Holdco; and
(c) one shall be a member of the management of Hydro Ottawa Limited who is not employed by an affiliate of Hydro Ottawa Limited

For greater certainty, notwithstanding the fact that the size of the Board may vary within the range specified above, the Board shall at all times be comprised of the director holding the office referred to in paragraph (a) above.

3.2 Term of Office

The term of office for a director shall be:

(a) In the case of the director who is the President and Chief Executive Officer of Holdco for so long as the director holds such office;

(b) Until November 30, 2014,in the case of members of the Council of the City of Ottawa, for the balance of the term for which the member of Council has been elected; and

(c) In the case of any other directors, for terms, which will be staggered, as may, from time to time, be provided in the by-laws of Hydro Ottawa Limited.

Any director may stand for re-election to the Board at the expiry of his or her term.

3.3 Chair of the Board

The Chair of the Board of Hydro Ottawa Limited shall be appointed by Holdco from among the members of the Board of Directors who are also members of the Board of Directors of Holdco.

3.4 Vacancies

If a member of the Board ceases to be a director for any reason, Holdco will fill the vacancy created thereby as soon as reasonably possible having regard to the provisions of section 3.1. If a member of the board of directors of a Subsidiary ceases to be a director for any reason, Hydro Ottawa Limited will cause the vacancy to be filled by another director, to be identified by Holdco, as soon as reasonably possible.

3.5 Remuneration

The remuneration of the members of the Board or the board of directors of a Subsidiary for their respective services as directors, will be as determined by Holdco from time to time. For greater certainty, only one annual stipend will be paid where an individual is a director of both Hydro Ottawa Limited and an Affiliate. Notwithstanding the foregoing,

(a) the director who is a member of the Council of the City of Ottawa will receive no remuneration; and
(b) the President and Chief Executive Officer of Holdco will receive no remuneration in his or her capacity as director,

(c) the member of the management of Hydro Ottawa Limited who is not employed by an affiliate of Hydro Ottawa Limited will receive no remuneration in his or her capacity as a director,

although the individuals described in paragraphs (a) and (b) will, along with all other directors, be reimbursed by Hydro Ottawa Limited for their out-of-pocket expenses upon presentation of supporting receipts therefor.

No amount shall be paid to the Chair, directors, members of their immediate families or entities in which they have a substantive ownership interest over and above the remuneration for directors determined by Holdco from time to time.

## ARTICLE 4
## SHAREHOLDER MATTERS

### 4.1 Shareholder Powers

In accordance with the provisions of the Act, Hydro Ottawa Limited will not, without the prior written approval of Holdco:

(a) amend its articles or make, amend or repeal any by-law;

(b) amalgamate (except for an amalgamation with one or more Subsidiaries), apply to continue as a body corporate under the laws of another jurisdiction, merge, consolidate or reorganize, or approve or effect any plan of arrangement, in each case whether statutory or otherwise;

(c) take or institute proceedings for any winding-up, arrangement, reorganization or dissolution;

(d) create new classes of shares or reorganize, consolidate, subdivide or otherwise change its outstanding securities;

(e) change its auditor;

(f) make any change to the number of directors comprising the Board; or

enter into any other transaction or take any other action that requires shareholder approval pursuant to the Act.

4.2 Additional Matters Requiring Shareholder Consent

The powers of the Board, including without limitation any committee thereof, from time to time are herby restricted, in part, such that Hydro Ottawa Limited shall not without the prior written approval of Holdco:

(a) cause a Subsidiary to be incorporated;

(b) make any change in the issued capital of Hydro Ottawa Limited;

(c) enter into any agreement or make any offer or grant any right capable of becoming an agreement to allot or issue any shares of Hydro Ottawa Limited;

(d) give shareholder approval, as shareholder of a Subsidiary, in respect of any matter which shareholder approval for a Subsidiary is required;

(e) implement a business plan other than a business plan approved by Holdco;

(f) incur operating or capital expenditures that exceed the budget for Hydro Ottawa Limited approved by Holdco;

(g) submit an application to a Regulator for the approval of rates to be charged by Hydro Ottawa Limited that seeks a rate of return on equity other than the rate approved by Holdco;

(h) borrow any money on the credit of Hydro Ottawa Limited other than from Holdco;

(i) grant any security or create an encumbrance on the assets of Hydro Ottawa Limited;

(j) make directly or indirectly loans or advances except advances made to employees to defray expenses to be incurred in the course of the business of Hydro Ottawa Limited;

(k) give security for or guarantee debts;

(l) make donations or contributions to any Person contrary to policies established by Holdco;

(m) permit any conduct contrary to codes of conduct or ethical standards established by Holdco applicable to directors, officers, employees, contractors or other representatives of Hydro Ottawa Limited;

(m.1) adopt any governance practices applicable to directors of Hydro Ottawa Limited other than governance practices established by Holdco;

(n) make any payment of remuneration to officers or employees of Hydro Ottawa Limited in any form in excess of guidelines or directives established by Holdco;

(o) declare any dividend prior to consultation with Holdco or any dividend which is inconsistent with the dividend policy communicated, from time to time in writing, by Holdco to the Board;

(p) appoint any auditor to fill any vacancy in the position of auditor which may occur during a year;

(q) appoint any director to fill any vacancy in the position of director, as contemplated by section 3.4 hereof;

(r) enter into any partnership or any arrangement for the sharing of profits, union of interests, joint venture or reciprocal concession with any Person; and

(s) establish any financial year end of Hydro Ottawa Limited which is not December 31;

4.3 Liability of Holdco

In the exercise of the rights, duties and powers assumed and transferred under this Declaration, Holdco, as the sole shareholder of Hydro Ottawa Limited, shall be subject to the same obligations and liabilities to which the Board would otherwise have been subject if this Declaration had not been made and the Board is hereby wholly relieved of all powers, duties and liabilities as directors of Hydro Ottawa Limited to the extent Holdco is subject thereto.

4.4 Residual Power of Boards

Without restricting the application of sections 4.1 and 4.2 hereof, the Board and the boards of directors of a Subsidiary shall have, subject to the Act and this Declaration, the full authority to manage the business and affairs of Hydro Ottawa Limited and a Subsidiary, respectively, including the authority to develop and recommend to Holdco decisions with respect to any of the matters specified in sections 4.1 and 4.2 hereof.

4.5 Holdco Power to Consent

The rights, powers and duties vested in Holdco pursuant to the provisions of this Declaration shall be exercised by or pursuant to a resolution or by-law of Holdco.

## ARTICLE 5
## REPORTING TO HOLDCO

5.1 Reports

Hydro Ottawa Limited will report to Holdco on any and all matters as requested by Holdco from time to time including reports relating to a Subsidiary. Without limiting the foregoing, Hydro Ottawa Limited shall provide, in a timely manner, to Holdco, an annual financial report containing such financial and other information as Holdco may reasonably request and which information Hydro Ottawa Limited is legally entitled to provide. Hydro Ottawa Limited shall provide to Holdco a report of material facts and material changes as they occur and shall be guided by securities laws applicable to publicly traded corporations when assessing the extent and timing of such disclosure

## ARTICLE 6
## GENERAL PROVISIONS

6.1 Reference on Certificates

Hydro Ottawa Limited shall cause a reference to this Declaration to be noted conspicuously on every share certificate issued by Hydro Ottawa Limited. Hydro Ottawa Limited shall cause each Subsidiary to ensure that a reference to the Declaration delivered to it pursuant to subsection 6.4 hereof is noted conspicuously on every share certificate issued by such Subsidiary.

6.2 Termination

This Declaration shall be effective as of the date hereof and shall continue in full force and effect until Holdco has given written notice to the Board of the revocation and termination of this Declaration.

6.3 Amendment of Declaration

This Declaration may be amended from time to time by Holdco as circumstances may require and Holdco will consult with the Board prior to completing any amendments and will promptly provide the Board with copies of such amendments.

6.4 Declaration re Subsidiaries

In the event that, with the approval of Holdco contemplated by subsection 4.2(a) hereof, Hydro Ottawa Limited causes a Subsidiary to be incorporated, and so often as the same may occur, Hydro Ottawa Limited shall execute and deliver a declaration to each such Subsidiary in the form of this Declaration, mutatis mutandis.

6.5 Revocation of Previous Declarations

The Declaration dated January 17, 2002 is hereby revoked and replaced by this Declaration.

6.6 Governing Law

This Declaration shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

6.7 Effective Date

This Declaration shall be effective as of and from August 28, 2014, except as otherwise expressly provided.

**IN WITNESS WHEREOF**, Holdco has executed this Declaration as a unanimous shareholder agreement pursuant to subsections 108(2) and 108(3) of the Act.

**HYDRO OTTAWA HOLDING INC./SOCIÉTÉ DE PORTEFEUILLE D'HYDRO OTTAWA INC.**

By: ______________________

Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Approved by the Board of Directors: April 2, 2009
Revised on: August 27, 2009
Revised on: November 14, 2013
Revised on: August 28, 2014

# <u>HYDRO OTTAWA HOLDING INC</u>

(HOHI)

**CHARTER OF THE BOARD OF DIRECTORS**

## 1. PRIMARY ROLE OF THE BOARD

"HOHI" means "Hydro Ottawa Holding Inc.", a corporation existing under the Ontario Business Corporations Act.

The Board of Directors (the "Board") of "HOHI" is appointed by the City of Ottawa (the sole Shareholder of HOHI) and is charged with the careful and responsible management of HOHI and, subject to the provisions of the shareholder declaration, *<u>is the highest decision making authority within the organization</u>*. This responsibility of the Board consists primarily of managing or supervising those who manage the business and affairs of HOHI. As such, the overarching role of the Board of Directors focuses on ***governance and stewardship*** rather than on running the day-to-day operations of HOHI – the latter of which is the responsibility of management. The Board is further authorized to delegate to an officer or officers of HOHI certain powers to manage the business and affairs of HOHI. As such,

a) the Board delegates to the Chief Executive Officer of HOHI (the "CEO") the powers and authority to manage the business and affairs of HOHI; and

b) the Board assumes the role of supervising the CEO's management of the business and affairs of HOHI (the "Supervisory Role").

The governance goal of the Board of Directors is to enhance executive decision making for the purpose of improving the performance of the organization. Accordingly, every member of the Board (a "Director") must, in discharging his or her Supervisory Role and other responsibilities,

c) act honestly and in good faith ***<u>with a view to the best interests of HOHI</u>***; and

d) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Board of Directors is accountable to the Corporation's Shareholder.

## 2. COMPOSITION

The Board of HOHI shall be appointed by the City of Ottawa and shall be comprised of not less than five (5) and not more than eleven (11) directors, and which will consist of eleven (11) directors of whom:

a) one (1) shall be the Mayor of the City of Ottawa or a member of the Council of the City of Ottawa designated by such Council in the event that such Mayor chooses not to act as a director;

b) two other members of the Council of the City of Ottawa until November 30, 2014 and shall be reduced to one other member of the Council of the City of Ottawa effective December 1, 2014;

c) the Chair of the Board of Directors of Hydro Ottawa Limited (unless such office shall be held at the same time by the Chair of the Board);

d) the President and Chief Executive Officer of HOHI; and

e) all other directors shall be External, one of whom shall become Chair of the Board.

**Paragraph c) shall be repealed effective December 1, 2014.**

3. **THE SUPERVISORY ROLE**

No provision of this Charter is intended to or may be construed to impose on the Board of Directors or any member thereof any duties, standard of care or liabilities in any way more onerous or extensive than those otherwise existing at law. In particular, to the extent that HOHI, acting as a shareholder, has not restricted the discretion or powers of the directors of an affiliated or subsidiary corporation to manage or supervise the management of its business and affairs, the Board of Directors and any member thereof shall not be considered to have assumed any duties, standard of care or liabilities in respect of the management or supervision of the management of the affairs of such affiliated or subsidiary corporation.

Without limiting the scope or nature of the Supervisory Role, the Board acknowledges and accepts that the Supervisory Role includes the following obligations and responsibilities of the Board:

**3.1 Financial Reporting**

a) The Board must gain and maintain reasonable assurance that HOHI meets all financial reporting and disclosure obligations imposed on HOHI by applicable laws, regulations, rules, policies and other requirements relating to financial reporting and disclosure promulgated by governments and regulatory agencies ("Financial Reporting Obligations"). The Board shall satisfy itself as to the quality and integrity of financial statements, internal controls, information systems and disclosure controls.

The Board recognizes that it has the responsibility to review and provide guidance to Management about:

i. financial strategies;
ii. capital and debt structures
iii. proposed mergers, acquisitions, divestitures and strategic investments;
iv. policies relating to financial management, including cash flow management, working capital and dividend distributions;
v. financial risk, including relevant policies, risk management and insurance; and
vi. other transactions or financial issues that management desires to have reviewed by the Board.

The Board must also gain reasonable assurance that:

1. HOHI's annual and interim financial statements present fairly HOHI's financial position, the results of its operations and its cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as well as certain industry related regulatory requirements;

2. HOHI's annual financial statements are audited and reported on by a reputable firm of chartered accountants (the "external auditor") which is objective and independent; and

3. Material financial information concerning HOHI is disseminated to its sole Shareholder in a timely manner and all financial information concerning HOHI which is disseminated to the Shareholder is accurate, complete and fairly presented.

b) The Board must also:

1. appoint and maintain an audit committee (the "Audit Committee") to assist the Board in discharging its responsibility to gain reasonable assurance that HOHI meets the Financial Reporting Obligations;

2. nominate a firm of chartered accountants for appointment by the Shareholder of HOHI as the external auditor of HOHI and its subsidiaries;

3. fix the compensation of the external auditor;

4. adopt policies governing HOHI's hiring of partners, employees and former partners and employees of the present and any former external auditor; and

5. approve the payment of dividends to the Shareholder in compliance with legal requirements and requirements of the Shareholder dividend policies.

**3.2 Strategic Planning**

a) The Board, in conjunction with the CEO, must develop a statement of the strategy which HOHI intends to pursue in carrying on business (the "Strategic Plan") which includes: (1) determining those long-term goals (i.e. mission, vision and values) and objectives which reflect an organization's sources of competitive advantage and which address important stakeholder needs; and (2) identifying the scope (or domain) of business activities within which those goals and objectives are to be achieved.

b) If at any time the Board is of the opinion that the then-existing Strategic Plan is no longer appropriate, the Board – in conjunction with the CEO - must develop a revised Strategic Plan.

**c)** After the Board has approved the Strategic Plan, the Board must monitor on an ongoing basis HOHI's implementation of the Strategic Plan and HOHI's progress toward achieving the Strategic Plan.

### 3.3 Business Planning

a) The Board must review and consider for approval the Business Plans of HOHI and its subsidiaries as presented by the CEO of HOHI.

b) The Board must review and consider for approval the annual budgets of HOHI and its subsidiaries as presented by the CEO of HOHI.

c) After the Board has approved the budget of HOHI the Board must monitor its progress and achievement at each regular meeting of the HOHI Board.

### 3.4 Risk Management

The Board must gain and maintain reasonable assurance that the risks confronting HOHI ("Risks") are identified, monitored and managed by the senior management of HOHI ("Management") (Note: Senior management is defined as being comprised of the CEO and those reporting directly to the CEO.)

In particular, the Board must gain and maintain reasonable assurance that:

a) Management has identified the most significant Risks currently confronting HOHI;

b) New significant Risks which confront HOHI will be identified in a timely manner and brought to the attention of the Board;

c) appropriate risk assessment processes to identify, assess and manage significant risks are implemented; and

d) Management directly and effectively monitors and manages HOHI's significant risks.

### 3.5 Human Resources

**a)** The Board must gain and maintain reasonable assurance that there exists within HOHI and its subsidiaries effective human resource policies and practices to enable HOHI to attract and retain the people <u>required by HOHI to meet the Strategic Plan</u>. In particular, the Board must annually gain and maintain reasonable assurance that:

1. HOHI's overall compensation philosophy for Management balances the objectives of (i) attracting and retaining highly competent managers, (ii) appropriately and fairly rewarding strong performance by managers, (iii) maintaining HOHI's employee costs at competitive levels, and (iv) linking managers' compensation to the achievement of HOHI's strategic objectives;

2. HOHI establishes and maintains a succession plan which identifies the potential successors to the holders of all Management positions in HOHI; and

3. HOHI establishes and maintains effective policies and practices for training and continuously improving the skills of high-potential managers and employees; and

4. HOHI is in compliance with its approved human resources policies, procedures and guidelines as well as all applicable laws, regulations, rules, policies and other requirements of governments and regulatory agencies relating to human resources.

b) The Board must also:

1. establish and regularly review a job description for the CEO which reflects the Board's delegation to the CEO of the powers and authority to manage the business and affairs of HOHI;

2. establish and execute processes for the recruitment, selection, motivation, evaluation and compensation of the CEO which will enable HOHI to achieve the Strategic Plan;

3. establish and approve the terms and conditions of the CEO's employment by HOHI;

4. Establish and approve a formal process for annually assessing the performance of the CEO; and

5. discharge the CEO when the Board believes he or she is no longer capable of managing the business and affairs of HOHI.

The Board may delegate to a Board committee (the "Governance and Management Resources Committee" or "GMRC") the authority to perform any of the tasks (a1) through (b5) in this section and to make recommendations to the Board concerning them.

**3.6 Pension Governance**

The Board must satisfy itself as to the oversight and governance of, and approve all material amendments to, any and all pension plans sponsored by the Corporation and its subsidiaries. In particular, the Board must annually gain and maintain reasonable assurance that

a) Appropriate pension plan governance structures are in place related to its obligations as plan sponsor and administrator in accordance with applicable legislation, regulations and industry guidelines;
b) Mandates regarding pension plan and fund administration are clearly described for the board, relevant committee(s), pension fund agents and trustees and other participants in the governance process;
c) Measures to implement the mandates are established and the plan governance structure is reviewed on a regular basis;
d) Documentation that evidences implementation of plan administration is developed and maintained;
e) The board or its relevant committee(s) receives and considers regular reports from the responsible executive involved in plan administration; and

f) The operation of the plan is made transparent through communication to plan members.

Subject to applicable law, the Board may delegate to a committee or committees appointed by the Board, various aspects of the operation and administration of any and all pension plans sponsored by the Corporation and its subsidiaries.

**3.7 Code of Conduct, Compliance and Communication**

The Board must:

a) establish, maintain and monitor compliance with a written code of business conduct and ethics (the “Code”) applicable to Directors, Officers and employees of the Corporation. The Code must constitute standards reasonably designed to promote integrity, the protection and proper use of assets, avoid conflicts of interest and both deter and report wrongdoing;

b) require every HOHI and subsidiary Director, member of Management and those in key financial positions to annually sign an attestation acknowledging acceptance of the Code of Conduct;

c) gain reasonable assurance that every employee of HOHI and its subsidiaries receives training on the Code of Conduct and signs an attestation acknowledging when they received it;

d) require waivers of compliance with the Code which shall be granted only by the Board or an appropriately empowered Board committee;

e) gain and maintain reasonable assurance as to the integrity, comprehensiveness and effectiveness of those elements of HOHI (including its resources, management information systems, processes, culture, structure and tasks) which, taken together (the “Internal Controls”), support HOHI’s personnel in meeting HOHI’s objectives and obligations, including the Financial Reporting Obligations;

f) adopt an external communications policy for HOHI and its subsidiaries;

g) gain and maintain reasonable assurance (i) as to the integrity of the CEO and the other members of Management, and (ii) that the CEO and the other members of Management create and maintain a culture of integrity throughout HOHI; and

h) gain and maintain reasonable assurance that Management, the Board, and the Corporation comply with the applicable laws, regulations, rules, policies and other requirements promulgated by legislation and applicable industry regulation and that appropriate policies and processes exist for compliance with environmental, health and safety laws and regulations.

The Board may delegate to a Board committee (the “Governance and Management Resources Committee” or “GMRC”) the authority to perform any of the tasks (a) through (h) in this section and to make recommendations to the Board concerning them.

## 4. GOVERNANCE

### 4.1 Governance Structures and Practices

**a)** The Board must gain and maintain reasonable assurance that the governance structures and practices of HOHI and its subsidiaries comply with the requirements of the Shareholder Declaration and enable the HOHI Board to discharge the Board's responsibilities in a highly effective manner. In particular, the Board must gain and maintain reasonable assurance that:

1. With the exception of the President and CEO, all HOHI Directors are independent. For the purposes of this charter, a Director is independent if the Director has no relationship with HOHI which, in the view of the Board, could reasonably be expected to interfere with the exercise of the Director's independent judgment;

2. the Chair of the Board is an External Director and not a member of Management;

3. every Board committee is comprised of a majority of independent directors;

4. the Board, as a whole, possesses the competencies and skills required to enable the Board to discharge the Supervisory Role and the Board's other responsibilities;

5. the number of Directors constituting the Board facilitates effective decision-making by the Board; and

6. as a part, or by means, of regularly scheduled meetings, the Board holds separate meetings of the Directors at which no member of Management is present.

b) The Board must also:

1. develop HOHI's approach to corporate governance, including a set of governance principles and guidelines specifically applicable to HOHI;

2. appoint and maintain any committees of the Board as the Board deems necessary in discharging its responsibilities;

3. develop and maintain written charters for the Board and each committee of the Board as well as written position descriptions for the individual Director and all Board leadership positions;

4. develop and implement processes for regularly assessing the effectiveness of the Board, each Board committee, the individual Directors and all Board leadership positions taking into account their respective charters and position descriptions;

5. identify the skills and knowledge required for directors and provide an orientation and continuing education process directed at enabling Directors to fully understand the nature and operation of HOHI's business(es) and affairs as well as the individual Director's and the Board's roles and responsibilities for the successful performance of HOHI; and

6. establish and maintain a process, that includes Board approval, by which any Director may, at the expense of HOHI, engage independent counsel or other advisors to provide advice to the

Director with respect to the Director's liabilities or the discharge of his or her responsibilities as a Director; and

The Board may delegate to a Board committee (the "Governance and Management Resources Committee" or "GMRC") the responsibility to perform any of the tasks (1) through (6) in this section and to make recommendations to the Board concerning them.

**4.2 Governance Principles**

The Board must use its best efforts to establish and sustain amongst all Directors governance principles which incorporate the following:

**a)** acceptance of the Board's accountability for HOHI's performance;

**b)** recognizing the responsibility to act in the best interest of the Corporation;

**c)** recognizing, that the Board as a whole, through the Chair, has the authority to direct the actions of the CEO and Management and that no individual director has the authority to direct such actions unless specifically authorized by the Board to do so;

**d)** recognizing that directors must comply with the Code of Business Conduct and that personal and external interests are not to be permitted to conflict with the interests of the Corporation;

**e)** recognizing the importance of solidarity ("the board speaks only with one voice") once decisions are taken;

**f)** recognizing that no member of the Board has the authority to speak or act on behalf of the Corporation unless specifically authorized to do so; and

**g)** respecting and preserving the confidentiality of corporate information.

Approved by the Board:
April 2, 2009
Revised on: August 27, 2009
Revised on: November 14, 2013
Revised on: August 28, 2014

# CHARTER OF THE BOARD OF DIRECTORS

## HYDRO OTTAWA LIMITED
(HOL)

## 1. Primary Role Of The Board

"HOL" means "Hydro Ottawa Limited", a corporation existing under the Ontario Business Corporations Act.

The Board of Directors (the "Board") of "HOL" is appointed by the City of Ottawa, on behalf of Hydro Ottawa Holding Inc (the sole Shareholder of HOL), and is charged with the supervision of the business activities of HOL. As such, the overarching role of the Board of Directors focuses on ***governance and stewardship*** rather than on running the day-to-day operations of HOL – the latter of which is the responsibility of management. The Board is further authorized to delegate to an officer or officers of HOL certain powers to manage the business and affairs of HOL. As such,

a) the Board delegates to the Chief Executive Officer of HOL (the "CEO") the powers and authority to manage the business and affairs of HOL; and

b) the Board assumes the role of supervising the CEO's management of the business and affairs of HOL (the "Supervisory Role").

The governance goal of the Board of Directors is to enhance executive decision making for the purpose of improving the performance of the organization. Accordingly, every member of the Board (a "Director") must, in discharging his or her Supervisory Role and other responsibilities,

c) act honestly and in good faith ***with a view to the best interests of HOL***; and

d) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Board of Directors is accountable to the Corporation's sole Shareholder, Hydro Ottawa Holding Inc. ("HOHI")

## 2. Composition

The Board of Hydro HOL shall be appointed by the City of Ottawa and, until November 30, 2014, shall be comprised of not less than five (5) and not more than seven (7) directors of whom:

a) one shall be the President and Chief Executive Officer of HOHI;

b) one shall be a member of Council of the City of Ottawa;

c) one shall be the Chair of HOHI; and

d) all other directors shall be External, independent Directors, one of whom may become Chair of the HOL Board.

Effective December 1, 2014, the Board of Hydro Ottawa Limited shall be comprised of not less than two (2) and not more than three (3) directors, and which initially will consist of three (3) directors elected by Holdco, of whom:

(a) one shall be the President and Chief Executive Officer of Holdco;
(b) one shall be the Chair of Holdco; and
(c) one shall be a member of the management of Hydro Ottawa Limited who is not employed by an affiliate of Hydro Ottawa Limited.

One-third of the Board shall, at all times, be independent from any Affiliate as required by the provisions of subsection 2.1.3 of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters.

For greater certainty, notwithstanding the fact that the size of the Board may vary within the range specified above, the Board shall at all times be comprised of the director holding the office referred to in paragraph (a) above.

## 3. <u>The Supervisory Role</u>

Without limiting the scope or nature of the Supervisory Role, the Board acknowledges and accepts that the Supervisory Role includes the following obligations and responsibilities of the Board:

### Financial Reporting and Disclosure

The Board must gain and maintain reasonable assurance that HOL meets all financial reporting and disclosure obligations imposed on HOL by applicable law and applicable regulations, rules, policies and other requirements relating to financial reporting and disclosure promulgated by governments and regulatory agencies ("Financial Reporting Obligations"). The Board shall satisfy itself as to the integrity of financial statements, internal controls, information systems and disclosure controls.

The Board recognizes that it has the responsibility:

a) To ensure that HOL's annual and interim financial statements present fairly HOL's financial position, the results of its operations and its cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as well as certain industry related regulatory requirements;

b) To ensure that HOL's annual financial statements are audited and reported on by a firm of chartered accountants (the "external auditor") which is objective and independent;

c) To review and approve the financial statements of HOL;

d) To approve the payment of dividends to HOHI in compliance with legal requirements and requirements of the shareholder dividend policy; and

e) To ensure that material financial information concerning HOL is disseminated to its sole Shareholder, HOHI, in a timely manner and all financial information concerning HOL which is disseminated to the Shareholder must be accurate, complete and fairly presented.

**Business Planning**

a) The Board, in conjunction with the CEO and subject to HOHI direction and approval, must develop a business plan which indicates the over-arching strategy that HOL intends to pursue in carrying on business. The Business Plan must align to the enterprise strategic plan established by HOHI.

b) The Board must regularly review the integrity of the business plan and, if at any time the HOL Board is of the opinion that the then-existing Business Plan is no longer appropriate, the Board – in conjunction with the CEO - must develop a revised Business Plan.

c) After the Board has approved the Business Plan, submitted the Business Plan to HOHI and received the approval of the Business Plan by the Board of HOHI, the Board must monitor on an ongoing basis HOL's implementation of the Business Plan and HOL's progress toward achieving it.

d) The Board must annually consider for approval the budget of HOL as presented by the CEO of HOL, subject to the approval of HOHI.

e) After the Board has approved the budget, submitted the budget to HOHI and received the approval of the budget by the Board of HOHI, the Board must monitor its progress and achievement at each regular meeting of the HOL Board.

**Risk Management**

The Board must gain and maintain reasonable assurance that the risks confronting HOL ("Risks") are identified, monitored and managed by the senior management of HOL

("Management") (Note: Senior management is defined as being comprised of the CEO and those reporting directly to the CEO).

In particular, the Board must gain and maintain reasonable assurance that:

a) Management has identified the most significant Risks currently confronting HOL;

b) New significant Risks which confront HOL will be identified in a timely manner and brought to the attention of the Board;

c) ensure the implementation of appropriate risk assessment processes to identify, assess and manage significant risks are implemented; and

d) Management directly and effectively monitors and manages HOL's significant risks.

**Human Resources**

The Board must gain and maintain reasonable assurance that there exists within HOL effective human resource policies and practices to enable HOL to attract and retain the people required by HOL to meet the Business Plan and the enterprise Strategic Plan.

In particular, the Board must annually gain and maintain reasonable assurance that:

a) HOL establishes and maintains effective policies and practices for training and continuously improving the skills of high-potential managers and employees; and

b) HOL is in compliance with its approved human resources policies, procedures and guidelines as well as all applicable laws, regulations, rules, policies and other requirements of governments and regulatory agencies relating to human resources.

**Code of Conduct and Compliance**

The Board must:

a) establish, maintain and monitor compliance with the written code of business conduct and ethics (the "Code") approved by HOHI and applicable to Directors, Officers and employees of the Corporation;

b) require that every HOL Director, member of Management and those in key financial positions annually sign an attestation acknowledging acceptance of the Code of Business Conduct;

Approved by the Board:
April 2, 2009
Revised on: August 27, 2009
Revised on: November 14, 2013
Revised on: August 28, 2014

c) gain and maintain reasonable assurance that every employee of HOL receives training on the Code of Business Conduct and signs an attestation acknowledging when they receive it;

d) gain and maintain reasonable assurance (i) as to the integrity of the members of Management, and (ii) that the members of Management create and maintain a culture of integrity throughout HOL; and

e) gain and maintain reasonable assurance that Management, the Board, and the Corporation comply with the applicable laws, regulations, rules, policies and other requirements promulgated by legislation and applicable industry regulation and that appropriate policies and processes exist for compliance with environmental, health and safety laws and regulations.

## 4. Governance Practices

The Board also acknowledges and accepts the following responsibilities and obligations of the Board.

a) As a part, or by means, of regularly scheduled meetings of the Board, the Board will hold separate meetings of the Directors at which no member of Management or the general public is present;

b) The Board will provide an orientation and continuing education process directed at enabling Directors to understand fully the nature and operation of HOL's business and affairs as well as the individual Director's and the Board's roles and responsibilities for the successful performance of HOL;

c) The Board will implement processes for regularly assessing the effectiveness of the Board, any Board committee, the individual Directors and all Board leadership positions taking into account their respective charters and position descriptions; and

d) The Board will establish and maintain a process that includes Board approval, by which any Director may, at the expense of HOL, engage independent counsel or other advisors to provide advice to the Director with respect to the Director's liabilities or the discharge of his or her responsibilities as a Director.

The Board must use its best efforts to establish and sustain amongst all Directors governance principles which incorporate the following values, and convictions:

a) acceptance of the Board's accountability for HOL's performance;

b) recognizing the responsibility to act in the best interest of the Corporation;

Approved by the Board:
April 2, 2009
Revised on: August 27, 2009
Revised on: November 14, 2013
Revised on: August 28, 2014

c) recognizing that the Board as a whole, through the Chair, has the authority to direct the actions of the CEO and Management and that no individual director has the authority to direct such actions unless specifically authorized by the Board to do so;

d) recognizing that directors must comply with the Code of Business Conduct and that personal and external interests are not to be permitted to conflict with the interests of the Corporation;

e) recognizing the importance of solidarity ("the board speaks only with one voice") once decisions are taken;

f) recognizing that no member of the Board has the authority to speak or act on behalf of the Corporation unless specifically authorized to do so; and

g) respecting and preserving the confidentiality of corporate information.

Société de portefeuille Hydro Ottawa Holding Inc

Approved by the Board of Directors:
May 14, 2009
Revised on August 28, 2014:

# HYDRO OTTAWA HOLDING INC
(HOHI)

## Nominating Committee ("NC") Charter

### 1. Composition

a) The Nominating Committee ("NC") of Hydro Ottawa Holding Inc. ("HOHI") is a Board Committee which shall be comprised of up to 5 members of which:

(i) A majority shall be external directors of HOHI;
(ii) One (1) shall be the Mayor of the City of Ottawa;
(iii) Until November 30, 2014, two members shall be members of the Council of the City of Ottawa who are members of the Board of Directors of HOHI (as long as the City of Ottawa remains as the sole shareholder of HOHI) and shall be reduced to one member effective December 1, 2014 in the event the Mayor of the City of Ottawa chooses to act as a Director;
(iv) One (1) shall be the Board Chair as an *ex officio* voting member.

b) The following skill set is normally looked for in the selection of NC members:
- Previous Board experience
- Familiarity with the legal and regulatory requirements of directorships and executive human resources management
- Previous experience in the recruitment, selection, motivation, evaluation and leadership of directors and senior executives
- Excellent interpersonal and conflict resolution skills

It is not necessary for any one member of the Committee to posses all of the skill set items. However, each skill set item (and parts thereof) should be present in the NC's composition.

c) The Chair of HOHI shall recommend, for HOHI Board approval, the members to serve on the NC.
d) The Chair of the Nominating Committee shall be the Chair of the Board of Directors.

### 2. Terms of Reference

a) The purpose of the Nominating Committee is to identify and evaluate potential candidates for appointment as Directors to the Boards of HOHI and its subsidiaries.

b) The NC shall make recommendations to the Shareholder of HOHI and its subsidiaries regarding the appointment of candidates as Directors.

c) For the purpose of carrying out items (a) through (c) in this section, the NC shall:

i. review with the Board, or the GMRC, the selection criteria for the appointment of Directors to the Boards of HOHI and its subsidiaries and any suggested changes to the selection criteria set out in the Shareholder Declaration;

ii. receive from the Board, or the GMRC, any selection criteria for the appointment of Directors to the Boards of HOHI and its subsidiaries in addition to those set out in the Shareholder Declaration;

iii. develop processes to identify, evaluate and nominate potential candidates for appointment as Directors to the Boards of HOHI and its subsidiaries in accordance with the requirements of the Shareholder Declaration;

iv. have the authority, in its sole discretion, to retain such outside consultants to help the NC identify candidates and to investigate their suitability for appointment as Directors; and

v. examine and report on any other matters necessary to meet the purposes of the Committee.

## 3. Operating Principles

The NC shall fulfill its responsibilities within the context of the following principles:

a) Conduct

The NC expects its Committee members and nominees for appointment to the Board of HOHI and its subsidiaries to operate in compliance with HOHI's Code of Business Conduct and policies and with all applicable laws and regulations governing HOHI.

b) Communications

The Chair and members of the NC expect to have direct, open and frank communications throughout the year with the Board, Management and other key NC advisors as applicable.

c) Committee Expectations and Information Needs

The NC shall communicate its expectations to the Board, Management and/or Governance and Management Resources Committee ("GMRC") with respect to the nature, timing and extent of its information needs. The Committee expects that all reasonably required and available information (including minutes) relating to each matter to be dealt with by the NC at its meetings will be received from the Board, Management and/or the GMRC within a reasonable time frame in advance of each Committee meeting.

d) Reliance on Experts

In contributing to the NC's discharging of its duties under this Charter, each member of the NC shall be entitled to rely in good faith upon:

i) the reports of HOHI represented to him or her by the Board Chair, the Chair of the GMRC, an officer of HOHI or in a written report of external advisors with respect to the recruitment and selection of Board members; and

ii) any report of a lawyer, accountant, appraiser or other person whose profession lends credibility to a statement made by any such person.

e) In Camera Meetings

The members of the NC shall meet in private session as part of each meeting, (i.e., without Management present). The NC shall meet in private session as often as it deems necessary.

## 4. Operating Procedures

a) The NC shall meet as circumstances dictate to carry out the responsibilities set out in its Terms of Reference. Meetings shall be held at the call of the Chair or upon the request of two (2) members of the Committee;

b) a quorum shall be a majority of the members;

c) in the absence of the Chair, the Committee members present shall appoint an Acting Chair;

d) NC meeting agendas shall be the responsibility of the Chair of the Committee in consultation with the Board Chair, Committee members and Management.

e) To assist the NC in discharging its responsibilities, the NC may, after consultation with the Board Chair, retain at the expense of HOHI, one or more persons having special expertise that will assist the NC in discharging its responsibilities.

f) The NC shall report to the shareholders its recommendations for the appointment of directors to the Boards of Directors of HOHI and its subsidiaries.

**5. Limitations on Committee's Duties**

In contributing to the Committee's discharging of its duties under this Charter, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is to gain reasonable assurance (but not to ensure) that the nominating policies, procedures and practices of HOHI (i) are being conducted effectively and in compliance with all applicable laws, statutes and regulations; (ii) are reasonable and appropriate in the circumstances given the nature of the organization and its strategy; and (iii) are sufficiently and accurately reported upon to the Board.

Approved by the Board of Directors: May 14, 2009
Revised on: August 22, 2013
Revised: November 14, 2013
Revised: November 27, 2014

# AUDIT COMMITTEE ("AC") CHARTER

## HYDRO OTTAWA HOLDING INC
(HOHI)

## 1. Composition

a) The Audit Committee ("AC") of Hydro Ottawa Holding Inc. ("HOHI") is a Board Committee which shall be comprised of that number of Directors as shall be determined from time to time by the Board, of which:

i. A majority shall be External Directors of HOHI;
ii. One (1) shall be the Board Chair as an *ex officio* voting member; and
iii. All members of the AC shall be independent of the management of HOHI and its subsidiaries.

b) The following skill set is normally looked for in the selection of AC members:

i. All members should be *financially literate* (i.e. have the expertise and capability to read and understand the financial statements of HOHI and its related subsidiaries);
ii. One of the members shall hold a financial accreditation and that person should normally be the Chair;
iii. Previous audit committee experience;
iv. Risk management experience;
v. Mergers and acquisitions experience; and
vi. Internal control, corporate disclosure and regulatory compliance experience.

Except as specifically set out above, it is not necessary for any one member of the committee to possess all of the skill set items. However, each skill set item (or parts thereof) should be present in the AC's composition.

c) The Chair of HOHI shall recommend, for HOHI Board approval, both the members to serve on the AC and the Chair of the AC.

## 2. Terms of Reference

The AC's role is to oversee the financial affairs of HOHI (which includes its subsidiaries) and to assist the Board of HOHI and any subsidiary board(s) in monitoring the organization's financial reporting and disclosure.

Reporting by the AC will be solely to the HOHI Board. However, the two HOL Board members on the AC, along with the Chief Executive Officer and the Chief Financial Officer, will be expected to advise the HOL Board of any matters of concern raised by the AC in reviewing HOL's financial affairs.

The objective of the Board's monitoring of HOHI financial reporting and disclosure (the "Financial Reporting Objective") is to gain reasonable assurance of the following:

a) that HOHI and its subsidiaries comply with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies relating to financial reporting and disclosure;

b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in HOHI and subsidiary financial statements, are the most appropriate in the prevailing circumstances;

c) that HOHI's and its subsidiaries' interim and annual financial statements present fairly HOHI's financial position as a result of its operations in accordance with:
(i) generally accepted accounting principles ("GAAP"); and
(ii) certain industry related regulatory requirements,
and together with the annual Management Discussion and Analysis (i.e., the document containing a complete and integrated view of the organization's historical operations, prospective analysis and financial condition explaining the 'why" behind performance and prospects) constitute a fair presentation of HOHI's financial condition; and

d) that appropriate information concerning the financial position and performance of HOHI is disseminated to the Board in a timely manner.

## 3. Fundamental Activities

The Board is of the view that the Financial Reporting Objective cannot be reliably met unless the following activities are conducted effectively:

a) HOHI's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of HOHI's and its subsidiaries financial transactions;

b) HOHI's internal financial controls are regularly assessed for effectiveness and efficiency; and

c) HOHI's and its subsidiaries' interim financial results and annual financial statements are prepared promptly by management and are prepared in accordance with GAAP - as well as certain industry related regulatory requirements.

**To fulfill its roles and responsibilities, the AC shall:**

## 4. Financial Reporting

a) review HOHI's and its subsidiaries' annual financial statements with Management and the external auditors, to gain reasonable assurance that the statements are prepared in accordance with GAAP, are complete, represent fairly HOHI's financial position and performance, and together with the Management's Discussion and Analysis ensure fair presentation of the HOHI's and subsidiaries' financial condition and report thereon to the Board;

b) receive from Management a copy of the engagement letter provided to the external auditors;

c) receive from the external auditors a copy of the "Management Letter" and Management's response to it;

d) review all aspects of the annual report which pertain to the historical, current or projected financial performance of the Corporation;

e) review HOHI's consolidated interim financial results with Management to gain reasonable assurance that the statements are prepared in accordance with GAAP, are complete, represent fairly HOHI's financial position and performance, and ensure fair presentation of HOHI's consolidated financial condition and report thereon to the Board;

f) receive from Management any additional representations required by the AC;

g) satisfy itself that adequate procedures are in place for the review of HOHI's disclosure of financial information extracted or derived from HOHI's financial statements (especially ratio and trend analyses) in order to satisfy itself that such information is fairly presented and periodically assess the adequacy of these procedures; and

h) obtain summaries of complex financings and other significant transactions and other potentially difficult matters whose treatment in the annual financial statements merits advance disclosure;

## 5. Accounting Policies

a) review with Management and the external auditors the appropriateness of HOHI's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto and obtain reasonable assurance that they are presented fairly in accordance with GAAP; and

b) review major issues regarding accounting principles and financial statement presentation including any significant changes in the selection or application of accounting principles to be observed in the preparation of the accounts of HOHI and its subsidiaries;

## 6. Risk and Uncertainty

In consultation with Management, to identify the principal financial risks facing HOHI and its subsidiaries and HOHI's tolerance for financial risk and approve financial risk management policies, the AC shall gain reasonable assurance that financial risk is being effectively managed or controlled.

## 7. Compliance with Legal, Ethical and Regulatory Requirements

Obtain reasonable assurance that HOHI has implemented appropriate systems of internal control to ensure compliance with legal, ethical and regulatory requirements and that these systems are operating effectively by:

a) reviewing summaries of matters reported pursuant to the Corporation's "Business Conduct Hotline" and actions taken in relation thereto;

b) inquiring about the policies and procedures the company has in place for monitoring compliance with laws and regulations and HOHI's own code of business conduct;

c) informing senior management and external auditors which matters the AC wishes them to report should such matters come to the auditors' attention during the course of the auditors' work;

d) asking senior management to provide a summary concerning compliance and any changes in the acts or regulations governing HOHI and its subsidiaries;

e) considering whether the CFO or others should be asked to undertake special assignments to monitor compliance with regulatory requirements;

f) reviewing no less than annually the reasonableness of the expenses reimbursed to the Chair and members of the Boards; and

g) receiving no less than annually the Board Chair's oral report with respect to his/her semi-annual review of the reasonableness of expenses reimbursed to the President and Chief Executive Officer.

## 8. Internal Audit

a) assess periodically the need for internal audit function within HOHI and, if needed, is adequately staffed and effectively carried out;

b) review and recommend the internal audit charter (i.e. the terms of reference, program of audit activities and resources of the internal audit function) to ensure its primary reporting relationship to the AC;

c) review and approve any internal audit plan; and

d) review any reports and recommendations of the internal auditors and monitor the implementation of recommendations.

## 9. Financial Controls

a) review both Management's overall approach to control and the plans of the CFO and external auditors to gain reasonable assurance that the combined evaluation and testing of internal financial controls is comprehensive, coordinated and cost-effective;

b) inquire specifically about HOHI's compliance with its internal control policies and procedures; and

c) receive regular reports from Management, the external auditors and HOHI's legal advisors on all significant deviations or any indications/detections of fraud and the corrective activity undertaken in respect thereto.

## 10. Relationship with External Auditors

a) recommend to the Shareholder, through the Board, the need for the annual financial statements of HOHI to be audited by external auditors;

b) approve the compensation to be paid to the external auditor;

c) recommend to the Shareholder, through the Board, the appointment of the external auditors;

d) review the performance of the external auditors annually or more frequently as required;

e) if deemed necessary, receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by HOHI;

f) review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit and the materiality levels which the external auditors propose to employ;

g) meet with the external auditors in the absence of Management to determine, that no Management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the AC;

h) establish effective communication processes with Management and HOHI's CFO and external auditors to assist the AC in monitoring objectively the quality and effectiveness of the relationship among the external auditors, Management and the Committee;

i) oversee the work of the external auditors and the resolution of disagreements between Management and the external auditors with respect to financial reporting;

j) request that the external auditors provide to the AC, at least annually, an oral and/or written report describing the external auditors' internal quality assurance policies and procedures as well as any material issues raised in the most recent internal quality assurance reviews; and

k) approve additional engagements of the external auditors for non-audit assignments.

## 11. Other Responsibilities

a) Investigate any matters that, in the AC’s discretion, fall within the Committee’s responsibilities; and

b) Perform such other functions as may from time to time be assigned to the AC by the Board.

## 12. Operating Principles

The AC shall fulfill its responsibilities within the context of the following principles:

a) Conduct

The AC expects the Management of HOHI to operate in compliance with HOHI's Code of Business Conduct and policies; with laws and regulations governing HOHI; and to maintain strong financial reporting and control processes.

b) Communications

The Chair and members of the AC expect to have direct, open and frank communications throughout the year with Management, other Committee Chairs, the external auditors, the Chief Financial Officer ("CFO") and other key AC advisors as applicable.

c) Financial Literacy

All AC members shall have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by HOHI's financial statements.

d) Annual AC work Plan

The AC, in consultation with Management and the external auditors, shall develop and present to the Board for the Board's approval a work plan which, amongst other things, will describe the activities in which the AC will engage for the purpose of carrying out the AC's responsibilities as set out in this Charter. In addition, the AC, in consultation with Management and the external auditors, shall develop and participate in a process for review of important financial topics that have the potential to impact HOHI's financial disclosure;

e) Committee Expectations and Information Needs

The AC shall communicate its expectations to Management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that all reasonably required and available information (including minutes) relating to each matter to be dealt with by the AC at its meetings will be received from Management and the external auditors within a reasonable time frame in advance of each Committee meeting.

f) Reliance on Experts

In contributing to the AC's discharging of its responsibilities under this Charter, each member of the AC shall be entitled to rely in good faith upon:

i. The financial statements of HOHI represented to him or her by the Management of HOHI or in a written report of the external auditors to present fairly the financial position of HOHI in accordance with generally accepted accounting principles; and

ii. Any report of a lawyer, accountant, appraiser or other person whose profession lends credibility to a statement made by any such person.

g) In Camera Meetings

The members of the AC shall meet in private session and separately with the external auditors annually; and, as part of each meeting, with the AC members only (i.e., without Management present). The Committee shall meet in private session as often as it deems necessary.

h) Committee Self-Assessment

The AC shall regularly review, discuss and assess its own performance. In addition, the AC shall periodically review its role, responsibilities and terms of reference as specified in this Charter.

i) The External Auditors

The AC expects that, in discharging their responsibilities to the Board, the external auditors shall be accountable to the Board through the AC. The external auditors shall report all material issues or potentially material issues to the AC.

## 13. Operating Procedures

a) The AC shall meet at least twice annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair, or upon the request of two (2) members of the Committee or at the request of the external auditors;

b) A quorum shall be a majority of the members;

c) in the absence of the Chair, the Committee members present shall appoint an Acting Chair;

d) AC meeting agendas shall be the responsibility of the Chair of the Committee in consultation with the Board Chair, Committee members, Management and the external auditors;

e) In addition to the external auditors, the AC may, after consultation with the Chair of the Board, retain one or more persons having special expertise that will assist the AC in discharging its responsibilities; and

f) The AC, through its Chair, shall report after each Committee meeting to the Board at the Board's next regular meeting.

## 14. Limitations on the Audit Committee's Responsibilities

In contributing to the AC's discharging of its responsibilities under this Charter, each member of the AC shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the AC a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the AC's responsibilities is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the Financial Reporting Objective is being met and to enable the AC to report thereon to the Board.

Approved by the Board of Directors: May 14, 2009
Revised: November 5, 2013
Revised: November 14, 2013
Revised: November 27, 2014

# GOVERNANCE AND MANAGEMENT RESOURCES COMMITTEE ("GMRC") CHARTER

## HYDRO OTTAWA HOLDING INC.
(HOHI)

### 1. Composition

a) The Governance & Management Resources Committee ("GMRC") of Hydro Ottawa Holding Inc. is a Board Committee which shall be comprised of up to 6 members of which:

   i. A majority shall be external directors of HOHI;
   ii. One (1) shall be the Board Chair as an *ex officio* voting member; and
   iii. All members of the GMRC shall be independent of the management of HOHI and its subsidiaries;

b) The following skill set is normally looked for in the selection of GMRC members:

   i. Previous governance committee and human resources committee experience
   ii. Familiarity with the legal and regulatory requirements of directorships and executive human resources management
   iii. Previous experience in the recruitment, selection, motivation, evaluation and leadership of senior executives
   iv. General corporate human resource management expertise

   It is not necessary for any one member of the committee to possess all of the skill set items. However, each skill set item (and parts thereof) should be present in the GMRC's composition.

c) The Chair of HOHI shall recommend, for HOHI Board approval, both the members to serve on the GMRC and the Chair of the GMRC.

### 2. Terms of Reference

a) The GMRC's role is to assist the Board in monitoring both the governance and human resources structures, processes and policies of HOHI (which includes its subsidiaries).

b) Reporting by the GMRC will be solely to the HOHI Board. However, the HOL Board members on the GMRC, along with the CEO and members of senior management reporting directly to the CEO will be expected to advise the HOL Board of any matters of concern raised by the GMRC affecting HOL.

Approved by the Board of Directors: May 14, 2009
Revised: November 5, 2013
Revised: November 14, 2013
Revised: November 27, 2014

### 3. Governance Structures and Practices

**a)** The GMRC must gain and maintain reasonable assurance that the governance structures and practices of HOHI and its subsidiaries comply with the requirements of the shareholder declaration and enable the HOHI Board to discharge the Board's roles and responsibilities in a highly effective manner. In particular, the GMRC must gain and maintain reasonable assurance that:

i. With the exception of the President and CEO and members of the Council of the City of Ottawa, all HOHI Directors are independent. For the purposes of this charter, a Director is independent if the Director has no relationship with HOHI which, in the view of the Board, could reasonably be expected to interfere with the exercise of the Director's independent judgment;
ii. the Chair of the Board is an external director and not a member of Management;
iii. every Board committee is comprised of a majority of external directors;
iv. the Board, as a whole, possesses the competencies and skills required to enable the Board to discharge the its responsibilities and roles; and
v. the number of Directors constituting the Board facilitates effective decision-making by the Board.

b) The GMRC must also:

i. develop and recommend to the Board HOHI's approach to corporate governance, including a set of governance principles and guidelines specifically applicable to HOHI;
ii. review and make recommendations with respect to the Bylaws and Shareholder Declaration of HOHI;
iii. recommend the creation of any committees of the Board as the GMRC deems necessary for the Board to discharge its responsibilities;
iv. develop and maintain written Charters for the Board and each committee of the Board;
v. review and recommend the enterprise risk management charter;
vi. develop and maintain written position descriptions for the Chair of the Board, the CEO, the Chairs of Board or Standing Committees and an individual Director;
vii. for the purpose of Board and Director development (and taking into account their respective charters and position descriptions), make recommendations to the Board of Directors regarding *the process* for ongoing and regular evaluations of the Board, each Board & Standing Committee, each individual Director, the Chair of the Board and the Chairs of Board and Standing Committees;
viii. identify the skills and knowledge required for directors and provide an orientation and continuing education process directed at enabling Directors to fully understand the nature and operation of HOHI's business(es) and affairs as well as the individual Director's and the Board's roles and responsibilities for the successful performance of HOHI;
ix. establish and maintain a process, that includes Board approval, by which any Director may, at the expense of HOHI, engage independent counsel or other advisors to provide advice to the Director with respect to the Director's liabilities or the discharge of his or her roles responsibilities as a Director;
x. develop policies and procedures for communication by HOHI and its subsidiaries with the Shareholder and other stakeholders;
xi. carry out any governance process adopted by the Board of Directors; and

xii. perform such other governance functions as may, from time to time, be assigned to the GMRC by the Board of Directors.

## 4. Risk Management

The GMRC shall review the risk management program to provide the Board reasonable assurance that appropriate risk management processes have been developed and implemented to identify, assess and manage significant risks.

## 5. Human Resources Management

a) The GMRC must gain and maintain reasonable assurance that:

i. HOHI's overall compensation philosophy for Management balances the objectives of (i) attracting and retaining highly competent managers, (ii) appropriately and fairly rewarding strong performance by managers, (iii) maintaining HOHI's employee costs at competitive levels, and (iv) linking managers' compensation to the achievement of HOHI's strategic objectives;
ii. the comprehensive compensation programs for the CEO and for other members of senior management is appropriate;
iii. HOHI establishes and maintains a succession plan which identifies the potential successors to the holders of key Management positions in HOHI; and
iv. HOHI establishes, maintains and is in compliance with its approved human resources policies, procedures and guidelines as well as all applicable laws, regulations, rules, policies and other requirements of governments and regulatory agencies relating to human resources.

b) The GMRC must also:

i. establish and regularly review a job description for the CEO which reflects the Board's delegation to the CEO of the powers and authority to manage the business and affairs of HOHI;
ii. recommend processes for the recruitment, selection, motivation, evaluation and compensation of the CEO which will enable HOHI to achieve the Strategic Plan;
iii. recommend the terms and conditions of the CEO's employment by HOHI;
iv. make appropriate recommendations to the HOHI Board of Directors for the for approval of the terms of employment or termination of the Chief Executive Officer ("CEO");
v. make recommendations to the Board of Directors regarding a formal process for annually assessing the performance of the CEO;
vi. establish the criteria against which the performance of HOHI and the CEO will be evaluated for the purposes of receiving any compensation adjustments;
vii. conduct an annual performance review of the CEO against the performance criteria approved by the Board and report thereon to the Board of Directors;

viii. review and recommend to the Board for approval any organization-wide benefit policies and practices related to the achievement of HOHI's strategy as well as general terms and conditions of employment at HOHI;
ix. review the CEO's report to the Board annually *summarizing* the results of his/her performance evaluations and compensation changes for senior managers;
x. review regularly the implementation of the evaluation, planning and development processes that focus attention on Management succession within HOHI;
xi. review and approve the criteria recommended by the CEO against which the performance of other members of senior management will be evaluated for the purpose of receiving any compensation adjustments;
xii. review and recommend to the Board of Directors for approval the organization wide human resources policies and procedures related to the achievement of HOHI's strategy *and any significant changes in them;*
xiii. identify with Management the risks associated with human resource activities at HOHI and to review Management's plan to control them; and
xiv. perform such other human resource functions as may, from time to time, be assigned to the GMRC by the Board of Directors.

## 6. Pension Governance

a) The GMRC must, on behalf of the Board, satisfy itself that any and all pension plans sponsored by the Corporation and its subsidiaries are properly operated and administered, and that the fiduciary obligations of the pension plan sponsor and administrator are met. In particular, the GMRC must annually gain and maintain reasonable assurance that

i. Mandates regarding pension plan and fund administration are clearly described for the board, relevant committee(s), pension fund agents and trustees and other participants in the governance process;
ii. Measures to implement the mandates are established and the plan governance structure is reviewed on a regular basis;
iii. Documentation that evidences implementation of plan administration is developed and maintained;
iv. The board or its relevant committee(s) receives and considers regular reports from others involved in plan administration; and
v. The operation of the plan is made transparent through communication to plan members.

b) The GMRC shall perform the specific duties, responsibilities and actions pursuant to the authority delegated to it by the Board, and shall make recommendations to the Board concerning them.

## 7. Code of Conduct & Compliance

The GMRC shall also, on behalf of the Board:

a) establish, maintain and monitor compliance with a written code of business conduct and ethics (the "Code") applicable to Directors, Officers and employees of the Corporation. The

Code must constitute standards reasonably designed to promote integrity, the protection and proper use of assets, avoid conflicts of interest and both deter and report wrongdoing;

b) require every HOHI and subsidiary Director, member of Management and those in key financial positions to annually sign an attestation acknowledging acceptance of the Code of Business Conduct;

c) gain reasonable assurance that every employee of HOHI and its subsidiaries receive training on the Code of Business Conduct and sign an attestation acknowledging when they received it;

d) gain reasonable assurance that waivers of compliance with the Code are granted only by the Board or an appropriately empowered Board committee;

e) gain and maintain reasonable assurance (i) as to the integrity of the CEO and the other members of Management, and (ii) that the CEO and the other members of Management create and maintain a culture of integrity throughout HOHI;

f) gain and maintain reasonable assurance that Management, the Board, and the Corporation comply with the applicable laws, regulations, rules, polices and other requirements promulgated by legislation and applicable industry regulation; and

g) review and recommend the governance process and procedures relating to the Business Conduct Hotline.

## 8. Operating Principles

The GMRC shall fulfill its responsibilities within the context of the following principles:

a) Conduct

The GMRC expects the Management (defined as being comprised of the CEO and his/her direct reports) of HOHI to operate in compliance with HOHI’s Code of Business Conduct and policies and with laws and regulations governing HOHI.

b) Communications

The Chair and members of the GMRC expect to have direct, open and frank communications throughout the year with Management, other Committee Chairs and other key GMRC advisors as applicable.

c) Annual GMRC Work Plan

The GMRC, in consultation with Management shall develop and present to the Board for the Board's approval an annual Committee work plan which, amongst other things, will describe the activities in which the GMRC will engage for the purpose of carrying out the GMRC's responsibilities as set out in this Charter.

In addition, the GMRC, in consultation with Management shall develop and participate in a process for review of important governance and human resources topics that have the potential to impact HOHI's effective operation.

d) Committee Expectations and Information Needs

The GMRC shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Committee expects that all reasonably required and available information (including minutes) relating to each matter to be dealt with by the GMRC at its meetings will be received from Management within a reasonable time frame in advance of each Committee meeting.

e) Reliance on Experts

In contributing to the GMRC's discharging of its roles and responsibilities under this Charter, each member of the GMRC shall be entitled to rely in good faith upon:

i. the reports of HOHI represented to him or her by the Management of HOHI or in a written report of external advisors with respect to the governance policies and human resources policies of HOHI ; and
ii. any report of a lawyer, accountant, appraiser or other person whose profession lends credibility to a statement made by any such person.

f) In Camera Meetings

The members of the GMRC shall meet in private session as part of each meeting, (i.e., without Management present). The GMRC shall meet in private session as often as it deems necessary.

g) Committee Self-Assessment

The GMRC shall regularly review, discuss and assess its own performance. In addition, the GMRC shall periodically review its role, responsibilities and terms of reference as specified in the Charter.

## 9. Operating Procedures

a) The GMRC shall meet at least twice annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair or upon the request of two (2) members of the Committee;

b) A quorum shall be a majority of the members;

c) In the absence of the Chair, the Committee members present shall appoint an Acting Chair;

d) GMRC meeting agendas shall be the responsibility of the Chair of the Committee in consultation with the Board Chair, Committee members and Management;

e) To assist the GMRC in discharging its responsibilities, the GMRC may, after consultation with the Board Chair, retain at the expense of HOHI, one or more persons having special expertise that will assist the GMRC in discharging its responsibilities.

f) The GMRC, through its Chair (or the Chair's designate), shall report after each Committee meeting to the Board at the Board's next regular meeting.

## 10. Limitations on Committee's Responsibilities

In contributing to the Committee's discharging of its responsibilities under this Charter, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's responsibilities is to gain reasonable assurance (but not to ensure) that the governance and human resources policies, procedures and practices of HOHI (i) are being conducted effectively and in compliance with all applicable laws, statutes and regulations; (ii) are reasonable and appropriate in the circumstances given the nature of the organization and its strategy; and (iii) are sufficiently and accurately reported upon to the Board.

**Approved by the Board of Directors on:**
**May 13, 2010**
**Revised on: None**

**HYDRO OTTAWA HOLDING INC.**
**(HOHI)**

**INVESTMENT REVIEW COMMITTEE ("IRC") CHARTER**

## 1. Composition

a) The Investment Review Committee ("IRC") of Hydro Ottawa Holding Inc. ("HOHI") is a Board Committee which shall be comprised of up to 5 members of which:

(i) A majority shall be external directors of HOHI;
(ii) One (1) shall be the Chair of the Audit Committee of HOHI;
(iii) One (1) shall be the Mayor of the City of Ottawa if that person is a member of the Board of Directors of HOHI;
(iv) Two members shall be directors who are members of the Board of Directors of HOHI who are independent of the management of HOHI and its subsidiaries;
(v) One (1) shall be the Board Chair as an *ex officio* voting member.

b) The following skill set is normally looked for in the selection of IRC members:
- Board experience
- Experience in relation to mergers and acquisitions;
- Experience in business development;
- Experience in the design, construction or development of capital projects;
- Experience in public or private financing or project financing

It is not necessary for any one member of the Committee to posses all of the skill set items. However, each skill set item (and parts thereof) should be present in the IRC's composition.

c) The Chair of HOHI shall recommend, for HOHI Board approval, the members to serve on the IRC.

d) The Chair of the IRC shall be the Chair of the Board of Directors.

## 2. Terms of Reference

a) The purpose of the Investment Review Committee is to assist management and the Board of Directors in the review and pursuit of business development, acquisition and investment opportunities.

b) For the purpose of carrying out its purpose, the IRC shall:

i. Review and consider potential business development, acquisition or investment opportunities and make recommendations to the Board of Directors with respect thereto, with a focus on:
   1) The consistency of the opportunity with the strategic plan adopted by the Board of Directors;
   2) The consistency of the opportunity with investment guidelines and acquisition criteria approved by the Board of Directors;
   3) The maximization of shareholder value;
   4) The financial resources as well as other resources required to benefit from the opportunity over the short and long-term;
   5) The material risks related to the opportunity;
   6) The compliance with legislative and regulatory restrictions on business activities in exercising the opportunity; and
   7) Such other matters as the Committee may consider relevant to the assessment and evaluation of the opportunity;

ii. Approve the submission of letters of intent, expressions of interest or other documents brought by management to the Committee for its consideration indicating the interest of the corporation in pursuing an investment or acquisition, subject to any applicable final decision of the Board of Directors with respect to the investment or acquisition;

iii. Provide guidance and advice to management in relation to potential acquisition or investment opportunities; and

iv. Perform such other functions as may be assigned by the Board of Directors.

## 3. Operating Principles

The IRC shall fulfill its responsibilities within the context of the following principles:

a) Conduct

The IRC expects its Committee members to operate in compliance with HOHI's Code of Business Conduct and policies and with all applicable laws and regulations governing HOHI.

b) Committee Expectations and Information Needs

The Chair and members of the IRC expect to have direct, open and frank communications throughout the year with Management, other Committee Chairs and other key IRC advisors as applicable.

c) Reliance on Experts

In contributing to the IRC's discharging of its duties under this Charter, each member of the IRC shall be entitled to rely in good faith upon:

i) the reports of HOHI represented to him or her by the Board Chair, the Chair of the IRC, an officer of HOHI or in a written report of external advisors; and

ii) any report of a lawyer, accountant, appraiser or other person whose profession lends credibility to a statement made by any such person.

**4. Operating Procedures**

a) The IRC shall meet as circumstances dictate to carry out the responsibilities set out in its Terms of Reference. Meetings shall be held at the call of the Chair;

b) a quorum shall be a majority of the members;

c) in the absence of the Chair, the Committee members present shall appoint an Acting Chair;

d) IRC meeting agendas shall be the responsibility of the Chair of the Committee in consultation with Management.

e) To assist the IRC in discharging its responsibilities, the IRC may, after consultation with the Board Chair, retain at the expense of HOHI, one or more persons having special expertise that will assist the IRC in discharging its responsibilities.

f) The IRC, through its Chair (or the Chair's designate), shall report after each Committee meeting to the Board at the Board's next regular meeting.

## 5. Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under this Charter, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject.

# HYDRO OTTAWA HOLDING INC.
# (HOHI)

## STRATEGIC INITIATIVES OVERSIGHT COMMITTEE ("SIOC") CHARTER

### 1. Composition

a) The Strategic Initiatives Oversight Committee ("SIOC") of Hydro Ottawa Holding Inc. ("HOHI") is a Board Committee which shall be comprised of that number of Directors as shall be determined from time to time by the Board, of which:

(i) A majority shall be external directors of HOHI;
(ii) One (1) shall be the Board Chair as an *ex officio* voting member; and
(iii) All other members shall be directors who are members of the Board of Directors of HOHI who are independent of the management of HOHI and its subsidiaries.

b) The following skill set is normally looked for in the selection of SIOC members:
- Board experience;
- Merger and acquisition experience including change and transition management and transformation capacity;
- Experience in business development;
- Experience in the design, construction or development of capital projects; and
- Experience in public or private financing or project financing.

It is not necessary for any one member of the Committee to posses all of the skill set items. However, each skill set item (and parts thereof) should be present in the SIOC's composition.

c) The Chair of HOHI shall recommend, for HOHI Board approval, both the members to serve on the SIOC and the Chair of the SIOC.

### 2. Terms of Reference

a) The purpose of the Strategic Initiatives Oversight Committee is to assist the Board of Directors in overseeing the development and implementation of certain key strategic initiatives set out in the annual corporate scorecard adopted by the Board of Directors in support of the strategic plan.

b) To fulfill its purpose, the SIOC shall:

(i) Oversee the planning and implementation of certain key strategic initiatives as identified by the Board of Directors from time to time;
(ii) Receive timely reports from management;
(iii) Review progress on planning as well as relevant communication, stakeholder engagement, and implementation plans;
(iv) Provide guidance and advice to management;

(v) Ensure that management has considered all significant risks in the development of plans;
(vi) Review and advise on the approval of major project decisions and monitor execution;
(vii) Keep the Board of Directors apprised of progress and results, as well as the most significant risks and risk mitigation strategies, and make recommendations to the Board of Directors on such matters; and
(viii) Perform such other functions as may be assigned by the Board of Directors.

**3. Operating Principles**

The SIOC shall fulfill its responsibilities within the context of the following principles:

a) Conduct

The SIOC expects its Committee members to operate in compliance with HOHI's Code of Business Conduct and policies and with all applicable laws and regulations governing HOHI.

b) Committee Expectations and Information Needs

The Chair and members of the SIOC expect to have direct, open and frank communications throughout the year with Management, other Committee Chairs and other key SIOC advisors as applicable.

c) Reliance on Experts

In contributing to the SIOC's discharging of its duties under this Charter, each member of the SIOC shall be entitled to rely in good faith upon:
(i) the reports of HOHI represented to him or her by the Board Chair, the Chair of the SIOC, an officer of HOHI or in a written report of external advisors; and
(ii) any report of a lawyer, accountant, appraiser or other person whose profession lends credibility to a statement made by any such person.

**4. Operating Procedures**

a) The SIOC shall meet as circumstances dictate to carry out the responsibilities set out in its Terms of Reference. Meetings shall be held at the call of the Chair;

b) a quorum shall be a majority of the members;

c) in the absence of the Chair, the Committee members present shall appoint an Acting Chair;

d) SIOC meeting agendas shall be the responsibility of the Chair of the Committee in consultation with Management;

e) To assist the SIOC in discharging its responsibilities, the SIOC may, after consultation with the Board Chair, retain at the expense of HOHI, one or more persons having special expertise that will assist the SIOC in discharging its responsibilities; and

f) The SIOC, through its Chair (or the Chair’s designate), shall report after each Committee meeting to the Board at the Board’s next regular meeting.

**5. Limitations on Committee's Duties**

In contributing to the Committee's discharging of its duties under this Charter, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject.

## 2014 Meeting Schedule - Hydro Ottawa Holding Inc. Board, its committees, and its subsidiary board, Hydro Ottawa Limited Board

| | JAN | FEB | MAR | APR | MAY | JUNE | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **AUDIT COMMITTEE** | | Feb 04<br>9-11:30 a.m. | Mar 25<br>9-11:30 a.m. | | May 13<br>9-11:30 a.m. | | | Aug 19<br>9-11:30 a.m. | | | Nov 18<br>9-11:30 a.m. | |
| **GOVERNANCE & MANAGEMENT RESOURCES COMMITTEE** | | | Mar 25<br>12-3 p.m. | | May 13<br>12-3 p.m. | | | Aug 19<br>12-3 p.m. | | | Nov 18<br>12-3 p.m. | |
| **INVESTMENT REVIEW COMMITTEE** | | | | Apr 02<br>1-2 p.m. | May 21<br>1-2 p.m. | | | Aug 26<br>1-2 p.m. | | | Nov 25<br>3:30-4:30 p.m. | |
| **HYDRO OTTAWA LIMITED BOARD** | | | | Apr 03<br>9-11:30 a.m. | May 22<br>9-11:30 a.m. | | | Aug 28<br>9-11:30 a.m. | Joint Board Strategy Session<br>Sept 18<br>8:30 a.m.-<br>5 p.m. | | Nov 27<br>9-11:30 a.m. | |
| **HYDRO OTTAWA HOLDING INC. BOARD** | | | | Apr 03<br>12-3 p.m. | May 22<br>12-3 p.m. | | | Aug 28<br>12-3 p.m. | | | Nov 27<br>12-3 p.m. | |
| **ANNUAL GENERAL MEETING (Board Chair Only)** | | | | | | Jun 25<br>10-noon | | | | | | |
| **NOMINATING COMMITTEE** | | | | | | Jun 13<br>9:45 a.m. | | | | | | |
| **STRATEGIC INITIATIVES OVERSIGHT COMMITTEE** | | Feb 20<br>3-4:30 p.m. | | | May 20<br>2-3:30 p.m. | | | | Sept 9<br>9-10:30 a.m. | | Nov 17<br>1-2:30 p.m. | |

Société de portefeuille Hydro Ottawa Holding Inc

 **Approved by the Board of Directors on: November 22, 2007**

# HYDRO OTTAWA HOLDING INC
(HOHI)

## Director Orientation and Continuing Education Policy and Process

As part of its commitment to ensuring that the corporation implements good governance practices consistent with a corporation of its size and nature of business activities, Hydro Ottawa Holding Inc. and its subsidiaries are committed to ensuring that members of the Board of Directors receive both an initial orientation and on-going education that will assist them in undertaking their roles as directors of the corporation and its subsidiaries. The Governance and Management Resources Committee shall be responsible for ensuring that appropriate and relevant practices are in place to director orientation and continuing education.

### Orientation of Directors

The program for the orientation of new directors will be tailored to reflect the knowledge, unique skills, experience and education of new directors.

Each new director shall receive an orientation package to assist the director in understanding the nature and structure of the businesses, an outline of current issues and an explanation of the expected roles and responsibilities of the directors. The overview of the businesses of the corporation will include a review of strategic directions, business, financial and capital plans, financial results, significant business issues and key areas of risk. The orientation package will also explain legal requirements applicable to the corporation and its subsidiaries including the regulatory environment within which the businesses operate, significant components of shareholder agreements (or declarations), by-laws, codes of conduct and key corporate and Board policies and procedures. The orientation package will also outline the structure of the organization and explain the roles and responsibilities of the Board, its committees and members of the executive.

In addition to the provision of an orientation package, new directors meet with members of the executive to review business activities and key functions and to review the roles and responsibilities of directors. The Chair will also meet with new directors during which the workload and expected time commitments will be further reviewed.

**Continuing Education**

Management will ensure that the members of the Board of Directors receive timely access to information needed to carry out their duties. Directors may contact the Chair, committee chairs and the Chief Executive Officer to recommend that matters be included in the agendas for meetings of the Board and its committees. Directors will receive a comprehensive information package in advance of meetings and may request further information to assist in the fulfillment of their roles as directors.

The corporation shall provide to directors with information relating to significant, specialized and complex business operations and activities. Management will also provide directors with information relating to good governance practices and other areas to assist the Board and its committees in fulfilling their responsibilities.

The corporation encourages directors to participate in external professional development education programs to assist in the execution of their roles as directors. The following process will apply to encourage participation in the programs:

1. The Corporate Secretary will disseminate information about external education opportunities brought to the attention of the corporation and directors are encouraged to provide to the Corporate Secretary information about other educational opportunities.
2. Directors may make a request to the Corporate Secretary to attend a specific educational program or to attend an undefined program addressing a defined topic or area. The Corporate Secretary will, in turn, forward requests to the Chair of the Board of Directors and the Chair of the Governance and Management Resources Committee.
3. The Chair of the Board of Directors, in consultation with the Chair of the Governance and Management Resources Committee, shall consider requests and determine which requests shall be approved having regard to the following:
    a. The educational needs of the individual director;
    b. The relevance of a particular program to the fulfillment of the role and responsibilities of the director;
    c. The scope of knowledge of the matters addressed by the program already held by the individual director and other members of the Board of Directors;
    d. The cost and quality of the program, including related travel costs;
    e. The existence, availability and quality of comparable programs;
    f. Existing budgetary restrictions of the corporation;
    g. The need to provide education opportunities for other members of the Board of Directors; and
    h. Any other matters relevant to participation in the educational program.
4. Where the Chair of the Board of Directors requests to participate in an external education program, such request shall be considered by the Chair of the Governance and Management Resources Committee who will determine whether such request shall be approved.

5. The corporation will also fund the participation of one director per year for a recognized director education program providing director certification. Priority for approval of participation of a director shall be provided first to the Chair of the Board of Directors, then to committee chairs followed by other members of the Board of Directors. The Chair shall determine which director shall be permitted to attend the director education program in a given year at the cost of the corporation.
6. For the purposes of this policy, participation and attendance at an external education program shall include receipt of educational information by electronic means.
7. Where the Chair approves the participation of a director at an external education program, such approval may be on the basis of funding of all expenses related to the participation of the director in the external education program (including travel, accommodation and program registration expenses) or on the basis of an agreed sharing of costs.
8. The payment or reimbursement of expenses incurred by the director in connection with the attendance or participation in an external education program shall be subject to any policies or guidelines established by the Board of Directors. No remuneration shall be paid to a director for participation or attendance at an external education program.

# CODE OF BUSINESS CONDUCT

HydroOttawa

## OUR VISION

Hydro Ottawa — a leading and trusted integrated utility services company.

## OUR MISSION

To create long-term value for our shareholder, benefiting our customers and the communities we serve.

Effective January 1, 2014

# TABLE OF CONTENTS

# I. INTRODUCTION

**WHY DO WE HAVE A CODE OF BUSINESS CONDUCT?**
Every day, individuals at Hydro Ottawa[1] strive to make the right choices in accordance with applicable laws and regulations, contractual commitments, company policies, professional standards, our standards of business conduct and our organizational values of Teamwork, Integrity, Excellence and Service. We do this because we know that how we accomplish our objectives, individually and as a company, is as important as what we achieve.

The Code of Business Conduct (also referred to as 'the Code') helps us make the right choices by:

- Guiding us as we make decisions and take action.
- Helping us understand where personal choices can be in conflict with our standards of business conduct, our values and our obligations to the company and each other.
- Providing examples of behaviours and attitudes that further define our values and the standard of business conduct required of each and every one of us.
- Describing a high standard that can be applied to any situation, including situations not specifically addressed in the Code.
- Setting specific, ethical direction and expectations.
- Explaining what we can do when we experience or observe non-compliance with the Code.

The Code outlines general principles of appropriate business conduct, with examples[2], rather than attempting to cover every situation we may possibly encounter. It is not a substitute for the use of sound judgement, and the seeking of advice as required, in assessing a particular situation.

**WHO DOES THE CODE APPLY TO?**
The Code applies to all employees, members of the Boards of Directors and, to the extent feasible, our external business partners – agents, representatives, consultants, contractors, vendors and suppliers.

The Code is not intended to conflict with our commitments to employees as stated in our collective agreements, terms and conditions of employment or contracts, nor with the professional standards by which certain of our employees and Board members are bound.

**SPECIFIC ROLES**
Each and every one of us has the responsibility to model the behaviours and attitudes that are outlined in the Code.

**All Employees and Board Members**
All employees and Board members are required to know, understand and apply the Code, as well as the related policies that apply to them. They must all complete any required training on the Code, acknowledge receipt of the Code and training, and report non-compliance with the Code in accordance with the Compliance section of the Code.

[1] Hydro Ottawa refers to Hydro Ottawa Holding Inc. and all of its subsidiaries.
[2] As time progresses, examples may be added, removed or updated to reflect best practices and changes in the workplace; any such changes will be posted on the Intranet.

### Additional Roles for All Those with Direct Reports

The importance of seeking the advice of your direct supervisor is stressed throughout the Code. As such, the company places added expectations on those with direct reports; we expect that they will:

- Respond when their advice regarding the Code is sought, making it comfortable for advice to be sought; and seek guidance from their next level of management, legal counsel or Human Resources when required, to ensure the advice provided is sound.
- Ensure that their direct reports understand the Code and the impact of individual behaviour on the company.
- Agree, in writing, to abide by the Code. This also applies to all Board members.
- Champion the Code; ensure that any required training on the Code and applicable documents are completed.
- Support those who report non-compliance with the Code.
- Immediately address issues of non-compliance by involving their next level of management, legal counsel, or Human Resources as appropriate.

### Additional Roles for Executive and Senior Management

Executives and senior management are responsible, in addition to all of the above, for establishing internal controls, ensuring that monitoring of compliance is in place, reviewing this Code on a regular basis to ensure it includes all necessary references, and ensuring that appropriate action is taken to investigate suspected or actual non-compliance.

### Annual Recommitment

Board members, members of the executive team, senior management and those in key financial positions are required to recommit to the Code, in writing, on an annual basis.

## WHEN THE CODE DOES NOT HAVE AN ANSWER

Codes of business conduct cannot address every possible situation. However, our Code sets a standard against which all situations can be assessed.

Ask yourself these questions:

- Does this feel right? Does it make me feel uncomfortable?
- Would I be proud to tell someone what I have decided or done?
- Am I adhering to the letter and spirit of the laws, regulations and contracts that may be involved?
- Is there any specific guidance in the Code, or in company policies? If not, do the Code and/or a policy give me a sense of the standard that I must apply in this situation?

If, after reading the Code and considering these questions, you are uncertain how to act or react in a given situation, or sense you may be in contravention of the Code if you take a certain action, speak to your direct supervisor, your next level of management, legal counsel or Human Resources without delay.

While all the laws and regulations, and contractual commitments, as well as all the policies that apply to us as individuals and as a company are not specifically described in the Code, the company requires compliance with all applicable laws and regulations and company policies. In situations where the law, policy and the Code appear to be different, each of us must always comply with the highest standard.

# II. OUR ORGANIZATIONAL VALUES

This section includes the definitions for our organizational values and examples of associated behaviours and attitudes, provided by our employees, which describe what our values look like in action. Our values are the ‘**TIES**’ that link our conduct to our vision and our mission; they speak to who we are and the kind of business we want.

**TEAMWORK** is getting the job done through cooperation. Working as a team means sharing our knowledge and skills, and willingly supporting each other. It’s striving toward a common goal, while respecting each other’s viewpoints and opinions, and acknowledging each other’s contributions.

You are living the value of **TEAMWORK** when you demonstrate behaviours and attitudes like these:

- Ensure clarity of team goals by communicating them at the outset and/or confirming your understanding.
- Trust colleagues to fulfill their responsibilities.
- Encourage and provide honest, courteous and constructive feedback, identifying what works and offering alternatives for what does not.
- Listen to what others have to say, and take the time to understand their reasons.
- Respect the workspace of others and the necessary limitations when working in open concept areas.
- Seek information and ideas from across the company, leveraging and relying on the diverse experience, background and knowledge of all team members.
- Willingly share workload; adapt your schedule/duties for team members who are away and participate positively in discussions and completion of tasks.
- Share information and ideas with those who need to know.
- Respect other people’s time and schedules, and be on time for meetings.
- Celebrate the achievement of milestones.
- Participate in activities that bring people together, to build team spirit.
- Share credit, by promoting and acknowledging the ideas and contribution of all team members.

**INTEGRITY** is doing what is right. It means we are trustworthy, we fulfill our commitments with honesty and fairness and we adhere to the highest ethical standards – no matter what the circumstance. It's taking responsibility for our actions and being transparent about our business practices.

You are living the value of **INTEGRITY** when you demonstrate behaviours and attitudes like these:

- Be fair and honest in your dealings with others.
- Do what is right, not what is convenient.
- Say what you will do and do what you say; promise only what you believe you can deliver – and follow through.
- Admit when you have made a mistake.
- Identify when a mistake has been made; don't cover up a mistake that is in your favour.
- Speak up when you recognize that something is wrong.
- Lead by example. Walk your own talk – don't tell someone to do something and then do it differently yourself.
- Give a full day's work for a full day's pay.
- Declare any potential or actual conflict of interest.
- Protect confidential or sensitive information.
- Let people know what you can and cannot tell them.
- Ensure that those who need to understand our business practices are given clear and transparent explanations.

**EXCELLENCE** is achieved through our commitment to quality, safety and learning. It means using our assets effectively to achieve the best possible outcomes, protecting the environment and caring for our employees by maintaining a positive and safe workplace. It means embracing innovation and continuous improvement, and developing our talent.

You are living the value of **EXCELLENCE** when you demonstrate behaviours and attitudes like these:

- Follow and encourage others to follow safety, environmental, and quality standards.
- Give and/or take assignments that develop new skills.
- Be proactive about learning and stay informed.
- Help others learn and perform, through proper instruction and documentation, coaching and mentoring.
- Keep company assets in good working order; identify when assets are not working properly.
- Ensure that your work is thorough, accurate and in line with what is needed. Take ownership, and take steps to ensure quality work.
- Encourage and/or apply creativity, while effectively managing the risks inherent in innovation.
- Always think about what can be done to add value to your work.
- Identify best practices - do not be satisfied with the status quo.
- Recognize and make use of diversity.

**SERVICE** is what we say and do to ensure satisfaction. It's all the actions and interactions that meet or exceed the expectations of our customers, our shareholder, our community and our colleagues. Satisfaction is rooted in being treated fairly and with respect, and being kept informed. Through effective service, we increase trust and recognition of the value we provide.

You are living the value of **SERVICE** when you demonstrate behaviours and attitudes like these:

> Take time to understand what the person wants—see yourself as an ambassador in every situation.

> Treat co-workers as valued customers.

> Ensure you provide/have the proper resources to provide good service.

> Respond to requests clearly, accurately and in a timely manner; acknowledge needs and follow through on your commitments. If your response will be delayed, explain why.

> Monitor products and services—so you know there is a problem before the customer knows—and keep the customer informed.

> When providing service, listen fully and with interest, and don't use terminology that the person may not understand.

> Address the person you are serving professionally; be honest, fair, objective and sensitive, without jeopardizing the company's interests.

> Whenever possible address the customer's issue during the first contact.

> Ask customers and other stakeholders for feedback and provide convenient avenues for feedback.

> Clearly and politely explain a policy when it conflicts with what the person wants, while working towards a solution.

# III. OUR STANDARDS OF BUSINESS CONDUCT

This section provides guidance and direction regarding key responsibilities and accountabilities, including specific required behaviours and attitudes that align with our organizational values. We are all responsible and accountable to disclose any concerns we have, and decline involvement in any decision or action that is contrary to these expected behaviours and attitudes.

# FINANCIAL STEWARDSHIP

We are accountable to our shareholder, and the stewards of significant assets. We must effectively and responsibly use and protect the assets entrusted to us.

**PROTECTION OF COMPANY ASSETS**[3]

We are all entrusted with protecting our company assets, the assets of our customers, and the assets of our employees and external business partners which are brought into our places of work, from theft, fraud, vandalism, embezzlement and illegal copying of licensed materials.

Additionally, we must protect our assets from neglect – through regular maintenance and care, from unauthorized use, and from inappropriate disclosure of information, any of which could damage our reputation or our success.

*For instance:*

- Only use company assets for activities associated with work; unauthorized personal use of any company asset is not permitted.
- Do not take company supplies home for personal use, such as pens, paper, electrical tape, batteries, cleaning supplies/tools, etc.
- If you see someone doing something improper or unsafe with a company asset you must report it to your direct supervisor.
- Maintain and make use of the systems Hydro Ottawa has in place to manage and safeguard assets and information.
- Safeguard keys and property access cards.
- Ask any unfamiliar, unescorted persons who are not displaying proper identification to identify themselves.
- Take all steps to protect information against disclosure, recognizing that corporate information and knowledge are amongst our most valuable assets; never share information with anyone who does not have a solid business need to know, and be careful about discussing company business in public venues.
- Do not make unauthorized or illegal copies of intellectual property belonging to or licensed to Hydro Ottawa.
- Dispose of assets only when the appropriate Executive or designate has given permission in writing, or when the method for disposal is clearly outlined in a policy.

**FINANCIAL DECISIONS**

We apply sound business principles and practices, and make decisions about purchases or expenses that are based on merit and value to the company.

*For instance:*

- Make purchasing decisions based on pre-set, objective criteria and fully disclose all transactions and payments.
- Conduct thorough cost/value analysis.
- Ensure that business expenses are reasonable and necessary for business or commercial needs.
- Obtain approval or pre-authorization before committing Hydro Ottawa funds.
- Ensure all payments made are appropriate for the level of goods/products and/or services received.
- Adhere to all legal and accounting standards when making purchases and subsequent payments.
- Take the necessary steps to ensure that our external business partners are paid in accordance with agreed terms.

**COMPETING FAIRLY AND PROTECTING COMPETITIVE ADVANTAGE**

Hydro Ottawa is committed to running our business in compliance with all competition laws, regulations, standards and practices. Unfair tactics such as bribery, extortion or bid rigging are prohibited.

*For instance:*

- Protect our competitive advantage by refraining from discussing, with outsiders, our customer lists or product and service development initiatives, except where there is a solid business requirement.
- Protect the competitive advantage of our external business partners by not sharing information contained in their bids or quotations with anyone who does not have a solid business need to know.

[3] Assets include, but are not limited to, cash, properties and their contents, furnishings, information, intellectual property, trademarks, logos, data, software, computing and communication devices, tools and equipment, vehicles, clothing, inventory, supplies and materials, etc.

# BUSINESS REPORTING AND RECORDS

To meet our financial and legal obligations, and to effectively manage our affairs, we must maintain and produce accurate and reliable records and reports.

### FINANCIAL REPORTING

Any records impacting on financial results – such as timesheets, sales reports, financial reports and expense reports - must accurately and clearly reflect the true nature of all business transactions. Revenues, expenses, assets and liabilities must all be disclosed, and documents and records must never be altered, hidden, or falsified. Anyone responsible for accounting must be diligent and insist on proper accounting practices.

*For instance:*

> Take the necessary steps to ensure there are no errors, misstatements or omissions in accounting documents, systems and analyses.

> Handle all transactions in a manner that avoids any impropriety or perception of impropriety.

> Never report financial transactions in a way that unlawfully evades tax or other charges imposed by government.

### OPERATIONAL INFORMATION AND RECORDS

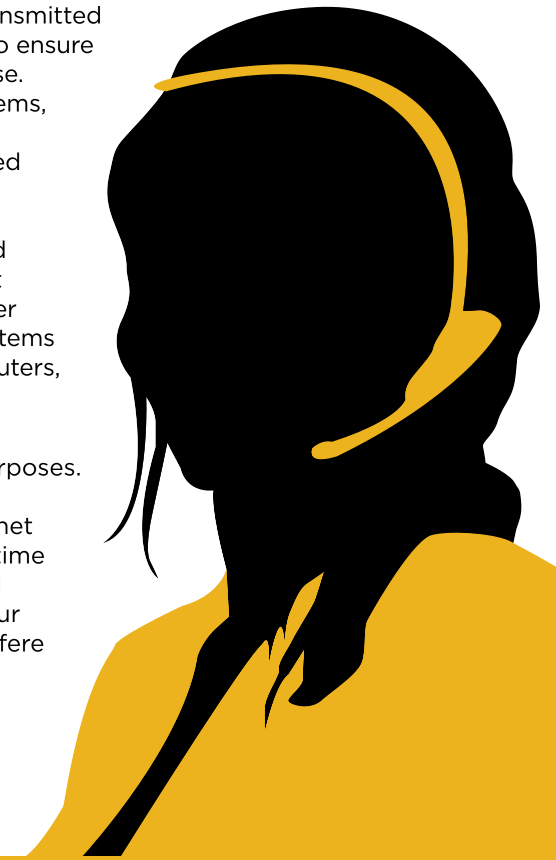
Unless making valid corrections, operational information and records must be left intact. When corrections are made, we must make certain that colleagues who are already in possession of the information/record are advised and provided with an appropriate explanation.

# USE OF TECHNOLOGY

Technology is a resource that we must use carefully and ethically, with consideration of our business needs and reputation and with respect for all those associated with Hydro Ottawa.

Hydro Ottawa's systems and the content (business records, data, information, messages, etc.) in those systems are the property of the company. Hydro Ottawa has the right to access, monitor, read and examine any content transmitted and/or stored on its systems/equipment, to ensure productive, ethical, legal and authorized use. This means content in any part of our systems, including the electronic communications system – Internet, Intranet and Email, shared directories and folders, hard drives and portable or removable electronic storage devices - such as compact discs, DVDs and memory sticks. You should not expect that any of your Email, Internet, Intranet or other technology activities on Hydro Ottawa systems which includes, but is not limited to, computers, laptops, tablets and smartphones, or the corresponding content, is private.

Our systems are intended for business purposes. Limited personal use of the electronic communications system - Internet and Email - is permissible, outside of the time you are expected to be working, provided that the time spent and the content of your electronic communications does not interfere with your productivity or the productivity of your colleagues, damages or have the potential to damage the reputation of Hydro Ottawa, negatively impact any individuals or violate the law.



Under no circumstances are you to use Hydro Ottawa systems and equipment which includes, but is not limited to, computers, laptops, tablets and smartphones to access, download, upload, receive or distribute pornographic content or any content that could be considered sexist, racist, discriminatory or hate-based.

Acting in any manner that is detrimental to the interests and/or reputation of Hydro Ottawa on Internet forums, blogs and social networking sites, including but not limited to, Facebook, YouTube and Twitter or chat rooms, regardless from where or how the Internet is accessed, is not acceptable. The company regularly monitors such sites.

*For instance:*

- Avoid using careless, exaggerated or inaccurate statements in electronic communications, which could be used against Hydro Ottawa.
- Do not download software, large electronic files from the Internet or any content such as images, stream video or music, as these could impact the performance of our technology by using bandwidth on the network needed for business activities or by introducing viruses into our systems.
- Pause and think before you post on social media sites and on the Intranet.
- Use social media only for personal reasons and never for business purposes unless you have been authorized to publish content on behalf of Hydro Ottawa.
- Do not associate or affiliate yourself with Hydro Ottawa when sending e-mails or using social media in a way which could reflect negatively on the company.
- Only install and use software approved by the Information Management and Information Technology Division; and never illegally reproduce software protected by copyright.

## AUDITS AND INVESTIGATIONS

We cooperate fully with investigations by authorized internal and external parties, including regulators, law enforcement agencies and auditors. We expect that you will cooperate by providing accurate and factual information to the authorized investigators and that you will never tamper with records or make misleading comments – such as a business rationale designed to mislead - or ask anyone else to do so.

## RESPECT FOR INDIVIDUALS

At Hydro Ottawa, we are committed to providing positive and respectful working environments where:

- You feel valued and appreciated
- The well-being of employees, customers, and external business partners is safeguarded
- Diversity is welcomed
- It is safe to discuss what is not working and focus on solutions
- Inappropriate or disrespectful behaviour is dealt with according to clearly established standards and in a timely manner

## DIGNITY AND FAIRNESS

Employees, customers, and external business partners will be treated with dignity and fairness.

Employees will be provided with fair compensation and working conditions in exchange for their performance.

All work locations – including customer premises and locations of Hydro Ottawa sponsored events - will be free from discrimination (treating someone differently based on a category), personal or sexual harassment (making someone feel intimidated, threatened, anxious or persecuted), and any form of direct or veiled threats of violence.

We will respect the dignity of our colleagues and treat them as they would like to be treated.

*For instance:*

> Demonstrate respect and dignity by the tone and words you use in writing and in conversation.

> Do not maliciously gossip about colleagues.

> Do not tolerate discrimination, harassment, violence or threats of violence, and report such incidents immediately.

If you are in a leadership role, address any such incidents brought to your attention immediately; or, report the incident to the employee's direct supervisor if they do not report to you.

Allow others to respectfully voice their thoughts and opinions without fear of retribution.

Avoid conduct that creates an uncomfortable situation or an unfriendly work environment such as inappropriate comments, jokes, intimidation, bullying or physical contact.

Recognize that certain actions generally considered inoffensive might trouble some individuals, and respect the wishes of those individuals.

## DIVERSITY

Diversity is about recognizing, respecting and valuing differences across an infinite range of unique individual characteristics and experiences. Hydro Ottawa values diverse backgrounds; we appreciate the different perspectives and experiences that everyone brings to the work environment.

*For instance:*

> Make it easy for our colleagues who reflect the diverse population of the communities we serve to become part of our company.

> Foster an inclusive work environment that embraces the diversity of our colleagues.

> Do not discriminate in hiring and employment practices on grounds prohibited by law.

## PROFESSIONALISM

By presenting ourselves professionally, we demonstrate respect for co-workers, customers and business partners, and ensure that Hydro Ottawa's reputation is viewed positively. Professionalism speaks to demeanour, positive attitude, style of dress, tone of voice and use of personal workspace.

*For instance:*

> Dress appropriately for the work situation.

> If you have been provided with Hydro Ottawa clothing to perform your duties, ensure that it is used for that purpose.

> Speak at a volume that does not impact the productivity of others or result in others hearing confidential information.

> Avoid inappropriate office decorations.

> Promote the company positively, both internally and externally, in appropriate forums.
Do not share personal negative viewpoints about Hydro Ottawa in any public forum, including, but not limited to, social networking sites such as Facebook, YouTube and Twitter.

## SAFETY

The safety of our employees, contractors, subcontractors, external business partners, customers and members of the public and visitors is paramount. We acknowledge that, integral to business success, is the establishment and continuous improvement of a safe workplace. We expect individuals to reduce potential harm by complying with all applicable laws, regulations, policies, procedures, guidelines, and work instructions and immediately reporting any situation that compromises safety.

As part of our concern for safety, Hydro Ottawa will not allow any employee or external business partner to work for or with the company if there is any reason to believe that individual safety or the safety of others is compromised or likely to be compromised.

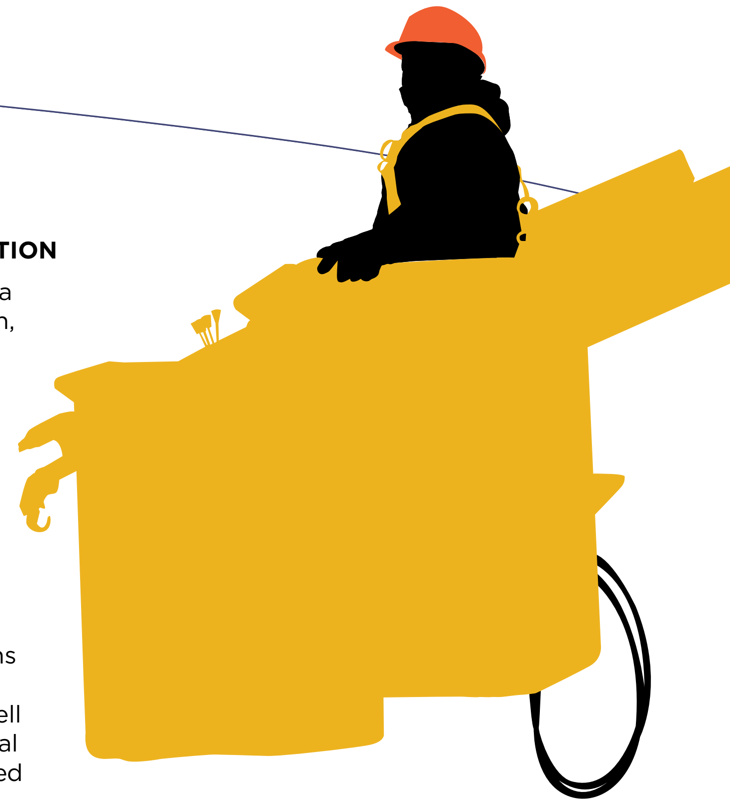
We are committed to minimizing the risk of injury to the public associated with our operations and the provision of services.

*For instance:*

- Come to work fit for duty, to work safely and to identify, report, and where appropriate, correct workplace hazards.
- Wear your protective equipment at all times and ensure it is in proper working condition.
- Do not erode safety through dangerous or careless driving, or by failing to adequately secure items on company vehicles.
- Smoke only in designated areas, and respect the concerns of others when smoking during work. Smoking is not permitted in the workplace, including garages and company vehicles.
- Never bring any weapon, or other type of object that could cause fear or physical harm and is not required in the completion of work duties, to any location where Hydro Ottawa work is being performed.
- Never consume alcohol during a break or at lunch if operating a vehicle or equipment that Hydro Ottawa owns or leases.
- Never attend to your job duties and responsibilities when the consumption of alcohol or the use of any drugs could adversely affect your performance on the job.
- Advise your direct supervisor if you feel that your performance or safety is or might be compromised as a result of alcohol or any drugs, including when called into work on an emergency basis.



## ENVIRONMENTAL PROTECTION



We are committed to being a responsible corporate citizen, and making the community in which we do business a better place to live. We believe that business growth and achievements must be shared with respect for and protection of the environment.

As such, we strive to continuously reduce the impact of our own operations on the environment and the communities we serve, as well as improve our environmental performance. We are dedicated to protecting and preserving the environment where we operate by following all applicable laws, regulations, policies, procedures, guidelines and work instructions and reporting any incidents that could impact the environment.

We will design, build and operate our facilities to make efficient use of resources, prevent pollution and reduce environmental effects to the extent that is reasonably achievable.

*For instance:*

- Look for ways to reduce the company's carbon footprint and improve the company's energy efficiency and waste management and recycling.
- Ensure that you understand the environmental impact of your work activities, and factor that impact into decisions.
- Take responsibility and accountability for contributing individually to reducing our environmental impact.

## CONFIDENTIALITY AND PRIVACY

Respecting the privacy of our employees, customers and external business partners is critical to our success and to building effective business relationships; these individuals have entrusted us with sensitive information. We have a responsibility to effectively manage the collection, access, use and disclosure of all sensitive information, and to only use such information for the purpose for which it was originally collected unless otherwise authorized. We must also safeguard sensitive information against theft, loss, destruction, unauthorized access or misuse.

This obligation and responsibility to protect and not divulge the Company's proprietary and confidential information may continue after your employment with Hydro Ottawa ends.

*For instance:*

- Know what information must be kept confidential; ask your direct supervisor when in doubt.
- Do not disclose personal and confidential information about customers to anyone inside or outside the company, unless it is authorized for the performance of their work.
- Do not discuss and/or disclose confidential company information except with those who have a solid business need to know.
- Respect and maintain the confidentiality of employees' personal information about compensation, performance, disabilities or illness, etc., disclosing this information only to those who have a solid business reason to know.
- Ensure that personal, sensitive and/or confidential information is not inadvertently distributed to inappropriate parties through access to computer system folders, email, etc.

# CONFLICT OF INTEREST

Many situations could involve a conflict of interest, or the appearance of such. Conflict of interest includes any situation or action that places you or could be perceived as placing you in conflict with Hydro Ottawa's interests, or impairs or could be perceived to impair your objectivity. It is important to place the Company's interests before our personal interests. Also, remember that the perception of a conflict of interest can be just as damaging as an actual conflict of interest.

*For instance:*

- Base any business decision on Hydro Ottawa's best interests.
- Ensure that your primary loyalty in the performance of your duties is to Hydro Ottawa.
- Derive no personal benefit from any business decision made on behalf of Hydro Ottawa.
- Do not use, for your personal gain or reasons, or for the personal gain or reasons of your family, friends or another business, any information obtained while performing duties at Hydro Ottawa which is not available to the public at large.
- Do not participate in any discussion or decision that could have, or be perceived to have, a benefit for you, your family members, your friends or another business in which you have personal interest.
- Inform your direct supervisor when you know that members of your family are employees or advisors of companies that have a business relationship with Hydro Ottawa.
- Decline involvement in awarding contracts to, or purchasing any goods and/or services from, business partners with whom you have a personal relationship.
- Inform your direct supervisor immediately if any new situation or business decision made by Hydro Ottawa places you, has the potential to place you, or could be perceived to place you in a conflict of interest.

## PERSONAL INVESTMENTS

When you are aware that you or your family members (spouse, children or other relatives) invest directly in a business that competes with or sells goods and/or services to Hydro Ottawa, including circumstances where there is control or direction over an investment without directly holding it, disclosure is necessary to avoid conflict of interest. Advise your direct supervisor; where the investment or control is significant our legal counsel should also be advised. By disclosing this information, Hydro Ottawa can ensure that you are not placed in a conflict of interest situation such as influencing the awarding of a contract, overseeing work done by that company or participating in any discussions or decisions about that company.

## INSIDER INFORMATION

You are not permitted to purchase – either directly or through an agent or associate – any assets or interests based on confidential knowledge gained while performing duties related to Hydro Ottawa.

## EXTERNAL EMPLOYMENT

Any employment outside Hydro Ottawa, i.e., work for pay or business interests, must not interfere in any way with your availability, productivity and performance at Hydro Ottawa, nor can it conflict with Hydro Ottawa interests. This would include using Hydro Ottawa assets, soliciting business for your own company from Hydro Ottawa customers or working for a company that competes with or provides services to Hydro Ottawa, without our company giving explicit permission.

*For instance:*

- Never identify yourself as a Hydro Ottawa employee when performing work for your own company or another company.
- Never refer Hydro Ottawa customers to other companies unless you are referring to a company on an approved Hydro Ottawa list.
- Do not perform paid work for another organization during working hours at Hydro Ottawa.
- Do not allow colleagues or customers from another organization where you work to contact you during working hours at Hydro Ottawa.
- Do not promote the products or services of another organization, including your own company, during working hours at Hydro Ottawa.
- Do not use company tools, vehicles, equipment, clothing, intellectual property and/or supplies for external employment.

## EMPLOYMENT OF FAMILY MEMBERS

As with conflicts of monetary interest, Hydro Ottawa employees and Board members must maintain objectivity, and the perception of objectivity, when dealing with human resources issues and immediate family members. An immediate family member is defined as: parent (natural or in-law), spouse and son or daughter (including step children and in-laws).

*For instance:*

- Do not place yourself, or allow yourself to be placed, in a position where you supervise, directly or indirectly, or influence the recruitment, hiring, pay or performance rating of any immediate family member.
- Inform your direct supervisor if you know that a family member is applying for employment with Hydro Ottawa.
- Do not pressure another employee to hire a family member, friend or relative.
- Maintain a professional relationship during work hours with a family member who also works for Hydro Ottawa.

## SERVICE ON BOARDS OF DIRECTORS

Membership on boards is encouraged, particularly boards of charitable and non-profit organizations or family businesses, when the organization is not in conflict with our company. In certain cases, Hydro Ottawa will ask an employee to serve on a board as part of their duties, officially representing our company.

You may not serve as a director, trustee, consultant or agent of any organization that competes with, provides goods or services to, or buys goods or services from Hydro Ottawa – not including the purchase of electricity services, unless expressly authorized by Hydro Ottawa.

### PROFESSIONAL ASSOCIATIONS

Individuals are encouraged to contribute to the promotion and development of their profession. You may be officially representing Hydro Ottawa, as part of your duties, or you may join for personal interest.

While involvement in associations can enhance the reputation of Hydro Ottawa and provide access to innovative solutions and useful information, there are some considerations.

> Your direct supervisor must approve any work time for attendance at association meetings or to complete association work.

> If you are not officially representing Hydro Ottawa, you must make it clear that you are speaking on behalf of yourself and not as a spokesperson or representative of our company.

> Information shared with other members of a professional association cannot include proprietary or confidential information.

### VOLUNTEERISM

Volunteering in the community is encouraged. There may be circumstances where use of Hydro Ottawa time or assets is authorized. Request approval from your direct supervisor, who will need to seek authorization from executive or senior management.

### POLITICAL OR CHARITABLE ACTIVITY

As a private citizen, you may participate in any level of political or charitable activity on your own time, but those activities must not interfere or conflict with your duties at Hydro Ottawa or involve the use of any Hydro Ottawa assets unless expressly authorized.

*For instance:*

> Make it clear, while involved in politics, that your comments and actions are your own, and not those of Hydro Ottawa.

> Apply for a leave of absence, without pay, before running for political office.

## ACCEPTING/GIVING GIFTS AND ENTERTAINMENT

Accepting or giving gifts and/or entertainment—including meals, beverages, invitations to social outings, accommodation and travel—may compromise or appear to compromise your ability to make decisions that are in the best interest of Hydro Ottawa.

It is acceptable, on occasion, to accept or give a gift or accept or offer entertainment when there is a business benefit to Hydro Ottawa. It is not acceptable to accept anything from business partners or customers that could be seen as potentially compromising fair decision-making.

Before you accept or give anything, ask yourself:

> Is the gift or entertainment of limited value?

> What is the benefit to Hydro Ottawa?

> Is the offer infrequent?

> Is there a pre-existing business relationship?

> Are the value and the reason for the gift or entertainment appropriate considering the situation, the people involved and your role at Hydro Ottawa?

> Is there an obligation or reciprocity implied for either party?

> Would you be comfortable telling your direct supervisor, peers or family about the gift or entertainment?

> Is the gift or entertainment compatible with normal business practices?

> Would Hydro Ottawa be embarrassed if the gift or entertainment was publicly disclosed; could it be perceived as a bribe or kickback?

Seek the advice of your direct supervisor, your next level of management, legal counsel or Human Resources if you are in any way unsure if you should accept or give any gift or offer of entertainment.

| EXAMPLES | | GUIDELINES |
|---|---|---|
| *You are offered a monetary gift – cash, loan or a discount that is not available to all other employees,* | > | Do not accept it. Such an offer should be reported to your direct supervisor in writing. |
| *You are offered sports or cultural events tickets.* | > | If there is a good business case for attending the event with the giver, accepting these tickets is appropriate, provided it is fully disclosed to your direct supervisor, in writing and in advance of the event.<br>If the giver will not be present, do not accept the tickets. If this is not possible, provide the gift to Human Resources as a prize for an employee draw or at a company event. |
| *You are offered a gift or form of entertainment from an external party who is active in the procurement process.* | > | Do not accept it. This is clearly unacceptable. Such an offer should be reported to your direct supervisor immediately, in writing. |
| *You are offered a gift of alcohol or an alcohol-related gift card/ certificate.* | > | Do not accept it. |
| *You are offered alcohol at an event or by an external party at a meal.* | > | You may accept it as long as the offer is infrequent and the amount is reasonable. |
| *An external party offers to pay for your expenses, including travel, to a trade show or to view a product.* | > | You should not accept this offer. If it is appropriate for you to attend, Hydro Ottawa will cover your expenses and arrange for you to attend. |
| *A holiday gift basket or gift card/ certificate from an external party arrives for you, either at work or at home.* | > | Share the gift with your colleagues within your work group, or provide the gift to Human Resources as a prize for an employee draw or at a company event. |
| *An external party's representative calls and offers to take you and your spouse or "plus one" out to dinner that evening to discuss their newest products.* | > | You may accept the invitation for yourself only so long as the invitation is reasonable and infrequent. |
| *You understand that an external party is willing to provide gifts to support a Hydro Ottawa holiday party, golf tournament, etc.* | > | You should neither solicit nor accept gifts from an external party unless the event is directly benefiting a charitable organization; express written permission from your Division Chief should be obtained. |
| *You are asked to solicit support for a local sports team or local event by using your position at Hydro Ottawa.* | > | You should not use your position at Hydro Ottawa to influence others. Any requests for support should be discussed with your direct supervisor. |
| *You are asked by your direct supervisor to support a cause or event that is not sanctioned by Hydro Ottawa* | > | Do not feel compelled to support the cause or event. |
| *You are asked to speak publicly at a conference on behalf of Hydro Ottawa to an external organization or professional association.* | > | Only accept reasonable honorariums or gifts. It may be acceptable for the organization to pay for travel and/or accommodations, provided the purpose of the event is not to solicit business from Hydro Ottawa. |
| *You are invited to attend a golf tournament.* | > | You should discuss the invitation with your direct supervisor. If there is a good business case, your attendance may be approved. Where possible and appropriate, Hydro Ottawa may pay for your fees. |
| *You are attending a golf tournament on behalf of Hydro Ottawa and win the tournament or a prize for some other accomplishment.* | > | Only accept prizes of a limited value. Otherwise, decline the prize. |
| *You attend a golf tournament, trade show, conference, etc during working hours and there is a raffle for prizes/cash.* | > | Only accept prizes of a limited value. Otherwise, decline the prize. |
| *You are offered a free fishing trip, ski trip, etc by an external party.* | > | You are not permitted to accept such offers. |
| *You are offered promotional items from an external party.* | > | You may only accept promotional items with a limited value. |
| *You will be entertaining an external party.* | > | Only Senior Management Team and Executive Management Team members are permitted to host external clients and will be reimbursed as per company policy. |

## DEALING WITH THE MEDIA

Hydro Ottawa respects the right of the public to know what we do and how we do it. The Director of Communications and Public Affairs is responsible for Hydro Ottawa's relationship with the media. As a general rule, the role of corporate spokesperson is delegated to the Manager, Media and Public Affairs (or designate).

*For instance:*

- Refer all media enquiries to the Manager, Media and Public Affairs and do not speak on behalf of Hydro Ottawa unless expressly authorized to do so.
- Do not discuss Hydro Ottawa matters with a member of the media "off the record" or "for background purposes" unless expressly authorized to do so by the Manager, Media and Public Affairs.
- Have external communications, such as advertising and articles for publication in journals, reviewed by the Manager, Media and Public Affairs before release.

# IV. COMPLIANCE WITH THE CODE

Hydro Ottawa is committed to holding itself to the highest standard. All employees and members of the Board of Directors are expected to uphold the standards in the Code.

### REPORTING NON-COMPLIANCE/POTENTIAL NON-COMPLIANCE

Hydro Ottawa expects its employees to be honest in every situation.

If you inadvertently fail to comply with the Code, report it to your direct supervisor immediately.

You must report any non-compliance immediately, and you must be willing to cooperate during any resulting investigation. Advise your direct supervisor immediately if you witness non-compliance, or suspect non-compliance has occurred.

Should the witnessed/suspected non-compliance involve your direct supervisor, you should endeavour to speak with him/her first to clarify the situation; but if you are not comfortable with that course of action, or it does not result in satisfaction, then report the situation to a higher level of management.

Individuals are encouraged to always address non-compliance internally before taking further action. Speak to your direct supervisor, your next level of management, legal counsel, or Human Resources.

If you feel that your attempts to address the non-compliance internally have not been responded to appropriately or you are not comfortable with such an approach, you may access the Business Conduct Hotline, the external reporting mechanism established by Hydro Ottawa through an independent third party provider. The third party provider will keep the identity of individuals who make a report confidential, except where prohibited by law.

Mischievous, frivolous or malicious allegations are, in themselves, breaches of the Code.

Hydro Ottawa will not tolerate any reprisal, retaliation or disciplinary action against an employee or Board member who responsibly reported, in good faith, a breach or suspected breach.

**CONSEQUENCES FOR NON-COMPLIANCE**

Non-compliance with the Code will be assessed on a case-by-case basis, and may lead to disciplinary action, up to and including termination.

When a violation of law has occurred, or is thought to have occurred, the appropriate law-enforcement authority will be notified.

*Effective January, 1, 2014, any prior Codes of Conduct, as well as any prior agreements which contradict the intent of the standards described and implied in this Code of Business Conduct, where the agreements were written or oral, expressed or implied, are terminated and cancelled, and superseded by this Code of Business Conduct. In the event that any provision or section in this Code, in part or whole, is deemed invalid or unenforceable by a court of competent jurisdiction, such invalidity or unenforceability shall attach only to the said provision or section, or part thereof, and the remainder of this Code shall be in full force and effect.*

*Enviromental Logos and paper description here.*

**Approved by the Board of Directors:**
**April 15, 2005**
**Revised on: None**

**HYDRO OTTAWA HOLDING INC**
(HOHI)

# Directors
# Conflict of Interest and Conduct Guidelines

Hydro Ottawa relies upon the high ethical standards and good judgment of its Directors to uphold the values of Hydro Ottawa Holding Inc and it's subsidiary companies: Hydro Ottawa Limited, Energy Ottawa Inc. and Telecom Ottawa, to be known herein, collectively, as 'Hydro Ottawa' or 'the Company'. Conflict of interest can take several forms, not all of which are listed in this document. These guidelines are intended to provide support for Directors in regards to a conflict of interest and provide direction regarding conduct as related to corporate values and ethical standards. The Board of Directors of Hydro Ottawa Holding Inc. and all of its subsidiaries hereby adopts the following Directors Conflict of Interest and Conduct Guidelines. These guidelines apply in conjunction with the Hydro Ottawa Code of Conduct. The Board's Governance and Management Resources Committee is to oversee the review and revision of these Guidelines, and the Code of Conduct.

## Principles

All Directors shall act in accordance with the provisions of the Ontario Business Corporations Act, the Shareholder's Declaration and common law. They shall:

a) demonstrate an understanding of their specific roles and act upon them,
b) serve, and be observed to be acting honestly and in good faith,
c) demonstrate loyalty to the Company and act only to enhance its reputation,
d) demonstrate an interest in and a commitment to the goals of the Company,
e) respect and preserve the confidentiality of corporate information, and
f) uphold the spirit and letter of all applicable federal and provincial statutes and regulations, the Code of Conduct and the policies of the Company.

Provisions Governing Director's Conduct:

a) The Business Corporations Act - Section 132
b) Shareholder's Declaration - Section 3.7
c) Hydro Ottawa by-law - Section 3.11

## Confidentiality

1. Directors shall maintain the confidentiality of information related to the Company or which comes to them through their professional duties with the Company, unless required to disclose by law.

2. Directors shall act at all times to uphold the standards of confidentiality set for all employees and Directors of the Company. This includes reporting any employee or Director known to be

sharing information regarding Company affairs outside of that which is made available to the public or demanded by law, and alerting management to potential sources of inappropriate corporate disclosure.

3. Board members shall not disclose any business discussed within their capacity as a Director, nor shall they offer personal opinion to the media or to the shareholder of Hydro Ottawa regarding its business dealings or personnel, outside of that approved by the Chairman of the Board of Directors.

**Business and Personal Conduct**

All Directors shall demonstrate an appreciation of the fiduciary duties of a Director by acting in good faith, and demonstrating the highest standards of business conduct. They shall enhance the reputation of Hydro Ottawa through their timeliness, accuracy of their input and openness in the appropriate sharing of their knowledge and skills. Directors shall devote sufficient time to their duties. Directors shall treat each other, Hydro Ottawa staff and shareholders with respect and courtesy.

To ensure accuracy of information and safeguard corporate interests all dealings with the media should be through designated Company spokespersons. Directors designated as spokespersons shall work with the Director, Shareholder and Investor Relations to finalize message content.

**Conflicts of Interest**

**Conflict of Interest**
A broad definition of ‘conflict of interest’ is any action or condition that compromises the objectivity of decision-making in relation to the Company. A conflict of interest can occur when a Director’s personal, professional or business interest is adverse to, or appears to be adverse to the best interests of the Company. A conflict can occur where there is an opportunity to further the Director’s private interests, or those of a member of his or her family, through the Director’s relationship with Hydro Ottawa. Any situation that involves, or may involve, a conflict of interest with Hydro Ottawa should be promptly disclosed to the Governance Committee and dealt with in the manner described below.

The perception of wrongdoing can be as damaging as an actual transgression. Therefore, Directors shall take all possible steps to ensure the public cannot be given the impression of any benefit ascribing to a Director or a member of his or her family through the Director’s association with Hydro Ottawa regardless of any real or anticipated benefit to the Company.

Although it would not be possible to describe every situation in which a conflict of interest may arise, the Board of Directors have adopted the following guidelines for dealing with specific situations:

1. Except for approved expenses for Board or Board related activities, no amounts are to be paid to Directors beyond the amount stipulated by the Shareholder Declaration as fair compensation for the role of Director. Expenses for Board or Board related activities shall be subject to the same guidelines as apply to management.

2. Directors and their spouses shall not be involved in either the actual performance of services or direct supervision of performance of services or the manufacture of goods, of anyone else under contract to Hydro Ottawa while they are serving as a Director of Hydro Ottawa.

3. Where a Director is involved with a charity that receives money from Hydro Ottawa they shall excuse themselves from any vote or presentation that could result in a benefit to the charity.

4. Directors shall not use Hydro Ottawa corporate assets, resources or information except in connection with Company business.

**Reporting of Interests by Directors**

1. Directors, and nominees for the position of Director, must declare to the Hydro Ottawa Board of Directors:

a. if they are receiving compensation from any contract or transaction with Hydro Ottawa outside of their relationship as a Director (for example as an investor in a company supplying a service to Hydro Ottawa);
b. if they could receive compensation in the future from any contract or transaction with Hydro Ottawa outside of their relationship as a Director. (This includes any organizations that are potential targets for acquisition or organizations that are potential acquirers of one of the Hydro Ottawa subsidiaries, or any portion thereof);
c. the nature and extent of any financial interest they hold, or that they are aware is held by a family member, in any party that is known to have applied to, or is entering into, or is currently in a business relationship with Hydro Ottawa; and
d. all other boards and advisory councils they serve upon.

2. This information shall be restated by all Directors annually and updated as they become aware of new business relationships.

3. Directors must keep the Board informed of any corporate or charitable/non-profit Directorships they accept during their tenure with Hydro Ottawa as they occur.

4. It is the responsibility of each Director to declare a conflict of interest or the potential for the perception of a conflict of interest as soon as they are aware of it.

**Governance and Management Resources Committee**

1. In the event of any inconsistency between the provisions of these Guidelines and the Code of Conduct, these Guidelines shall prevail.

2. Any matter that could be perceived as a conflict of interest will be considered by the Governance and Management Resources Committee who will review the situation and recommend an appropriate course of action.

3. The Governance and Management Resources Committee may determine that a conflict of interest exists based on more stringent standards than the preceding guidelines where the Governance and Management Resources Committee considers it to be appropriate.

4. The Governance and Management Resources Committee will report to the Board of Directors in regards to the facts they were presented with and their recommendations. The contract or transaction must then be considered and the Governance and Management Resources Committee's recommendations approved by the Board of Directors. The interested Director, after providing the Board of Directors and/or Governance and Management Resources Committee with any required information, shall remove himself or herself from the room when the matter is discussed and voted upon.

**Compliance**

Signature of this document shall indicate a willingness to abide by its contents.

______________________________

Signature

______________________________

Name (in print)

______________________________

Date

Société de portefeuille Hydro Ottawa Holding Inc



**Approved by the Board of Directors on: April 13, 2006**
**Basis of Reporting Approved by Shareholder on: June 29, 2006**

**HYDRO OTTAWA HOLDING INC**
(HOHI)

**Related Party Transaction Disclosure**
**Policy and Process**

**Process**

1. Directors and their spouses are not to be involved in the performance or supervision of the performance of any work undertaken for Hydro Ottawa or its subsidiaries. The *Directors Conflict of Interest and Conduct Guidelines* require that directors declare to the Board of Directors if they receive any compensation or could receive any compensation in the future from any contract or transaction with Hydro. The required disclosure also relates to any transactions involving family members as well as any interest that they or a family member holds in an entity involved in a business relationship with Hydro Ottawa and its subsidiaries. Any matter that could be contrary to the Guidelines is to be reported by the director and is addressed to the Governance and Management Resources Committee for consideration. A report of the recommendation made by the Governance and Management Resources Committee is required to be provided to the Board of Directors for consideration and approval;
2. At each meeting of the Board of Directors and each of its committees an agenda item shall be included that requires that Board members make declarations of interest. At this time directors shall be asked to disclose any transactions in which they could have an interest but also to disclose any entities in which they have come to have a financial interest that could be involved in transactions with HOHI or its subsidiary companies;
3. On a semi-annual basis, directors and officers shall asked to provide to the General Counsel a list of all entities in which they, their spouse or dependent children have an interest either by virtue of the director's employment with the entity or by virtue of being a director, officer or shareholder in such entity. This list shall be provided to the external auditor as part of the annual audit of the company and its subsidiaries. The list of entities created by the disclosure made by directors (including subsequent disclosures made at meetings of the Board of Directors and its committees) shall be placed in the company's enterprise business system and provided to the procurement section of the organization. Any proposed contract with or payment to one of the listed entities shall be reported to the General Counsel and to the Chief Financial Officer to determine compliance with the company's *Code of Conduct* or the *Directors Conflict of Interest and Conduct Guidelines* prior to the transaction being completed or the payment being made. Any transactions or proposed transactions that could infringe these requirements shall be reported to the Governance and Management Resources Committee for consideration.

No identified transaction is approved and no payment made unless the General Counsel represents that the *Code of Business Conduct* and the *Directors Conflict of Interest and Conduct Guidelines* do not apply to the transaction or, in the event of any uncertainty, that the Board of Directors has approved the transaction based on a determination that the transaction complies with the requirements;

4. Material related party transactions involving directors, as defined pursuant to Generally Accepted Accounting Principles (GAAP) shall be reported annually to the Audit Committee and to the Board of Directors as part of the presentation of annual financial statements. Notice of the existence of any material related party transactions would also appear as a note in the consolidated financial statements for the company that are presented to the shareholder as represented by the Council of the City of Ottawa.

**Policy: Disclosure to the Shareholder**

Hydro Ottawa Holding Inc. will disclose annually to the shareholder, through the City Manager, notice of the following related party transactions involving directors of Hydro Ottawa Holding Inc. and of its subsidiary companies. The notice shall include certification by the company of compliance with the restrictions contained in the Shareholder Declaration relating to restrictions on payments to directors, their family members and entities in which directors have a substantive ownership interest:

(1) Contracts and other transactions in which a director was involved in the delivery of services or the supervision of the delivery of goods or services for Hydro Ottawa Holding Inc. or a subsidiary company outside of the individual's role as a director of Hydro Ottawa Holding Inc. or of a subsidiary;
(2) Contracts or other transactions with an entity for which a director was a director, officer, shareholder (holding a substantive ownership interest) or otherwise holds a substantive ownership interest in the entity;
(3) Contracts and other transactions in which the spouse or dependent child of a director was involved in the delivery of goods or services or the supervision of the delivery of goods and services for Hydro Ottawa Holding Inc. or a subsidiary; and
(4) Contracts and other transactions with an entity for which a director's spouse or dependent child was a director, officer or shareholder (the latter, holding a substantive ownership interest).

The disclosure provided to the City of Ottawa will not include the following contracts and transactions:

(a) Contracts or transactions that arise because Hydro Ottawa Holding Inc. or its subsidiary provides goods or services in like manner and subject to like conditions applicable to other customers. Examples of such contracts and transactions include electricity distribution goods and services, electricity connection service, energy audits, energy conservation and demand management consulting services, and broadband telecommunications services;

(b) Transactions with a charitable or not-for-profit entity where the director, the director’s spouse or the director’s spouse or dependent child is a director or officer of the entity provided that the director, the director’s spouse or dependent child receives no remuneration for being a director or officer of the entity; and

(c) Membership dues incurred in the course of business paid by Hydro Ottawa Holding Inc. or its subsidiary for membership in an entity on which a director or officer is a member of the board of directors of the entity.

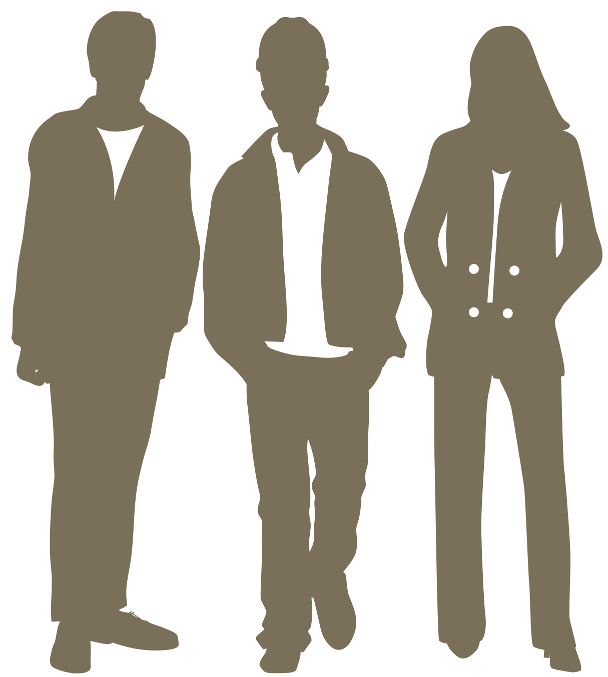
**Hydro Ottawa Group of Companies**

Printed on Enviro 100 stock, which contains 100% of recycled post-consumer fibre and is Ecologo[M] certified.

July 2010-2

BusinessConduct
# HOTLINE

## If You Have A Concern
## Contact the Hotline



**Hydro Ottawa Group of Companies**

BusinessConduct
# HOTLINE

## CONFIDENTIAL. CONVENIENT. EFFECTIVE.

The Business Conduct Hotline allows all employees and Board members to express concerns regarding perceived non-compliance with our Code of Business Conduct in a secure and confidential manner. It is operated by an external independent third party provider. And, it lets you find out precisely what has been done to address your concerns. All reports to the Hotline service are taken seriously and will be investigated if they are deemed to have merit.

**You can express concerns by telephone, online and by regular mail.**

**PHONE**
**1-866-505-5037**
Live operator or voice mail

**ONLINE**
**clearviewconnects.com**

**MAIL**
**P.O. Box 11017**
**Toronto, Ontario**
**M1E 1N0**

***The Hotline is not meant to replace common sense practices—such as speaking to colleagues or your direct supervisor about concerns. But it is meant to make it easy for everyone to anonymously express concerns.***

Hydro Ottawa Group of Companies

# BUSINESS CONDUCT HOTLINE

### What is the Business Conduct Hotline?

At the Hydro Ottawa Group of Companies, we are committed to an organizational environment that fosters and demonstrates ethical business conduct at all levels and reflects our shared values of *teamwork, integrity, excellence* and *service*. Every employee must lead by example in this endeavor. For this reason, we have established our Business Conduct Hotline, a third party service that allows Hydro Ottawa employees to anonymously report any concerns they might have related to perceived improper activities in the workplace and/or non-compliance with our Code of Business Conduct, or even suggestions for improvement.

### Why Have a Hotline?

A hotline is an emerging best practice in leading organizations, providing employees an alternative and confidential process to share their concerns or suggestions for improvement.

### Who Operates the Hotline?

The Hotline is operated by Clearview Strategic Partners, an external and independent third party with extensive experience providing similar services to leading companies in Canada.

### Who Can Use the Hotline?

All employees and members of the Boards of Directors can use the Hotline to express a concern or suggest improvements.

### Is It Anonymous?

There is no requirement for those using the Hotline to identify themselves in any way, and no attempt will be made to identify anyone accessing the Hotline.

### How Do I Use the Hotline?

You can contact the Hotline and express a concern by telephone, with the option of either speaking to a live operator or leaving a voicemail. You can also submit your concern securely online or in writing by mail.

### What Kinds of Concerns Can I Report on the Hotline?

You can report on all matters relating to the business conduct of the Hydro Ottawa Group of Companies, including:

- Financial Stewardship
- Business Reporting and Records
- Use of Technology
- Audits and Investigations
- Respect for Individuals
- Conflict of Interest
- Accepting/Giving Gifts and Hospitality
- Dealing with the Media
- Suggestions for Improvement

### When Should I Use the Hotline?

Everyone is encouraged to report instances of perceived impropriety and/or non-compliance internally, by speaking with your immediate supervisor or higher levels of management. You may also speak to our company's Human Resources employees or legal counsel. However, if you feel your attempts to address your concern through internal channels are not being responded to appropriately, or you are not comfortable with that approach, use the Hotline.

### What Happens When I Make a Report?

Your confidential report on the Clearview system automatically triggers an email to one of two individuals: Hydro Ottawa Holding Inc.'s General Counsel for matters involving all employees; or the Chair of the Audit Committee for matters involving the President and CEO or members of the Board of Directors.

- ***Matters Involving Those At or Below Manager Level***
  These confidential reports are forwarded to an internal Complaints Review Committee comprised of the General Counsel, the Chief Enterprise Risk Management Officer and the Director of Corporate Planning. This Committee determines if an investigation is required, directs the investigation and decides upon action to be taken in consultation with the Chief Human Resources Officer and Chief Operating Officer as required.

- ***Matters Involving Those Above the Manager Level***
  These confidential reports are forwarded to the President and CEO. The President and CEO determines if an investigation is required, directs the investigation and decides upon action to be taken in consultation with the Chief Human Resources Officer and Chief Operating Officer as required.

- ***Matters Involving the President and CEO or Board Members***
  These confidential reports are forwarded to the Chair of the Audit Committee. The Audit Committee Chair reviews the report and recommends to the Chair of the Board whether or not an investigation should take place. The Audit Committee Chair recommends to the Board Chair what actions should be taken based on the results of the investigation.

- ***Matters Involving the Audit Committee Chair***
  The Board Chair oversees all aspects of confidential reports involving the Audit Committee Chair.

## IF IT IS DETERMINED THAT A REPORT WARRANTS FURTHER INVESTIGATION, THE FOLLOWING APPLIES:

### Who Investigates Reports?

If a report is deemed worthy of investigation, an investigator will be appointed. Internal investigators are generally senior managers within the Hydro Ottawa Group of Companies. Where appropriate, external investigators may also be engaged.

### What Happens If It Becomes Known That I Made a Report?

There will be no reprisal, retaliation or disciplinary action taken against any employee or Board member who responsibly reports in good faith.

### Can I Find Out What Happens to My Report?

Yes, but only if your report is submitted online or to a live operator. You will be assigned a reference number that you can reference when following up. With the reference number you can contact Clearview Strategic Partners by telephone or online and find out the status of your report.

### What If I Am Falsely Accused?

Mischievous, frivolous and malicious allegations made via the Hotline or any other means are in themselves breaches of our Code of Business Conduct. As outlined above, there is a systematic process for reviewing the merit of all reports, and for dealing with each report individually and thoroughly.

### Will There Be Oversight of the Process?

Yes, the Audit Committee will receive quarterly reports and the Board of Directors will receive an annual report summarizing all matters raised through the Hotline and the action taken in response. In this way, the Board of Directors will oversee matters raised through the Hotline and ensure that they are being dealt with appropriately.

BusinessConduct
**HOTLINE**

# RATE BASE

## 1.0 INTRODUCTION

This Schedule provides an overview of Hydro Ottawa Limited's ("Hydro Ottawa") distribution rate base and a discussion of year over year variances.

In accordance with the Ontario Energy Board's ("the Board") Update to Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications, issued July 18, 2014, the rate base used to determine the revenue requirement for the Test Years include a forecast of net fixed assets, calculated on a mid-year average basis, plus working capital allowance ("WCA"). Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

Table 1 shows Hydro Ottawa's rate base values for historical years (2012 Approved, 2012 and 2013 Actual, 2014 forecast), bridge year 2015 and test years 2016 through 2020 Budget. Table 1 provides the opening, closing and average balances for gross assets and accumulated depreciation. Table 1 further provides the closing balance for net fixed assets and Hydro Ottawa's working capital allowance.

Table 2 shows the following variances:

- Historical Board-approved (2012) vs. Historical Actual (2012);
- Historical Actual (2013) vs. preceding Historical Actual (2012);
- Forecast (2014) vs. preceding Historical Actual (2013);
- Bridge (2015) vs. Forecast (2014)
- Test Year (2016) vs. Bridge (2015); and
- Test Years (2017 to 2020) vs. preceding Test Years (2016 to 2019)

## Table 1 – Summary of Rate Base (000)

| | 2012 Approved | 2012 Actual | 2013 Actual | 2014 Forecast | 2015 Bridge Year | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year | 2020 Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Opening Gross Assets | 586,645 | 571,283 | 626,263 | 616,643[1] | 728,873 | 834,010 | 920,628 | 1,005,754 | 1,098,217 | 1,165,068 |
| Closing Gross Assets | 653,691 | 626,263 | 730,170 | 728,873 | 834,010 | 920,628 | 1,005,754 | 1,098,217 | 1,165,068 | 1,276,967 |
| Average Gross Assets | 620,168 | 598,773 | 678,217 | 672,758 | 781,441 | 877,319 | 963,191 | 1,051,986 | 1,131,643 | 1,221,018 |
| Opening Accumulated Depreciation | $39,178 | $36,818 | $75,370 | $0[2] | $35,919 | $73,464 | $113,277 | $156,409 | $202,443 | $250,379 |
| Closing Accumulated Depreciation | $78,417 | $75,370 | $114,030 | $35,919 | $73,464 | $113,277 | $156,409 | $202,443 | $250,379 | $299,661 |
| Average Accumulated Depreciation | $58,798 | $56,094 | $94,700 | $17,960 | $54,692 | $93,371 | $134,843 | $179,426 | $226,411 | $275,020 |
| Average Net Fixed Assets Closing | 561,371 | 542,679 | 583,517 | 654,798 | 726,750 | 783,948 | 828,348 | 872,559 | 905,231 | 945,998 |
| Working Capital Allowance | 107,692 | 111,188 | 119,825 | 119,859 | 132,740 | 139,358 | 142,234 | 147,738 | 145,493 | 148,273 |
| **Rate Base** | **669,062** | **653,867** | **703,342** | **774,657** | **859,490** | **923,306** | **970,582** | **1,020,297** | **1,050,724** | **1,094,270** |

[1] Includes one-time adjustment of a decrease to opening Gross Asset values of $114,030k as well as an adjustment of $502k for IFRS financial reporting as described in B-2-1
[2] Includes one-time adjustment of a decrease to opening Accumulated Depreciation values of $114,030k for IFRS financial reporting as described in B-2-1

## Table 2 – Rate Base Variances (000)

| | 2012 Board Approved Vs Actual | 2013 Vs 2012 | 2014 Vs 2013 | 2015 Vs 2014 | 2016 Vs 2015 | 2017 Vs 2016 | 2018 Vs 2017 | 2019 Vs 2018 | 2020 Vs 2019 |
|---|---|---|---|---|---|---|---|---|---|
| Opening Gross Assets | 15,362 | 54,980 | (9,621)[3] | 112,230 | 105,137 | 86,618 | 85,126 | 92,463 | 66,851 |
| Closing Gross Assets | 27,428 | 103,907 | (1,297) | 105,137 | 86,618 | 85,126 | 92,463 | 66,851 | 111,899 |
| Average Gross Assets | 21,395 | 79,443 | (5,459) | 108,684 | 95,878 | 85,872 | 88,795 | 79,657 | 89,375 |
| Opening Accumulated Depreciation | 2,360 | 38,551 | (75,370)[4] | 35,919 | 37,545 | 39,813 | 43,132 | 46,034 | 47,936 |
| Closing Accumulated Depreciation | 3,047 | 38,660 | (78,110)[5] | 37,545 | 39,813 | 43,132 | 46,034 | 47,936 | 49,282 |
| Average Accumulated Depreciation | 2,704 | 38,606 | (76,740) | 36,732 | 38,679 | 41,473 | 44,583 | 46,985 | 48,609 |
| Average Net Fixed Assets | 18,691 | 40,838 | 71,281[6] | 71,952 | 57,199 | 44,400 | 44,211 | 32,672 | 40,766 |
| Working Capital Allowance | (3,496) | 8,637 | 35 | 12,881 | 6,617 | 2,876 | 5,504 | (2,245) | 2,780 |
| **Rate Base Change** | **15,195** | **49,475** | **71,316** | **84,833** | **63,816** | **47,276** | **49,716** | **30,427** | **43,546** |

[3] Includes one-time adjustment to opening Gross Asset values of $114,030k
[4] Includes one-time adjustment to opening Gross Asset values of $114,030k
[5] Includes one-time adjustment to opening Gross Asset values of $114,030k
[6] 2014 opening Net Fixed Asset balance includes a one-time adjustment $502k, please see Exhibit B-2-1

## 2.0 2012 ACTUAL RATE BASE VERSUS 2012 APPROVED

Hydro Ottawa's approved 2012 rate base was $15.2M higher than actual rate base

- Average assets were $18.7M lower in 2012 actual
    - Additional $16.4M in net assets, $11.4M less than Board approved
    - $27.1M more actual construction in progress ("CIP") than forecasted
- $3.5M more was required in WCA in 2012 actual over approved

## 3.0 2013 ACTUAL VERSUS 2012 ACTUAL

Hydro Ottawa's actual 2013 rate base was $49.5M higher than 2012 actual

- Average assets were $40.8M higher in 2013
    - $65.2M additions in 2013, $48.8M higher than 2012
    - $2.8M in net deletions, $3M higher than 2012
- $8.6 more was required in WCA over 2012

## 4.0 2014 FORECAST VERSUS 2013 ACTUAL

Hydro Ottawa's forecasted 2014 rate base was $71.3M higher than 2013 actual.

- Average assets are forecasted to be $71.3M higher
    - $76.3M additions are forecasted in 2014[7], $11.1M higher than 2013
    - $1.1M in net deletions, $1.7M less than 2013
    - $6.1M less is forecasted to be in CIP at the end of 2014
- WCA is forecasted to stay relatively flat

## 5.0 2015 BRIDGE VERSUS 2014 FORECAST

[7] Excluding one-time adjustment to 2014 opening net fixed assets

Hydro Ottawa's 2015 Bridge Year rate base is budgeted to be $84.8M higher than 2014 forecast.

- Average assets are budgeted to be $72.0M higher
    - $67.6M additions are budgeted in 2015, $8.7M less than 2014,
    - $18.2M less is budgeted to be in CIP at the end of 2015
- WCA is budgeted to be $12.9M more than required 2014 forecast

## 6.0 2016 TEST YEAR VERSUS 2015 BRIDGE YEAR

Hydro Ottawa's 2016 Test Year rate base is budgeted to be $63.8M higher than budgeted for the 2015 Bridge Year.

- Average assets are budgeted to be to be $57.2M higher
    - $46.8M additions planned in 2016, $20.8M less than 2015
    - $8.2M more is budgeted to be in CIP at the end of 2016
- WCA is budgeted to be $6.6M more than required 2015

## 7.0 2017 TEST YEAR VERSUS 2016 TEST YEAR

Hydro Ottawa's 2017 Test Year rate base is budgeted to be $47.3M higher than the 2016 Test Year.

- Average Assets are budgeted to be to be $44.4M higher
    - $42M additions planned for 2017, $4.8M less than 2016
    - $4.1M more is budgeted to be in construction in progress at the end of 2017
- WCA is budgeted to be $2.9M more than required in 2016

## 8.0 2018 TEST YEAR VERSUS 2017 TEST YEAR

Hydro Ottawa's 2018 Test Year rate base is budgeted to be $49.7M higher than 2017 Test Year.

- Average Assets are budgeted to be to be $44.2M higher

- $46.4M additions planned for 2018, $4.4M more than 2017
- $4.1M less is budgeted to be in CIP at the end of 2018

- WCA is budgeted to be $5.5M more than required in 2017

## 9.0 2019 TEST YEAR VERSUS 2018 TEST YEAR

Hydro Ottawa's 2019 Test Year rate base is budgeted to be $30.4M higher than the 2018 Test Year.

- Average Assets are budgeted to be  to be $32.7M higher
  - $18.9M additions planned for 2019, $27.5M less than 2018
  - $29.0M more is budgeted to be in CIP at the end of 2019
- WCA is budgeted to be $2.2M less than required in 2018

## 10.0 2020 TEST YEAR VERSUS 2019 TEST YEAR

Hydro Ottawa's 2020 Test Year rate base is budgeted to be $43.5M higher than the 2019 Test Year.

- Average Net Assets are budgeted to be  to be $40.8M higher
  - $62.6M additions planned in 2020, $43.7M more than 2019
  - $18M less is budgeted to be in CIP at the end of 2020
- WCA is budgeted to be $2.8M more than required in 2019

For more details on Capital Additions see Exhibit B-2-1. In addition, for more details related to the Allowance for Working Capital see Exhibit B-3-1.

Hydro Ottawa

# Distribution System Plan 2016


2016 Hydro Ottawa Limited Electricity Distribution Rate Application

# List of Figures

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1 # Glossary

| | |
|---|---|
| AIP | Asset Investment Planning |
| AMP | Asset Management Process |
| AMPR | Asset Management Planning Report |
| APR | Annual Planning Report |
| BDC | Builder Developer Council |
| CAIDI | Customer Average Interruption Duration Index |
| CCRA | Connection & Cost Recovery Agreement |
| CDP | Community Design Plan |
| CEA | Canadian Electrical Association |
| CEATI | Centre for Energy Advancement through Technological Innovation |
| CGA | Common Ground Alliance |
| Chapter 5 | Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013 |
| CIA | Connection Impact Assessment |
| CSA | Canadian Standard Association |
| DC | Direct Current |
| DER | Distributed Energy Resources |
| DGA | Dissolved Gas Analysis |
| DS | Distribution Station |
| DSC | Distribution System Code |
| DSP | Distribution System Plan |
| ECA | Electrical Contractors Association |
| EDA | Electricity Distributors Association |
| ESA | Electrical Safety Authority |
| FEMI | Feeders Experiencing Multiple Interruptions |
| FIT | Feed-In-Tariff |
| FSM | Field Service Management |

| | |
|---|---|
| GEA | Green Energy Act |
| GIS | Geographic Information System |
| GOHBA | Greater Ottawa Home Builders Association |
| GTAP | Grid Transformation Action Plan |
| HCI | Hydroelectric Contract Initiative |
| HESOP | Hydroelectric Standard Offer Program |
| HOL | Hydro Ottawa Limited |
| HONI | Hydro One Networks Inc. |
| HVDS | High Voltage Distribution Station |
| Hydro One | Hydro One Networks Inc. |
| IEEE | Institute of Electrical and Electronics Engineers |
| IESO | Independent Electricity System Operator |
| IR | Infrared |
| IRRP | Integrated Regional Resource Planning |
| ITIC | Information Technology Industry Council |
| KPI | Key Performance Indicator |
| LDC | Local Distribution Company |
| LoS | Loss of Supply |
| LRT | Light Rail Transit |
| LTR | Limited Time Rating |
| NRC | National Research Council of Canada |
| O&M | Operation & Maintenance |
| O/H | Overhead |
| OEB | Ontario Energy Board |
| OLRT | Ottawa Light Rail Transit |
| OM&A | Operation, Maintenance & Administration |
| OMS | Outage Management System |
| OPA | Ontario Power Authority |
| ORCGA | Ontario Regional Common Ground Alliance |
| ORTAC | Ontario Resource and Transmission Assessment Criteria |

| | |
|---|---|
| PCB | Polychlorinated Biphenyl |
| PILC | Paper Insulated Lead Cable |
| PMBOK | Project Management Body of Knowledge |
| PSUI-CDM | Process and Systems Upgrade initiative - Conservation Demand Management |
| REG | Renewable Energy Generation |
| RESOP | Renewable Energy Standard Offer Program |
| RFP | Request for Proposal |
| RIP | Regional Infrastructure Planning |
| RTU | Remote Terminal Units |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SARFI | System Average Root Mean Square (RMS) Variation Frequency Index |
| SCADA | Supervisory Control And Data Acquisition |
| SF6 | Sulfur Hexafluoride |
| SLA | Service Level Agreement |
| the Board | Ontario Energy Board |
| the City | City of Ottawa |
| TIM | Testing, Inspection & Maintenance |
| TOD | Transit Oriented Developments |
| TS | Transmission Station |
| U/G | Underground |
| UCC | Utility Coordinating Committee |
| XFMR | Transformer |
| XLPE | Cross-Linked Polyethylene |

1 # Definitions

| | |
|---|---|
| 10 day Limited Time Rating (LTR) | the maximum loading level that can be applied to a station power transformer over a 10 day period resulting in a 0.1% loss in transformer life |
| Asset Management Planning Report | part of the Annual Planning Report (see Attachment B-1(B)) where asset management practices used by HOL are documented |
| Budget Program | A grouping of similar projects that address the same assets and primary drivers. |
| Capital Program | A grouping of Budget Programs that have a similar asset type which are grouped on a meaningful basis for management reporting and are associated with the OEB Investment Categories. |
| Cold Load Pick Up | the operation of restoring power to equipment that has been without power for a period of time and thus will require additional current for the equipment restart |
| Corrective Maintenance | activities aimed at fixing discovered issues of an asset |
| Distribution Assets | all infrastructure and equipment owned by HOL outside of the substation used to distribute power to customers |
| Distribution Station (DS) | A sub-transmission (44kV or 13.2kV) connected substation that steps down voltage to a distribution level (<44kV) |
| High Voltage Distribution Station (HVDS) | a transmission (≥50kV) connected substation that steps down voltage to a distribution or sub-transmission level (<50kV) |
| Key Performance Indicator | a measure of continuous improvement in asset management planning, capital investment planning and in customer oriented performance |
| LEAN | a continuous improvement program focused on eliminating waste from business processes |
| Maintenance Program | a set of planned activities which improve the condition of HOL's assets |
| Measures | a quantifiable unit used to identify KPIs |
| Overhead | all infrastructure and equipment used to distribute power to customers |

| | |
|---|---|
| | that is supported above ground level by a series of poles |
| Predictive Maintenance | activities that are used to determine the condition of an asset in order to predict when maintenance or replacement should be performed |
| Preventative Maintenance | activities that are regularly performed on equipment to lessen the likelihood of it failing |
| Program | an activity plan that includes multiple subprojects |
| Project | a specific plan carried out to address a need |
| Station Assets | all infrastructure and equipment owned by HOL inside the substation yard used to convert transmission voltages to distribution voltages |
| System Distribution Assets | all distribution and station assets owned by HOL used to convert transmission voltages to distribution voltages and distribute power to customers |
| Transmission Station (TS) | a transmission (≥50kV ) connected substation that steps down voltage to a lower transmission voltage (≥50kV ) |
| Underground | all infrastructure and equipment used to distribute power to customers that is located beneath ground level |

1 # HOL Substation Table

2 The following HOL and HONI owned stations in the table below are used to supply HOL's
3 customers. The stations are herein referenced by the nomenclature (HOL Station Name) used
4 by HOL.

| HOL Station Name | Designation | Owner | Primary/Secondary Voltage (kV) |
|---|---|---|---|
| Albion TA | HVDS | HONI-HOL | 230/13.2 |
| Albion UA | DS | HOL | 13.2/4.16 |
| Alexander DS | DS | HONI | 44/27.6 |
| Augusta UD | DS | HOL | 13.2/4.16 |
| Bantree AL | DS | HOL | 13.2/4.16 |
| Barrhaven DS | DS | HOL | 44/8.32 |
| Bayshore DS | DS | HOL | 44/8.32 |
| Bayswater UJ | DS | HOL | 13.2/4.16 |
| Beaconhill MS | DS | HOL | 44/8.32 |
| Beaverbrook | DS | HOL | 44/12.43 |
| Beckwith DS | DS | HONI | 44/27.6 |
| Beechwood UB | DS | HOL | 13.2/4.16 |
| Bells Corner DS | DS | HOL | 44/8.32 |
| Bilberry TS | HVDS | HONI | 115/27.6 |
| Blackburn MS | DS | HOL | 44/8.32 |
| Borden Farm DS | DS | HOL | 44/8.32 |
| Bridlewood MS | HVDS<br>DS<br>HVDS<br>DS | HOL | 115/27.6<br>44/27.6<br>115/8.32<br>44/8.32 |
| Bronson SB | DS | HOL | 13.2/4.16 |
| Brookfield AF | DS | HOL | 13.2/4.16 |
| Cahill AN | DS | HOL | 13.2/4.16 |

| | | | |
|---|---|---|---|
| Cambridge AM | DS | HOL | 13.2/4.16 |
| Carling SM | DS | HOL | 13.2/4.16 |
| Carling TM | HVDS | HONI-HOL | 115/13.2 |
| Casselman MS | DS | HOL | 44/8.32 |
| Centrepointe DS | HVDS | HOL | 115/8.32 |
| Church AA | DS | HOL | 13.2/4.16 |
| Clifton UL | DS | HOL | 13.2/4.16 |
| Clyde UC | DS | HOL | 13.2/4.16 |
| Cyrville MTS | HVDS | HOL | 115/27.6 |
| Dagmar AC | DS | HOL | 13.2/4.16 |
| Eastview UT | DS | HOL | 13.2/4.16 |
| Edwin UV | DS | HOL | 13.2/4.16 |
| Ellwood MTS | HVDS | HOL | 230/13.2 |
| Epworth DS | HVDS | HOL | 115/8.32 |
| Fallowfield MS | HVDS | HOL | 115/27.6 |
| Fisher AK | DS | HOL | 13.2/4.16 |
| Florence UF | DS | HOL | 13.2/4.16 |
| Gladstone UX | DS | HOL | 13.2/4.16 |
| Hawthorne TS | HVDS | HONI | 230/44 |
| Henderson UN | DS | HOL | 13.2/4.16 |
| Hillcrest AH | DS | HOL | 13.2/4.16 |
| Hinchey TH | HVDS | HONI-HOL | 115/13.2 |
| Holland SH | DS | HOL | 13.2/4.16 |
| Janet King DS | DS<br>DS | HOL | 44/27.6<br>44/8.32 |
| Jockvale DS | DS | HOL | 44/8.32 |
| Kanata MTS | HVDS | HOL | 230/27.6 |
| King Edward SK | DS | HOL | 13.2/4.16 |
| King Edward TK | HVDS | HONI-HOL | 115/13.2 |
| Langs AP | DS | HOL | 13.2/4.16 |

| | | | |
|---|---|---|---|
| Leitrim MS | DS | HOL | 44/27.6 |
| Limebank MS | HVDS | HOL | 115/27.6 |
| Lincoln Heights TD | HVDS | HONI-HOL | 115/13.2 |
| Lisgar TL | HVDS | HONI-HOL | 115/13.2 |
| Longfields DS | DS | HOL | 44/27.6 |
| Manordale DS | HVDS | HOL | 115/8.32 |
| Manotick DS | HVDS | HONI | 115/8.32 |
| Marchwood MS | HVDS | HOL | 115/27.6 |
| McCarthy AQ | DS | HOL | 13.2/4.16 |
| Merivale DS | HVDS | HOL | 115/8.32 |
| Moulton MS | HVDS | HOL | 115/27.6 |
| Munster DS | DS | HOL | 44/8.32 |
| Nepean AB | DS | HOL | 13.2/4.16 |
| Nepean TS | HVDS | HONI | 230/44 |
| Overbrook SO | DS | HOL | 13.2/4.16 |
| Overbrook TO | HVDS | HONI-HOL | 115/13.2 |
| Parkwood Hills DS | DS | HOL | 44/8.32 |
| Playfair AJ | DS | HOL | 13.2/4.16 |
| Q.C.H. DS | DS | HOL | 44/8.32 |
| Queens UQ | DS | HOL | 13.2/4.16 |
| Richmond North DS | DS | HOL | 44/8.32 |
| Richmond South DS | HVDS | HOL | 115/8.32 |
| Rideau Heights DS | DS | HOL | 44/8.32 |
| Riverdale SR | DS | HOL | 13.2/4.16 |
| Riverdale TR | HVDS | HONI-HOL | 115/13.2 |
| Russell TB | HVDS | HONI-HOL | 115/13.2 |
| Shillington AD | DS | HOL | 13.2/4.16 |
| Slater SA | DS | HOL | 13.2/4.16 |
| Slater TS | HVDS | HONI-HOL | 115/13.2 |
| South Gloucester DS | HVDS | HONI | 115/8.32 |

| | | | |
|---|---|---|---|
| South March TS | HVDS | HONI | 230/44 |
| South March DS | DS | HOL | 44/12.43 |
| Stafford Road DS | DS | HOL | 44/8.32 |
| Startop MS | DS | HOL | 44/8.32 |
| Terry Fox MTS | HVDS | HOL | 230/27.6 |
| Uplands MS | HVDS | HOL | 115/27.6 |
| Urbandale AE | DS | HOL | 13.2/4.16 |
| Vaughan UG | DS | HOL | 13.2/4.16 |
| Walkley UZ | DS | HOL | 13.2/4.16 |
| Woodroffe DS | DS | HOL | 44/8.32 |
| Woodroffe TW | HVDS | HONI-HOL | 115/13.2 |
| Woodroffe UW | DS | HOL | 13.2/4.16 |

# 1 Distribution System Plan

Hydro Ottawa Limited's (HOL) Distribution System Plan (DSP) has been put together in line with the Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements (Chapter 5).

## 1.0 HOL DSP

Table 1.0.1 shows the mapping of the sections within HOL's DSP to those identified in Chapter 5.

Table 1.0.1 - DSP Section Mapping

| HOL DSP Section | | Chapter 5 Section | |
|---|---|---|---|
| **1** | **Distribution System Plan** | **5.2** | **Distribution System Plans** |
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|---|---|---|---|
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| **3.3** | **System Capability Assessment for Renewable Energy Generation** | **5.4.3** | **System capability assessment for renewable energy generation** |
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| **3.4** | **Capital Expenditure Summary** | **5.4.4** | **Capital expenditure summary** |
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| 3.4.2 | System Access | 5.4.4 | Capital expenditure summary |
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| **3.5** | **Justifying Capital Expenditures** | **5.4.5** | **Justifying capital expenditures** |
| 3.5.1 | Overall Plan | 5.4.5.1 | Overall plan |
| 3.5.2 | Material Investments | 5.4.5.2 | Material investments |
| **3.6** | **Material Investments** | **5.4.5.2** | **Material investments** |

The purpose of the DSP is to consolidate HOL's practices as they relate to the planning and execution of System Access, System Renewal, System Service and General Plan investments through the Asset Management Process (Section 2 Asset Management Process). These practices will be detailed throughout the DSP. The DSP details the forecast years' (2016-2020) capital spending activities and the planning processes through which they are identified and prioritized, activities relating to third party coordination and information on customer engagement.

Historically, HOL has produced an Annual Planning Report (APR) which covers the four main areas of planning described above, with a 20-year outlook, summarizing the outcomes of the process described in Section 2 of this DSP. As the DSP and the Annual Planning Report share a number of commonalities, the 2014 APR has been included in Attachment B-1(B), and is referenced throughout the DSP.

HOL's DSP has been divided into three sections as outlined in Chapter 5:

**Section 1 – Distribution System Plan (corresponding to Section 5.2 of Chapter 5)**

The first section of the Distribution System Plan is intended to provide the Ontario Energy Board (OEB) and stakeholders with a high level overview of the information filed within the DSP including key elements that affect rate proposals and sources of cost savings expected to be achieved, information on coordinated planning with third parties, and performance measurements for continuous improvement.

**Section 2 – Asset Management Process (corresponding to Section 5.3 of Chapter 5)**

The purpose of the second section is to provide the Board and stakeholders with an understanding of the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan and how they impact operation and maintenance (O&M) expenditures. Included in this section is an overview of the process, a description of the assets managed, and details of HOL's optimization policies and practices as they related to asset replacements, testing, inspection and maintenance.

**Section 3 – Capital Expenditure Plan (corresponding to Section 5.4 of Chapter 5)**

The third and final section of the DSP details HOL's O&M expenditures and capital system investments that have been derived from the asset management process (described in section 2) and the capital expenditure planning process. Details included are in relation to the capital expenditure planning process, the capability of the system to connect new load and embedded generation, a summary of capital expenditures and O&M expenditures and justifications for projects and Budget Programs that meet the materiality threshold of $750k.

### 1.0.1 Corporate Strategic Direction & Asset Management Objectives

HOL's planning practices and Asset Management Process tie back to the Corporate Strategic Direction. Understanding of this framework provides context for the Distribution System Plan and is referenced throughout.

**Mission**

To create long-term value for our shareholder, benefitting our customers and the communities we serve.

**Vision**

To be a leading and trusted utility services company.

- Leading – consistently being among the top performers in the business, in every critical area of our operations; and being regarded as a credible and trusted voice in our industry, helping to shape policy, regulatory and operational responses to the critical issues of the day.
- Trusted – Trust is fundamental to HOL's success – a continuing belief among our stakeholders that we will deliver on our mission, reliably, in a transparent and accountable fashion.
- Integrated – realizing synergies and economies of scale in 'close to the customer' utility services, to create additional value for the company's shareholder, and savings and enhanced service to customers.

**Strategy**

With our mission and vision in mind HOL's goal is two-fold:

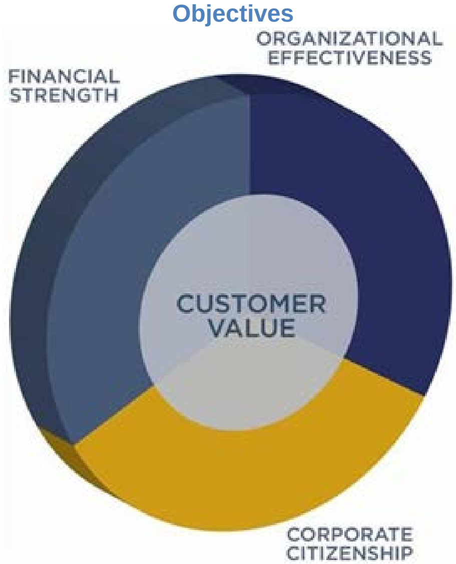
- To continue to fulfill our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the homes and businesses that rely on us every day; and
- To ensure a more sustainable energy future for our community.

To achieve these goals, HOL's strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations – for service quality, cleaner energy, and greater control over the management of energy costs – will be key to HOL's continued success in an evolving landscape.

**Corporate Strategic Objectives**

To achieve our strategy, the plan is structured around four critical areas of performance that have driven our success to date, shown in Figure 1.0.1. In each of these areas, we have set one overreaching objective. These four areas of focus will continue to guide our activities throughout the current plan, but one, Customer Value, takes on central importance.

Figure 1.0.1 - Corporate Strategic Objectives




*Customer Value* – we will deliver value across the entire customer experience – by providing reliable, responsive and innovative services at competitive rates

*Financial Strength* – we will create sustainable growth in our business and our earnings – by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people

*Organizational Effectiveness* – we will achieve performance excellence – by cultivating a culture of innovation and continuous improvement

*Corporate Citizenship* – we will contribute to the well-being of the community – by acting at all times as a responsible and engaged corporate citizen

**Asset Management Objectives**

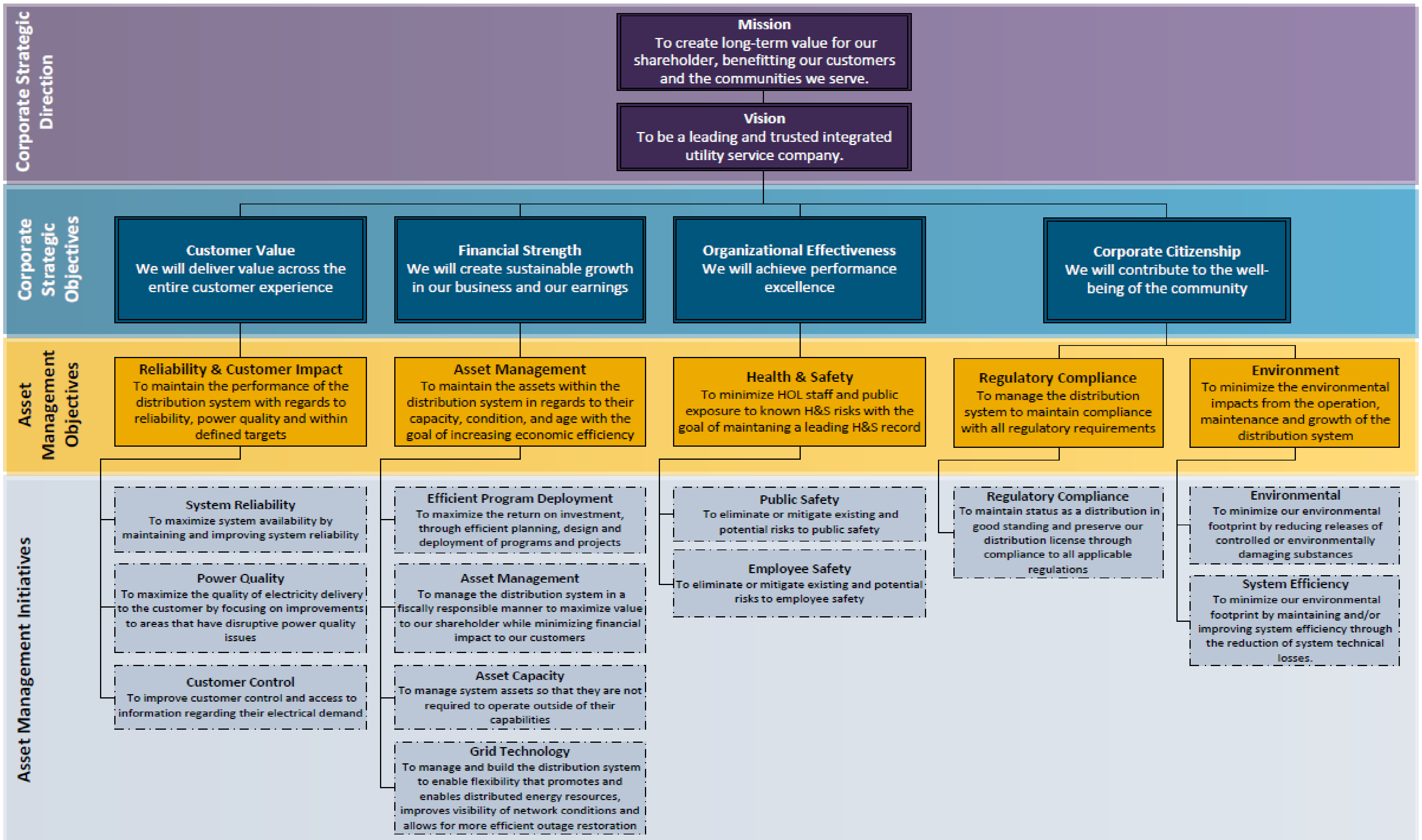
The goal of the Asset Management Process is to deliver a portfolio of projects which support the Key Areas of Focus in a transparent, consistent and sustainable manner. In this regard, there are five (5) key Asset Management Objectives, which have been identified in support of the Corporate Strategic Objectives.

**Asset Management Initiatives**

Support of the Asset Management Objectives is expressed in terms of initiatives. These are specific operational goals which are directly impacted by the work carried out under the Asset Management Process.

The hierarchy between the Corporate Strategic Direction through to the Asset Management Objectives is shown in Figure 1.0.2.

**Figure 1.0.2 - Corporate Strategic Direction & Asset Management Objectives**



## 1.1 Distribution System Plan Overview

The Distribution System Plan (DSP) overview provides a high level synopsis of the information that can be found in the DSP, providing context for the remaining document with regards to the capital expenditures, O&M expenditures and vintage of the information provided and the areas of cost savings found as a result of HOL's distribution system planning, i.e. - planning and execution of System Access, System Renewal, System Service and General Plant investments through the Asset Management Process.

### 1.1.1 Key Elements of the DSP

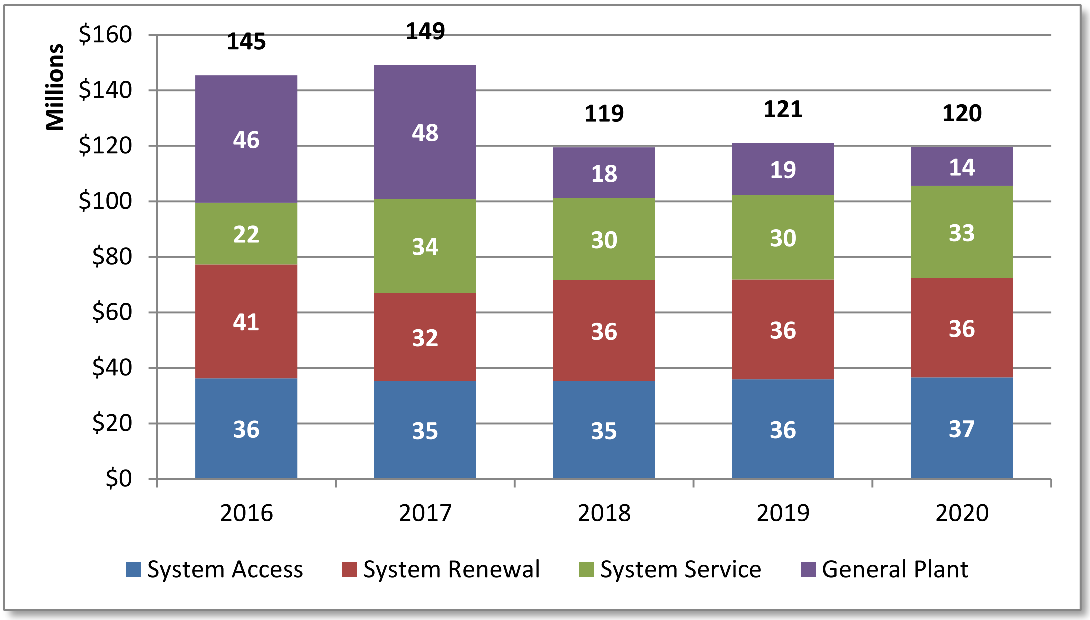
HOL's DSP details the planning process used by HOL as well as the process to take the system demographics and needs described to translate them into specific projects and expenditure plans. The DSP also addresses how productivity, lifecycle optimization, consultation with customers, coordination with third parties and requirements of Renewable Energy Generation (REG) play a key role in achieving Corporate Strategic Objectives of HOL.

Table 1.1.1 and Figure 1.1.1 show HOL's planned capital spending levels in each of the Ontario Energy Board's defined investment categories.

**Table 1.1.1 - Forecast by Investment Category**

| Investment Category | $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| System Access (Gross) | 36,263 | 35,156 | 35,132 | 35,835 | 36,551 |
| System Renewal | 41,033 | 31,823 | 36,491 | 35,980 | 35,718 |
| System Service | 22,235 | 33,957 | 29,518 | 30,473 | 33,314 |
| General Plant | 45,899 | 48,138 | 18,276 | 18,695 | 13,954 |
| **Grand Total** | **145,430** | **149,073** | **119,418** | **120,982** | **119,538** |

1 Figure 1.1.1 - Forecast by Investment Category

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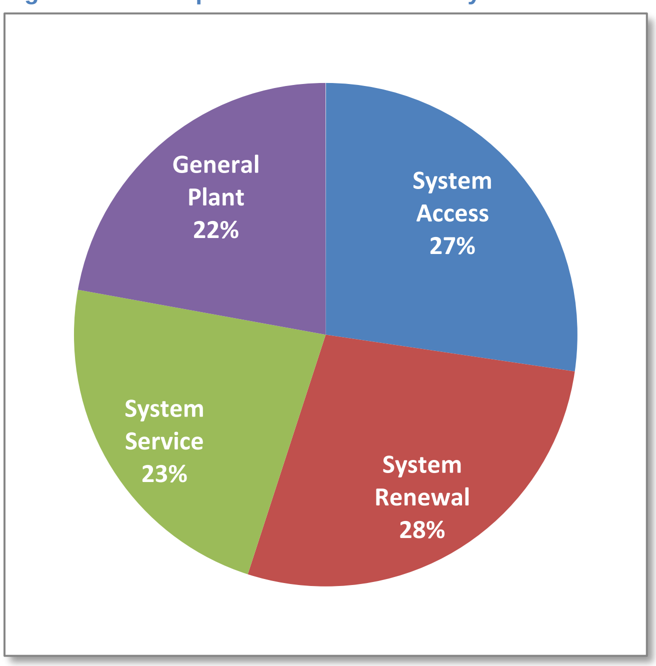
3 Figure 1.1.2 - Average Forecast Expenditure Distribution by Investment Category (2016-2020)

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### 1.1.2 Sources of Cost Savings

The DSP details HOL's prioritizations and optimization of distribution system expenditures. Through the Asset Management process outlined in the DSP, HOL strives to level investments to minimize the risks associated with reliability and customer impact, safety, environment while improving on our service to our customers and providing increasing value to our shareholder. As displayed in Section 3 Capital Expenditure Plan, business cases are created to evaluate project alternatives so that the most effective, in regards to cost and benefits, solution is identified for implementation. Annual expenditures are then paced so that the timing of investments are optimized to minimize overall risk to HOL`s business values as much as possible for every dollar spent.

HOL is focused on productivity and developing efficiencies as sources of cost savings in both capital and O&M programs. Examples such as asset lifecycle optimizing and increased planning can result in real cost savings. The following list outlines a number of key areas of cost savings HOL is focusing on:

**Operational productivity**

HOL is striving to create a culture of continuous improvement. Whether through process improvement or by leveraging new technology, HOL has been, and continues to look for new ways to more efficiently provide the best possible service to our customers. The following is a list of the initiatives introduced at HOL:

- *Lean Method of Management* – A continuous improvement program focused on eliminating waste from business processes;
- *Corporate Productivity Scorecard* – Development of a suite of KPIs to measure and monitor productivity across the organization; and
- *CEO Productivity and Innovation Award* – Intended to recognize those teams and individuals who have driven a tangible or measureable productivity improvement.

These directly relate to the DSP through the following:

- Capital Execution Process Review

- o In 2011 HOL completed a Lean review of our capital execution process from project initiation and design through to project closure. A cross functional team of employees involved in different aspects of projects was assembled to review the current state, identify issues and opportunities and make recommendations for implementation that would demonstrate improvements to how we do business.

- Aligned Staff Geographically
  - o The Asset Management and Design groups were realigned to match the geographical structure of our construction and maintenance groups. This improved communication and quality of projects from planning through to execution.
- Centralized Scheduling
  - o HOL undertook a review of its scheduling systems for capital and maintenance programs and determined that greater efficiencies could be derived from implementing a centralized scheduling system.
- Multi-Disciplined System Designer
  - o HOL is working towards changing from a model with functional specific designers to a system with multi-disciplined designers to enable designers to manage all aspects of a project.
- Operational Process Liaison Committee
  - o A new cross functional committee was established within the Operations group consisting of staff and management from Design, Scheduling, Service Desk and Construction. The mandate of this cross functional group is to take a look at core business processes that cut across departmental lines to look for opportunities to improve overall efficiency and effectiveness of operational processes.
- Unit Bills
  - o Unit bills are lists of material and construction components that are used to create estimates for distribution capital projects. In the old process, a Designer was required to input each unit of material and labour into JD Edwards (HOL Enterprise System) on a job by job basis. This made the task of creating material lists for projects very labour intensive. To reduce this, in 2014 Distribution Design undertook the task of assigning labour and trucking units to each overhead

standard. To avoid the task of building material lists for each overhead project, each standard had a list or unit bill of material, labour and trucking created for it.

**Planning Effectiveness**

Through an ever improving inspection, testing and maintenance planning and project prioritization process HOL has developed a plan that paces spending while still meeting the reliability requirements of the distribution system. The short term, 5-year plan is tied into the long-term 20-year plan which is developed to align with HOL's Corporate Strategic Objectives: Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship. As part of the continuous betterment of the planning process, HOL is implementing a new asset investment planning software tool which will improve data flow, asset condition models and will take HOL to the next level of asset analytics and project optimization.

**Increased Use of New Technology**

When replacing assets at the end of life, or evaluating projects to improve reliability, HOL incorporates new technologies where feasible. This includes:

- Replacing end of life switches with a smart, Supervisory Control and Data Acquisition (SCADA) controlled switches capable of remote operation thus reducing crew and truck time previously required for switching and power restoration.
- Installing fault current indicators (FCIs) based on past experience and evaluation of single line diagrams for ideal installation locations. The smart FCIs report is communicated back to system office through the SCADA network which provides indication to the operators as to the location of the fault, speeding up switching and restoration time by reducing the time spent on trouble shooting.
- HOL is trialing cable rejuvenation through the use of cable injection to extend the life of direct buried XLPE cables. The cable injection process proves to be significantly more cost effective compared to the traditional asset replacement. Should this program prove successful, HOL will be able to redirect the savings obtained through injection versus replacement in the cable replacement program to other areas of the asset management process, helping to close the gap between the needs identified and available expenditure levels.

- HOL has invested in an Asset Investment Planning initiative to implement Copperleaf's C55 program. The C55 program will allow HOL to automate the optimization process further improving the ability to mitigate risks and increase benefits amongst a variety of project ideas. This is achieved by comparing all possible scenarios of projects which fit within the user specified constraints and recommends a list of projects which best meets the Corporate Strategic Objectives.
- HOL has recommended the acquisition of a Mobile Workforce Management (MWM) tool to address three core requirements; Unified Dispatching, Intelligent Job and Route Optimization, and Performance Management capability. MWM tools will enable the following:
    - Increase in daily job completion rates
    - Improve on-time performance
    - Decrease kilometers driven and reduce fuel consumption
    - Cut overtime
    - Reduce field service teams administrative load
    - Reduce morning preparation time before trucks roll
    - Reduce inbound "Where's My Tech" calls
    - Reduce unnecessary truck rolls
    - Improve customer satisfaction
    - Significantly enhance Performance Management discipline

Implementation of today's MWM tools will allow HOL to enjoy the benefits of improved productivity and cost reductions, while also staying a step ahead of the increasing demands of its customers.

Through the use of these technologies a reduction of manual efforts is achieved, thereby creating better efficiencies and overall better reliability. They also allow for greater O&M savings than their initial investments thus reducing the overall lifecycle cost.

**Detailed Short Term Planning**

Having multiple years' worth of projects identified and justified allows design packages to be created in advance, creating a more adaptive plan. Should a project be advanced or deferred due to third party constrains not previously know, crews are able to quickly redirect their time to a project whose construction package is ready for implementation, minimizing down time. As well, by having a detailed short term plan improves coordination with third parties by enabling HOL to start communications far in advance of work being scheduled.

**Storm Hardening**

The Storm Hardening project was a project identified to assess the current state of trees in proximity to HOL's overhead infrastructure and develop new trimming standards that would decrease the impact of tree contact cause outages during adverse weather conditions. Over the course of three years HOL inspected all of the overhead spans of conductor in its service territory. The data gathered is being used to evaluate the current tree trim cycles and look for opportunities to improve the effectiveness of the program with more information on tree species for each span. Also identified through the inspections were 2,650 spans with branches overhanging the conductor. This overhang increases the risk of an outage caused by fallen branches. To reduce this risk, HOL is working to eliminate all vegetation overhangs in the system through a dedicated vegetation management project. Reducing the number of outages caused by tree contacts will save resource costs associated with responding to an outage as well as the cost of repairing or replacing damaged equipment as a result of the fallen branches. This will also have a positive impact on reliability. Moving forward, the elimination of overhang will become part of HOL's tree trimming standards and will be maintained as part of regular trim cycles.

**Committee Participation with Third Parties**

HOL continues to actively participate in committees with third parties, which assist HOL in identifying deficiencies and improvements that allow the company to service customers with a reliable, cost effective supply of electricity at the lowest possible cost. HOL is a member of many technical and standards committees which allows the company to deploy best practices and processes. These committees include:

- Electricity Distributors Association (EDA) Operations Council;
- Electrical Contractors Association (ECA) Ottawa;
- Canadian Standards Association (CSA) Standards committees;
- Electrical Safety Authority (ESA);and
- Canadian Electricity Association (CEA)

**Centre for Energy Advancement through Technological Innovation (CEATI)**

CEATI is a user-driven organization that is committed to providing technology solutions to its electrical utility participants, who are brought together to collaborate and act jointly to advance the industry though the sharing and development of practical and applicable knowledge. These innovations address issues pertinent to day-to-day operations, maintenance, and planning.

In addition to enabling information exchange through topic-driven interest groups and industry conferences, CEATI International brings participants together to collaborate on technical projects. The outcome of these projects has great impact on the infrastructure that HOL plans to use in the future. HOL is a member of numerous interest groups and specialized task forces within CEATI. They are joined by over 120 participating organizations which include electric and gas utilities, governmental agencies, and provincial and state research bodies such as: Hydro One Networks Inc., PowerStream Inc., Toronto Hydro Electric System Limited, National Research Council, Ontario Power Generation, and Ontario Power Authority.

### 1.1.3 DSP Period

The DSP covers the historical period from 2011 to 2015 and outlines the forecast years 2016 to 2020.

### 1.1.4 Vintage of Information

All information and details provided have been compiled throughout 2014, unless otherwise stated, and should be considered as current.

### 1.1.5 Asset Management Process Updates

HOL has not previously filed a DSP, and as such there are no changes since the last filing.

### 1.1.6 Aspects Contingent on Ongoing Activities or Future Events

HOL is currently involved in the Integrated Regional Planning Process (IRRP) (1.2.1.1 Integrated Regional Resource Planning Process) for the Ottawa area, the results of which are currently not final. A number of regional and bulk system needs are currently being studied to determine optimal solutions. The results of the study may recommend specific projects that could impact capital expenditures over the forecast period of 2015 through 2020.

Through HOL's annual Capacity Plan evaluation process, a need for additional capacity in the Lisgar TL station area was identified. HOL opted to engage Hydro One through the IRRP, for the upgrade of the two station transformers to meet the capacity requirements. Hydro One is currently creating estimates for this work so the final costs are not yet determined, and it is anticipated that expenditures will be required within the forecast period of 2015-2020.

Also engaged through Regional Infrastructure Planning (RIP), HOL has a number of station projects identified in the forecast period whose costs are dependent on the outcome of Hydro One Network Inc. evaluation and estimating process – Connection & Cost Recovery Agreements (CCRA), timelines of which have not yet been determined. Refer to 3.4.5 General Plant for more details on the forecasted expenditures.

## 1.2 Coordinated Planning with Third Parties

HOL continues to actively participate in consultations with third parties, which assist HOL in identifying deficiencies and improvements that allow the company to service customers with a reliable, cost effective supply of electricity at the lowest possible cost. HOL consults with customers, the transmitter, the Ontario Power Authority (OPA) (now Independent Electricity System Operator (IESO)), local distribution companies (LDCs), the City of Ottawa, and other third parties to better coordinate infrastructure planning now and into the future. These consultations are described in detail below.

### 1.2.1 Consultations

The following sections provide details on the various groups that HOL consults with in relation to the coordination of infrastructure planning.

#### *1.2.1.1 Integrated Regional Resource Planning Process*

HOL is currently involved in an Integrated Regional Resource Planning (IRRP) process which is being developed by the IESO (includes former OPA). The IRRP began in 2011 but has since been updated due to the OEB's adoption of the Planning Process Working Group report in 2013.

The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission

Assessment Criteria (ORTAC), and develops integrated solutions to address any needs that are identified. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. HOL has provided the IESO (OPA) with an updated long term load forecast, which is provided in Appendix A. The forecast outlines several transmission and distribution stations that will exceed their capacity limitations within the near, medium, and long term. HOL also contributes to the IRRP by identifying feasibility limitations within the planning area that may not be known to the working group (i.e. Greenbelt). The IRRP is to address the arising needs, identifying cost effective and viable solutions. The working group, which consists of the IESO (OPA), HOL, Hydro One Network Inc., and Hydro One Distribution, holds several meetings throughout the year to discuss progress on the study.

The final deliverables from this study are:

- Handoff letters from the OPA to direct the implementation of near term actions; Delivered on June 27th, 2014, Appendix B
- Final 20 year IRRP report; expected in Q1 2015
- Handoff letters from the IESO (OPA) to implement actions addressed via the IRRP report; expected in Q1 2015

#### *1.2.1.2 Customer Engagement*

HOL recognizes customer value at the centre of its Corporate Strategic Objectives and annually engages customers to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and a Touch Logic Survey. The results of these surveys are used to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities. Further details on HOL led customer engagement activities that have a direct impact on the DSP are discussed in section 3.1.10 Customer Engagement Activities.

#### *1.2.1.3 E8 Smart Grid Working Group*

The OEB established the E8 Smart Grid Working Group in 2012 in order to provide a forum for LDCs to share their experiences relating to smart grid technologies. The working group discussions focus on:

- Sharing views, strategic thinking, and development of investment drivers
- Verifying technology specifications
- Examining processes and methodologies
- Identifying business and technical challenges with developing smart grid technologies
- Pursuing opportunities to share these experiences with other LDCs

The members of the working group include the OEB, Hydro One, and the 8 largest LDCs in Ontario which are: HOL, Enersource, Hydro Mississauga Inc., Hydro One Brampton Networks Inc., London Hydro Inc., PowerStream Inc., Veridian Connections Inc., Toronto Hydro Electric System Limited, and Horizon Utilities Corp.

Each LDC has the opportunity to host a meeting and highlight its own smart grid endeavours. HOL continues to benefit from the furthered understanding of smart grid technologies and incorporates these technologies into HOL’s system through future planning processes.

#### *1.2.1.4 City of Ottawa Utility Coordinating Committee (UCC)*

The UCC provides a forum for communication between invited utilities and the City of Ottawa in order to ensure safe and efficient management of the infrastructure within road allowances and other right-of-ways. Every fall, HOL provides the road authority with their proposed major works plan for the following year to gain efficiency enhancements through improved construction scheduling coordination, damage prevention initiatives, and development of standards.

The primary functions of the committee are:

- Jointly plan construction activities
- Set technical standards
- Protect plant
- Provide a quick communication network
- Maintain a central registry
- Resolve disputes
- Assist the road authority with proposed utility installation permit processes

The committee members are: City of Ottawa, HOL, Hydro One Networks Inc., Heavy Construction Association, Enbridge Gas Distribution, Birch Hill Telecom, Bell Canada, Rogers Cable Communications, Telus Communications, and Allstream.

#### *1.2.1.5 Hydro One - LDC Generation Working Group*

The LDC Generation Working Group provides an opportunity for its members to discuss, develop, and potentially adopt policies and best practices relating to LDC distributed generation connections. This allows for better management of the grid when using distributed energy resources, plus effectively and consistently delivering services to generators. The Working Group discussions have also addressed the operational challenges being experienced due to the increase of connected distributed generation. The primary areas addressed by the Working Group are:

- Program administration, both internally within the LDC, and externally to the customer
- Inter-utility communications (especially with embedded LDCs and the Transmitter)
- Engagement with the generation industry
- Engagement with the OEB, IESO (includes the former OPA), and ESA as needed on policy and procedural issues
- Forecast of and adaptation to generation trends and needs
- Technical concerns, resolutions, and standards with respect to:
    - Generation connection: enhancing the customer’s experience
    - Grid management: planning and assessing available generation capacity
    - Operations: outage planning and restoration, permitting temporary run on alternate feeders
    - Inspections and maintenance: ensure safety of people and assets
    - Assessing impact of distributed generation on existing customers and the distribution system

The working group meets quarterly and is comprised of: Hydro One Networks Inc., HOL, Kingston Hydro Corp., Horizons Utilities, Newmarket-Tay Power Distribution Limited, Greater Sudbury Hydro Inc., PowerStream Inc., Toronto Hydro Electric System Limited, London Hydro Inc., and the OPA (now IESO).

HOL believes that continued discussions with the Working Group will improve future planning and operating processes related to the integration of REGs.

### *1.2.1.6 Ontario Regional Common Ground Alliance (Ottawa)*

The Ontario Regional Common Ground Alliance (ORCGA) was established after the amalgamation of the Ontario Prevention Committee and the Third Party Damage Prevention Task Force. It was formally recognized by the Common Ground Alliance (CGA) in 2003 as a partner. The ORCGA develops best practices which represent a dynamic statement of the type of activities that ORCGA believes would provide optimum levels of due diligence towards preventing damage to underground infrastructure. Beyond establishing standard practices, the committee allows for a forum between its members to discuss upcoming projects and local issues. The ORCGA actively tries to improve safety to all stakeholders by raising awareness about safe digging practices via Dig Safe Month in Ontario.

The committee members are: ORCGA, Ontario One Call, HOL, BayCadd Solutions, Promark-Telecon, Enbridge Gas Distribution, Broadband Maintenance, Bell, Hydro One Networks Inc., Goldie Mohr Limited, Drain All, Aecon Utilities, City of Ottawa, TransCanada Pipelines, TransNorthern Pipelines, TSSA, Oakwood Renovations, Marathon Drilling, Bell, UES, Dunda Powerline, and Taggart Construction.

HOL ensures that these standards and processes are used in its practices and through the forum discussions, actively plans future construction activities with the committee members.

### *1.2.1.7 Greater Ottawa Home Builders Association (GOHBA) – Builder Developer Council (BDC)*

GOHBA represents home building and renovation professionals in the Greater Ottawa area with a primary goal of delivering quality housing for Canadians. HOL attends the BDC monthly meetings to take note of and provide input on development plans. The benefits of this council are:

- Customers provide feedback on HOL's practices
- HOL provides insight into developments in order to minimize cost and deliver a timely supply
- HOL provides updated standards and financial changes that may affect projects

- Future development plans allow HOL to forecast load growth and plan infrastructure in order to supply the area

The BDC has over 30 members representing home developers, law firms, and utilities. These members include: GOHBA, HOL, Bell Canada, Rogers Cable Communications, Minto, Mattamy Homes, Walton Development, Vice & Hunter LLP, and Borden Ladner Gervais LLP.

### 1.2.2 Deliverables

The numerous consultations between HOL and the various third parties described in Section 1.2.1 above continue to be ongoing. The outcome of these efforts result in better understanding and coordination between the various parties involved. Any final deliverables that arise from the coordinated efforts are used in HOL's planning process and capital expenditure plans.

At this time, the IRRP has produced a final deliverable in the form of a handoff letter from the OPA (now IESO) to Hydro One Networks Inc. as seen in Appendix B. This letter details the initiation of development work on near and mid-term transmission solutions to meet the needs identified by the working group. Specifically, the letter contains two transmission solutions that have been identified in impacting HOL's capital expenditure plan. These solutions will be developed and implemented by Hydro One Networks Inc. Currently, the date and cost to HOL is not known and it is unlikely that material investment will be identified for this Application's Test Year period. However, the date and costs of this work has the potential to fall within HOL's Forecast Years.

### 1.2.3 IESO Letter of Comment – HOL's REG Investments Plan

As described in Chapter 5, the IESO Comment Letter, which can be found in Appendix C, outlines the IESO's assessments of HOL's REG Investments Plan including:

- The applications the IESO has received from renewable generators through the Feed-In-Tariff (FIT) program for connection in the HOL distribution service area;
- Whether HOL has consulted or participated in planning meetings with the IESO;
- The need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- Whether the REG investments proposed in the DSP are consistent with any RIP.

## 1.3 Performance Measurement for Continuous Improvement

HOL uses Key Performance Indicators (KPI) to measure continuous improvement in asset management planning, capital investment planning and in customer oriented performance. These indicators include quantitative measures to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement. Table 1.3.1 outlines the key performance indicators, by category, which are described in detail in the following sections.

**Table 1.3.1 - Key Performance Indicators by Category**

| Category | Key Performance Indicator | Sub KPI |
|---|---|---|
| **1.3.1.1 Customer Oriented Performance** | 1.3.1.1.1 Customer Engagement | |
| | 1.3.1.1.2 System Reliability Performance Indicators | o SAIFI<br>o SAIDI<br>o CAIDI<br>o $FEMI_{10}$ |
| | 1.3.1.1.3 Worst Feeder Analysis | |
| | 1.3.1.1.4 System Average RMS Variation Frequency Index (SARFI) | |
| **1.3.1.2 Cost Efficiency & Effectiveness** | 1.3.1.2.1 Cost Efficiency | |
| | 1.3.1.2.2 Labour Utilization | o Productive Time<br>o Labour Allocation |
| **1.3.1.3 Asset Performance** | 1.3.1.3.1 Defective Equipment Contribution to SAIFI | |
| | 1.3.1.3.2 Health, Safety and Environment | |
| **1.3.1.4 System Operations Performance** | 1.3.1.4.1 Stations Exceeding Planning Capacity | |
| | 1.3.1.4.2 Feeders Exceeding Planning Capacity | |
| | 1.3.1.4.3 Stations Approaching Rated Capacity | |
| | 1.3.1.4.4 Feeders Approaching Rated Capacity | |
| | 1.3.1.4.5 System Losses | |

### 1.3.1 Distribution System Planning Process Performance Indicators

The following sections describe the quantitative KPIs used by HOL to monitor the quality of the planning process and the efficiency with which the plans are implemented and the extent to which the planning objectives have been met.

#### *1.3.1.1 Customer Oriented Performance*

HOL continuously seeks feedback from customer on their satisfaction with the services provided by HOL. The customer satisfaction levels have proven to be greatly impacted by the distribution system's service reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, as part of the Annual Planning Report (see Attachment B-1(B)), HOL undertakes a thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

##### 1.3.1.1.1 Customer Engagement

HOL recognizes customer value at the centre of its Corporate Strategic Objectives and annually engages customers to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the annual Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and monthly Touch Logic Surveys. The results of these surveys provide HOL with KPIs which HOL uses to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities.

##### 1.3.1.1.2 System Reliability Performance Indicators

HOL tracks system reliability performance using the following indicators:

**System Average Interruption Frequency (SAIFI)**

This index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words, the definition is:

$$SAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

This index is reported both including and excluding Loss of Supply (LoS). *SAIFI including LoS* provides information as to the total interruptions which are seen by the 'average' customer. *SAIFI excluding LoS* indicates the 'average' customer interruptions which are the result of causes under the direct control of HOL.

HOL's target is always to reduce SAIFI. Reliability driven sustainment projects along with better defined testing, inspection and maintenance programs will help to reduce the number of outages experienced.

**System Average Interruption Duration Index (SAIDI)**

This index is designed to provide information about the average time customers are interrupted. In words, the definition is:

$$SAIDI = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

This index is reported both including and excluding Loss of Supply (LoS). As with SAIFI, the *SAIDI including LoS* provides information as to the total duration of interruptions which are seen by the 'average' customer whereas *SAIDI excluding LoS* provides an indication as to the duration which the 'average' customer is interrupted as the result of causes under the control of HOL.

HOL's target is always to reduce SAIDI. Increased investments in system automation and new equipment trials will help expedite restoration efforts after outages occur.

**Customer Average Interruption Duration Index (CAIDI)**

CAIDI represents the average time required to restore power to the average customer per sustained outage. In words, the definition is:

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customer\ interruptions}$$

**Feeders Experiencing Multiple Sustained Interruptions (FEMI$_n$)**

This index represents the number of feeders experiencing sustained (greater than 1 minute) outages greater than or equal to value n; current reporting is done for n=10. It is a customer centric measure as it provides an indication as to which regions have seen high localized issues. $FEMI_{10}$ is reported excluding Scheduled Outages as well as Loss of Supply, to more accurately track regions seeing issues, as opposed to including regions seeing multiple outages due to maintenance, repair and upgrade activities.

HOL's target is always to reduce FEMI. Reliability driven sustainment projects as well as better defined testing, inspection and maintenance programs will help to reduce the number of outages experienced.

#### 1.3.1.1.3 Worst Feeder Analysis

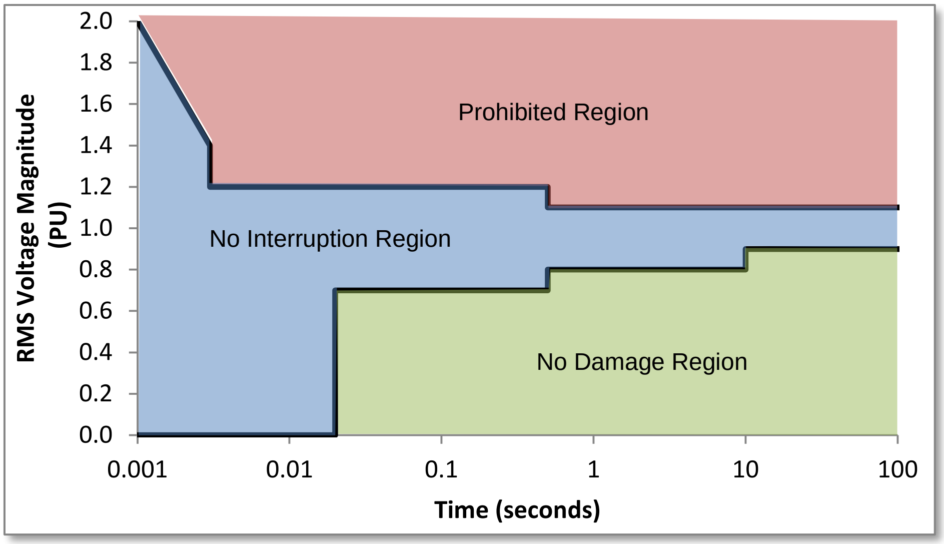
In 2011, a standard method to determine the "Worst Feeders" was defined. This method takes into consideration the duration, frequency and number of sustained outages as well as the number of momentary (duration < 1min) interruptions a feeder experiences. See Appendix D for details on how these factors are incorporated in the overall determination of the Worst Performing Feeders. Annually, based on the Worst Feeder Methodology, the 10 worst feeders are evaluated and potential improvements to the feeders are proposed.

The worst feeder program is designed to address short term reliability issues in an immediate time-frame. All work identified in the previous year review will be carried out in the following budget year, with targeted completion before the beginning of storm season. In the fall of 2015, identification and assessment of the worst feeders will again be carried out and appropriate actions will be undertaken to improve performance of the identified circuits.

#### 1.3.1.1.4 System Average RMS Variation Frequency Index (SARFI)

The System Average Root Mean Square (RMS) Variation Frequency Index (SARFI) is an indicator of system power quality which measures the average number of voltage sags on the system. Poor voltage is considered to be outside ±6% of the system nominal voltage and it is HOL's objective to maintain voltage within these tolerances and below the prohibited region of the Information Technology Industry Council (ITIC) curve (see Figure 1.3.1). The target is to put corrective measures in place as soon as possible.

**Figure 1.3.1 - ITIC Curve**




### 1.3.1.2 *Cost Efficiency & Effectiveness*

On an annual basis, HOL uses the cost efficiency and labour utilization KPIs to report on the progress, efficiency and effectiveness to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement.

#### 1.3.1.2.1 Cost Efficiency

Cost Efficiency is an indicator of the amount of planned capital activities as a ratio to actual capital activities performed throughout the year. Cost efficiency is strictly a measure of all planned projects in System Renewal and System Service Investment Categories, but does not include System access or General Plant investments. Completion of the planned capital projects are monitored through HOL's financial system. Deviations from the project budget are managed through a change request process that must be justified and approved. Representatives from scheduling, construction, engineering and design meet on a bi-weekly basis to prioritize on-going and upcoming work in order to ensure work is completed on time and within budget. The target of the cost efficiency indicator is to achieve 100% completion of the annual planned work within the approved budget.

#### 1.3.1.2.2 Labour Utilization

HOL tracks labour utilization performance using the following indicators:

**Productive Time**

Productive time represents the total regular hours charged to a work order as a ratio to total regular hours. The target of the productive time indicator is to maximize this index by identifying and improving efficiencies.

$$Productive\ Time = \frac{Percent\ of\ Billable\ Hours}{Total\ Regular\ Hours}$$

**Labour Allocation**

The labour allocation index represents the amount of labour spent on capital activities as a ratio to the total productive time. The target of the labour allocation indicator is to ensure that the appropriate amount of time is spent on Capital activities versus OM&A type activities as per annual work plans.

$$Labour\ Allocation = \frac{Percent\ of\ Labour\ Time\ on\ Capital\ Activities}{Total\ Productive\ Time}$$

### 1.3.1.3 *Asset Performance*

HOL tracks asset performance using the following KPIs:

#### 1.3.1.3.1 Defective Equipment Contribution to SAIFI

This indicator tracks the contribution of defective equipment outages by asset class to the overall system SAIFI per 100 customers (SAIFI x 100). HOL’s objective is to reduce the number of interruptions caused by defective equipment from year to year.

#### 1.3.1.3.2 Health, Safety and Environment

The Health & Safety and Environment indicator tracks the number of public safety concerns and the amount of oil spilled into the environment. Public safety concerns and oil spills are addressed immediately; therefore no specific objective has been set, as the goal is to simply reduce these numbers.

#### 1.3.1.4 *System Operations Performance Indicators*

HOL tracks system operation performance using the following KPIs:

##### 1.3.1.4.1 Stations Exceeding Planning Capacity

This indicator is defined by the percentage of stations with a summer peak operating above 100% of their planned capacity rating.

The planned capacity rating is defined as the sum of either the transformers' 10 day LTR or the allowable top load rating if there is no published LTR for the remaining transformers following a single contingency loss of the largest element within the substation (N-1 contingency). An N-1 contingency for a station is defined as the loss of the largest transformer within the station. Note that for stations with a single supply and a single transformer, the planning capacity rating is considered to be the rated capacity of the single unit (10 day LTR or allowable top load rating if there is no published LTR).

##### 1.3.1.4.2 Feeders Exceeding Planning Capacity

This indicator is defined by the percentage of feeders with a summer peak operating above 100% of their planned capacity rating.

The planned capacity rating for a feeder takes three factors into consideration:

1. Coordination with lo-set instantaneous protection;
    - Under normal pre-contingency operating conditions, a feeder cannot be loaded above a level that would result in the lo-set instantaneous protection preventing feeder restoration, see the description below for cold load pick up.
2. Feeder cold load pick up ability; and
    - Outage analysis indicates that the cold-load and hot load pick up phenomenon results in approximately 2-times the feeder pre-contingency loading at 0.2 seconds (trip time setting for lo-set instantaneous protection).

| Voltage (kV) | Lo-set Inst. Pick Up (A) | Cold Load Factor | Feeder Load Limit (A) |
|---|---|---|---|
| 4.16 | 600 | 2 | 300 |
| 8.32 | 600 | 2 | 300 |
| 12.47 | 700 | 2 | 350 |
| 13.2 | 1000 | 2.5 | 400 |
| 27.6 | 1000 | 2.5 | 400 |

3. Short term (8 hour) egress cable overload capabilities
    - Under normal pre-contingency operating conditions, a feeder cannot be loaded above the nominal capacity rating of the cable. In addition, a feeder must be capable of backing up neighbouring feeder(s) in the event of failure of supply of the neighbouring feeder or other contingency conditions. For the purposes of providing back-up ability, it is assumed that the feeder will be required to operate in the abnormal configuration with post-contingency loading levels for up to 8 hours.

| Voltage (kV) | Typical Egress Cable | Design Rating (A) | 8hr Rating (A) |
|---|---|---|---|
| **4.16** | 5kV 4/0 Cu PILC, buried in duct | 285 | 330 |
| **8.32** | 15kV, 500 MCM Cu XLPE, direct buried | 675 | 870 |
| **12.47** | 15kV, 500 MCM Cu XLPE, direct buried | 675 | 870 |
| **13.2** | 15kV 500 MCM Cu PILC, duct bank | 425 | 510 |
| **27.6** | 29kV, 750 MCM Al XLPE, duct bank | 450 | 620 |
| **27.6** | 29kV, 1000 MCM Al XLPE, duct bank | 500 | 685 |

Given the constraints outlined above, the following limits are used based on feeder egress cable type:

| Voltage (kV) | Typical Egress Cable | 8hr Loading Limit (A) | Cold Load Limit (A) | Planning Limit (A) | Limiting Factor |
|---|---|---|---|---|---|
| **4.16** | 5kV 4/0 Cu PILC | 330 | 300 | 300 | Coordination between Lo-set instantaneous protection and cold/hot load pick-up |
| **8.32** | 15kV, 500 MCM Cu XLPE | 870 | 300 | 300 | Coordination between Lo-set instantaneous protection and cold/hot load pick-up |
| **12.47** | 15kV, 500 MCM Cu XLPE | 870 | 350 | 350 | Coordination between Lo-set instantaneous protection and cold/hot load pick-up |
| **13.2** | 15kV 500 MCM Cu PILC | 510 | 400 | 255 | Ability to provide adequate back-up capability for neighbouring circuits |
| **27.6** | 29kV, 750 MCM Al XLPE | 620 | 400 | 310 | Ability to provide adequate back-up capability for neighbouring circuits |
| **27.6** | 29kV, 1000 MCM Al XLPE, | 685 | 400 | 340 | Ability to provide adequate back-up capability for neighbouring circuits |

##### 1.3.1.4.3 Stations Approaching Rated Capacity

This indicator is defined by the percentage of stations at or above 100% of the station rated capacity.

The rated capacity is defined as the sum of the top rating (10-day LTR or allowable flat rating should an LTR not be published) of all transformers within the station. If the loading on a transformer exceeds this limit it will cause accelerated loss of life.

##### 1.3.1.4.4 Feeders Approaching Rated Capacity

This indicator is defined by the percentage of feeders at or above 90% of the rated capacity.

The rated capacity is defined as the egress cable 8 hour loading limit. If the circuits are loaded above this limit for longer than 8 hours it will cause overheating and accelerated loss of life.

##### 1.3.1.4.5 System Losses

Distribution losses are defined in the *Ontario Energy Board's Distribution System Code* as: "energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows".

### 1.3.2 Performance Summary

The following sections provide a summary of performance and performance trends over the historical period using the methods and measures identified above.

#### *1.3.2.1 Customer Oriented Performance*

HOL continuously seeks feedback from customer on their satisfaction with the services provided by HOL. The customer satisfaction levels have proven to be greatly impacted by the distribution system's service reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, as part of the Annual Planning Report (see Attachment B-1(B)), HOL undertakes a thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

#### 1.3.2.1.1 Customer Satisfaction

Customer value is at the centre of HOL's Corporate Strategic Objectives and customers are engaged annually to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and a Touch Logic Survey. The results of these surveys provide HOL with KPIs which HOL uses to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities.

#### 1.3.2.1.2 System Reliability Performance Indicator

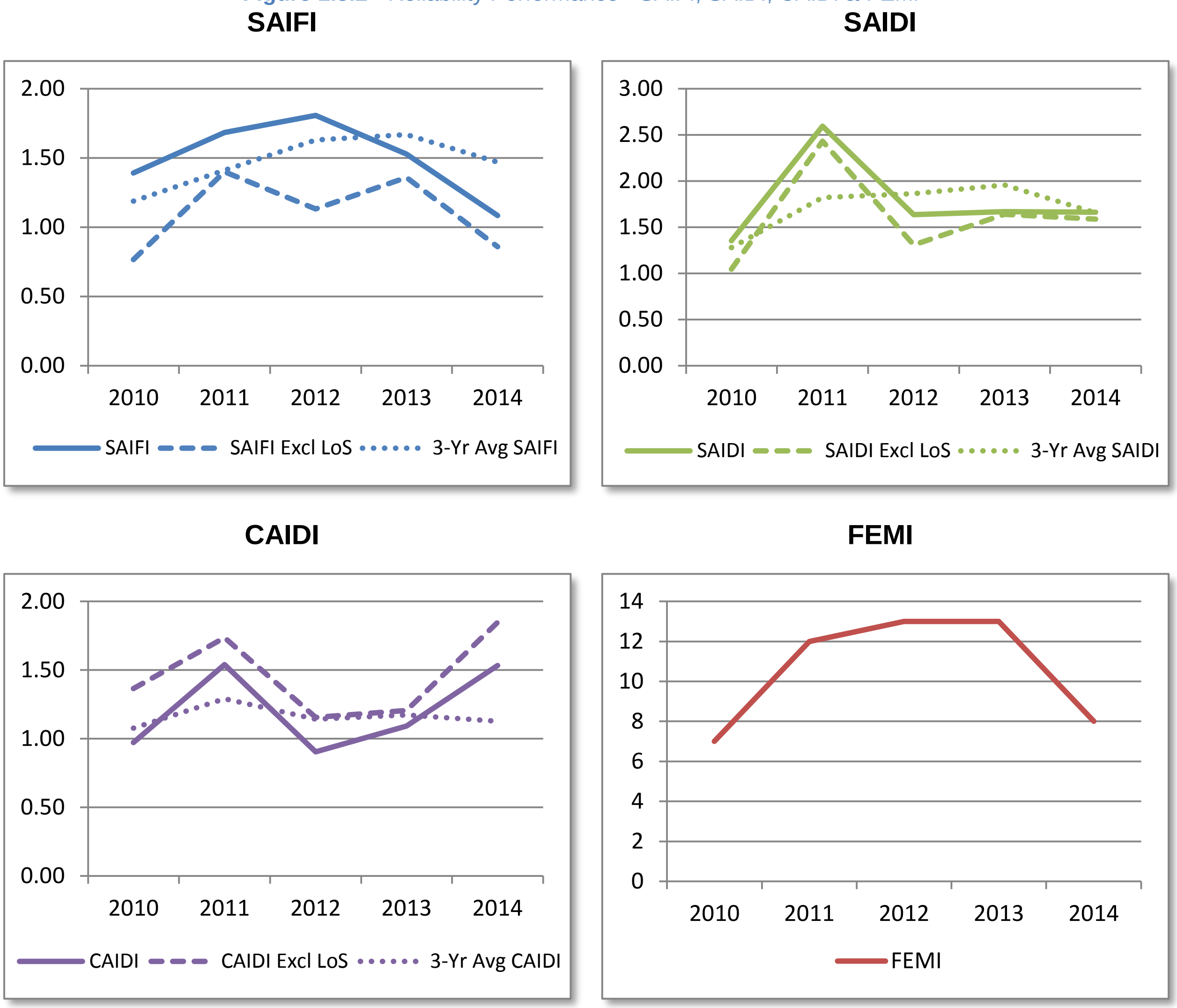
HOL's reliability performance in 2014 improved from previous years. Interruption categories such as defective equipment and adverse weather, or storm related outages have been progressively trending worse and have exceeded the previous 3-year averages. Improvements to the asset management processes are underway making use of the new C55 Asset Investment Planning software to enhance our ability to prioritize end of life asset replacements. Maintenance, inspection and testing of existing assets will continue to be essential to ensure equipment operates as expected and to identify failures before they occur. Consideration of new ways of operating to reduce system susceptibility to storm damage and foreign interference is vital. In addition, investing in grid technologies will benefit reliability by reducing restoration times and aid in predicting system faults. HOL's objective is to improve the System Reliability Performance Indicators from year to year.

**Table 1.3.2** - Reliability Performance Summary

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Annual SAIFI | 1.39 | 1.68 | 1.81 | 1.53 | 1.08 |
| SAIFI Excl LoS | 0.77 | 1.40 | 1.13 | 1.36 | 0.86 |
| 3-Yr Average SAIFI | 1.19 | 1.41 | 1.63 | 1.67 | 1.47 |
| Annual SAIDI | 1.35 | 2.60 | 1.64 | 1.67 | 1.66 |
| SAIDI Excl LoS | 1.05 | 2.43 | 1.31 | 1.64 | 1.59 |
| 3-Yr Average SAIDI | 1.28 | 1.82 | 1.86 | 1.96 | 1.66 |
| Annual CAIDI | 0.97 | 1.54 | 0.90 | 1.09 | 1.53 |
| CAIDI Excl LoS | 1.37 | 1.74 | 1.15 | 1.21 | 1.85 |

| | | | | | |
|---|---|---|---|---|---|
| 3-Yr Average CAIDI | 1.08 | 1.29 | 1.14 | 1.17 | 1.13 |
| $FEMI_{10}$ | 7 | 12 | 13 | 13 | 8 |

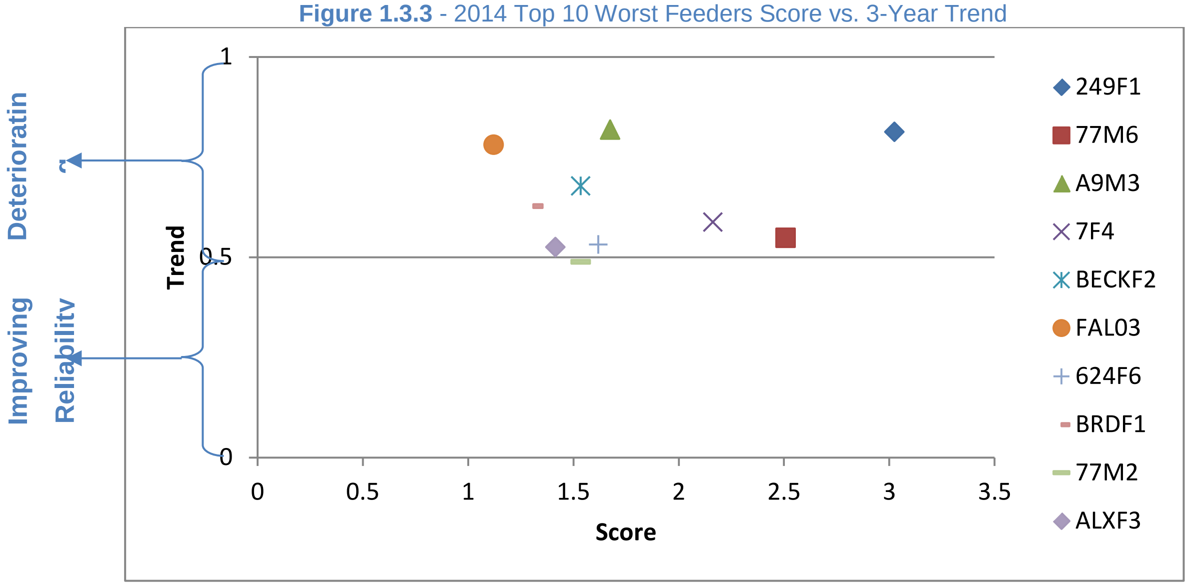
**Figure 1.3.2** - Reliability Performance - SAIFI, SAIDI, CAIDI & FEMI




### 1.3.2.1.3 Worst Feeder Analysis

The Worst Feeder Methodology recommends tracking the worst feeders over a three year period to allow time for the improvements to be seen. The following figure outlines the 10 worst feeders for 2014 and where they sit in regards to Score versus Trend. Note that feeders that have a trend below 0.5 are seeing an improvement in reliability (1 feeder in 2014 – 77M2). Moving forward, the feeders will need to be continually tracked to determine whether the improvements made in the distribution have had an impact on improving the feeder's reliability. It is believed that there will be at least a three year lag in seeing the improvements on the feeder – 1 year for the improvement to be implemented and the two following years to develop a new trend.

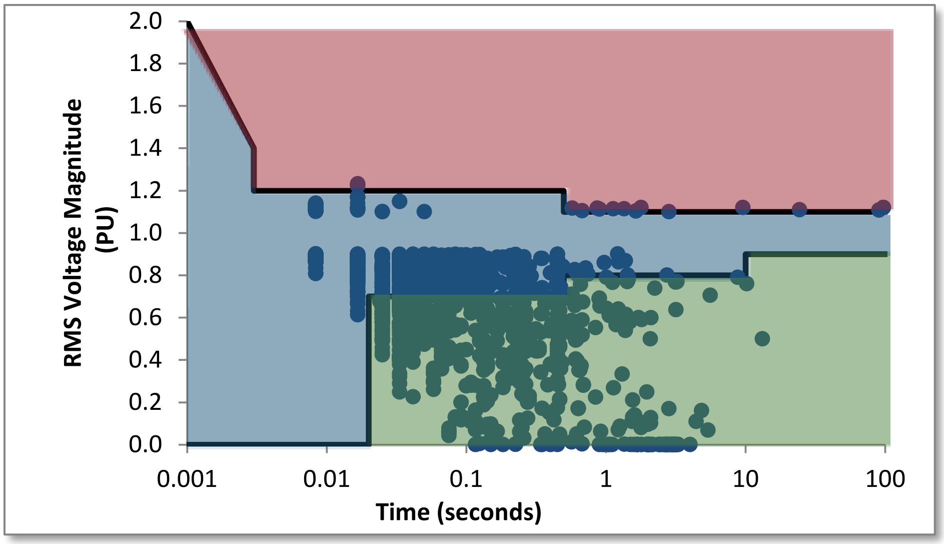
**Figure 1.3.3** - 2014 Top 10 Worst Feeders Score vs. 3-Year Trend




### 1.3.2.1.4 System Average RMS Variation Frequency Index (SARFI)

The Information Technology Industry Council (ITIC) curve represents the 2013 RMS voltage variation events plotted against the variation envelope which single phase modern devices can tolerate. Of the 2820 events recorded in 2013, 16 fell within the prohibited region. The target is to put corrective measures in place as soon as possible. Of the 16 prohibited events, 11 were due to events on the transmission system (not owned by HOL), 2 were of unknown cause and 2 were due to HOL feeder faults.

**Figure 1.3.4** - 2013 Power Quality Events ITIC Curve




*Note that 2014 Power Quality Events ITIC Curve is not yet available

### *1.3.2.2 Cost Efficiency & Effectiveness*

On an annual basis, HOL uses the cost efficiency and labour utilization KPIs to report on the progress, efficiency and effectiveness to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement.

#### 1.3.2.2.1 Cost Efficiency

HOL identified the Cost Efficiency indicator in 2011 which annually targets to complete 100% of the work planned. In 2011 and 2012, the target was not achieved as a result of resources being unavailable due to the amount of plant failure repairs that were completed in those years. In 2013, HOL was able to complete an additional 5% above the target of the work planned as a result of unplanned work that was deemed required to increase the amount of risk mitigated.

**Table 1.3.3 - Cost Efficiency**

| KPI | Target | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Cost Efficiency | **100%** | 94% | 94% | 105% | 94% |

#### 1.3.2.2.2 Productive Time

HOL's annual target for the Productive Time indicator is to improve from the year before. The indicator which began being tracked in 2011, is affected by training, vacation and sick time, but also does not account for the work completed on overtime. Further efficiencies will need to be identified in order to maximize this index and contribute to trending improvement.

**Table 1.3.4 - Productive Time**

| KPI | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Productive Time | 70% | 71% | 69% | 69% |

#### 1.3.2.2.3 Labour Allocation

HOL identified the Labour Allocation indicator in 2011 which aims to aid in the evaluation that the proper amount of time is spent on capital versus OM&A as per each year's annual plan. Labour allocation is hindered by aging infrastructure requiring increased hours spent on O&M activities

**Table 1.3.5 - Labour Allocation**

| KPI | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Labour Allocation | 61% | 55% | 56% | 59% |

### *1.3.2.3 Asset Performance*

HOL tracks asset performance using the following KPIs:

#### 1.3.2.3.1 Defective Equipment Contribution to SAIFI

Asset failures impact the ability to provide reliable customer service to different extents. The impact of asset failures on system reliability is currently on an upward trend. The specific assets which are contributing to this trend include Underground Cable Attachments, Station Switchgear, Overhead and Underground Transformers, and Poles. Increased or more targeted asset replacement may be required to manage these assets such that they do not adversely impact system reliability performance. Trends are reviewed in HOL's Asset Management Planning Report as part of the Annual Planning Report (see Attachment B-1(B)) on an annual basis to establish a target for the frequency and the quantity of assets to be replaced.

**Table 1.3.6** - Defective Equipment SAIFI per 100 Customers

| Asset | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|
| U/G Cable - Polymer | 5 | 10 | 4 | 2 |
| Insulator | 2 | 7 | 0.3 | 0.1 |
| Station Switchgear | 2 | 5 | 0 | 3 |
| O/H Switchgear | 4 | 4 | 3 | 6 |
| U/G Cable Attachment | 2 | 3 | 2 | 5 |
| Station Transformer | 1.2 | 1.2 | 2 | 0 |
| U/G Switchgear | 1 | 1 | 7 | 0.1 |
| U/G Cable - PILC | 0.7 | 0.6 | 0.6 | 1.5 |
| O/H Transformer | 0 | 0 | 1 | 2 |
| Pole | 0 | 0 | 1 | 4 |
| U/G Transformer | 1 | 0 | 3 | 3 |
| Other | 6 | 9 | 6 | 5 |
| Total | 25 | 41 | 30 | 32 |

*Note that 2014 Defective Equipment SAIFI per 100 Customers data is not yet available

### 1.3.2.3.2 Health, Safety and Environment

HOL reports to the Ministry of the Environment on oil spilled and the cost of remediation. Recent trends are seeing more leaking residential padmounted transformers which have increased the cost of remediation. This emphasizes the importance of active inspection and replacement of padmounted transformers to mitigate this environmental impact.

**Table 1.3.7 - Health & Safety and Environment**

| | | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Public Safety | Number of Public Safety Concern (PSCs) | 9 | 4 | 2 | 10 |
| Oil Spills | Annual Oil Spilled (L) | 1,262 | 1,225 | 3,249 | 5,828 |
| | Annual Oil Clean up ($'000) | $378 | $563 | $465 | $792 |

*Note that 2014 Health & Safety and Environment indicators are not yet available

### *1.3.2.4 System Operations Performance Indicators*

System capacity is currently trailing load growth in the City of Ottawa; this has resulted in fifteen percent of the stations owned by HOL operating above their planning capacity rating set to ensure that adequate capacity is reserved for reliable operation during system contingency.

In 2013, three stations were loaded above their equipment ratings at system peak: Richmond North DS, Nepean TS and Hawthorne TS. Work to increase capacity at Richmond South DS is scheduled to begin in 2015 and will allow for better load balancing between Richmond North and South to alleviate the overload condition. The Hawthorne TS units are currently planned for replacement by Hydro One and load balancing at Nepean TS should resolve the slight overload seen in 2013. There is a positive trend being shown in the data: as capacity projects progress the system is seeing less stress since 2010.

Losses remained within the acceptable range of between 2% to 4%. HOL continues to work to reduce system losses through better system planning and the updating or replacement of equipment.

Feeders exceeding their planning ratings are within target (≤ 10%), but careful review and planning is being undertaken to ensure adequate backup is maintained to allow for secure and reliable delivery of power for HOL's Customers.

**Table 1.3.8 - System Operations Performance Indicators**

| KPI | Target | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Stations Exceeding Planning Capacity | ≤ 5% | 26% (20) | 24% (22) | 20% (18) | 15% (14) |
| Feeders Exceeding Planning Capacity | ≤ 10% | 3.5% (28) | 3.4% (27) | 3.3% (26) | 3.2% (22) |
| Stations Approaching Rated Capacity | zero | 4.4% (4) | 2.2% (2) | 2.2% (2) | 3.3% (3) |
| Feeders Approaching Rated Capacity | zero | 0.4% (3) | 0.5% (4) | 0.5% (4) | 0.3% (2) |
| System Losses | ≤ 4.00% | 3.12% | 3.13% | 3.60% | 2.63% |

*Note that 2014 System Operations Performance Indicators are not yet available

### 1.3.3 Effect of Key Performance Indicators on the DSP

HOL's Corporate Strategic Objectives and targets provide the framework for the DSP. The KPIs used to evaluate the company are defined by the Customer Oriented Performance indicators, the Cost Efficiencies & Effectiveness indicators, the Asset Performance indicators and the System Operations Performance indicators. Tracking of these KPIs will allow HOL to set benchmarks and milestones to ensure that the company objectives of continuous improvement are achieved across all areas of business.

# 2 Asset Management Process

The following sections outline HOL's Asset Management Process – the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures. The information is intended to provide the Board and stakeholders with an understanding of the process, and the direct links between the process and the expenditure decisions that comprise the investment plan.

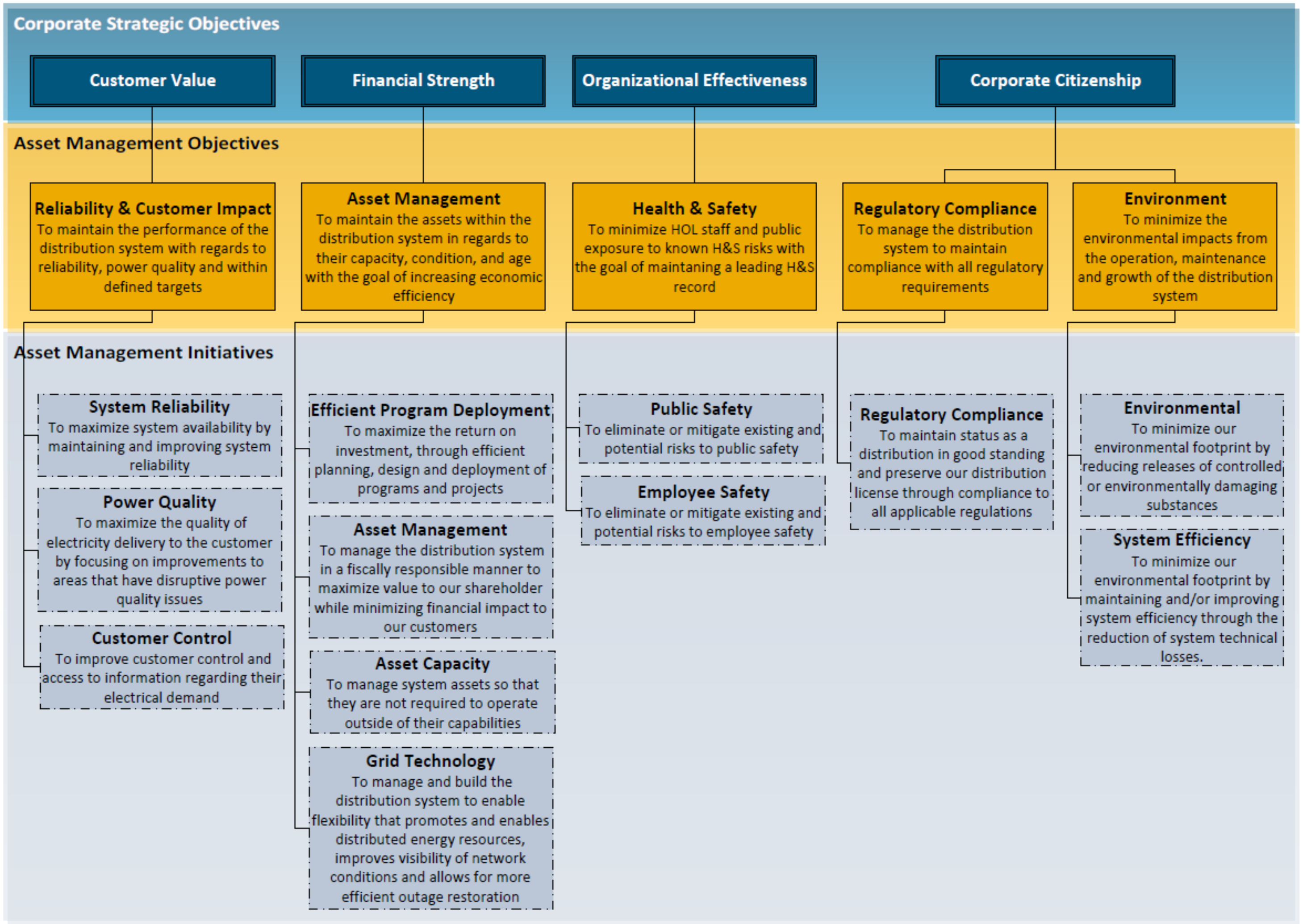
## 2.1 Asset Management Process Overview

The Asset Management Process Overview section details the Asset Management Objectives and each component in the Asset Management Process.

### 2.1.1 Asset Management Objectives

The Asset Management Process aligns with HOL's Corporate Strategic Direction by adhering to the Asset Management Initiatives that directly support the Corporate Strategic Objectives as outlined in Section 1.0.1. The hierarchy between the Corporate Strategic Direction through to the Asset Management Initiatives is shown in Figure 1.0.2. Figure 2.1.1 describes the Asset Management Objectives and the associated Asset Management Initiatives which drive the decision making through the Asset Management Process.

1 **Figure 2.1.1 - Asset Management Objectives & Asset Management Initiatives**




2

### 2.1.2 Asset Management Process Components

HOL's Asset Management Process, as shown in Figure 2.1.2, is a function of 5 difference phases:

1) Project Concept Definition (Section 2.1.2.1)
2) Project Evaluation (Section 2.1.2.2)
3) Project Prioritization (Section 2.1.2.3)
4) Project Execution (Section 2.1.2.4)
5) Risk Assessment & Review (Section 2.1.2.5)

The Project Concept Definition phase gathers all internal and external drivers to describe the needs of the organization. Concept projects are created to meet requirements, mitigate or remove risk, and reach goals and objectives.

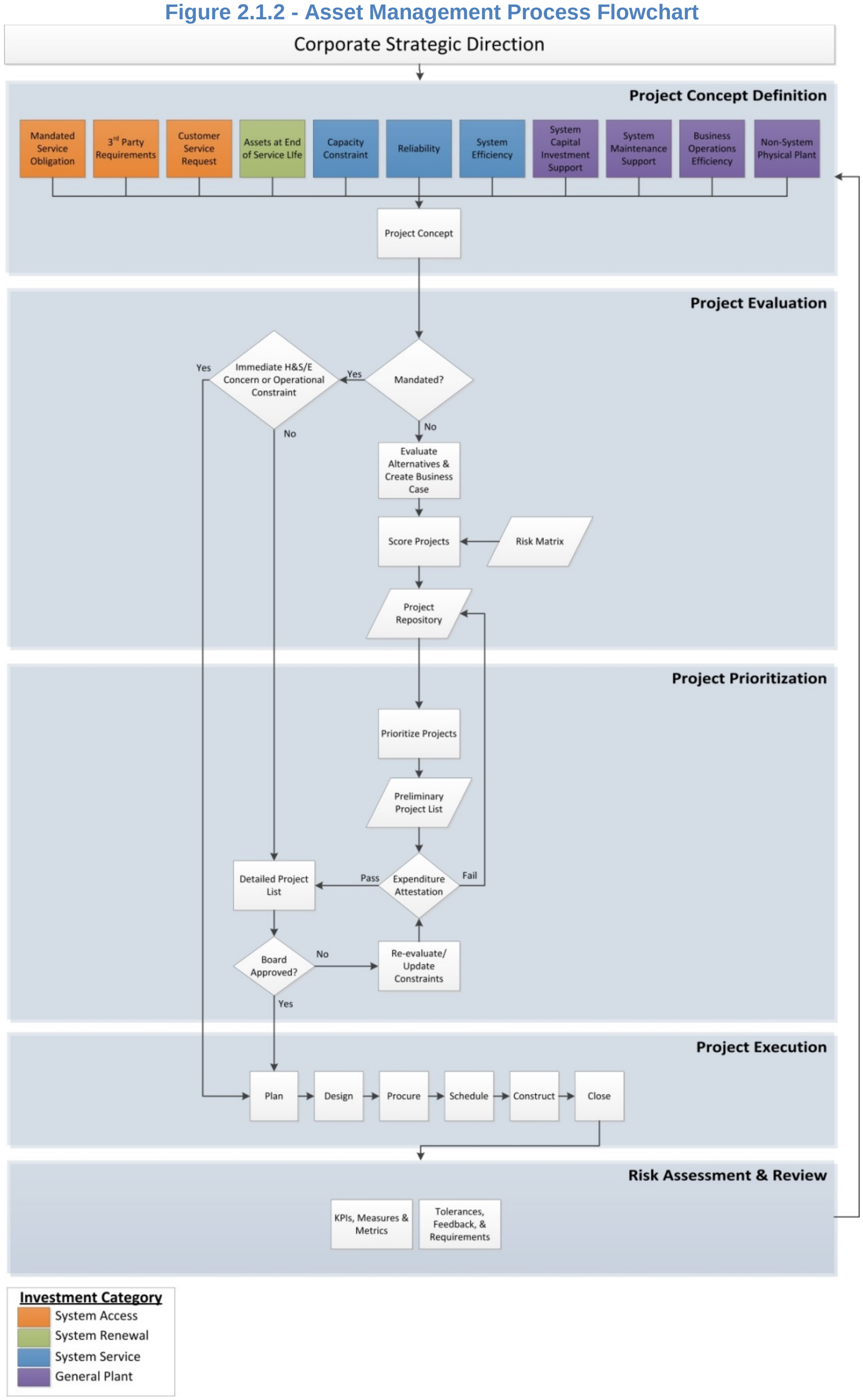
The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated and valued based on their impact to HOL`s Corporate Strategic Objectives.

The Project Prioritization phase ranks each project based on their value. Resource constraints are used to create a detailed project list for HOL Executive Board approval.

The Project Execution phase uses HOL's Project Coach methodology to manage and execute the project plan. HOL's project coach is based on Project Management Institute best practices.

The Risk Assessment & Review phase measures progress on the Corporate Strategic Objectives, through the Asset Management Initiatives, and evaluates risk based on acceptable tolerances. This phase also captures feedback from the Project Execution phase to allow for continuous improvement and adjustments to the Asset Management Process such as lessons learned and increased forecast accuracy.

**Figure 2.1.2 - Asset Management Process Flowchart**



#### *2.1.2.1 Project Concept Definition*

The Project Concept Definition phase gathers all internal and external drivers to describe the needs of our organizational environment. Concept projects are created to meet requirements, mitigate or remove risk, and reach Corporate Strategic Objectives. Table 2.1.1 outlines the description of the drivers by Investment Category, which are detailed in following sections.

**Table 2.1.1 - Driver Descriptions**

| Investment Category | Driver | Description |
|---|---|---|
| System Access | Mandated Service Obligation | Regulatory requirement to maintain distribution licence under the OEB's Distribution System Code or requirement as per HOL's Conditions of Service |
| | 3rd Party Requirements | Request by a 3rd party for plant relocation or upgrade to an existing service |
| | Customer Service Request | Customer request for new connection (load or generation) |
| System Renewal | Assets at End of Service Life<br>i. Failure<br>ii. Failure Risk<br>iii. Substandard Performance<br>iv. High Performance Risk | i. Asset no longer meets functional requirements<br>ii. Asset is at risk to no longer meet functional requirements<br>iii. Asset still meets functional requirements; however, falls below standards for operability or efficiency<br>iv. Asset is at risk of failure in a way that can cause harm or damage to other equipment or assets or would put the distribution system in a detrimental state |
| System | Capacity Constraint | Requirement for additional capacity |

| | | |
|---|---|---|
| Service | | (station transformation or circuit) due to planned or realized load increases |
| | Reliability | Requirements driven by poor distribution system performance such as abnormally (high) duration or frequency of interruptions |
| | System Efficiency | Requirements for improved system operability and visibility |
| General Plant | System Capital Investment Support | • Capital contributions to Hydro One for connection projects<br>• Requirement for fleet/vehicle acquisition |
| | System Maintenance Support | Requirement for tools and associated equipment |
| | Business Operations Efficiency | Requirements for Information Technology software and systems |
| | Non-System Physical Plant | Building infrastructure requirements |

##### 2.1.2.1.1 System Access

**Mandated Service Obligations**

Mandated Service Obligations are requirements of a distributor as defined by the OEB's Distribution System Code, as well as any additional obligations as defined by HOL's Conditions of Service. For example, providing metering and making repairs to damaged equipment to provide service to customers.

**3rd Party Requirements**

3rd Party Requirements are initiated from requests received for the relocation or upgrade (modifications) of assets or infrastructure. For example, pole relocation for road widening.

**Customer Service Request**

Customer Service Requests arise from the needs of load or generation customers for new connections. For example, servicing for new commercial buildings, residential subdivisions, or generators including any system expansion required to supply the site of development.

#### 2.1.2.1.2 System Renewal

**Assets at End of Service Life**

HOL describes its asset replacement strategy, or asset management plan, in the Asset Management Planning Report (AMPR), contained within the Annual Planning Report (Attachment B-1(B)). The intention of the AMPR is to document the asset management practices used by HOL as part of an optimized lifecycle strategy for distribution and station assets and to document the Asset Condition Assessment (ACA). The objective of the ACA is to confirm that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future while staying within the targeted levels of risk.

The ACA is a key component of the asset management planning process. Addressed in the asset management plan are the financial, technical, and management elements needed for making sound, innovative or best practice asset management decisions.

The asset management plan looks ahead 20 years with a main focus on the first five years – for this period most of the planned projects have been identified. Beyond this period, analysis is less precise. Based on long term trends, current asset demographics, known asset issues or needs on the system, it is likely that new and planned projects will evolve in the latter half of the forecasted period.

The intent of the asset management plan is on optimizing the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet reliability service targets and future demand. Each year, the aim is to improve the plan by taking advantage of new information and changing technology.

HOL's system assets range in age from new to over 50 years old. The management of these assets is critical to providing safe, reliable and efficient electricity distribution services to its customers.

The following list describes the key variables that are used to inform the Asset Condition Assessment as part of the asset management plan.

- Testing, inspection & maintenance records to inform condition;
- Asset demographic and nameplate information;
- Asset failure statistics – number of failures and frequency by asset type (SAIFI);
- Financial useful lives; and
- Financial records – cost per replacement.

The following list describes the results of the asset management planning process.

- Recommended asset replacement rates, refurbishment and associated annual spend;
- Asset condition (health index); and
- Projected failure rates based on spending/replacement levels.

#### 2.1.2.1.3 System Service

**Capacity Constraints**

HOL routinely assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and upgrades which are consistent with all regulatory requirements for the connection of customers and with due consideration for safety, environment, finance and supply system reliability/security are developed. HOL summarizes the results of this capacity planning process in the Capacity Planning Report, contained within the Annual Planning Report (Attachment B-1(B)), in which the short and long term capacity needs for the service territory are identified.

In this regard, the supply needs in the service territory have been assessed to determine if additions and/or upgrades are required to maintain adequate and reliable/secure system capacity. HOL, being an amalgamation of 5 utilities, is composed of several subsystems which are segregated by operating voltage and geographical boundaries. The capacity planning process reviews and summarizes the business case for each subsystem, identifying short and long term projects. Forecasted growth, asset replacement schedules, and reliability are all factors in planning the system.

The following describes the key variables that are used to inform the capacity planning process.

- Historical station transformer loading from the system wide annual peak day (weather normalized and adjusted to a one-in-ten year peak for forecasting);
- Historical feeder loading from the system wide annual peak day (weather normalized and adjusted to a one-in-ten year peak for forecasting);
- Station, station transformer and feeder planning capacity and ratings;
- Asset condition;
- System configuration and operating characteristics (and restrictions);
- Number of HOL customers;
- Historic energy purchased and delivered;
- Summer and winter peak load;
- City of Ottawa Official Plans and Community Development Plans;
- Land use designation and population and employment projections;
- Known developments through conversation with developers and City staff;
- Distributed generation connections and capacity;
- Station capacity to connect generation and plans in place to address any restrictions;
- Details and plans resulting from the Integrated Regional Resource Planning process with the IESO and Hydro One; and
- Details relating to Connection & Cost Recovery Agreements (CCRA) with Hydro One for station or transmissions projects

The following describes the results of the capacity planning process.

- One-in-ten year peak load forecasts (20 years) for each region/station;
- Need dates for capacity concerns; and

- Projects to address capacity needs (station upgrades, new stations, line extensions, transmission upgrades, voltage conversions);

**Reliability**

HOL continuously assesses the distribution system's service reliability. Where issues are found, the appropriate actions are identified to address these concerns. Service reliability is integral to all work undertaken as part of system planning and asset management. The reliability planning process is summarized in the Reliability Planning Report, contained within the Annual Planning Report (Attachment B-1(B)), and does not supersede the importance of good asset management and system capacity planning in the management of system reliability. Rather, it provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

Reliability driven projects are those which are designed to reduce outage frequency or duration regardless of the cause. Such initiatives are almost exclusively automation projects. In general, work considered as part of the system reliability plan are:

- Deployment of remote sensors;
- Deployment of remotely operable and autonomous devices;
- Deployment of field devices to provide fault indications locally;
- Supporting technologies to automation (i.e. communication & SCADA); and
- Modifications to existing standards (i.e. animal guards).

Successful lifecycle management of HOL's assets will have direct impact on system reliability – assets that are optimally maintained throughout their life, asset replacement prior to failure, and system planning to increase operability and reduce downtime.

The following describes the key variables that are used to inform the reliability planning process.

- Historical outage statistics (primary cause, secondary cause, duration, number of customers affected, circuit affected, station affected, date of interruption);
- Power quality measures (System Average RMS Frequency Index – voltage sags and swells); and
- Worst Feeder evaluation.

The following describes the results of the reliability planning process.

- Asset failure statistics – number of failures and frequency by asset type (SAIFI);
- Projects to improve the Worst Feeders reliability performance;
- Initiatives to improve overall reliability (specific to top 3 causes of interruption from the previous year); and
- Details on automation plans and how they will impact reliability.

**System Efficiency**

HOL's reliability planning process also reviews system efficiency, monitoring system losses and power quality. By maintaining voltage to CSA standards, customers can expect all of their devices, equipment and appliances to operate as intended and expected without damage or noticeable irritations such as dimming or flickering lights.

System Efficiency also comes from operating the system in an effective way. The SCADA system is key element for monitoring, controlling, and diagnosing HOL's network. It allows HOL's operators to quickly react to anomalies in the system by remotely operating devices or dispatching local crews to an accurate location.

#### 2.1.2.1.4 General Plant

**System Capital Investment Support**

System Capital Investment Support captures the requirements for capital contributions to Hydro One for transmission connection projects as well as for HOL fleet acquisition.

**System Maintenance Support**

System Maintenance Support covers the requirements for tools and associated equipment used by HOL crews.

**Business Operations Efficiency**

Business Operations Efficiency is the requirement for Information Technology software and systems used to support daily business activities.

**Non-System Physical Plant**

Non-System Physical Plant captures the life cycle requirements for buildings.

### *2.1.2.2 Project Evaluation*

The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated and valued based on their impact to HOL`s Corporate Strategic Objectives.

Project concepts are first reviewed to determine if they are a mandatory project. Mandatory projects are typically dictated through the Distribution System Code or the Electricity Act. They range from customer connections, to line relocations, to restoring power in a timely fashion. Sometimes several alternatives are available to address a mandatory need in which case they are evaluated and one alternative is selected. These projects are then prioritized if they pose immediate concerns to health & safety, environment, or constrain the operation of the system. Immediate concerns move directly to the Execution phase and have the potential to take precedence over planned projects and cause deferral or delays. Otherwise, the projects make their way into the Detailed Project List, in the Investment Prioritization phase and are scheduled to be completed in an appropriate timely manner.

Non-mandated project concepts are reviewed and evaluated and possible alternatives are developed which will meet the desired objectives of the project. This evaluation is done through a business case development which clearly documents decisions.

Project alternatives are then scored by identifying their risk and/or benefit as it relates to HOL's Asset Management Initiatives through use of the Risk Matrix. The evaluation Consequence Matrix is shown in Table 2.1.2 which specifies the probability of an event occurring and the consequence of that event.

Event probability is specified either as a certainty or a variable associated with a state of a system element. The probability of an event is defined based on existing HOL process/evaluation or through sound engineering judgment. The key to the scoring process is that the probability is acknowledged to be variable in time (often increasing). To enable the development of a work plan, event probability reaching out to 20 years is required; with a 5 year window (i.e. probability is assessed for year 0, 5, 10, 15 and 20).

The consequence as it pertains to each measure is assessed on a linear scale. This scale covers the range of impact from *None* to *Severe* with an associated score of 0 to 6, respectively.

Each consequence has an associated weighting, see Figure 2.1.3, each having a dual function to normalize and to rank. While it is intended that the scoring scales between measures are normalized, the use of the weighting factors to assist in this is acceptable. Further, weighting is used to rank both the priority of a measure and its impact; a measure which has a relatively low impact on its associated initiative will also have a lower weighting. The sum of the weights of all the measures for a given Asset Management Objective must be equal to 1. The weighting of the measures is under the purview and approval of the Manager of Asset Planning.

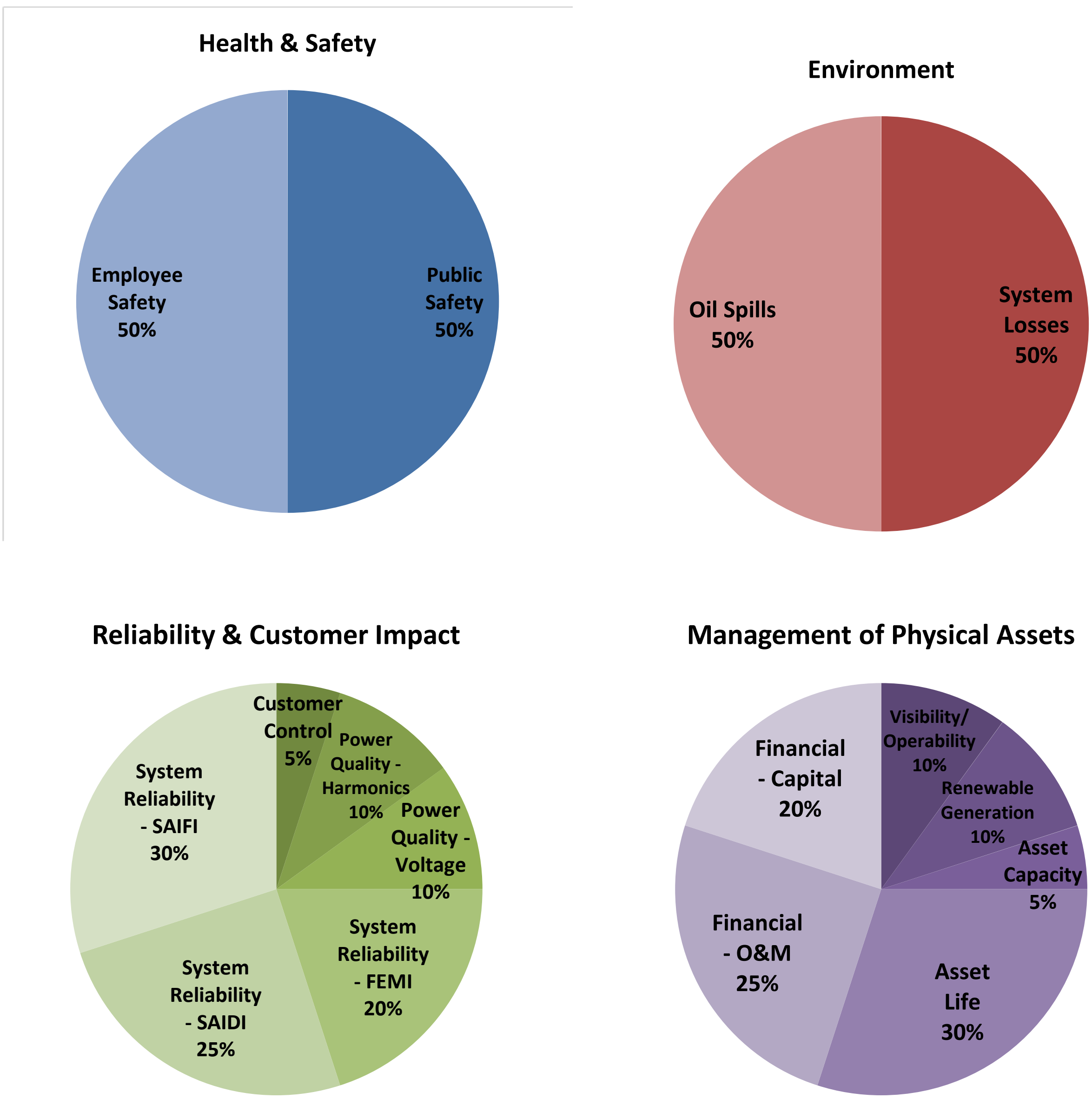
1 Table 2.1.2 - Asset Management Consequence Matrix (1/3)

| Score | Level | Reliability & Customer Impact | | | | |
|---|---|---|---|---|---|---|
| | | **System Reliability (SAIFI)** | **System Reliability (SAIDI)** | **System Reliability (FEMI)** | **Power Quality (Voltage)** | **Power Quality (Harmonics)** |
| 6 | **Severe** | Will the project impact ≥ 5000 customers? | Will the project impact an area where restoration takes several days and may require additional resources? | Will this project impact feeder(s) within the upper decile of the FEMI score? | Will this project mitigate a customer investment of $5000 to rectify an issue? | Will this project mitigate a customer investment of $5000 to rectify an issue? |
| 5 | **Major** | Will the project impact ≥ 2500 customers? | Will the project impact an area where restoration takes up to 24 hours and will require all available crews? | Will this project impact feeder(s) within the upper quarter of the FEMI score? | Will this project mitigate a customer investment of ≤$5000 to rectify an issue? | Will this project mitigate a customer investment of ≤$5000 to rectify an issue? |
| 4 | **Significant** | Will the project impact ≥ 1000 customers? | Will the project impact an area where restoration takes up to 12 hours? | Will this project impact feeder(s) within the median and upper quarter of the FEMI score? | Will this project mitigate customer complaints and equipment damage? | Will this project mitigate customer complaints and equipment damage? |
| 3 | **Moderate** | Will the project impact ≥ 500 customers? | Will the project impact an area where restoration takes up to 8 hours? | Will this project impact feeder(s) within the lower quarter and median of the FEMI score? | Will this project mitigate customer complaints? | Will this project mitigate customer complaints? |
| 2 | **Minor** | Will the project impact ≥ 250 customers? | Will the project impact an area where restoration takes up to 6 hours? | Will this project impact feeder(s) within the lower quarter of the FEMI score? | Will this project mitigate customer complaints and voltages exceeding the standard levels defined in the Conditions of Service? | Will this project mitigate customer complaints and result in the generation of harmonics outside standard levels defined in the Conditions of Service? |
| 1 | **Minimal** | Will the project impact ≥ 100 customers? | Will the project impact an area where restoration will take up to 4 hours? | Will this project impact feeder(s) within the lower decile of the FEMI score? | Will this project mitigate voltages exceeding the standard levels defined in the Conditions of Service? | Will this project mitigate the generation of harmonics outside standard levels defined in the Conditions of Service? |
| 0 | **None** | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable |

| Score | Level | Asset Management | | | |
|---|---|---|---|---|---|
| | | Efficient Program Deployment | Asset Management (Asset Condition) | Asset Management (Asset Life) | Asset Capacity |
| 6 | Severe | Will the project eliminate an increase to O&M costs by >10% per year? | Will the project impact an asset that has failed? | Will the project impact an asset that will be required to operate beyond 50% of the useful life? | Will the project reduce the requirement of an asset to operate 20% beyond the rated capacity? |
| 5 | Major | Will the project eliminate an increase to O&M costs by ≤10% per year? | Will the project impact a Condition 5 asset? | Will the project impact an asset that will be required to operate beyond 35% of the useful life? | Will the project reduce the requirement of an asset to operate 17.5% beyond the rated capacity? |
| 4 | Significant | Will the project eliminate an increase to O&M costs by ≤8% per year? | Will the project impact a Condition 4 asset? | Will the project impact an asset that will be required to operate beyond 25% of the useful life? | Will the project reduce the requirement of an asset to operate 15% beyond the rated capacity? |
| 3 | Moderate | Will the project eliminate an increase to O&M costs by ≤6% per year? | Will the project impact a Condition 3 asset? | Will the project impact an asset that will be required to operate beyond 15% of the useful life? | Will the project reduce the requirement of an asset to operate 12.5% beyond the rated capacity? |
| 2 | Minor | Will the project eliminate an increase to O&M costs by ≤4% per year? | Will the project impact a Condition 2 asset? | Will the project impact an asset that will be required to operate beyond 10% of the useful life? | Will the project reduce the requirement of an asset to operate 10% beyond the rated capacity? |
| 1 | Minimal | Will the project eliminate an increase to O&M costs by ≤2% per year? | Will the project impact a Condition 1 asset? | Will the project impact an asset that will be required to operate beyond 5% of the useful life? | Will the project reduce the requirement of an asset to operate 5% beyond the rated capacity? |
| 0 | None | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable |

| Score | Level | Health & Safety | | Environment |
|---|---|---|---|---|
| | | **Public Safety** | **Employee Safety** | **Oil Spills** |
| 6 | **Severe** | Will the project mitigate the possibility of a severe injury? (permanent injury) | Will the project mitigate the possibility of a severe injury? (permanent injury) | Will the project mitigate the potential release of more than 2000L of oil? |
| 5 | **Major** | Will the project mitigate the possibility of a minor injury? (require hospital stay) | Will the project mitigate the possibility of a minor injury? (require hospital stay) | Will the project mitigate the potential release of 1000L to 2000L of oil? |
| 4 | **Significant** | Will the project mitigate the possibility of a significant injury? (require hospital visit) | Will the project mitigate the possibility of a significant injury? (require hospital visit) | Will the project mitigate the potential release of 200L to 1000L? |
| 3 | **Moderate** | Will the project mitigate the possibility of an injury? (short term medical leave) | Will the project mitigate the possibility of an injury? (short term medical leave) | Will the project mitigate the potential release of 100L to 200L of oil? |
| 2 | **Minor** | Will the project mitigate the possibility of a minor injury? (require first aid) | Will the project mitigate the possibility of a minor injury? (require first aid) | Will the project mitigate the potential release of 50L to 100L of oil? |
| 1 | **Minimal** | Will the project mitigate the possibility of a very minor injury? (bump, bruise, etc.) | Will the project mitigate the possibility of a very minor injury? (bump, bruise, etc.) | Will the project mitigate the potential release of less than 50L of oil? |
| 0 | **None** | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable | Immaterial consequence or Not Applicable |

**Figure 2.1.3 - Measure Weighting**

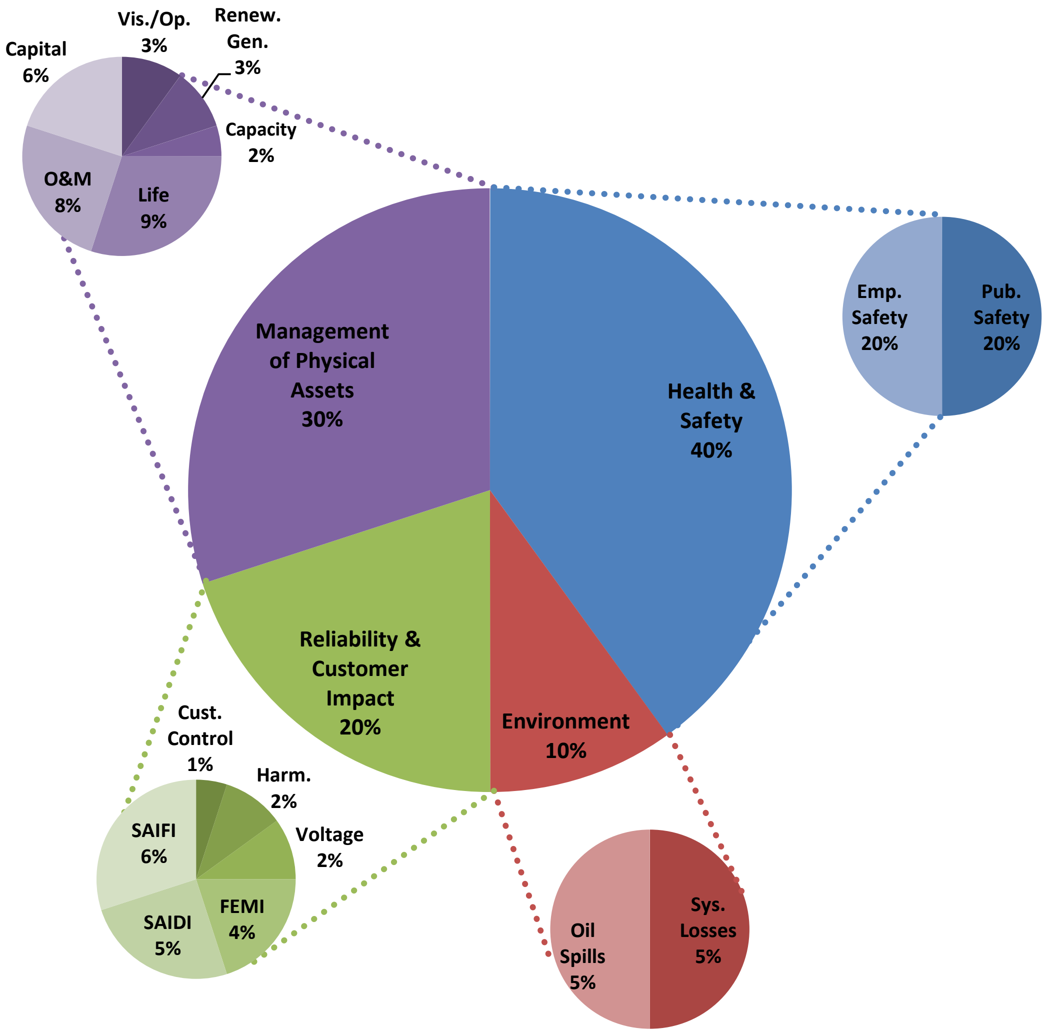


The risk associated with not undertaking an investment is calculated for each of the Asset Management Objectives first. Risk related for a given event is then calculated as the product of the event probability in a given year and the weighted sum of the associated consequences for each measure. Risk to the Asset Management Objective is calculated as the maximum risk, in a given year, of all of the associated events.

Each *Asset Management Objective* has an associated weight, which reflects the organizational prioritization of that objective and, as such, the associated weighting must be endorsed by the HOL Executive. The current objective weightings are summarized in Figure 2.1.4.

The Risk Score is a value which reflects a given overall investment's support of the Asset Management Objectives. This is calculated as the weighted sum of the risk for each Asset Management Objective in a given year. Although it is not quantified, Risk Score is considered to have an associated monetary value.

**Figure 2.1.4 - Asset Management Objective Weightings**




Once all projects have been scored on their risks and benefits, they are recorded in the Project Repository which contains all short and long term projects under consideration. This central location allows for all projects to be evaluated against one another and prioritized for planning.

### *2.1.2.3 Project Prioritization*

The Project Prioritization phase ranks each project based on their value. All projects in the project repository are prioritized based on their risk score. This allows for all projects to be evaluated based on the same criteria to determine what projects will provide the most value based on the Asset Management Initiatives. Investments are prioritized to maximize the value (i.e. risk score per dollar of investment). This cost/benefit ratio is calculated as the present value of the project cost (maximum 5 year window) over the 5 year present value of the project Risk Score. Investments are then prioritized based on ranking of this cost/benefit ratio. Projects with the lowest cost/benefit ratio are given higher priority over those with higher cost/benefit ratios.

A Preliminary Project List is created based on the prioritization process and expert knowledge of the needs and impact of the proposed projects. This list is attested against expenditure and resource constraints to create the Detailed Project List.

While it is preferred that the timing for all investments are based on this prioritization, mandated investments will arise, typically due to external drivers. When such investments occur they will have reasoning clearly documented and the impact to planned objectives will be reviewed.

The Detailed Project List of prioritized investments then moves on for approval from HOL's Executive Management Team and Board of Directors before proceeding to execution. This ensures that Corporate Strategic Objectives are being met through the proposed investment plan. Constraints may be re-evaluated and updated to meet objectives or mitigate risk.

#### *2.1.2.4 Execution*

The Execution phase follows an HOL internal project management methodology called "Project Coach" which defines the core lifecycle for projects. Project Coach is based on the internationally accepted standard for project management: Project Management Body of Knowledge (PMBOK) issued by the Project Management Institute.

Project Coach provides specific guidelines, procedures, work instructions and industry best practices that will allow Hydro Ottawa personnel to perform project work in an efficient, effective and high quality manner. Processes described in Project Coach are intended to be scalable and applicable to all projects, regardless of complexity and implements a consistent approach to planning, scheduling and execution of projects.

Project Coach describes 6 steps in the execution of the project:

1) **Planning & Project Initiation (Plan) –** The project charter, scope and objectives are created. Key players take steps to initiate the project and engage any needed authorization.
2) **Design –** The project charter, scope and objectives is reviewed and approved. Preliminary and detailed project design and estimates are created.
3) **Procurement & Circulation (Procure) –** The project design is approved. Material and services are procured.
4) **Scheduling (Schedule) –** The project is scheduled with key milestones and deliverable dates.
5) **Construction (Construct) –** The project is executed with a continuous review on progress and risk to completion.
6) **Closure (Close) –** The project documentation, financials, and reviewed lessons learned are completed. Feedback and lessons learned are registered and communicated for continuous improvement.

#### *2.1.2.5 Risk Assessment & Review*

The Risk Assessment & Review phase measures progress on the Corporate Strategic Objectives, through the Asset Management Initiatives, and evaluates risk based on acceptable tolerances. This phase captures feedback from the Project Execution phase to allow for continuous improvement and adjustments to the Asset Management Process.

The results of the Execution Phase are measures on operational performance which can be compared against baselines to identify trends. These measures are used to support the performance measurements identified in Section 1.3. The results are used to re-establish drivers by identifying what work was completed, if objectives have been met, and if there is still unacceptable risk that needs to be addressed.

## 2.2 Overview of Assets Managed

The overview of assets managed section of the DSP provides a summary of the features of HOL's distribution service area, demographics and condition of the assets managed. It also summarizes the current state of the system loading as it relates to station and feeder capacity.

### 2.2.1 Features of the Distribution Service Area

HOL was formed in November 2000 following the amalgamation of 5 municipal utilities of the former region of Ottawa-Carleton, and the restructuring of the Ontario electricity sector as a result of the Electricity Act, 1998. This has resulted in a diverse system with multiple service voltages and a variety of construction standards. HOL has worked hard since amalgamation to unite the former utilities with common processes and design standards.

HOL distributes electricity to 318,706 (October 2014) metered customers within the City of Ottawa and the Village of Casselman – an urban environment. See Figure 2.2.1 - HOL Service Territory for a map of HOL's service territory. The service area covers 1,104 square kilometers and is supplied by an even mix of overhead and underground feeders. In 2013, HOL purchased a total of 7,722 Gigawatt hours of electricity from the provincial grid to supply our customers. As the City grows, former rural areas fed by long distribution lines are becoming urban centres. This demands higher reliability expectations from customers.

HOL's service territory is additionally challenged by the natural barrier of the Rideau River and the Greenbelt which limits distribution connectivity in some areas of the system. As a result, system planning must consider these barriers when mapping out the distribution circuitry and evaluating capacity options.

Large segments of the system were constructed in the 1960s, 70s and 80s – as most assets have a lifespan on the order of 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end of life. The increased potential of failures posed by these aging assets will, without intervention, impact the organization's ability to guard worker and public safety, maintain system reliability and protect organizational strength in the future.

Overall, the City of Ottawa continues to grow in population and developed lands, primarily focused in five regions: the Downtown Core, Nepean & Riverside South, South Kanata &

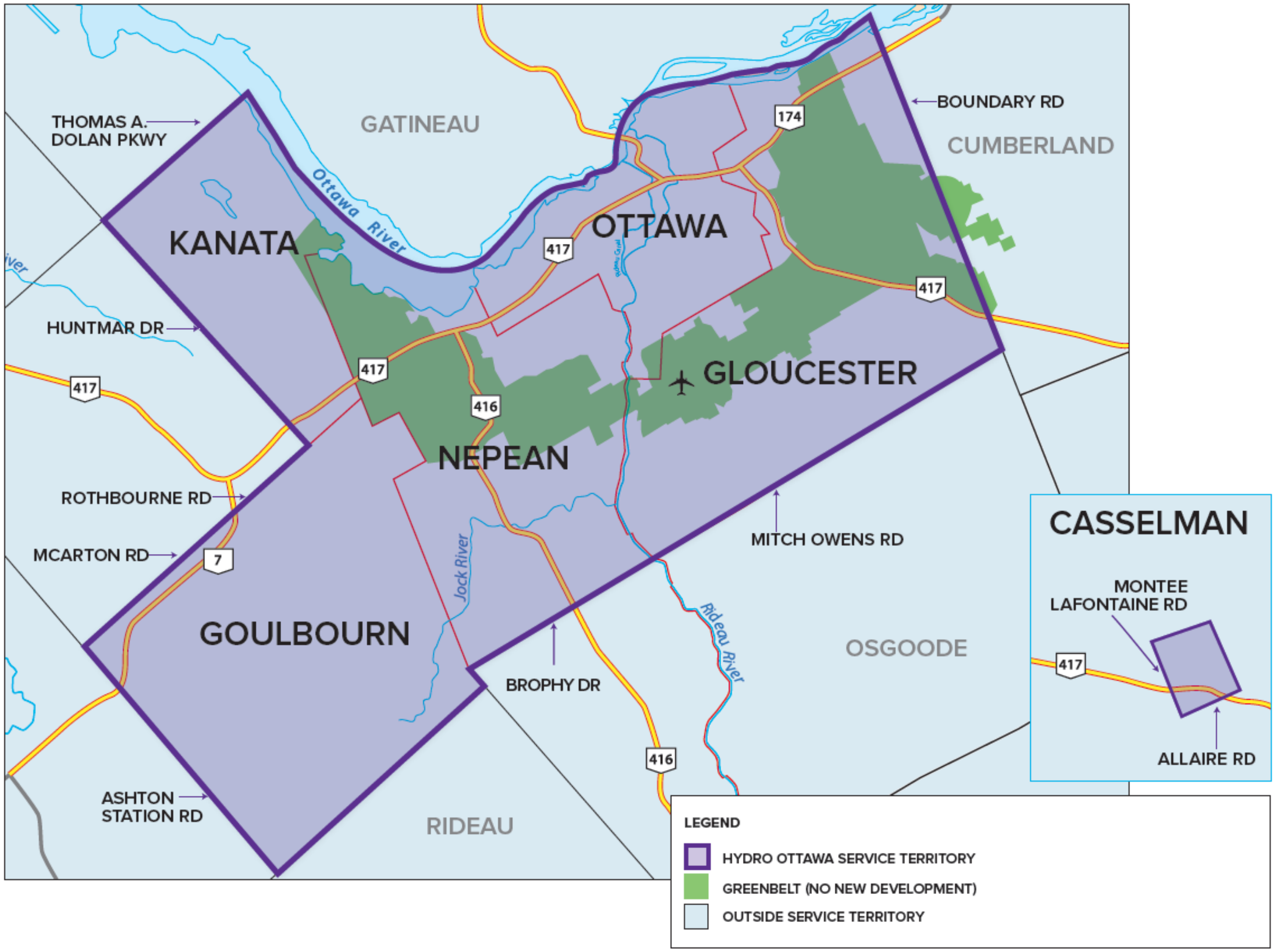
Stittsville, the Village of Richmond and Orleans. The City has not seen any slowing of development as a result of the economic downturn and growth is expected to continue into the future. This growth is being seen through the development of new mixed commercial/residential communities, intensification of existing communities as well as major projects like the Ottawa Light Rail Transit (OLRT) system.

**Table 2.2.1 - Conference Board of Canada Population and GDP Forecast**

| | | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Pop | ('000) | 1,237 | 1,258 | 1,277 | 1,295 | 1,311 | 1,322 | 1,333 | 1,346 |
| | (%) | 0.44% | 0.40% | 0.37% | 0.33% | 0.29% | 0.20% | 0.21% | 0.27% |
| GDP | ($M) | $60,424 | $62,273 | $63,028 | $62,459 | $62,870 | $63,676 | $65,036 | $ 66,518 |
| | (%) | 0.55% | 0.70% | 0.36% | -0.16% | 0.00% | 0.41% | 0.53% | 0.57% |

*Source: Conference Board of Canada, Ottawa-Gatineau Region

1 **Figure 2.2.1 - HOL Service Territory**

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The following examples outline some of the issues that need to be addressed while planning the distribution system in Ottawa.

**Climate Normals Comparison**

In comparison to other major Ontario cities, Ottawa is characterized by having generally lower wind speeds and colder winters with higher snowfall (with the exception of Sudbury).

HOL strives to complete capital work year round; however, work must be scheduled to accommodate the winter months in which there are greater hazards to our crews and more challenges to overcome in the field, such as snow removal before work can even begin.

The data presented in the following charts represents the Climate Normals from 1981-2010 as recorded by the Government of Canada.

**Figure 2.2.2 - Daily Maximum Temperature**

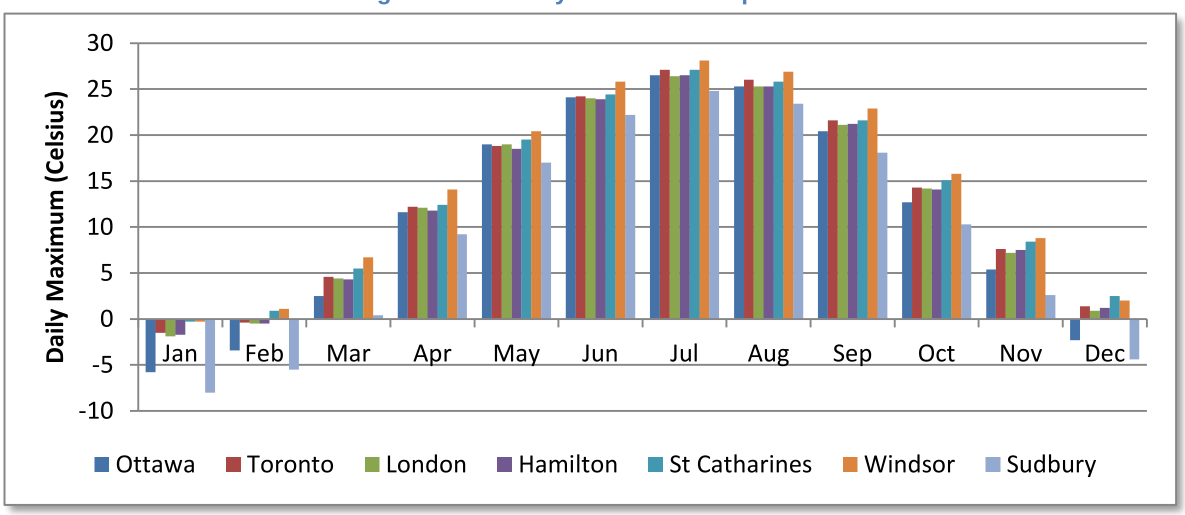


Figure 2.2.3 - Daily Minimum Temperature

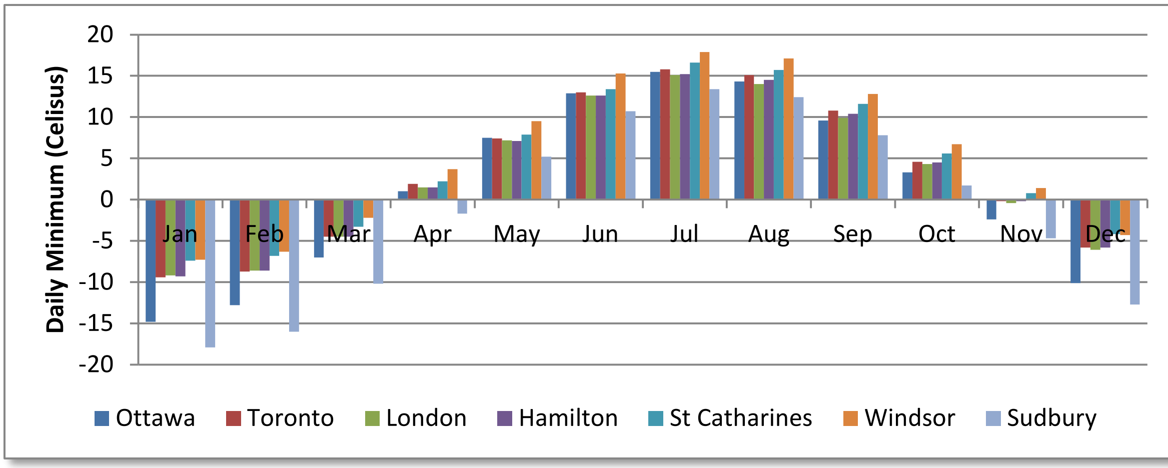



Figure 2.2.4 - Rainfall

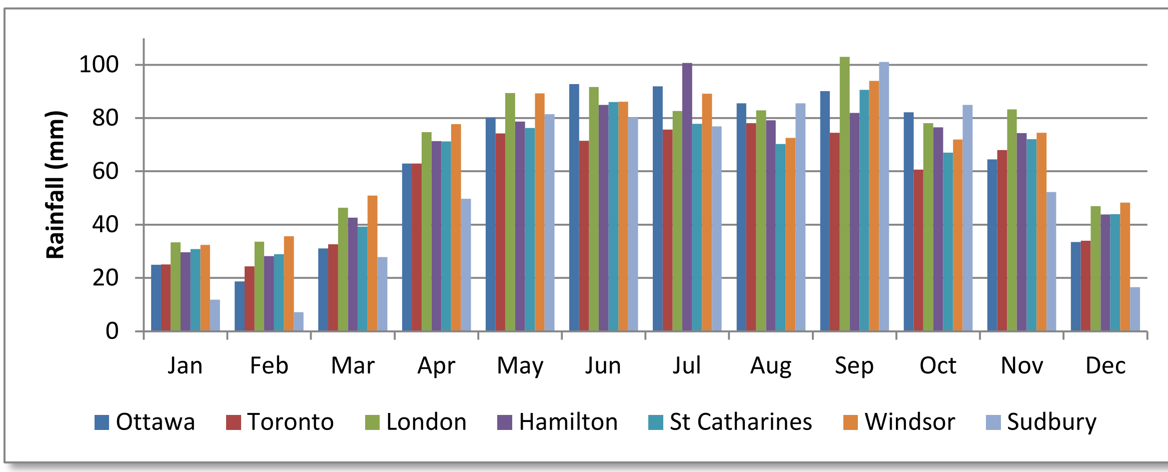



Figure 2.2.5 - Snowfall

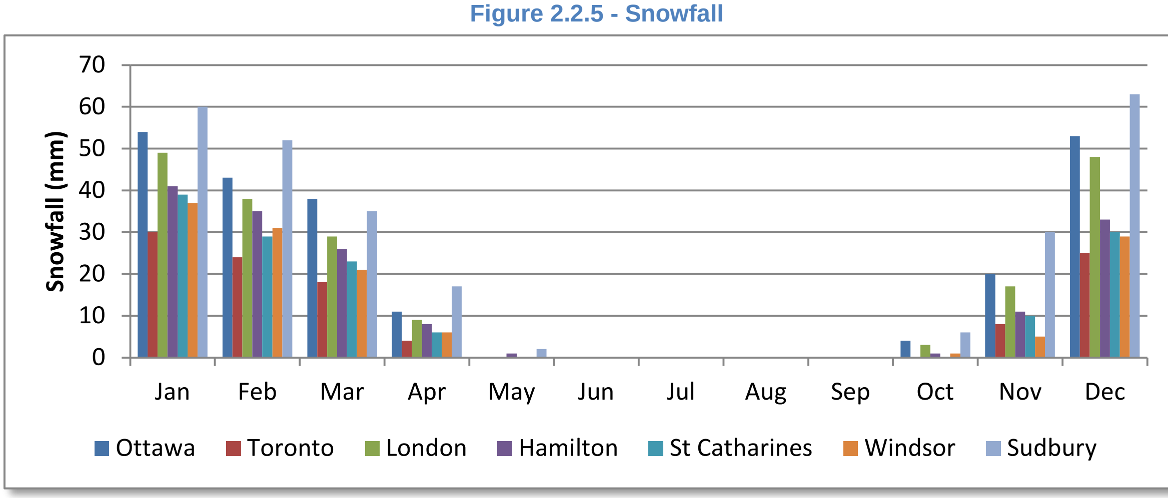
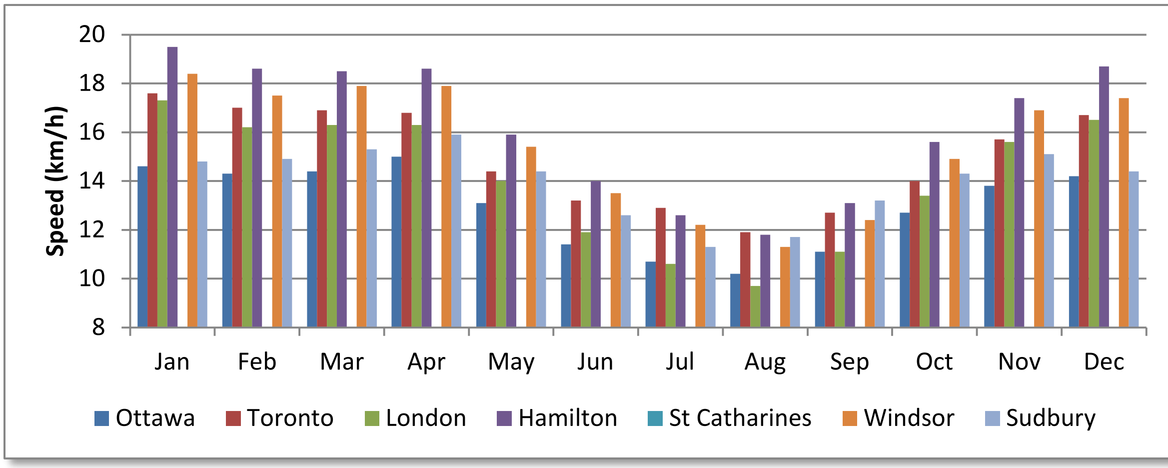


**Figure 2.2.6 - Wind Speed**




## Temperature Profile

The Ottawa region temperature profile requires that equipment operate under a temperature range of -40 to +40 degrees centigrade. Various pieces of equipment that contain inert gasses may not operate reliably at the lower end of this range and thus require extra heaters to ensure reliable operation. Extra heaters on equipment causes design changes and non-standard equipment procurement. The requirement of additional heaters thus impacts capital investment and may require a larger initial investment than that of a similar equipment model in an area with a warmer temperature range.

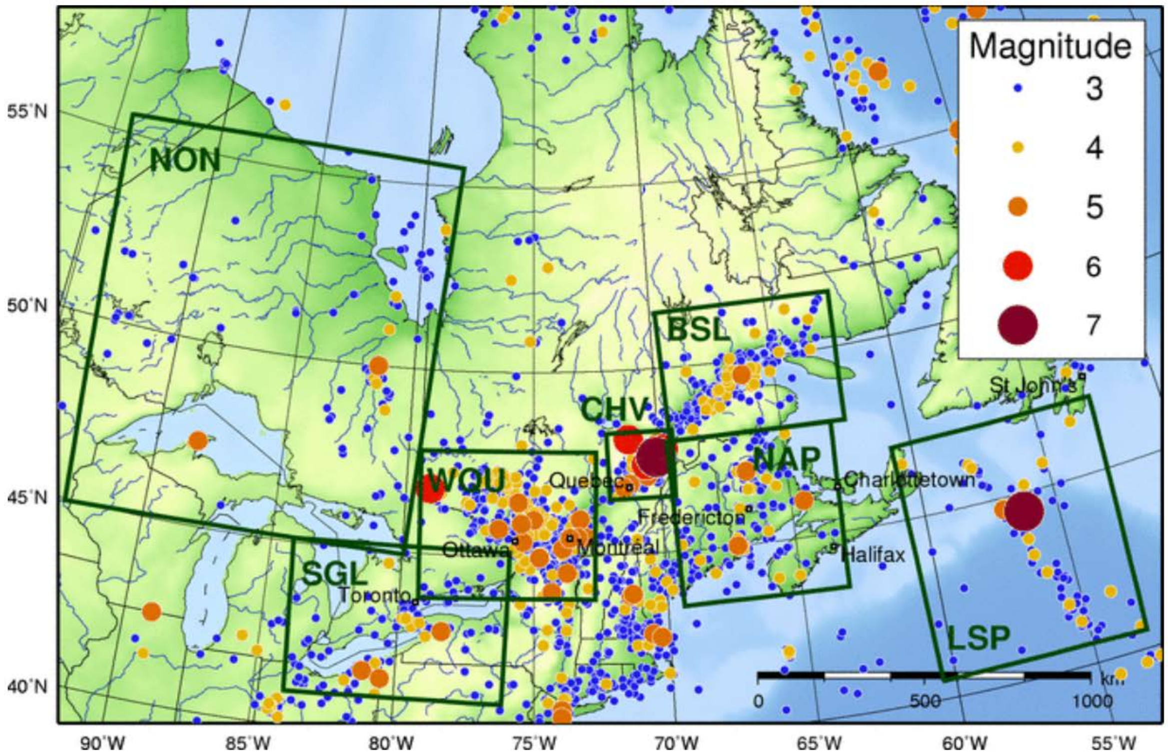
## Seismic Zone

Ottawa sits within Zone 4 for Seismic Acceleration (0.16-0.23g) and Zone 2 for Seismic Velocity (0.0-0.11m/s). Ottawa sits within the Western Quebec seismic zone which sees on average one earthquake every five days (Natural Resources Canada).This requires civil footings and foundations to be designed and constructed to withstand these higher seismic levels. Larger foundations and footings means more reinforcing steel (rebar), larger excavations, and more concrete, contributing to increases in capital expenditures.

The seismic zone also requires that additional steel cross bracing is designed and installed on all structures. The additional bracing causes for larger design, fabrication, and installation costs than that of a zone of lower seismic activity.

Figure 2.2.7 depicts the historic level of seismic activity as recorded by the Canadian seismograph network and reported by the Government of Canada on Natural Resource Canada's website.

**Figure 2.2.7 - Historic Seismic Activity (Years: 1627-2008)**




**Source: Government of Canada, Natural Resources Canada*

**Ice Accumulation & Snow Loading**

Due to the amount of snowfall and ice accumulation experienced in Ottawa (see Figure 2.2.5), civil structures (structural steel) must be able to withstand a significant amount of ice build-up without impacting structural integrity. This requires that the specific alloys chosen must be of high quality and thus increases the cost of fabrication.

Another impact of the harsh winters is an increased use of road salt which can lead to premature rusting of padmounted and pole mounted equipment located along the road right of way. The salt spray from roadways impacts O&M costs by increasing the need to wash insulators to prevent arcing and flash overs which leads to asset failures as well as an increase in the need to repaint and repair rusted padmounted and pole mounted equipment.

**Soil Conditions**

The Ottawa area soil conditions generally fall within two categories: till soils with loam to sandy loam texture, and clay soils. There are also extensive bogs within the region consisting of pockets of moist to wet soils. In the west area of the City, soil materials are shallow and there are regions of exposed sedimentary bedrock.

The sandy and clay soil conditions call for increased civil infrastructure (piling) beneath the civil footings to ensure the stability of structures, specifically within substations. The piling necessitates further excavation, resources, material and design, and therefore higher costs. Due to the shallow bedrock there can be increases in costs associated with boring, for example with the installation of poles, ducts or piling to support civil structures.

### 2.2.2 System Configuration

HOL's diverse system comes from the amalgamation of the 5 former municipal utilities. The system has 6 different distributing voltages that are constructed in a mix of overhead and underground systems. The majority of the underground infrastructure is built in the downtown and integrated suburb areas.

The substations supplying the service area are a mix of HOL and Hydro One Networks Inc. (HONI) owned stations and transformers. Formally, HONI owned all transmission connected transformers supplying HOL owned breakers at the low voltage side to distribute electricity throughout the service area. The current practice for newly built transmission connected stations is for HOL to construct and own all equipment.

Below is a summary of the system configurations:

**Table 2.2.2 - Length (km) of Underground & Overhead Systems**

| Orientation | Total Length (km) |
|---|---|
| Underground | 2,782 |
| Overhead | 2,702 |
| Total | 5,484 |

Table 2.2.3 - Number & Length of Circuits by Voltage Level

| Voltage Level | Number of Circuits | Total Overhead (km) | Total Underground (km) |
|---|---|---|---|
| 4.16 kV | 298 | 664 | 289 |
| 8.32 kV | 112 | 717 | 504 |
| 12.43 kV & 13.2 kV | 12 kV – 6<br>13 kV – 299 | 431 | 830 |
| 27.6 kV | 52 | 720 | 1,152 |
| 44 kV | 17 | 170 | 7 |
| Total | 784 | 2702 | 2782 |

Table 2.2.4 - Number & Capacity of Transformer Stations

| Secondary Voltage Level | # of Station | # of Transformers Owned by HOL | # of Transformers Owned by HONI | Total Transformation (MVA) |
|---|---|---|---|---|
| 4.16 kV | 36 | 103 | 0 | 662 |
| 8.32 kV | 24 | 39 | 3 | 448 |
| 12.43 kV | 2 | 3 | 0 | 26 |
| 13.2 kV | 12 | 2 | 25 | 1776 |
| 27.6 kV | 14 | 21 | 4 | 843 |
| 44 kV | 3 | 0 | 6 | 416 |
| Total | 91 | 168 | 38 | 4170 |

*Note that this is a sum of top rating (not planning limit) of all in-service units in HOL's service territory

### 2.2.3 Asset Demographics and Condition

The following section summarizes the demographics and condition assessment for the major asset classes within HOL's system. Asset condition is based upon health index calculations which are unique for each asset class. Where information is lacking, a correlation is implied between condition and age. Further details on the asset demographics can be found in the AMPR.

Table 2.2.5 summarizes the condition and population statistics for the asset classes that are detailed in the following sections. All information is current as of the end of 2013. Note that the cable lengths in the table below represent total kilometers of installed cable (sum of each run of cable, i.e. 3x for three-phase circuits) and differs from the stats provided above which represent circuit kilometers (1x for three-phase circuits).

**Table 2.2.5 - Asset Demographics & Condition**

| Asset Type | Population | Average Age | % in Poor & Critical Condition |
|---|---|---|---|
| Poles | 59,450 | 39 | 12% |
| Polemounted Transformers | 15,663 | 30 | 11% |
| Kiosk & Padmounted Transformers | 15,633 | 33 | 4% |
| Vault Transformers | 3,474 | 34 | 7% |
| Distribution Cables (XLPE) | 4,128 km | 25 | 17% |
| Distribution Cables (PILC) | 356 km | 35 | 15% |
| Underground Switchgear | 439 | 15 | 2% |
| Station Transformers | 170 | 36 | 2% |
| Station Breakers | 1,003 | 36 | 5% |

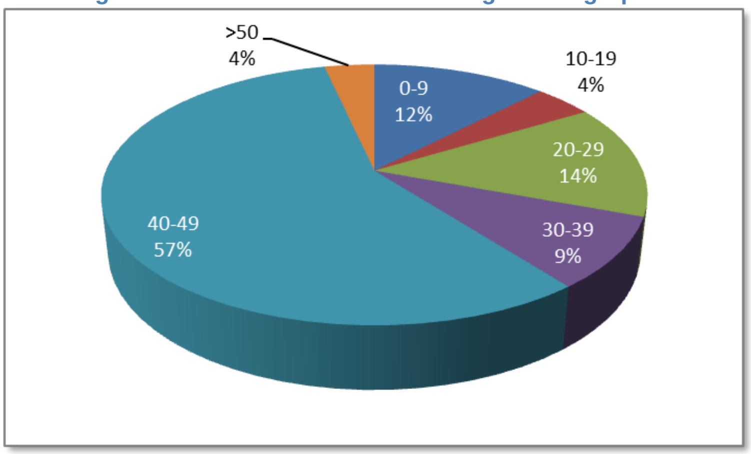
**Table 2.2.6 - Asset Management Strategy**

| Type | Asset | Strategy | Age / Condition Based Replacement |
|---|---|---|---|
| Substation | Transformers | Proactive | Condition |
| | Switchgear | Proactive | Condition |
| | Batteries | Proactive | Age |
| Distribution | Overhead Conductor | Proactively replaced with other projects | N/A |
| | Poles | Proactive | Condition |
| | Cable – PILC | Reactive | N/A |
| | Cable – XLPE | Proactive/Refurbish | Condition |
| | Cable – Butyl Rubber | Proactive | Condition |
| | Cable – EPR | Reactive | N/A |
| | Padmounted & Kiosk Transformers | Reactive | N/A |
| | Polemounted Transformers | Reactive | N/A |
| | Vault Transformers | Reactive | N/A |
| | Underground Switchgear | Proactive | Age |
| | Underground Civil Structures | Proactive | Condition |
| | Overhead Distribution Switches and Reclosers | Reactive | N/A |

### *2.2.3.1 Station Transformers*

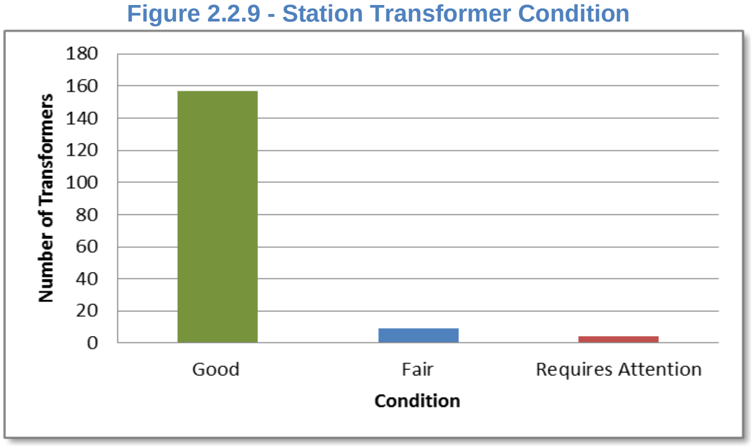
Station transformers are critical pieces of equipment among HOL's groups of assets. They provide voltage transformation from high voltage transmission lines to a lower voltage to distribute electricity throughout the City. HOL has 170 station transformers with different primary voltages: 103 at 13.2kV, 39 at 44kV, 22 at 115kV and 6 at 230kV.

**Figure 2.2.8 - Station Transformer Age Demographics**




HOL currently tracks the health index of Station Transformers through results from dissolved gas analysis (DGA), oil quality analysis and Doble testing. These various quality tests allow HOL to monitor the concentration of the Key Gases, the rate at which these gases are increasing, and the quality of the mineral oil inside the transformer. Once the gases, rate of change, and oil quality have reached an unacceptable level, the transformer will be scheduled for an out-of-service inspection and potential refurbishment or replacement.

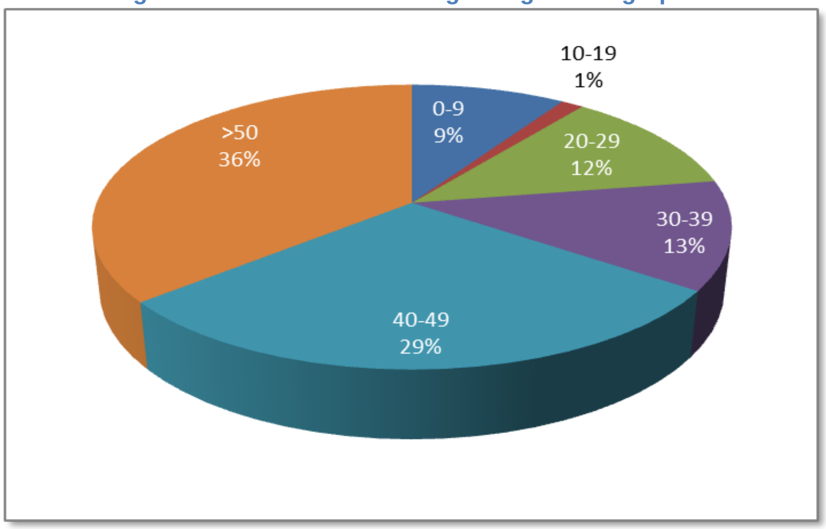
**Figure 2.2.9 - Station Transformer Condition**



### *2.2.3.2 Station Switchgear*

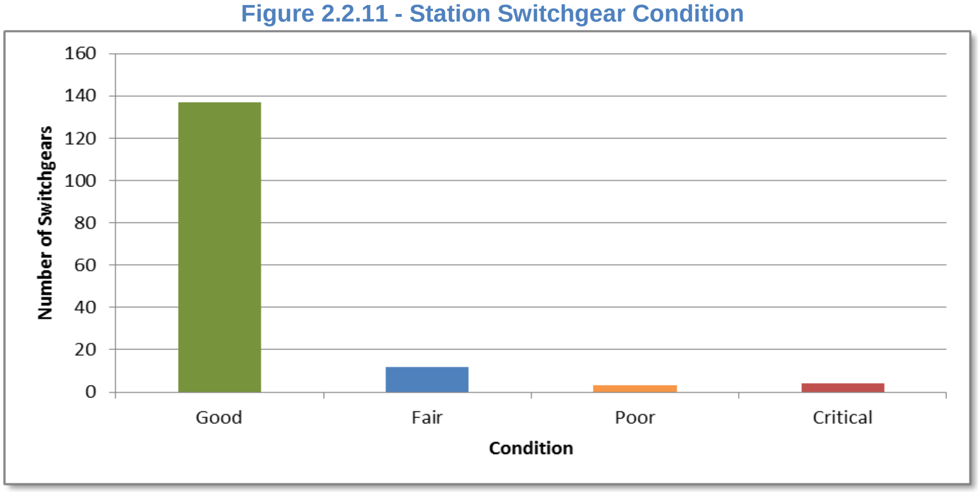
HOL owns and maintains switchgear assemblies in 83 substations. The station switchgear asset class consists of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation and fuses.

**Figure 2.2.10 - Station Switchgear Age Demographics**




The health index for Station Switchgear takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

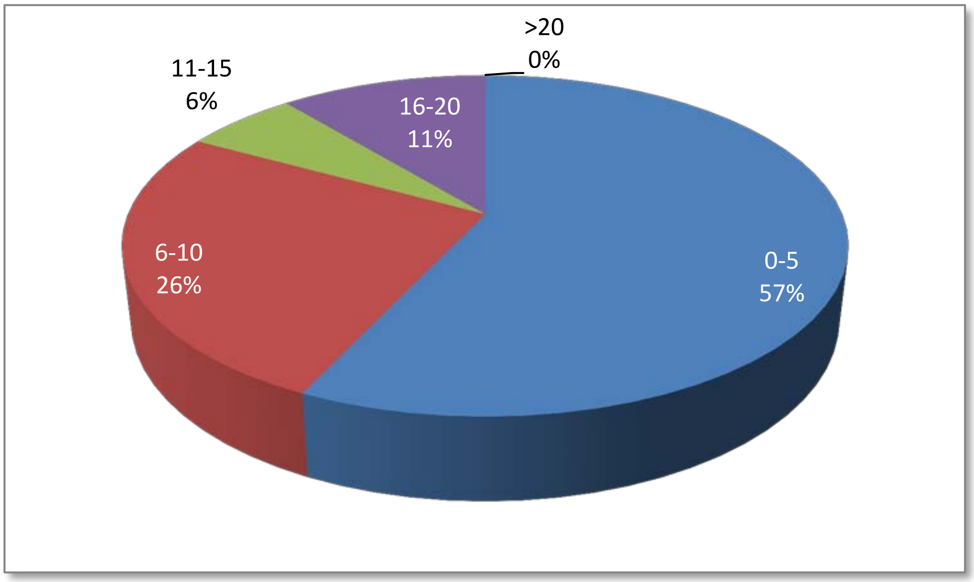
**Figure 2.2.11 - Station Switchgear Condition**



#### *2.2.3.3 Station Batteries*

HOL's station batteries and chargers asset class provide power for operating station breaker trip and closing coils, DC lights and relays when the station service power is lost. HOL has 53 station battery banks that supply 24V, 48V and 125V. The life expectancy of a station battery bank is in the range of 20-25 years.

**Figure 2.2.12 - Station Battery Bank Age Demographics**




The condition of station batteries is assessed through regular inspections. Routine maintenance is also performed which enables their health to be closely related to their age. The failure consequence for this asset can be significant as all the controls in a substation rely on the DC system to operate in case of power interruption. For this reason HOL replaces 2-3 station battery and charger banks per year to ensure reliable operation.

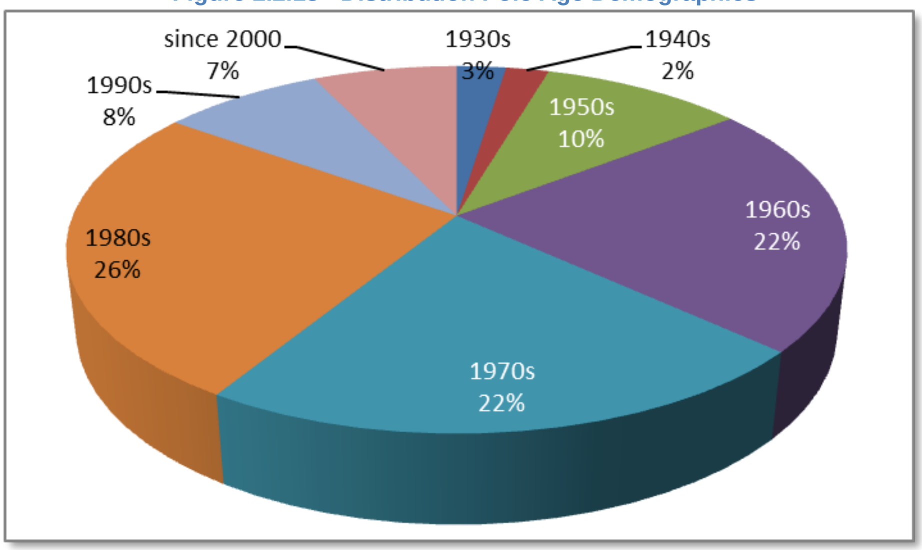
#### *2.2.3.4 Overhead Conductor*

HOL owns and operates on over 2900km of overhead conductor. Due to the rarity of overhead conductor failures, HOL does not record or perform inspections. The conductors are replaced during work on pole top equipment or pole replacement projects. This allows for the greatest efficiency. During this time the area is studied to assess whether larger conductors need to be installed.

### *2.2.3.5 Distribution Poles*

HOL owns 47,815 wood poles and 537 non-wood poles and operates on an additional 11,635 wood and 126 non-wood poles which are owned by third parties. Currently, HOL has installation date information for approximately 25% of its poles (41% of those operated on). For poles that do not have available installation information, install data has been estimated using manufacture date, estimated from the adjacent property legal records, or assumed to be equivalent to the average age of the known poles in that region (roughly 41% of asset group).

**Figure 2.2.13 - Distribution Pole Age Demographics**




The condition of poles is evaluated against a health index developed by HOL. The health index for poles is based on determining the percentage of remaining strength left in the pole. As per Canadian Electrical Code - CSA 22.3, poles should be replaced once they fall below 60% of the required strength. HOL uses the CSA criteria that once a pole's ultimate strength has been reduced to 60% of its original design, it will be considered to be at end of life and scheduled for replacement.

Health Index Inputs:

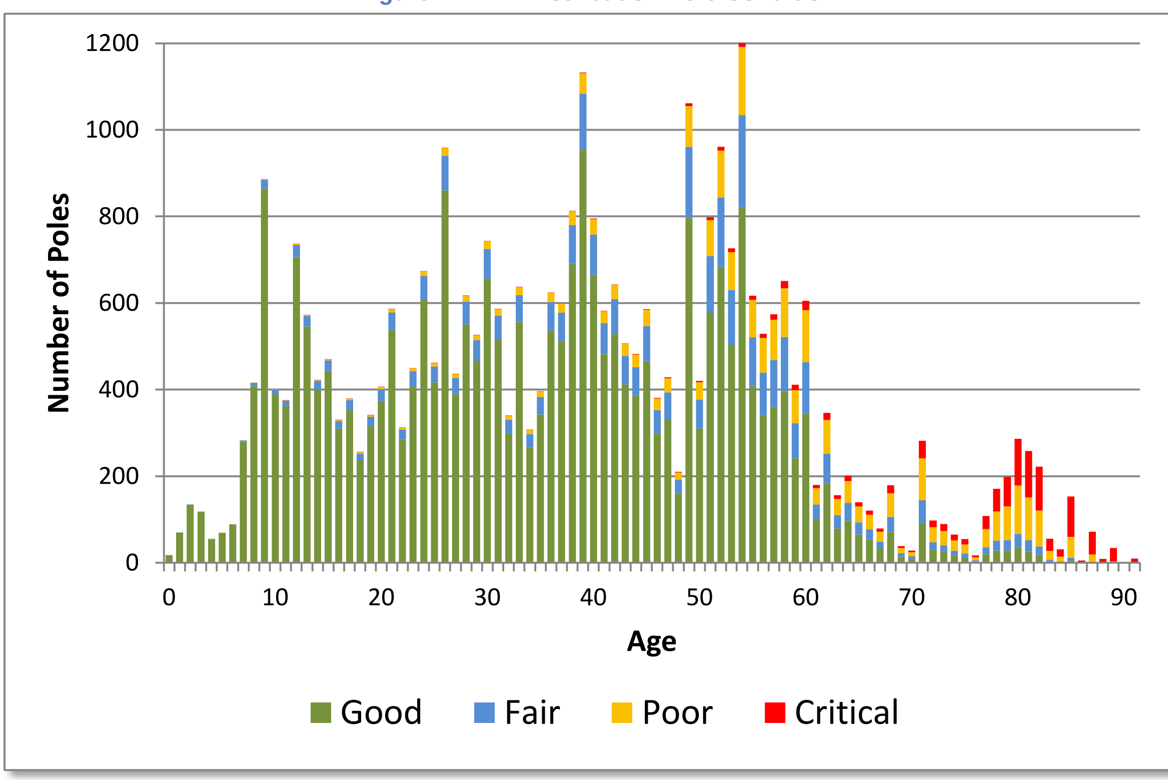
1. Maximum and minimum ground line circumference to determine the extent of surface rot and mechanical damage due to vehicles and snow plows;
2. Width and depth of pocket holes along the pole caused by rot or woodpeckers; and

3. Width of the external shell of a pole, measured from the center, which can be reduced due to internal rot.

HOL has inspected 14,370 poles since 2011, an average of 3,592 poles per year with a continued program inspection target of 4,500 poles per year over a ten year cycle. These inspections are initially done visually and if a pole appears to be in a degraded state a drill test is completed. As mentioned above, if the pole is determined to have a remaining strength below 60% it is replaced. When an area is identified as having numerous poles in a degraded state a pole replacement project is initiated.

Currently, HOL is working to prioritize and replace poles with a known condition of critical or poor from the 14,370 completed inspections, with an intention to continue to the inspection process and continue to replace poles based on the inspection results. Although not all poles have yet been inspected, the information already collected (shown in Figure 2.2.14 below) has been used to project the condition over the population of remaining poles.

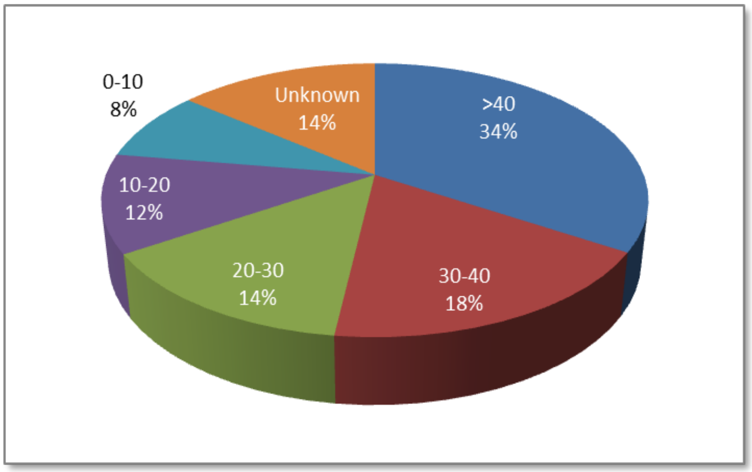
**Figure 2.2.14 - Distribution Pole Condition**



### *2.2.3.6 Distribution Cables (PILC)*

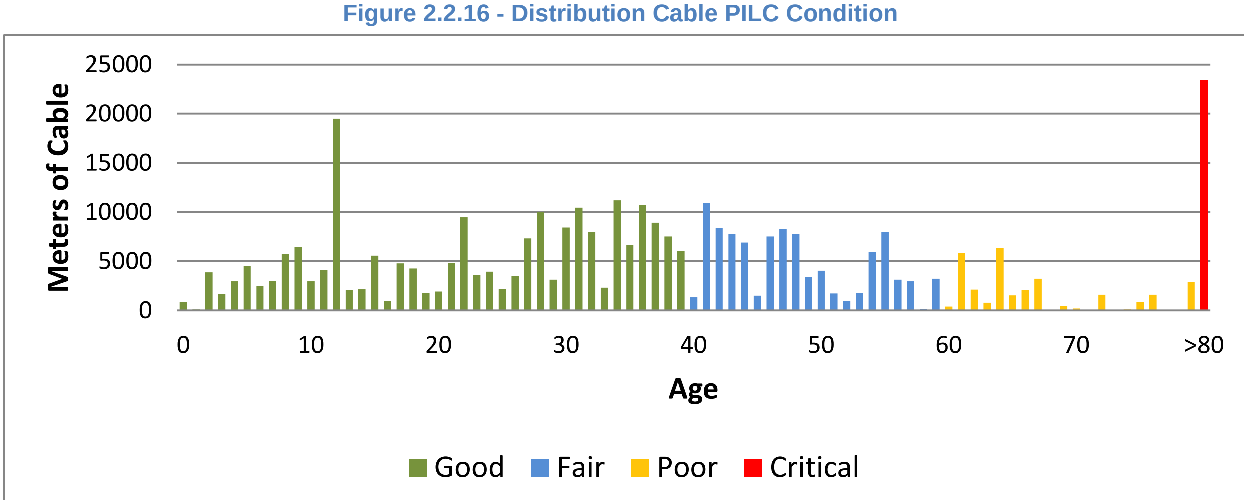
HOL owns and operates 356 km of triple conductor Paper Insulated Lead Cable (PILC). It was primarily installed in the Core of Ottawa on the 13kV system and is some of the oldest cable in the service area. Due to higher material costs, increasing procurement lead times, and the need for specialised tradesmen, HOL is passively phasing out this cable type by installing alternative cable types for new installations.

**Figure 2.2.15 - Distribution Cable PILC Age Demographics**




The condition assessment for PILC cables is based on age alone. Critical and poor condition cables are considered to be over the ages of 80 (Weibull Analysis) and 60 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

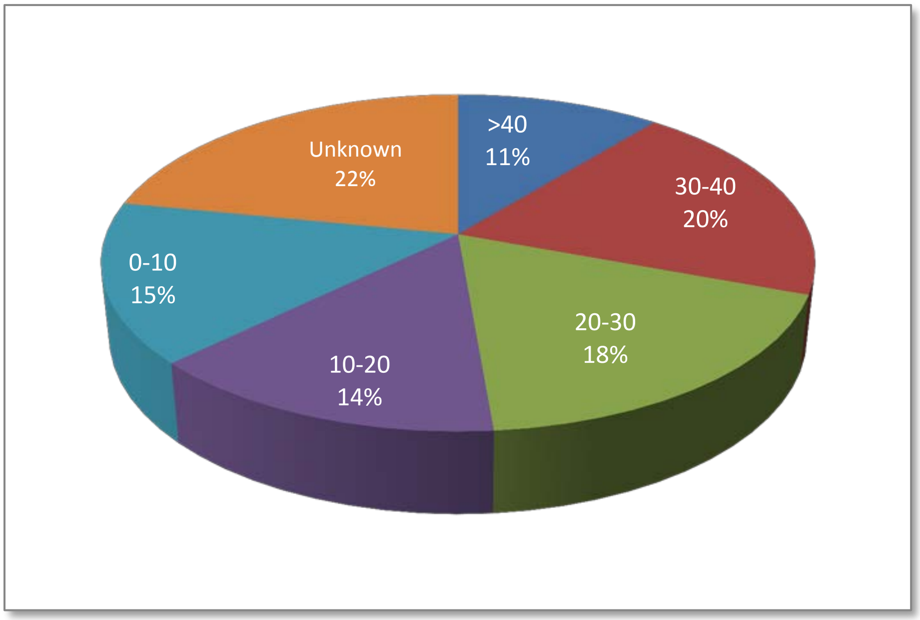
**Figure 2.2.16 - Distribution Cable PILC Condition**



### *2.2.3.7 Distribution Cables (Polymer)*

HOL owns and operates 4,128 km of single conductor Polymer Cable (Cross-Linked Polyethylene (XLPE), Ethylene Propylene Rubber (EPR) and Butyl Rubber) which is primarily installed in developed suburbs. The installation of this cable uses a mix of concrete encased duct, direct buried duct, and direct buried cable which can add to the cost and labour requirements when replacing under planned and unplanned events.

**Figure 2.2.17 - Distribution Polymer Cable Age Demographics**

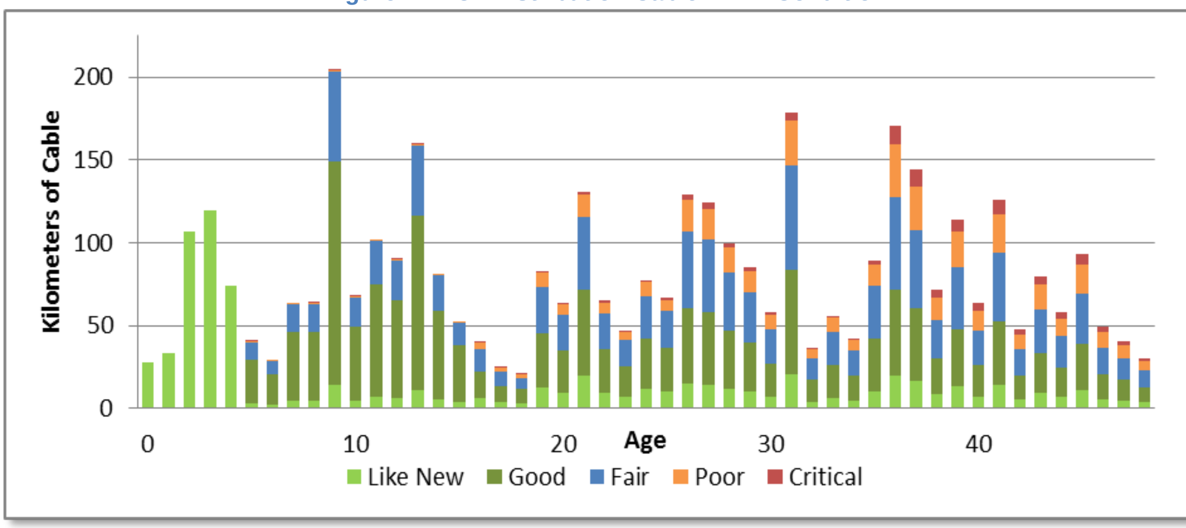



The vast majority of the underground polymer cable is XLPE. Butyl Rubber is in the process of being phased out of HOL's system due to the number of failures. EPR has been newly introduced into the HOL system and only makes up a small portion of underground cable. Therefore, the condition of underground polymer cable uses data collected from tests on XLPE cable.

The condition of distribution XLPE cables are monitored through an underground cable testing program which collects information useful for developing an asset health index. The health index for XLPE is based on the remaining insulation strength of the cable. The tests done on XLPE provide a Quality (Q) Value which indicate the condition of the cable. HOL uses the criteria that once the Q Value reaches a value of 32 or greater, it is considered to in either Bad or Critical condition and should be scheduled for replacement.

The entirety of the XLPE cable population within the HOL system has not yet been tested, however a correlation of the current findings are represented across the entire demographics in the figure below.

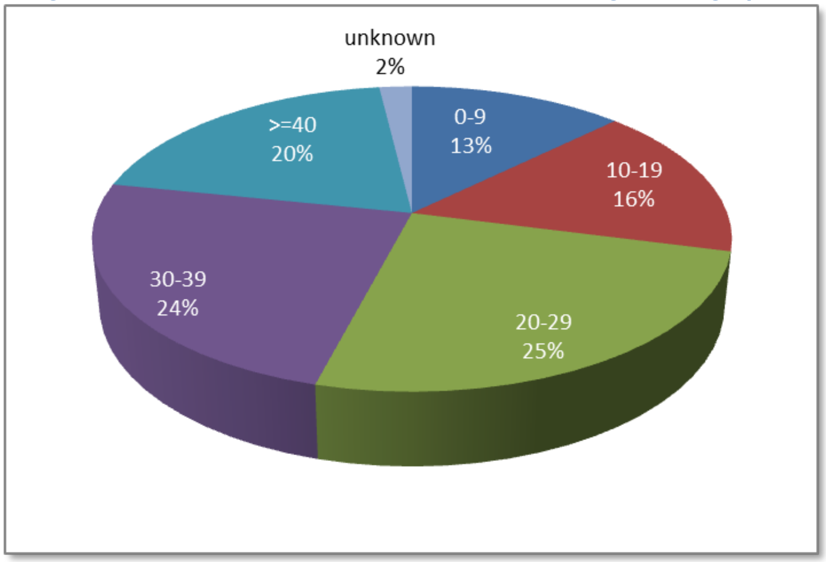
**Figure 2.2.18 - Distribution Cable XLPE Condition**




### *2.2.3.8 Kiosk & Padmounted Transformers*

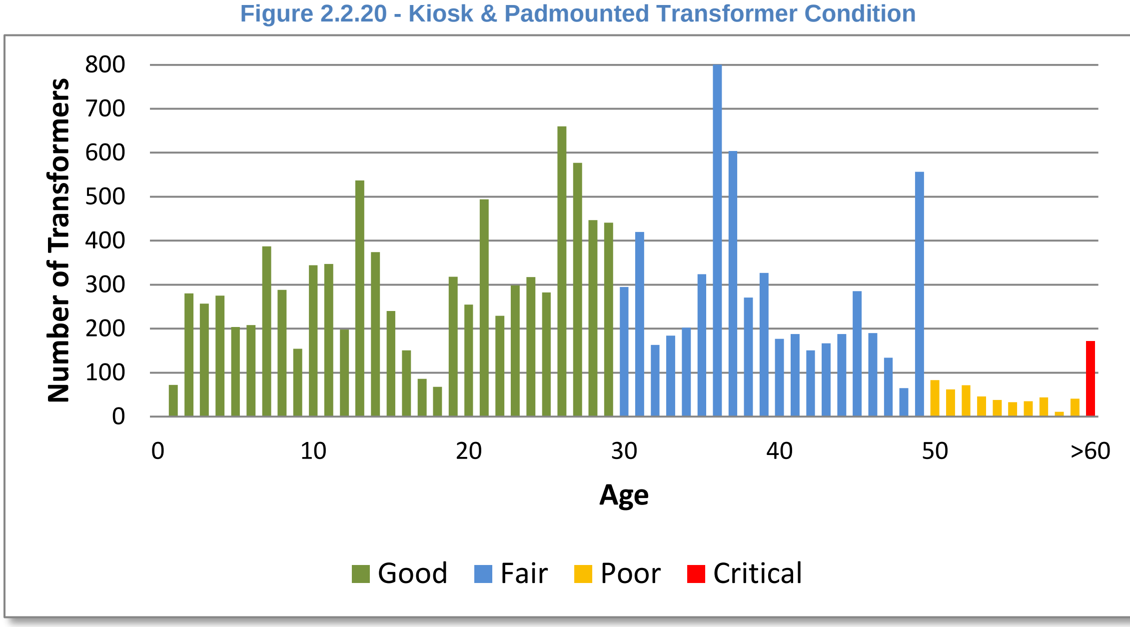
HOL owns roughly 1,800 kiosk transformers and 14,000 padmounted transformers. Kiosk style transformers have been in use for longer than padmounted transformers and as a result there is a higher proportion of this style at end of life.

**Figure 2.2.19 - Kiosk & Padmounted Transformer Age Demographics**




The condition assessment for padmounted transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 60 (Weibull Analysis) and 50 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

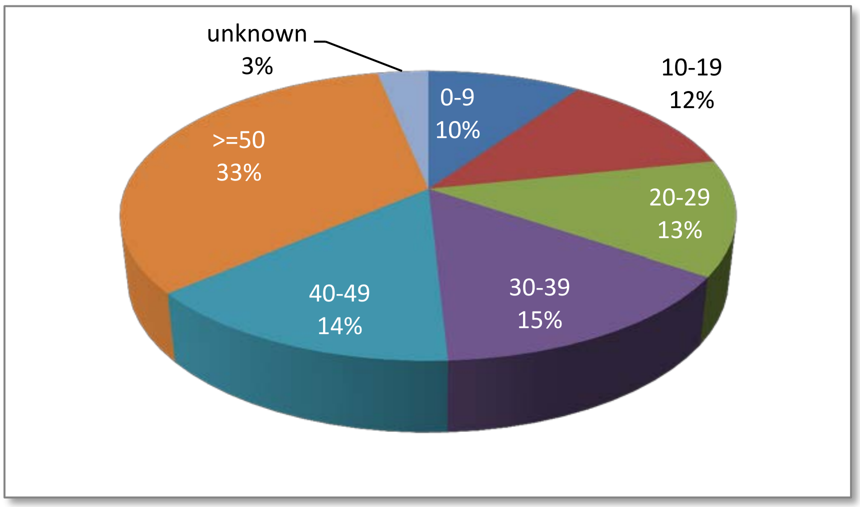
**Figure 2.2.20 - Kiosk & Padmounted Transformer Condition**



### 2.2.3.9 Polemounted Transformers

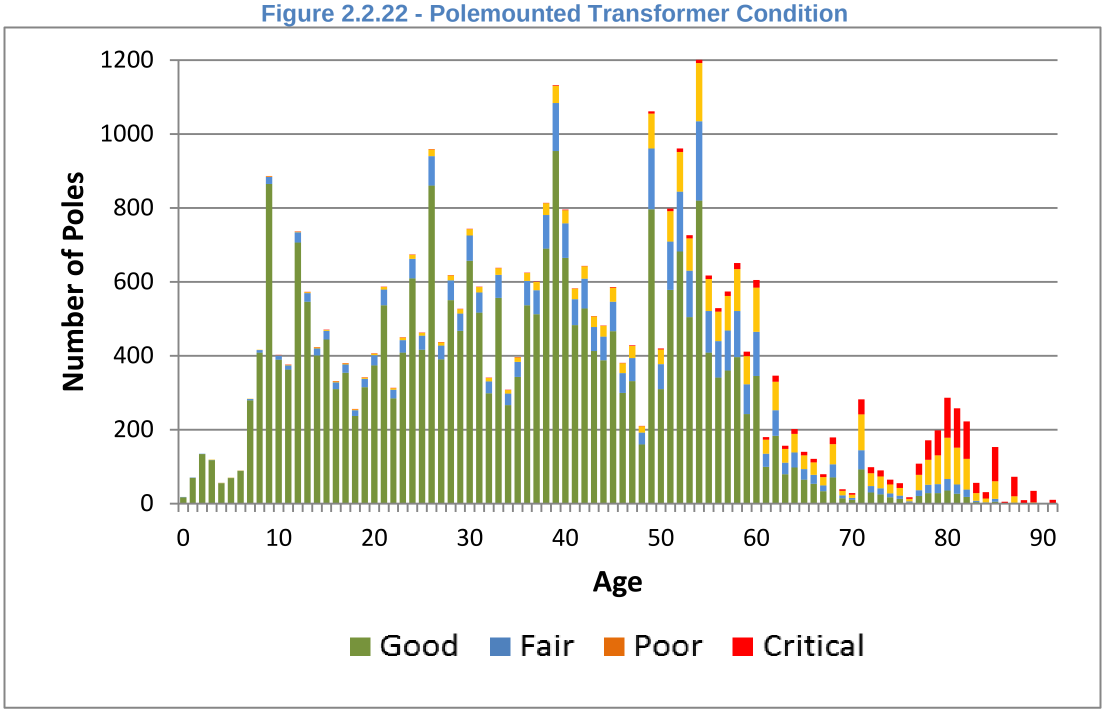
Demographic information for polemounted transformer assets such as purchase date, manufacture date, ratings and manufacturer are stored in HOL's Geographical Information system (GIS). HOL owns and operates 15,663 polemounted transformers. Currently, the installation and manufacture date are not consistently available. As such, where install year is not available it has been approximated based on the purchase year, estimated install year, or based on legal documentation of the surrounding properties.

**Figure 2.2.21 - Polemounted Transformer Age Demographics**




The condition assessment for polemounted transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 90 (Weibull Analysis) and 60 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

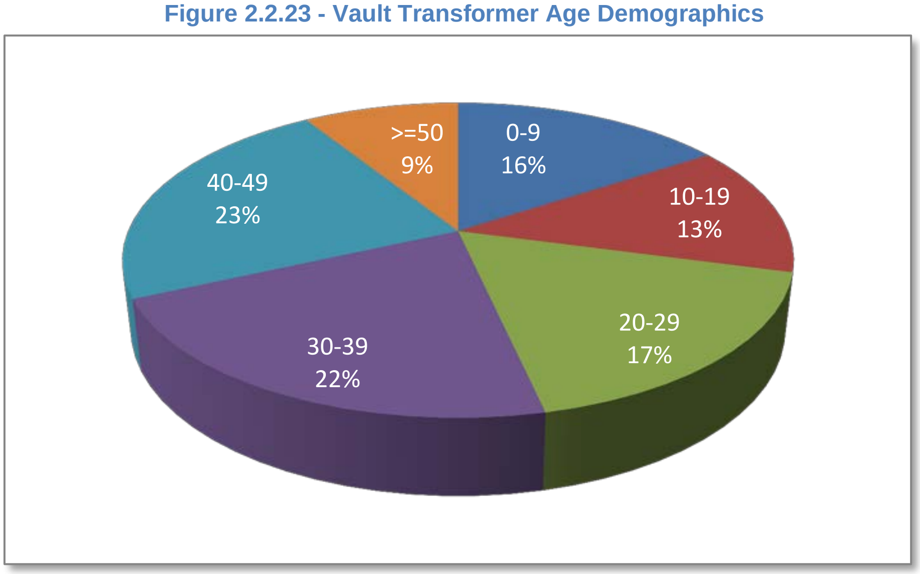
**Figure 2.2.22 - Polemounted Transformer Condition**




### *2.2.3.10 Vault Transformers*

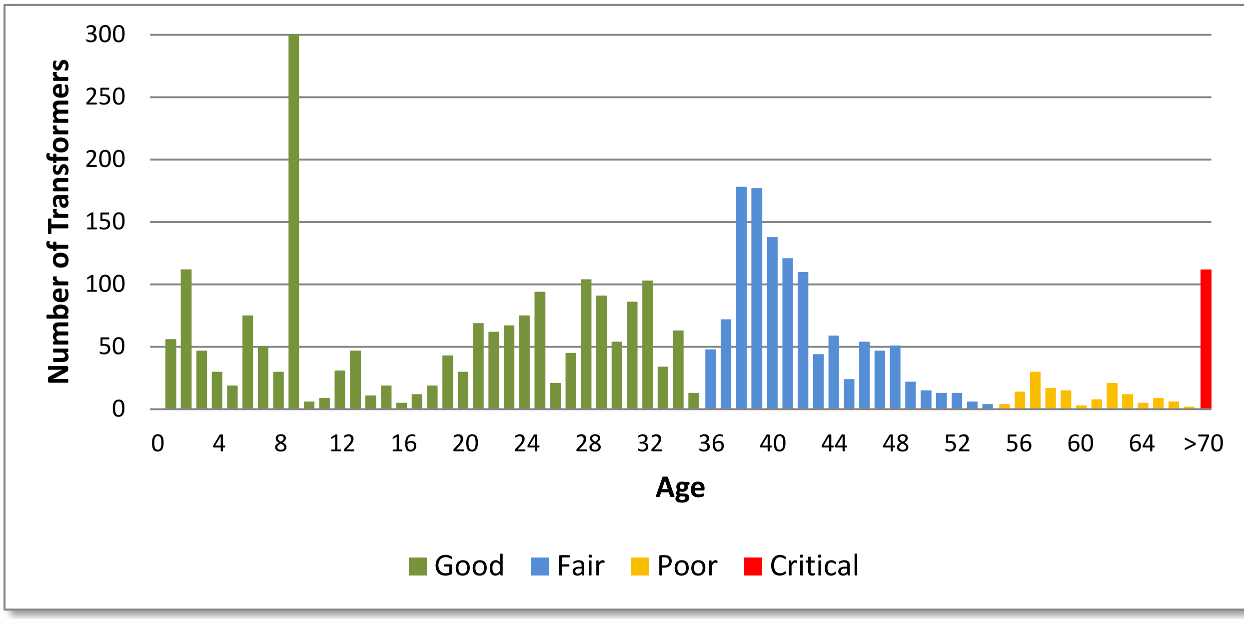
HOL's vault transformers are located in building vaults and typically service a single large customer. Currently HOL owns 3,474 vault transformers.

**Figure 2.2.23 - Vault Transformer Age Demographics**



The condition assessment for vault transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 70 (Weibull Analysis) and 65 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

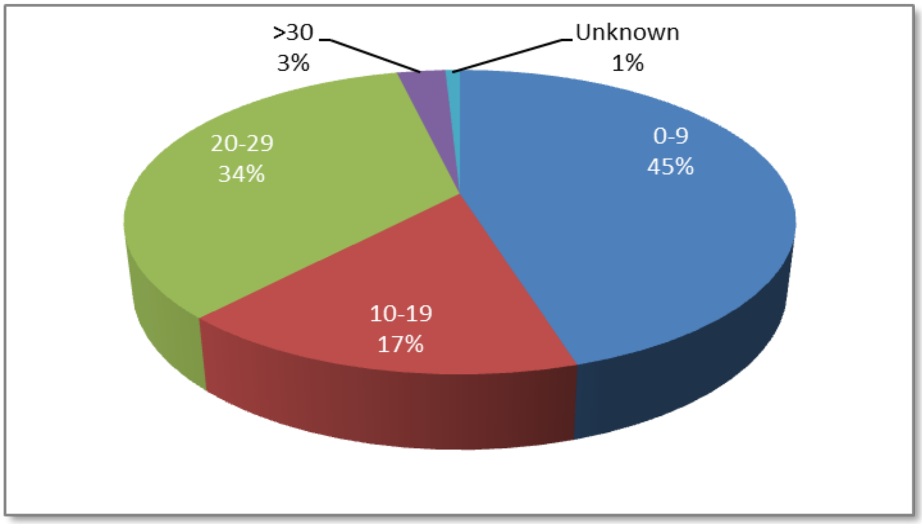
**Figure 2.2.24 - Vault Transformer Condition**




### *2.2.3.11 Underground Switchgear*

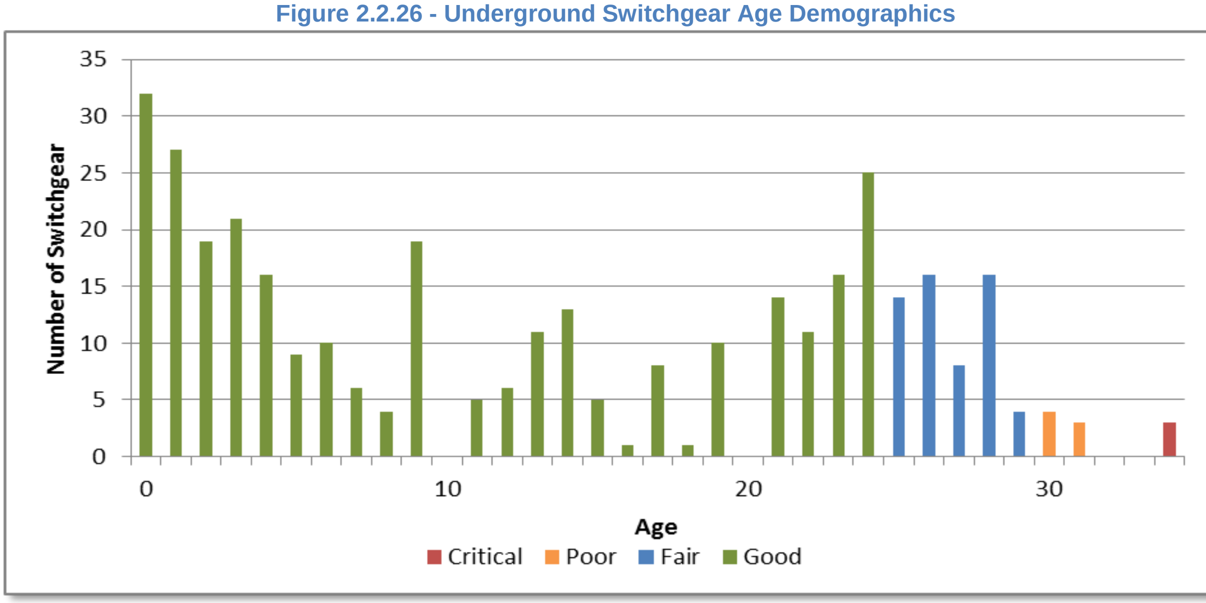
HOL’s distribution switchgear asset class consists of 439 pad-mounted, 191 vault installed and 2 submersible types. There are many different configurations and types of switchgear in service due to the amalgamation of the former utilities and their varying policies for servicing customers. HOL is developing policies and procedures for incorporating these different practices in a consistent manner.

**Figure 2.2.25 - Underground Switchgear Age Demographics**




The condition assessment for underground switchgear is based on age alone. Critical and poor condition switchgears are considered to be over the ages of 35 (Weibull Analysis) and 30 (Historical Failures) respectively. These assets are considered to be at a higher risk of failure.

**Figure 2.2.26 - Underground Switchgear Age Demographics**



### *2.2.3.12 Underground Civil Structures*

Hydro Ottawa's Underground Civil Structure asset class consists of underground duct banks, hand holes and various types of underground chambers forming a network through which cables may be installed. Distribution underground civil structures are used in areas where underground wiring is required for aesthetics or clearances, to improve reliability, to reduce the time to access and correct faulty wiring, to permit access in congested areas and to allow re-entry or expansion in areas where further excavation would be costly.

The asset class has been divided into two primary groups; Duct Structures and Underground Chambers. While duct structures are run to the unlikely event that they fail, underground chambers are maintained through a replacement and rehabilitation program based on regular condition assessment. Based on the currently available inspection data it is recommended that the program target a minimum of 10 underground chambers per year.

**Table 2.2.7 - Civil Structure by Type**

| Civil Structure Type | Pre 1970 | Post 1970 | Unknown | Total |
|---|---|---|---|---|
| **Cable Chambers** | **760** | **2,017** | **731** | **3,508** |
| Precast | 66 | 661 | 159 | 886 |
| Cast in Place | 694 | 1,284 | 551 | 2,529 |
| Unknown/other | - | 23 | 6 | 29 |
| Pre-Cast Switch Cable Chambers | - | 49 | 15 | 64 |
| **Handholes** | **9** | **240** | **115** | **364** |
| **Sidewalk Vaults** | **-** | **34** | **-** | **34** |
| **Equipment Pad** | **-** | **3,300** | **18,040** | **21,340** |
| Miscellaneous Pad | - | 32 | 2,164 | 2,196 |
| Primary Pedestal | - | - | 7 | 7 |
| Secondary Pedestal Pad | - | 1,642 | 2,671 | 4,313 |
| Service Disconnect Pad | - | 38 | 552 | 590 |
| Switchgear Pad | - | 23 | 238 | 261 |
| Transformer Pad | - | 1,565 | 12,408 | 13,973 |

#### *2.2.3.13 Overhead Distribution Switches and Reclosers*

Hydro Ottawa's distribution overhead switch and recloser asset class consists of all pole mounted load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating up to 44 kV. The primary purpose for this asset class is to provide a means to isolate or re-route a section of overhead line due to a fault condition or planned work.

The overhead switch and recloser program is typically a run-to-failure asset class unless a technical or health and safety issue have been identified.

**Table 2.2.8 - Overhead Switch & Recloser Demographics**

| Switch Type | 4.16 kV | 8.32 kV | 12.43 kV | 13.2 kV | 27.6 kV | 44 kV | Total |
|---|---|---|---|---|---|---|---|
| Non-Load Break | 1,610 | 2,293 | 39 | 1,342 | 1,467 | 483 | 7,234 |
| Load Break | 51 | 137 | 0 | 159 | 446 | 309 | 1,102 |
| Cut-Outs | 8,333 | 6,139 | 41 | 2,770 | 3,977 | 9 | 21,323 |
| Reclosers | 0 | 19 | 2 | 1 | 35 | 0 | 57 |

### 2.2.4 Capacity of the Existing System Assets

The following section outlines the degree to which the capacity of the existing system assets is utilized relative to planning criteria, referencing the related objectives as set out in section 1.3.1.4 System Operations Performance.

#### *2.2.4.1 Stations Exceeding Planning Capacity*

The planned capacity rating is defined as the sum of either the transformer's 10 day LTR or the allowable top loading rating if there is no published LTR for the remaining transformers following a single contingency loss of the largest element within the substation (N-1 contingency). An N-1 contingency for a station is defined as the loss of the largest transformer within the station. Note that for stations with a single supply and a single transformer, the planning rating is considered to be the rated capacity of the single unit (10 day LTR or allowable top load rating if there is no published LTR).

Station loading must be maintained within the planning capacity to allow for efficient transfer of load during an N-1 contingency reducing the duration of the interruption, while respecting equipment ratings.

Stations loaded above their planning capacity on the system peak day:

**Table 2.2.9 - Stations Exceeding Planning Capacity**

| | Station | 2013 System Peak Day Load (MVA) | Planning Capacity (MVA) | Planning Factor (%) |
|---|---|---|---|---|
| 1 | Bridlewood MS 28kV | 48.9 | 25.0 | 196% |
| 2 | Rideau Heights DS | 19.6 | 12.5 | 157% |
| 3 | Merivale DS | 15.6 | 10.0 | 156% |
| 4 | Borden Farm DS | 12.3 | 8.0 | 154% |
| 5 | Longfields DS | 20.1 | 15.0 | 134% |
| 6 | Marchwood MS | 43.7 | 33.0 | 132% |
| 7 | Startop MS | 15.4 | 12.0 | 128% |
| 8 | Alexander DS | 15.5 | 12.5 | 124% |
| 9 | Limebank MS | 39.0 | 33.0 | 118% |
| 10 | Bayshore DS | 11.6 | 10.0 | 116% |
| 11 | Centrepointe DS | 15.9 | 14.0 | 114% |
| 12 | Stafford Road DS | 15.5 | 14.0 | 111% |
| 13 | Fallowfield MTS | 27.0 | 25.0 | 108% |
| 14 | Manordale DS | 10.1 | 10.0 | 101% |

#### *2.2.4.2 Stations Approaching Rated Capacity*

The rated capacity is defined as the sum of the top rating (LTR or allowable flat rating should an LTR not be published) of all transformers within the station. If the loading on a transformer exceeds this limit it will cause accelerated loss of life.

Transformer loading must be maintained within the rated capacity in order to avoid any accelerated loss of life to the unit.

1 Stations loaded within 90% of their rated capacity on the system peak day:

2 **Table 2.2.10 - Stations Approaching Rated Capacity**

| | Station | 2013 System Peak Day Load (MVA) | Rated Capacity (MVA) | Capacity Factor (%) |
|---|---|---|---|---|
| 1 | Richmond North DS | 5.5 | 5.0 | 110% |
| 2 | Nepean TS | 153.6 | 160.0 | 96% |
| 3 | Hawthorne TS | 103.5 | 110.0 | 94% |

### 3 2.2.4.3 Feeders Exceeding Planning Capacity

4 The planned capacity rating for a feeder takes three factors into consideration.

5 1. Coordination with lo-set instantaneous protection;
6 2. Feeder cold load pick up ability; and
7 3. Short term (8 hour) egress cable overload capabilities

8 Feeders must be maintained within the planning capacity to allow for efficient load transfer
9 during an N-1 contingency situation, thereby reducing the duration of interruption while
10 respecting equipment ratings.

11 Table 2.2.11 lists the feeders above 100% of their planning capacity.

**Table 2.2.11 - Feeders Exceeding Planning Capacity**

| | Station | Feeder | 2013 System Peak Day Load (A) | Rated Capacity (A) | Capacity Factor (%) |
|---|---|---|---|---|---|
| 1 | King Edward TK | 404 | 229 | 85 | 269% |
| 2 | Rideau Heights DS | 180F3 | 470 | 300 | 157% |
| 3 | Startop MS | 6F10 | 391 | 300 | 130% |
| 4 | Bridlewood MS 28kV | BRDF3 | 399 | 310 | 129% |
| 5 | Russell TB | 5304 | 326 | 255 | 128% |
| 6 | Russell TB | TB2JP (TB13) | 313 | 255 | 123% |
| 7 | Parkwood Hills DS | 190F5 | 356 | 300 | 119% |
| 8 | Stafford Road DS | 200F6 | 341 | 300 | 114% |
| 9 | Limebank MS | 7F2 | 344 | 310 | 111% |
| 10 | Jockvale DS | 145F1 | 333 | 300 | 111% |
| 11 | Uplands MS | Q4801F8 | 342 | 310 | 110% |
| 12 | Kanata MTS | 624F5 | 367 | 340 | 108% |
| 13 | Overbrook TO | TO1UT | 273 | 255 | 107% |
| 14 | Kanata MTS | 624F1 | 361 | 340 | 106% |
| 15 | Albion TA | 2209 | 268 | 255 | 105% |
| 16 | Woodroffe TW | TW2UC | 264 | 255 | 104% |
| 17 | Overbrook TO | 1801 | 263 | 255 | 103% |
| 18 | Lisgar TL | TL7TS (TL19) | 261 | 255 | 102% |
| 19 | Hinchey TH | TH2UL | 257 | 255 | 101% |
| 20 | Carling TM | 306 | 256 | 255 | 100% |
| 21 | Bilberry TS | 77M2 | 310 | 310 | 100% |
| 22 | Carling TM | 307 | 254 | 255 | 100% |

### *2.2.4.4 Feeders Approaching Rated Capacity*

The rated capacity is defined as the egress cable 8 hour loading limit. If the circuits are loaded above this limit for longer than 8 hours it will cause overheating and accelerated loss of life. Feeder loading must be maintained within the rated capacity in order to avoid damaging equipment and causing an accelerated loss of life to the cables.

Table 2.2.12 lists the feeders loaded within 90% of the rated capacity on the system peak day.

**Table 2.2.12 - Feeders Approaching Rated Capacity**

| | Station | Feeder | 2013 System Peak Day Load (A) | Rated Capacity (A) | Capacity Factor (%) |
|---|---|---|---|---|---|
| 1 | Rideau Heights DS | 180F3 | 470 | 475 | 99% |
| 2 | Startop MS | 6F10 | 391 | 420 | 93% |

## 2.3 Asset Lifecycle Optimization Policies and Practices

This section documents HOL's asset lifecycle optimization policies and practices. The HOL approach is to maximize the lifecycle of an asset while providing a reliable service using a Plan, Deploy, Maintain, Evaluate, and Retire process (see Figure 2.3.1 - Asset Lifecycle Optimization). HOL optimizes the lifecycle of its assets by tracking and analyzing asset failure rates, historical asset Budget Program costs, and asset demographics. Effective testing, inspections and maintenance (TIM) programs ensure that adequate information is gathered about the assets to properly prioritize asset replacement and refurbishment while balancing operation and maintenance (O&M) costs.

**Plan** – determine the optimal equipment usage and arrangement based on requirements and develop standards and procedures for installation and maintenance;

**Deploy** – install the equipment in the field following approved standards;

**Maintain** – inspect and maintain the equipment following internal standards, manufacturer recommendations and best practice;

**Evaluate** – review inspection and maintenance records to ensure the equipment continues to perform as required – based on evaluation, continue the Maintain cycle, or move on to Retire;

**Retire** – once the equipment no longer is able to meet requirements, it is disposed of in a sustainable manner, following environmental and regulatory requirements. Circle back to plan, where once again the equipment requirements will be evaluated before a replacement or re-arrangement is completed.

**Figure 2.3.1 - Asset Lifecycle Optimization**


HOL prioritizes asset replacement, refurbishment and maintenance by assessing the health condition of an asset. If insufficient data is available for an asset group, HOL will use age alone as the primary determinant of condition. HOL has implemented an Asset Investment Planning and Management software known as Copperleaf C55. One of the functions of this software is to act as a new asset repository, creating better defined health indices and reforming the TIM programs to gather required asset information for improving condition assessment processes.

### 2.3.1 Asset Replacement and Refurbishment

HOL plans asset replacement and refurbishment projects annually through the Asset Management Process (AMP) (see section 2.1 Asset Management Process Overview). The AMP mostly involves determining investment requirements under the System Renewal investment category of Chapter 5. The intention of the AMP is to document the asset management practices used by HOL as part of an optimized lifecycle strategy for distribution assets. The objectives of the Asset Condition Assessment are to demonstrate that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future while staying within the targeted levels of risk.

The HOL asset lifecycle optimization plan is achieved by forecasting equipment failures using available information regarding equipment demographics, inspection data and historical failure records.

#### *2.3.1.1 Asset Replacement and Refurbishment Policies and Practices*

HOL manages its asset replacement and refurbishment through proactive replacement, reactive replacement and refurbishment. HOL strategizes asset replacement and refurbishment through the use of asset failure curves, asset demographics and TIM programs. The asset replacement approach is determined based on the failure consequence of the asset, replacement costs, required lead-time for materials and the available information for that asset group.

HOL's two main drivers for asset refurbishment and replacement are age and condition. Assets with more established TIM programs continue to use health indexing based on condition to prioritize replacement. All other proactive replacement programs use age to prioritize replacement.

HOL is continuing to develop the TIM programs to achieve health indexing for all assets. Asset health indices will allow HOL to create a proactive replacement strategy for all assets, including reactively replaced assets.

##### 2.3.1.1.1 Proactive Replacement

HOL has adopted a practice of proactive replacement for assets that incur higher failure consequences. This can be in the form of additional expenses or affect additional customers when replaced reactively following failure. Therefore, a more planned approach for acquiring and dedicating resources to minimize costs and customer impacts is required. HOL proactive replacement programs and rate of replacement are justified by reviewing historical asset failure rates and creating asset failure curves. Asset failure curves allow HOL to predict future failure rates to forecast replacement rates and costs. An increase in the failure rates may signify the need to increase replacement rates.

Proactive replacement of assets mitigates failure consequence by often minimizes costs, minimizes outage impact and decreases the project duration. HOL is striving to establish more asset information to maximize proactive replacement projects.

The evaluation of the technical life of assets focuses on the failure modes rather than the broader question of asset retirement, and as such does not consider assets retired from service for external reasons, such as capacity upgrades, relocations, and vehicle collisions. The ACA's focus on end of life failure provides appropriate models for forecasting proactive asset replacement requirements, but typically results in higher average age than would be appropriate for asset depreciation.

Asset replacement projects can also be driven by the need to upgrade the system to meet the needs of new developments and intensification or new system operation requirements. Additional replacement projects are developed through the management of assets to minimize health and safety concerns, reduce environmental impact and improve reliability.

HOL develops all details of replacement projects well in advance of construction to ensure all aspects of the projects are known and documented, maximizing efficiency by being fully aware of all risks and potential obstacles up front. The consequence of all projects are assessed for their potential risks and analysed to mitigate known risks. This is done in an attempt to maximize the benefits versus costs ratio. Business cases are prepared to justify the project and select the preferred alternative from various options by comparing costs, associated risks and benefits of each.

HOL has developed a consequence scoring and prioritization process to streamline selecting proactive projects. HOL assesses risk based on five objectives: Health and Safety, Environment, Reliability and Customer Impact, Asset Condition and Regulatory. Each of these categories is given a measure based on a seven step scale from “None” to “Severe”. The scale measure describes the potential consequences of delaying the project. Refer to Section 2.1 for the full description of the process.

While it is preferred for all investments to be selected based on this prioritization, mandated investments will arise typically due to external drivers. When such investments occur they have reasoning clearly documented and are scored so that the impact to objectives is clearly understood and communicated. An example of this type of replacement would be due to equipment recalls, environmental regulation or major safety concerns.

#### 2.3.1.1.2 Reactive Replacement

HOL has developed capital programs that manage assets through reactive replacement. These assets have minimal failure consequence, have spares readily available, and require minimal resources for installation. HOL reactive replacement strategy has been developed based on historical failure rates and considers utility best practices.

#### 2.3.1.1.3 Refurbishment

Asset refurbishment is approached on a per asset case, or through an asset refurbishment program and utilizes results from inspections, manufacturer recommendations, internal standards and/or regulatory requirements as drivers. Asset refurbishment is thoroughly compared to asset replacement to ensure there is financial and/or operational benefit.

Refurbishment of an asset is a life extension investment to offset the planned replacement. HOL determines the best course of action, refurbishment or retirement, by examining:

- Asset remaining useful operating life;
- Life extension forecasted from refurbishment activity;
- Cost of refurbishment as compared to cost of replacement;
- Availability of replacement parts;
- Obsolescence of asset;
- Impact to reliability, refurbishment outage vs. replacement outage;
- Refurbishment warranty; and
- Asset remaining financial life: cost of de-recognition if replaced;

### *2.3.1.2 Maintenance Planning Criteria*

Annual review of the HOL maintenance programs are completed through the Testing, Inspection and Maintenance Planning Process (TIM) and documented in the Annual Planning Report (Attachment B-1(B)) TIM section. The TIM Planning Report was developed to serve as a summary and guide of the current activities, data collection methodologies as well as to identify the gaps in the existing practices. HOL's TIM programs are crucial to ensuring a reliable and sustainable distribution system by ensuring that all assets are effectively meeting requirements. Information from the TIM programs feed back into the ACA to allow for effective life-cycle planning of assets. Currently, there are many different types of testing, inspection and maintenance activities that are used to gain asset information, health information required for the determination of replacement and/or maintenance prioritization in order to increase asset reliability, safety and longevity.

The purpose of the HOL TIM programs is to test, inspect and maintain the equipment and to gather equipment information for use in asset lifecycle planning. HOL retains maintenance records for assets used to optimize asset replacement, refurbishment, and maintenance activities. HOL currently splits the maintenance activities into two groups; distribution maintenance and station maintenance.

Through the TIM Plan the annual O&M spend is tracked by maintenance program to ensure an optimal balance between inspection and maintenance versus replacement is achieved.

##### 2.3.1.2.1 Criteria and Assumptions

HOL maintenance planning criteria and assumptions are asset dependent and rely on either internal standards or regulatory requirements (OEB Distribution System Code Appendix C – Minimum Inspection Requirements). Internal maintenance program requirements follow industry best practises or are formed through HOL historical experience. HOL develops maintenance and replacement programs by comparing their associated benefits and costs: it may be practical to replace an asset if the cost of maintaining the asset outweighs the value of its replacement.

### *2.3.1.3 Preventive Inspection and Maintenance Programs*

HOL TIM program activities include visual or infrared inspection as well as more intrusive testing of equipment condition and operation. The TIM program also includes maintenance activities referring to physical work on equipment. Most of HOL asset maintenance activities are on a cyclic schedule. The cycle period is selected based on manufacturer’s recommendation, regulatory requirement or internal experience and standards.

Table 2.3.1 outlines the inspection and maintenance cycles of each program. The following sections describe the HOL inspection and mainteneance programs, further details can be found in the Testing, Inspection and Maintenance Plan, included in the APR.

1

**Table 2.3.1 - Maintenance Programs**

| | TIM Type | Cycle | Type |
|---|---|---|---|
| Substation | Station IR Scans | Annually | Predictive |
| | Switchgear Inspections | Annually | Preventative |
| | Breaker & Recloser | Every 4-6 Years | Preventative |
| | Station Switches | Annually | Preventative |
| | SCADA Inspections | Annually | Preventative /Predictive |
| | Relay | Every 4-6 Years | Preventative |
| | Station Inspections | Monthly | Predictive/Corrective |
| | Battery Maintenance | Annually | Predictive |
| | Transformer Maintenance | Every 3-5 Years | Preventative |
| | Transformer Doble | Every 3-5 Years | Predictive |
| | Transformer Oil Analysis | Annually | Predictive |
| | Transformer Tapchanger Maintenance | Every 3-5 Years | Preventative /Predictive |
| Distribution | Padmounted Switchgear IR and Visual | Every 3 Years | Predictive/Corrective |
| | Padmounted XFMR IR and Visual | Every 3 Years | Predictive/Corrective |
| | O/H IR Inspection | Every 3 Years | Predictive |
| | Vault Maintenance | Not Defined | All |
| | Vegetation Management | Every 2 or 3 Years | Preventative /Corrective |
| | Pole Inspection | Every 10 years | Predictive/Corrective |
| | Critical Switch Inspection | Every 3 Years | Preventative |
| | Insulator Washing | Annually | Preventative |
| | Switchgear $CO_2$ Washing | Every 3 Years | Preventative |
| | Cable Inspection | 120 segments annually | Predictive |
| | Manhole Inspections | 10 Year | Corrective |
| | Graffiti Abatement | Routinely | Corrective |

### 2.3.1.3.1 Station Infrared (IR) Inspections

Infrared (IR) inspection on station equipment is completed in conjunction with more specific equipment inspection. The IR inspection checks equipment for hot spots to indicated loose connections, defective equipment, overloading, contamination, short circuits and ground faults. HOL performs IR scanning, internally, on station equipment.

### 2.3.1.3.2 Station Switchgear Maintenance

**Switchgear General Maintenance**

Switchgear undergoes inspections, as part of the monthly cycle, that check the switches, over current relays, position indicator, heaters, breaker tools, and breaker and racking mechanism operation.

**Breaker Maintenance**

The current TIM activities for circuit breakers include: visual inspection and electrical, mechanical, and operational tests. Visual inspection ensures that the breakers are clean, there are no signs of arcing or leaking oil, and there is no damage to the breaker or arc chute. Electrical testing includes performing insulation resistance and contact resistance testing. Mechanical tests include: cleaning the bushing, checking for any leaks around the gaskets, cleaning, lubricating and testing the operating mechanism, checking the contacts, and tightening all bolts, pins, and connections. Operational testing of the breaker checks the operating mechanisms, and ensures the proper operation of the breaker and the charging motor.

**Station Recloser Maintenance**

Recloser maintenance includes: visual inspection, electrical testing, mechanical testing and dielectric sampling. The visual inspection checks the bushings, contacts and liquid level and includes an IR scan of the recloser and its components. The electrical, mechanical, and operational inspection includes checking mechanical connections, testing insulation resistance and recloser function test to ensure proper operation.

**Station Switch Maintenance**

Switches undergo visual inspection on a monthly basis. Visual inspection checks for issues with the arc shoots, arc tips, broken insulators, burned insulators, and dirty components. The visual inspection is completed to ensure that the switch has no issues that could indicate a problem with day to day operation.

**High Voltage Fuse Maintenance**

High voltage fuse inspection involves: IR scans, visual inspection and cleaning and clip pressure inspection. The visual inspection includes: inspecting the fuse holders, insulators and fuse for breaks, cracks, burns, pitting, and indication of flashover and signs of deterioration. The IR inspection checks the fuse holder to ensure the components are under the threshold temperature.

#### 2.3.1.3.3 Supervisory Control and Data Acquisition (SCADA) Maintenance

Supervisory Control and Data Acquisition (SCADA) is a control system that allows for the monitoring and control of compatible electrical equipment in the HOL electrical system. The maintenance performed on SCADA controlled equipment includes visual inspection, checking communication, cleaning, torquing, function testing and ground inspection.

#### 2.3.1.3.4 Relay Maintenance

Relays are currently undergoing complete inspections every 4 to 6 years. Visual inspections are part of the monthly stations inspection and check for obvious equipment deficiencies. Electrical, mechanical and operational inspections identify loose connections, broken studs, burned insulation, dirty contacts, setting configuration and proper operation. IR scans are completed as part of the station annual IR scan and detects equipment operating over the manufacturers temperature specifications.

#### 2.3.1.3.5 Station Visual Inspection

The Station Visual Inspection program is used to assess the condition of the station yard, the station building exterior and interior, the station security, and general equipment condition. The inspections are conducted monthly.

#### 2.3.1.3.6 Battery Maintenance

The station battery and battery charger are inspected by completing voltage measurements and visual inspection of the direct current (DC) supply components. Included in the voltage measurements are recording individual cell voltages, the battery charger normal charging voltage and the battery charger equalization voltage. The voltage of the individual cells will ensure that they are holding their nominal level and will confirm the cell is in good condition. The charging voltages are taken to ensure the battery charger is set up to charge the battery at the manufacturer's recommendations. Visual inspections are completed for the bonding connections, the battery and battery charger as well as all connecting equipment. The visual inspection determines if there are low electrolyte levels and if corrosion exists at the battery terminals.

#### 2.3.1.3.7 Station Transformer Maintenance

Transformer maintenance currently includes: visual inspection, electrical tests, mechanical tests and oil sampling. The visual inspection involves current and voltage readings, temperature readings, liquid level check, physical condition assessment and pressure/vacuum gauge readings.

The visual inspections of current, voltage and temperature readings ensure that the transformers are operating within the acceptable limits. If the levels are measured outside of the specifications, investigation will be required to determine the root cause and remediation plans.

Liquid, pressure and vacuum level readings are checked to ensure that the transformer is not leaking in any way. If the readings are out of the acceptable range, the stations office is contacted to provide immediate support or schedule follow-up action.

#### 2.3.1.3.8 Station Transformer Doble Testing

Doble testing equipment is being used to assess the overall power factor, turns ratio testing, leakage reactance and exciting current of the transformer. These tests are used to detect moisture in the oil or insulation, detect contamination in the transformer bushing, determine the electrical insulation quality, and locate bad connections and winding movement. The Doble equipment provides test results and expected values and thresholds to effectively translate the results. Doble testing, DGA testing and oil quality analysis complement each other to provide clear indication of the overall health of the transformer.

#### 2.3.1.3.9 Station Transformer Oil Analysis Testing

Transformers undergo dissolved gas analysis (DGA) and oil quality analysis annually. The DGA and oil quality analyses are an important diagnostic tool used to monitor the condition of the unit. Emphasis is placed on these tests for detecting insulation breakdown, water in the oil, stressing of the coils, localized overheating and arcing that can lead to failure of the transformer. Currently, HOL sends oil samples to an oil testing laboratory, uses DGA portable equipment and uses DGA online monitoring equipment. The oil testing laboratory uses sophisticated lab equipment that creates a full analysis of the oil sample, compares the results to any previous transformer oil samples, and specifies detailed recommendations for the transformer. If the laboratory processing lead time is too lengthy, HOL will use portable DGA equipment for immediate results. The online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to set alarms at specific gas concentration thresholds. DGA online monitoring systems are being installed as part of HOL standards and are capable of sending DGA data to the PI server data historian.

DGA and oil quality tests identify abnormalities within the transformer and provide detailed information to allow for sound decision making for future operation and maintenance of the transformer.

#### 2.3.1.3.10 Tap Changer Maintenance

**Oil Filled (Filtered) Tap Changers**

Oil filled tap changer TIM activities include recording position of the tap changer, inspecting the physical and mechanical condition, verifying correct auxiliary device operation, verifying correct liquid level in all tanks, performing tests as recommended by the manufacturer, verifying operation of heaters and verifying grounding. An internal inspection is also conducted and includes removing of the oil and cleaning carbon residue and debris from compartment, inspecting the contacts for wear and alignment, tightening all electrical and mechanical connections to calibrated specifications, inspecting the tap changer components for signs of moisture, cracks, electrical tracking or excessive wear and then refilling the tank with filtered oil.

**Oil/Vacuum Filled Tap Changers**

Oil/vacuum tap changer inspection includes: recording position of the tap changer, inspecting the physical and mechanical condition, verifying correct auxiliary device operation, verifying vacuum level, performing tests as recommended by the manufacturer, verifying operation of heaters, verifying grounding, and inspecting the vacuum bottles for wear or erosion.

#### 2.3.1.3.11 Infrared (IR) and Visual Inspection

HOL performs infrared (IR) and visual inspection for many of its assets. The IR inspections allow crews and contractors to examine equipment operating temperature to detect defective components, poor connections, or overloaded equipment which can indicate the potential for failures. Visual inspections are important to monitor cleanliness, ease of access, obtain updated nomenclature and equipment information, and to assess damage and any potential follow-up activities required.

In order to effectively use the IR scanning information, an equipment health index was created and is used for various pieces of equipment. The condition rating is based on the temperature difference between the reference temperature and the equipment’s actual measured temperature. Equipment that is within the critical temperature range has an Outage Management System (OMS) ticket created to schedule immediate repair. It is the responsibility of the area supervisor to schedule the work and close out the ticket when the issue is verified to be resolved.

**Padmounted Switchgear**

The padmounted switchgear inspection consists of IR scanning and a visual inspection of air-break switchgear. The IR scan detects loose connections, tracking, overloaded equipment, and other heat related problems. Visual inspection includes recording equipment information as well as checking for swollen elbows, exposed electrical hazards, operating hazards, rusting and graffiti.

**Padmounted and Kiosk Transformers**

The padmounted and kiosk transformer inspections consist of an infrared scan and a visual inspection. Infrared scanning detects loose connections, tracking, equipment overload, and other heat related problems. Visual inspection checks for swollen elbows, exposed electrical hazards, operating hazards and graffiti. Additional patrol inspection is performed as a result of the Graffiti Abatement and Repainting program.

**Overhead Equipment**

Overhead switches, transformers, lines, and associated attachments are inspected through the IR Scanning Program. The IR Scanning Program consists of performing infrared inspections on overhead equipment from ground level. Equipment that is over a temperature threshold is flagged as requiring further investigation.

#### 2.3.1.3.12 Vault Maintenance

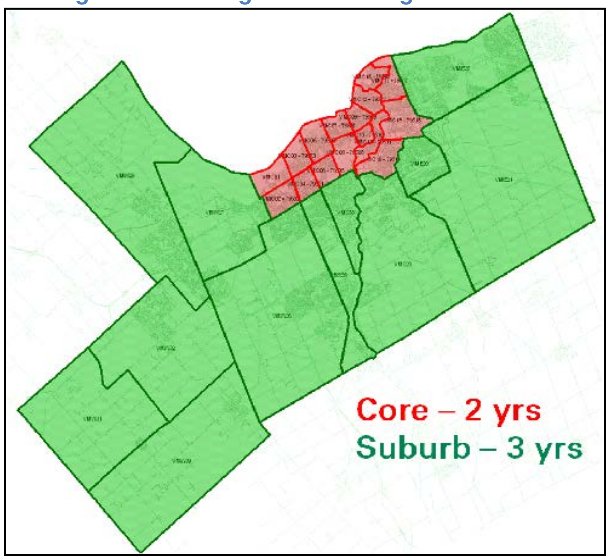
HOL has approximately 1500 vaults in its system, most of which are customer owned. HOL is in the process of creating a vault maintenance program. Customer owned vaults are the customers' responsibility to maintain along with the containing equipment. If no current maintenance is being performed on customer owned vaults, HOL will recommend that maintenance is performed by the customer. In the rare case that a customer does not complete maintenance on their vaults, and there are obvious issues, the vault could be reported to the Electrical Safety Authority (ESA) for follow-up.

Vault maintenance being performed is at the discretion of the customer or the contractor completing the work. Most often vault maintenance includes visual inspection of the civil structure, ventilation fans, and all electrical equipment, cleaning of the switchgear, transformer(s), breakers, the vault floors and any other required equipment, IR scanning of the electrical equipment, torquing connections, inspecting grounding and lighting and any other supplementary maintenance.

#### 2.3.1.3.13 Vegetation Management

Vegetation that encroaches on the distribution lines on any right-of-way is managed to ensure system reliability and public safety. The HOL's service territory is currently divided into regions for vegetation management: 12 suburb and 16 core areas (Figure 2.3.2). Third party arborist contactors are hired to maintain certain vegetation areas annually. Recently, HOL undertook a project to evaluate each of the circuits in the distribution system through physical inspection. This produced a large amount of data regarding tree species to aid in a potential redevelopment of the vegetation management program to improve upon the effectiveness of the program. Also identified during the inspections were a number of circuits with overhanging branches. As a result, HOL is working through a storm hardening activity to remove the overhanging branches in an effort to further improve reliability.

**Figure 2.3.2 - Vegetation Management Areas**




### 2.3.1.3.14 Pole Inspections and Testing

One of HOL's largest asset classes is distribution poles and attached hardware. These assets are used to support overhead distribution and sub-transmission conductors throughout the City. Maintaining these assets is essential for a reliable and safe system.

HOL currently performs visual inspection and drill testing on poles. Visual inspections record detailed information about the pole, the attached hardware and any other relevant information. This information is used in conjunction with the drill test to prioritize pole replacement, hardware replacement or to create new designs that will integrate with the present configuration. Drill assessment is a non-destructive testing method using an International Distribution Network (IML) Resistograph drill which measures the density or resistivity of the wood against the drill bit. The drill test provides an overall indication of rot, void, and solid wood thickness that can be used to calculate the remaining strength of the pole.

### 2.3.1.3.15 Critical Switches Inspection

HOL currently has a critical switch program with the purpose of maintaining and inspecting switches that are deemed a high priority. These switches are selected based on the requirements to interrupt higher loads, supply many customers, or critical customers such as hospitals. The cyclic inspection program will ensure all areas will be visited, and problems detected before they lead to system failures that may:

- Impair the safety of HOL employees or the public at large;
- Impair system reliability and reduce the quality of service to our customer;
- Seriously reduce the life expectancy of the equipment and increase costs; and/or
- Adversely affect the environment.

Currently, the critical switch maintenance includes a visual and mechanical inspection, electrical tests, and comparison of resistance tests with similar connections. The mechanical and visual inspection includes a visual check of the physical appearance of the mechanical and electrical connections, cleaning of the switch, and mechanical operator test. The electrical test includes connection resistance checks, equipment torquing, and Megger checks on each pole and/or control wiring.

### 2.3.1.3.16 Washing

**Insulator Washing**

HOL has adopted an extensive insulator washing program with full washing of critical 44 kV, 27.6 kV and 13.2 kV circuits.

Washing is used to clean insulators with contamination build-up. Contamination decreases the insulation strength and causes tracking and flashover. This arcing causes electrical losses but can also lead to pole fires, further equipment damage, and outages to the system. Currently, only porcelain insulators are being washed as part of the program.

The program was revisited in 2013 and the insulator routes were modified based on several criteria. The main selection criteria were system voltage, type of traffic or nearby industry, numbers of recorded pole fires and percentage of porcelain insulators.

The insulator wash is a supplementary activity from those stated in the OEB's Minimum Inspection Requirement document

**Padmounted Switchgear $CO_2$ Wash**

All identified air-brake switchgear are Carbon Dioxide ($CO_2$) washed by contractors to remove contamination, such as road salt or dirt, that contributes to tracking and flashover. To eliminate the contamination's impact on the IR results, the switches are washed prior to performing IR scan. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. $CO_2$ wash allows switchgear to be cleaned while energized, is environmentally friendly, safe, and will increase system reliability by removing surface contamination that can lead to flashover.

**Cable Inspection**

Underground cables are patrol inspected during manhole inspections. Select condition testing of XLPE cable is done annually in the winter through a cable testing program with National Research Council of Canada (NRC). Specific cable segments are tested using a polarization / depolarization technique and the results are compared to reference cables. Test locations are determined based on fault history, age and future planned replacement projects. Test results provide input to HOL's cable replacement and cable injection strategy.

#### 2.3.1.3.17 Civil Structure Inspections

The manhole inspection program targets 300 manholes annually as part of a 10 year inspection cycle. Underground chambers are also inspected through regular work activities when crews perform scheduled work in manholes and handholes.

#### 2.3.1.3.18 Graffiti Abatement

The objective of the Graffiti Abatement program is for painting rusted equipment, graffiti removal, refurbishment and removal of eyesores and extending equipment life when necessary. Currently, equipment requiring attention is identified through regular patrol by a contractor. The Graffiti Abatement program was developed in response to the City of Ottawa Graffiti By-Law to ensure HOL keeps its property free of graffiti. It also allows HOL to work cooperatively with the City of Ottawa By-Law department to address criminal acts of graffiti to deter future acts of vandalism.

## 2.3.2 Asset Life Cycle Risk Management

HOL uses several different TIM programs and activities to provide different approaches to asset failure mitigation; predictive, preventive and corrective maintenance. The HOL maintenance programs may use more than one approach to minimize asset failure and for input into strategic asset management planning.

### *2.3.2.1 Methods*

#### 2.3.2.1.1 Predictive Maintenance

HOL practices predictive maintenance techniques to mitigate asset failure by evaluating testing and inspection information to identify when proactive or corrective maintenance is required to ensure that the equipment continues to meet requirements.

**Infrared Scanning**

HOL proactively performs infrared (IR) scanning on most equipment as a predictive tool for maintenance. Equipment that undergoes IR scans includes but is not limited to:

- station transformers;
- station switchgear;
- station switches;
- station terminations;
- station batteries;
- overhead conductors and terminations;
- padmounted transformers;
- padmounted switchgear;
- polemounted transformers; and
- supervisory control and data acquisition (SCADA) system equipment

Table 2.3.2 - Infrared Condition Rating

| |
|---|
| **Critical - (>75°C), immediate repair** |
| **Major Problem - (>36°C-75°C), repair as soon as possible** |
| **Intermediate - (>10°C- 36°C)** |
| **Minor - 10°C or less** |

IR scans are a useful tool to locate overloaded equipment, bad termination, or failed equipment to prioritize maintenance activities to eliminate the potential risk of failure. HOL uses a conditioned rating to prioritize follow-up preventative maintenance (see Table 2.3.2).

**Dissolved Gas Analysis**

Substation transformers and tap changers undergo dissolved gas analysis (DGA) and oil quality analysis annually. The DGA and oil quality analyses are an important diagnostic tool used to monitor the condition of the equipment. DGA and oil quality tests identify abnormalities within the transformer and tap changer and provide detailed information to allow for sound decision making for future operation and maintenance practices to ensure the equipment continues to run efficiently.

**Station Batteries and Chargers**

HOL performs testing on substation direct current (DC) systems to assess the condition of the charger and the battery. Testing ensures the charging system is performing as expected and evaluates the individual cell health. The cell health condition predicts any problematic cells in the battery to flag corrective maintenance or replacement before a failure can occur.

**Poles**

HOL poles are visually and drill tested for condition assessment and as input to develop the health indexing. The visually inspection and drill testing are a predictive approach used to calculate the remaining strength of the pole and any attachments. The remaining strength is used to assess if the pole is adequate, if it needs immediate replacement, or to forecast when replacement will be required. The visual inspection identifies any risks of failure to pole attachments which includes insulators, crossarms, guying or anchoring. Any immediate concerns are dealt with and follow up work is scheduled for resolution.

#### 2.3.2.1.2 Preventive Maintenance

HOL performs preventive maintenance on distribution and station assets. Preventive maintenance is an approach where cyclic testing, inspection, and maintenance results in safe and reliable equipment operation by proactively identifying issues that could lead to future concerns.

**Insulator Washing**

HOL executes overhead insulator washing to decrease flashovers and potential pole fire due to contamination, such as salt spray, dust or pollution, which can cause tracking. Insulator washing is done in selective areas deemed to be critical based on the following factors: system voltage, type of traffic or nearby industry, numbers of recorded pole fires and percentage of porcelain insulators.

**$CO_2$ Washing**

Air-brake switchgear are carbon dioxide ($CO_2$) washed to remove contamination in order to reduce the probability of tracking and flashover. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. $CO_2$ washing allows switchgear to be cleaned while energized, is environmentally friendly, safe, and will increase system reliability by removing surface contamination that can lead to flashover.

**Vegetation Management**

The HOL vegetation management program combines preventive and corrective activities. The preventative work is regular trimming that occurs on a 2 or 3 year cycle depending on region aimed at maintaining proper clearances to lines. This trimming manages the majority of trees in HOL right of ways. The vegetation management program removes tree hazards that are within the encroachment limits to decrease tree related failures and interruptions. Corrective work includes unpredictable vegetation activities and includes customer calls for tree hazards, emerald ash trees affected by the emerald ash borer, and emergent work from storms.

**Critical Switch Program**

The purpose of HOL's critical switch program is to maintain and inspect switches that are deemed to have a high consequence of failure. These switches are selected based on the requirements to interrupt higher loads, supply many customers, or critical customers such as hospitals. The cyclic inspection program ensures all areas are visited, and problems detected before they lead to system failures that may:

- Impair the safety of HOL employees or the public at large;
- Impair system reliability and reduce the quality of service to our customers;
- Seriously reduce the life expectancy of the equipment and increase costs; and/or
- Adversely affect the environment.

**Station Equipment**

Substation equipment has a larger failure consequence as compared to distribution equipment based on an increase in number of customer affected by any failure, increased equipment procurement time and higher cost, and as such, has more regular, rigorous and frequent testing, inspection and maintenance activities. The following list details the regular maintenance performed on station equipment.

- The oil from transformers and tap changers is drained to perform an internal visual inspection and the oil is replaced to eliminate any potential contamination;
- Tap changers are cleaned and tested to ensure reliable operation;
- Switchgear is cleaned thoroughly;
- Breakers are tested and calibrated to ensure adequate timing
- Breaker racking mechanisms are cleaned, greased and tested.

During these routine maintenance activities any problematic components identified are proactively replaced.

#### 2.3.2.1.3 Corrective Maintenance

Corrective maintenance activities are identified through visual inspection or by equipment failure indication. HOL uses predictive and preventive maintenance to minimize corrective maintenance which can typically result in longer interruption duration and higher overall costs. Reactive maintenance is commonly performed on equipment with low consequence of failure or due to unpredicted failure.

Corrective maintenance is prioritized in HOL's tracking system (Outage Management System, OMS) depending on the criticality of the work. Issues identified as a reliability, safety or environmental concern are resolved immediately and progress on other issues is tracking through the OMS to ensure completion in a timely manner.

### *2.3.2.2 Information Collection and Analyses*

HOL is currently in the process of maximizing digital collections of maintenance information. Digital collection of information, through the use of ruggedized tablets, optimizes the ability to perform data analyses and allows for more effective implementation of health indexing and project prioritization. HOL is reviewing its asset health index to identify the gaps in the inspections process. Identifying the gaps will allow the maintenance programs to improve and evolve to provide more qualitative results.

The TIM Plan documents HOL's current programs; including the programs schedule, performance indicators, data governance, corrective maintenance activities and program gaps (refer to the Annual Planning Report Testing Information and Maintenance – Data Governance for the information collected by HOL, Attachment B-1(B)).

#### *2.3.2.3 Asset Risk Analysis*

HOL risk analysis is completed as part of the Asset Management Process. The risk is calculated using objective weighting and risk scoring (see Section 2.1.2 Asset Management Process Components) that prioritizes activities that address a higher level of risk.

#### *2.3.2.4 Risk Analyses and Prioritizing Capital Expenditures*

HOL risk analysis and capital project prioritization is completed as part of the Asset Management Process. The capital expenditures are prioritized to maximize benefit to cost (see Section 2.1.2 Asset Management Process Components).

# 3 Capital Expenditure Plan

The capital expenditure plan details the system investment decisions which are made through the asset management and capital expenditure planning process. Investments are detailed by investment category, HOL Capital Program and Budget Program for the historic years of 2011 through 2015 and the forecast years of 2016 through 2020.

## 3.1 Summary

HOL's Capital Expenditures are broken into categories based on the following hierarchy: Investment Category, Capital Program followed by Budget Program, as shown in Table 3.1.1 along with the primary driver. For a description of each driver refer to Table 2.1.1 - Driver Descriptions.

**Table 3.1.1 - Capital Expenditure Categories**

| Investment Category | Capital Program | Budget Program | Primary Driver |
|---|---|---|---|
| System Access | Plant Relocation | Plant Relocation & Upgrade | 3rd party requirements |
| | Residential | Residential Subdivision | Customer service request |
| | Commercial | New Commercial Development | Customer service request |
| | System Expansion | System Expansion | Customer service request |
| | Stations Embedded Generation | Embedded Generation Projects | Customer service request |
| | Infill & Upgrade | Infill Service (Res & Small Com) | Customer service request |
| | Damage to Plant | Damage to Plant | Mandated service obligation |
| | Metering | Suite Meters | Mandated service obligation |
| System Renewal | Station Assets | Stations Transformer Replacement | Assets at end of service life – failure risk |
| | | Stations Switchgear Replacement | Assets at end of service life – failure risk |
| | | Stations Plant Failure | Assets at end of service life – failure |
| | Stations | Stations Enhancements | Assets at end of service |

| | | | |
|---|---|---|---|
| | Refurbishment | | life – substandard performance |
| | Distribution Assets | Planned Pole Replacement | Assets at end of service life – failure risk |
| | | Insulator Replacement Program | Assets at end of service life – high performance risk |
| | | Elbow & Insert Replacement | Assets at end of service life – substandard performance |
| | | Distribution Transformer Replacement | Assets at end of service life – failure risk |
| | | Vault Rehab or Removal | Assets at end of service life – failure risk |
| | | Civil Rehabilitation | Assets at end of service life – failure risk |
| | | Cable Replacement | Assets at end of service life – failure risk |
| | | Switchgear New & Rehab | Assets at end of service life – failure risk |
| | | O/H Equipment New & Rehab | Assets at end of service life – failure risk |
| | | Plant Failure | Assets at end of service life – failure |
| | Metering | Remote Disconnected Smart Meter | Assets at end of service life – substandard performance |
| **System Service** | Stations Capacity | Stations New Capacity | Capacity constraint |
| | Distribution Enhancement | Line Extensions | Capacity constraint |
| | | System Reliability | Reliability |
| | | Distribution Enhancements | System efficiency |
| | | System Voltage Conversion | Capacity constraint |
| | Automation | Distribution Automation | Reliability |
| | | Substation Automation | System efficiency |
| | | SCADA Upgrades | System efficiency |
| | | RTU Additions | System efficiency |
| **General Plant** | Hydro One Payments | Hydro One Payments | System capital investment support |

| | | | |
|---|---|---|---|
| | Facilities Management | Facilities Management | Non-system physical plant |
| | Fleet Replacement | Fleet Replacement | System capital investment support |
| | Tools Replacement | Tools Replacement | System maintenance support |
| | IT Life Cycle & On-going Enhancements | IT Life Cycle & On-going Enhancements | Business operations efficiency |
| | IT New Initiatives | IT New Initiatives | Business operations efficiency |
| | ERP System | ERP System | Business operations efficiency |
| | Customer Service | Customer Service | Business operations efficiency |
| | Operation Initiatives | Operation Initiatives | Business operations efficiency |
| | Facilities Implementation Plan | Facilities Implementation Plan | Non-system physical Plant |

The following sections outline the descriptions of the Capital Programs and Budget Programs by Investment Category.

### 3.1.1 System Access

System Access investments, as defined in the Chapter 5, Section 5.1.1 Investment Categories are "modifications (including asset relocation) to a distributor's system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system". Figure 3.1.1 shows the System Access financial hierarchy and drivers.

**Figure 3.1.1 - System Access Financial Hierarchy and Drivers**

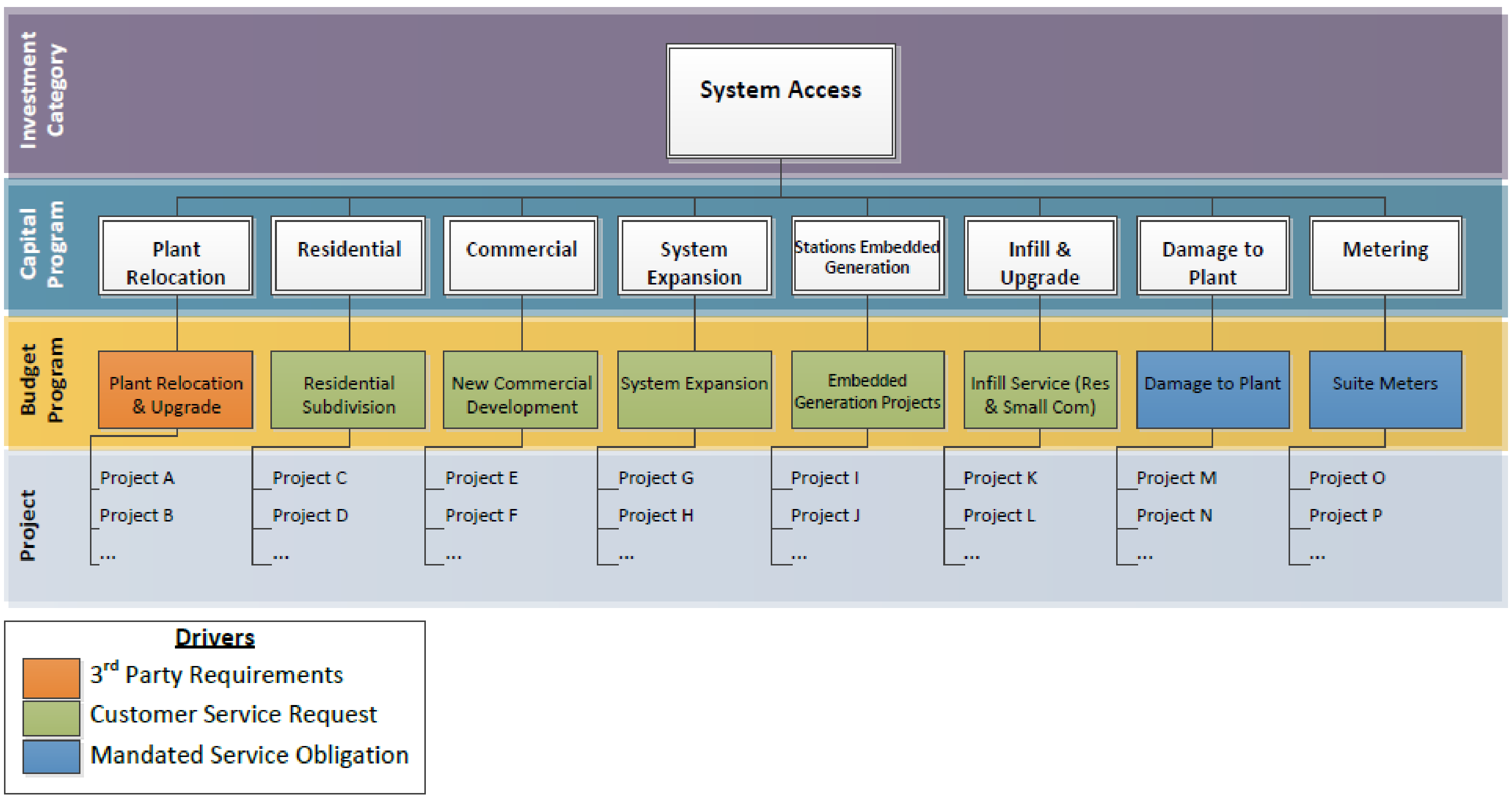


**Table 3.1.2 - System Access Capital Program & Budget Program Descriptions**

| Capital Program | | Budget Program | |
|---|---|---|---|
| **Name** | **Description** | **Name** | **Description** |
| Plant Relocation | • Work triggered by road widening, relocation and upgrade of plant during relocation and any plant removal due to conflict;<br>• Typically 50% contributed capital | Plant Relocation & Upgrade | • Relocation or upgrade of HOL owned or joint-use overhead lines or underground;<br>• equipment to permit for safe limits of approach. |
| Residential | • Connection of new subdivision developments;<br>• Exclusive of work considered under Infill & Upgrade | Residential Subdivision | • To connect new residential subdivisions consisting of townhomes, semi-detached, single, or any combination of housing units;<br>• Includes alternative bid and HOL built subdivisions;<br>• Trunk, primary & secondary distribution infrastructure all considered within scope |
| Commercial | • To connect new developments with secondary voltage at or above 600V;<br>• Exclusive of work considered under Infill & Upgrade | New Commercial Development | • New developments serviced via padmounted equipment (switchgear and/or transformers) or via a vault |
| System Expansion | • An addition to the distribution system in response to a request for | System Expansion | • A demand driven addition to a distribution feeder in response to a request for |

| | | | |
|---|---|---|---|
| | additional customer connections that otherwise could not be made | | additional customer connections; for example a line extension |
| Stations Embedded Generation | • Projects that HOL undertakes to ensure the system can accept customer embedded generation connections while ensuring reliability of the existing system is maintained | Embedded Generation Projects | • Connection of customer driven embedded generation projects;<br>• Includes metering, service connection and protection and control as required |
| Infill & Upgrade | • Residential infill and small commercial connections (one-offs);<br>• Excluding those covered under Residential or Commercial;<br>• Appendix G in HOL's Conditions of Service outlines fees, servicing standards, and conditions for infill and upgrade connections to the distribution network | Infill Service (Res & Small Com) | • Infill service or service upgrade for either residential or small commercial developments, i.e. services that do not require padmounted equipment or vault installations |
| Damage to Plant | • Replacement of harmed assets that has resulted in the loss of functional use or a safety hazard and are caused by a third party | Damage to Plant | • Unplanned replacement of harmed assets as caused by a third party |

| | | | |
|---|---|---|---|
| | (e.g. motor vehicle collision, cable dig-in, etc.);<br>• Asset may be no longer functional or has an aesthetic condition beyond normal wear and tear;<br>• Target 100% recovery of cost from the third party; however, where tracking information is not available, HOL absorbs the cost or may attempt at recovery from its insurer;<br>• Includes damaged distribution or stations assets, excluding metering | | |
| Metering | • Retrofit or installation of suite meters in commercial installations capable of measuring consumption on a per dwelling (as opposed to bulk) basis | Suite Meters | • Retrofit or installation of suite meters (retrofit of bulk meters) for commercial buildings;<br>• Focus of the program is on residential retrofits and new construction in vertically arranged establishments with a minimum of 25 units |

### 3.1.2 System Renewal

System Renewal investments, as defined in Chapter 5, Section 5.1.1 Investment Categories "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services". Figure 3.1.2 shows the System Renewal financial hierarchy and drivers.

**Figure 3.1.2 - System Renewal Financial Hierarchy and Drivers**

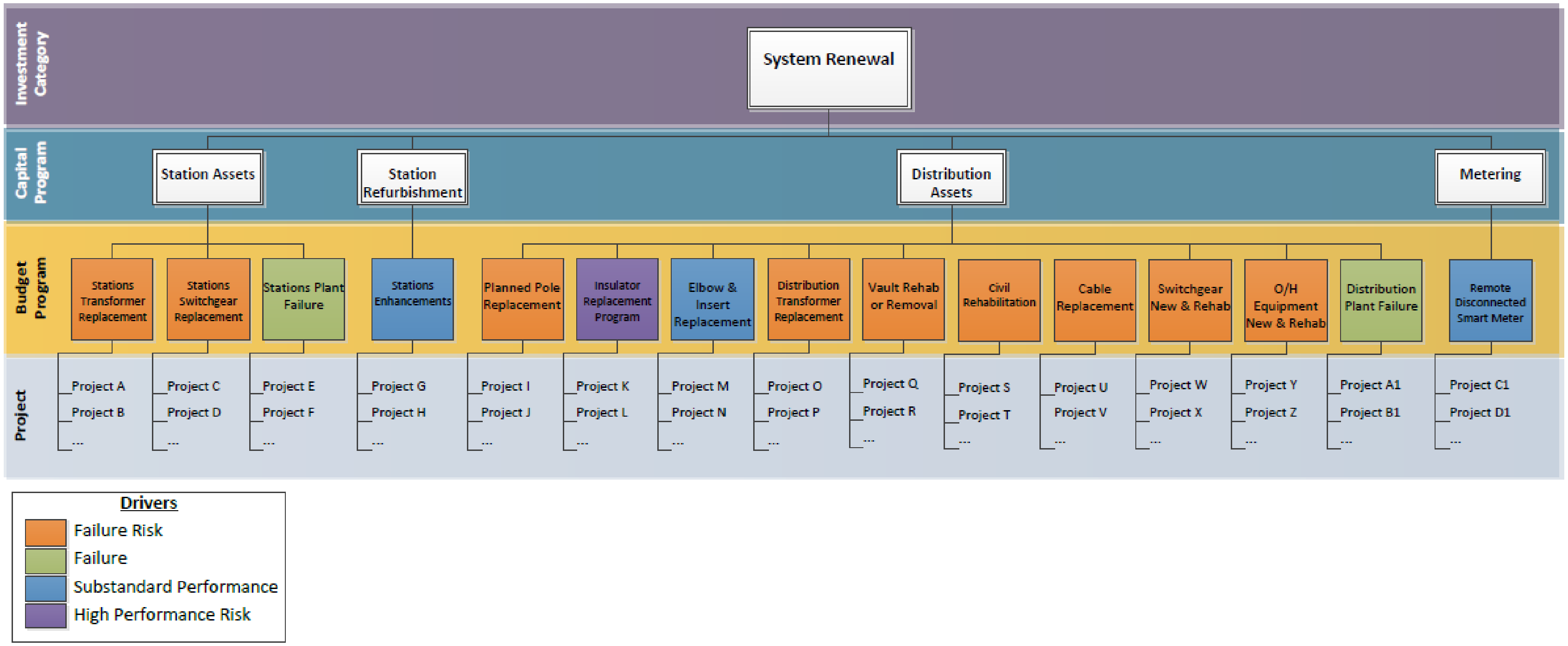


**Table 3.1.3 - System Renewal Capital Program & Budget Program Descriptions**

| Capital Program | | Budget Program | |
|---|---|---|---|
| **Name** | **Description** | **Name** | **Description** |
| Station Assets | • Sustainment of discreet stations assets based on condition (Health Index) and prioritization (See Section 2.1 Asset Management Process Overview) | Stations Transformer Replacement | • Station transformer refurbishment (life extension), or replacement as guided by the Asset Management Planning process |
| | | Stations Switchgear Replacement | • Stations switchgear and relay refurbishment (life extension), or replacement as guided by the Asset Management Planning process |
| | | Stations Plant Failure | • Unplanned replacement of failed station assets;<br>• In cases where there is no full functional failure (causing an interruption), or immediate safety or environmental concern then work should be planned and prioritized based on crew and resource availability (where work is not considered to be an emergency);<br>• If the equipment has been damaged by a third party then it is considered under Damage to Plant |
| Stations | • Repairs and/or | Stations | • Repairs, refurbishment and/or |

| | | | |
|---|---|---|---|
| Refurbishment | refurbishment of existing station building or property assets for the purposes life extension or safety/regulatory requirements | Enhancements | replacement of existing station building or property assets |
| Distribution Assets | • Sustainment of discreet distribution assets based on assessed condition (Health Index) and prioritization (See Section 2.1 Asset Management Process Overview) | Planned Pole Replacement | • Planned replacement or upgrade of HOL owned poles or cross-arms based on condition assessment;<br>• Pole attachments and conductors are considered in scope for replacement along with the poles/cross-arms where they are of the same vintage as the poles |
| | | Insulator Replacement Program | • Replacement or upgrade of HOL owned insulators that have been deemed a safety hazard, operationally inadequate and/or may cause pole fires |
| | | Elbow & Insert Replacement | • Replacement and upgrade of distribution transformer non-vented elbows and/or inserts on the 27.6 kV system due to safety concerns of flash over during operation below $0^{o}$C |

| | | | |
|---|---|---|---|
| | | Distribution Transformer Replacement | • Replacement of overhead or underground distribution transformers due to functional, safety or environmental concern (leaks, PCBs, corrosion, failure risk, etc.), or upgrade, including transformer shop testing and commissioning |
| | | Vault Rehab or Rebuild | • Vault rehabilitation due to condition of equipment or removal for consolidation or system betterment;<br>• Includes replacement of Jack-Bus arrangements;<br>• Exclusive of work considered under Plant Relocation & Upgrade |
| | | Civil Rehabilitation | • Rehabilitation or rebuild of underground cable chambers, collars, ducts, and equipment pads due to condition or failure risk;<br>• Includes installation of pads and vault space under pads;<br>• Duct extensions considered under Line Extensions |
| | | Cable Replacement | • Replacement or injection of underground cable based on condition; |

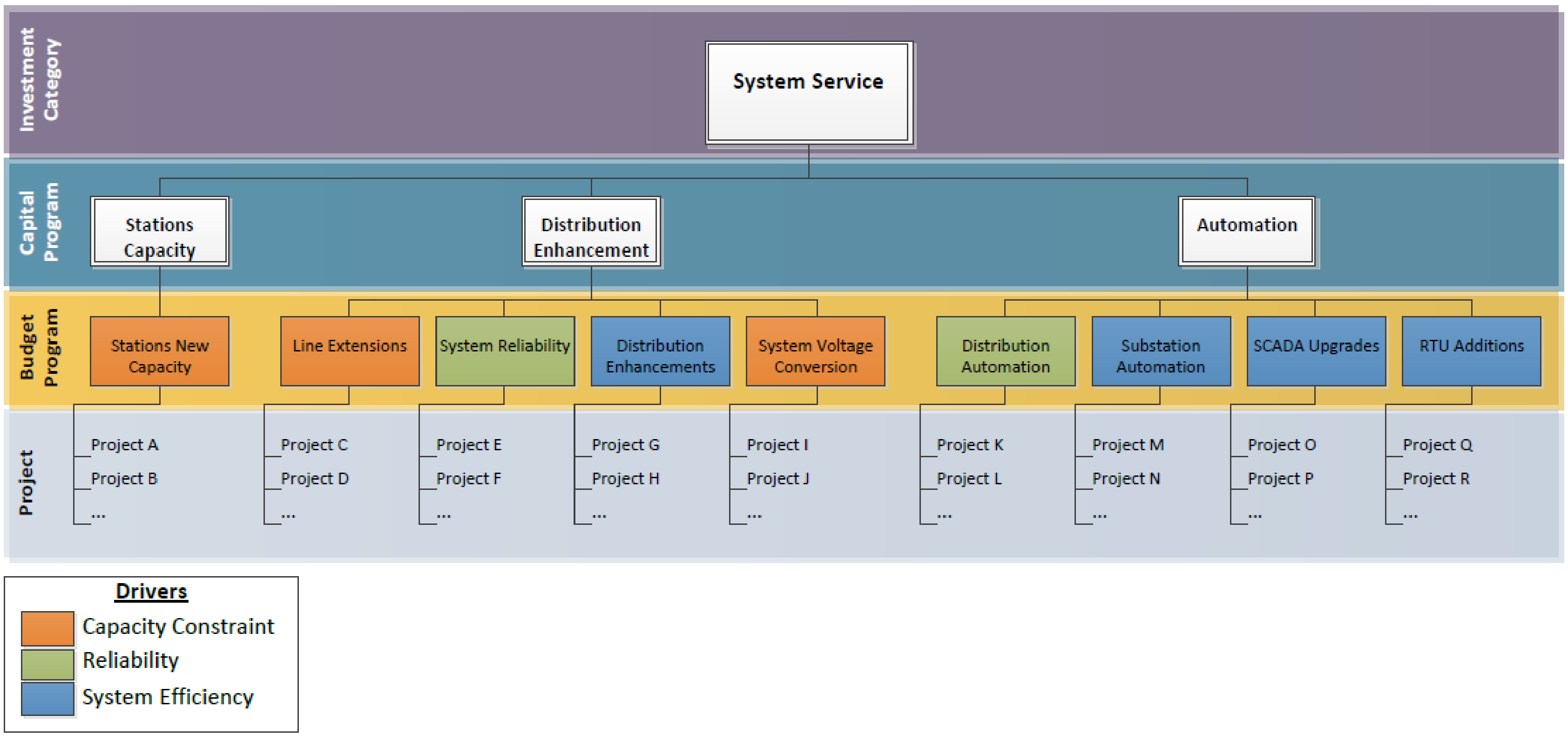
| | | | |
|---|---|---|---|
| | | | • All cable types considered, i.e. PILC, XLPE, butyl rubber, etc.;<br>• Can include associated distribution transformer replacements based on condition assessment on a case-by-case basis |
| | | Switchgear New & Rehab | • Replacement, refurbishment or upgrade of HOL owned switchgear based on condition |
| | | O/H Equipment New & Rehab | • Installation of new, or the rehabilitation of overhead equipment ( i.e. switches, reclosers, cutouts, or arrestors) based on condition or functional requirements (i.e. upgrade to gang operable switches or automated devices) |
| | | Distribution Plant Failure | • Unplanned replacement of failed distribution assets;<br>• In cases where there is no full functional failure (causing an interruption), or immediate safety or environmental concern then work should be planned and prioritized based on crew and resource availability (where work is not considered to be an |

| | | | |
|---|---|---|---|
| | | | emergency);<br>• If the equipment has been damaged by a third party then it is considered under Damage to Plant |
| Metering | • Upgrading customer meters for the ability to remotely disconnect and reconnect | Remote Disconnected Smart Meter | • Upgrading customer meters for the ability to remotely disconnect and reconnect |

### 3.1.3 System Service

System Service investments, as defined in Chapter 5, Section 5.1.1 Investment Categories are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements". Figure 3.1.3 shows the System Service financial hierarchy and drivers.

**Figure 3.1.3 - System Service Financial Hierarchy and Drivers**



1 Table 3.1.4 - System Service Capital Program & Budget Program Descriptions

| Capital Program | | Budget Program | |
|---|---|---|---|
| **Name** | **Description** | **Name** | **Description** |
| Stations Capacity | • Increase in station capacity by either increasing existing station transformation or through the construction of new substations;<br>• Identified through the Asset Management Process (see 2.1.2.1.3 System Service) for the purpose of ensuring adequate and reliable supply | Stations New Capacity | • New stations or increased station transformation through transformer upgrades or additions at existing stations as identified through the Capacity Planning process |
| Distribution Enhancement | • Modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability, power quality or for relieving system capacity constraints as identified through the Asset Management Process (see 2.1.2.1.3 System Service ) | Line Extension | • Line extensions (overhead or underground) for the purpose of increased capacity, reliability and/or improved power quality as identified through either the Reliability or Capacity planning processes |
| | | System Reliability | • Specific enhancements to particular areas identified as having poor historic system reliability, as identified through the Asset Management |

| | | | |
|---|---|---|---|
| | | | Process (see 2.1.2.1.3 System Service);<br>• Includes projects to support the betterment of the Worst Performing Feeders (see 1.3.1.1.3 Worst Feeder Analysis) |
| | | Distribution Enhancements | • Modifications to an existing distribution system made for purposes of improving system operating characteristics or operability (e.g. circuit reconfiguration) |
| | | System Voltage Conversion | • Distribution voltage conversion for increased capacity in areas seeing significant growth;<br>• Typically coincide with retirement of existing stations or distribution assets due to condition or failure risk |
| Automation | • Installation and commissioning of automated equipment for the purposes of communication or operability | Distribution Automation | • Installation of remotely operable or intelligent overhead or underground equipment, i.e. fault current indicators, Vipers, VBMs, SCADA operable switchgear, etc. |

| | | | |
|---|---|---|---|
| | | Substation Automation | • Automation of non-operational information and functionality (not SCADA) |
| | | SCADA Upgrades | • Upgrades to the Supervisory Control and Data Acquisition (SCADA) system;<br>• Both hardware and software upgrades are considered |
| | | RTU Additions | • Upgrading and addition of Remote Terminal Units (RTUs) in the distribution network to improve SCADA functionality |

### 3.1.4 General Plant

General Plant investments, as defined in, Chapter 5, Section 5.1.1 Investment Categories are “modifications, replacements or additions to a distributor’s assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities”. Figure 3.1.4 shows the General Plant financial hierarchy and drivers.

Figure 3.1.4 - General Plant Financial Hierarchy and Drivers

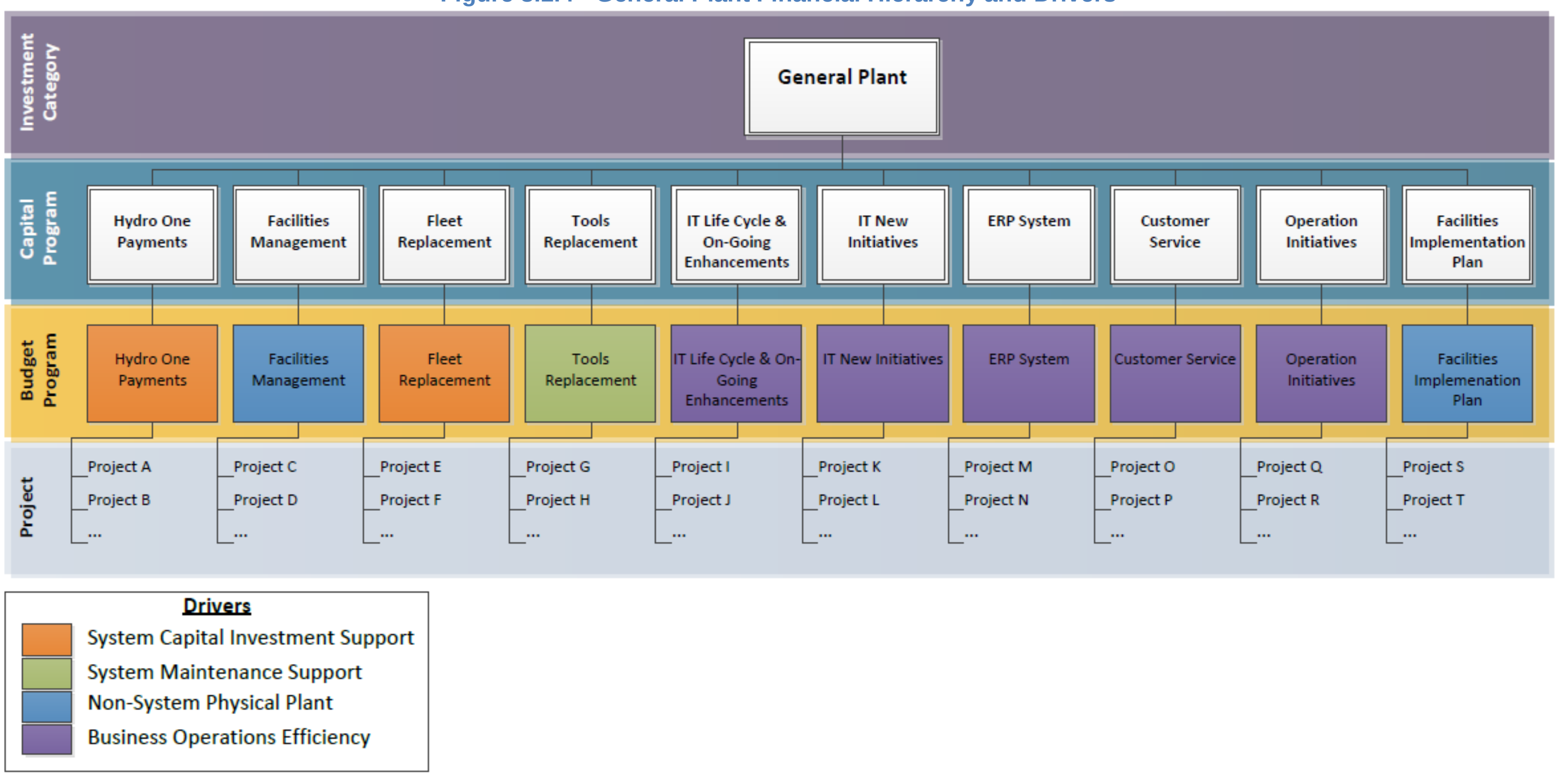


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Table 3.1.5 - General Plant Capital Program & Budget Program Descriptions

| Capital Program | | Budget Program | |
|---|---|---|---|
| **Name** | **Description** | **Name** | **Description** |
| Hydro One Payments | Capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects. Generally referred to as CCRA. | Hydro One Payments | Capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects. Generally referred to as CCRA. |
| Facilities Management | The program addresses the necessary building improvements for the admin buildings and the operation centres to ensure employees with a safe environment to operate. | Facilities Management | The program addresses the necessary building improvements for the admin buildings and the operation centres to ensure employees with a safe environment to operate. |
| Fleet Replacement | Acquisition of vehicles to replace end of life vehicles. Program objective is to provide safe, reliable and efficient vehicles to meet the operational requirements. | Fleet Replacement | Acquisition of vehicles to replace end of life vehicles. Program objective is to provide safe, reliable and efficient vehicles to meet the operational requirements. |
| Tools Replacement | Tools replacements are needed to carry out the distribution maintenance and capital program efficiently and effectively. | Tools Replacement | Tools replacements are needed to carry out the distribution maintenance and capital program efficiently and effectively. |
| IT Life Cycle & On-Going | The program addresses the renewal and maintenance of | IT Life Cycle & On-Going | The program addresses the renewal and maintenance of |

| | | | |
|---|---|---|---|
| Enhancements | the IT infrastructure including PC replacements, network security, data loss prevention program, network switches upgrade, network file storage, and software licenses. | Enhancements | the IT infrastructure including PC replacements, network security, data loss prevention program, network switches upgrade, network file storage, and software licenses. |
| IT New Initiatives | The program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System | IT New Initiatives | The program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System |
| ERP System | The ERP is a vital technology solution to achieve business outcomes. Hydro utilizes J.D. Edwards (JDE) as its enterprise resource planning system. It is used to manage budgets, procurement, inventory, payroll, job cost, and general ledger functions. | ERP System | The ERP is a vital technology solution to achieve business outcomes. Hydro utilizes J.D. Edwards (JDE) as its enterprise resource planning system. It is used to manage budgets, procurement, inventory, payroll, job cost, and general ledger functions. |
| Customer Service | The program includes the Customer Care and Billing system, Customer Service Strategy, and Website Enhancements. The | Customer Service | The program includes the Customer Care and Billing system, Customer Service Strategy, and Website Enhancements. The program |

| | | | |
|---|---|---|---|
| | program objective is to add value to the customers. | | objective is to add value to the customers. |
| Operation Initiatives | The program objective is to strengthen the Geospatial Resource Management (GRM) system, enhance reliability services, and increase productivity and organizational effectiveness. | Operation Initiatives | The program objective is to strengthen the Geospatial Resource Management (GRM) system, enhance reliability services, and increase productivity and organizational effectiveness. |
| Facilities Implementation Plan | The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities | Facilities Implementation Plan | The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities |

### 3.1.5 Load and Generation Connection Capability

This section summarizes HOL's capability to connect new load or generation. More details are found in the System Capacity Plan section of the 2014 Annual Planning Report, in Attachment B-1(B).

#### *3.1.5.1 Ability to Connect New Load*

HOL regularly assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and modifications consistent with all regulatory requirements and with due consideration for safety, environment, finance and supply system reliability/security are developed.

In this regard, the supply needs have been assessed to determine if additions and/or modifications are required to maintain an adequate and reliable/secure system capacity.

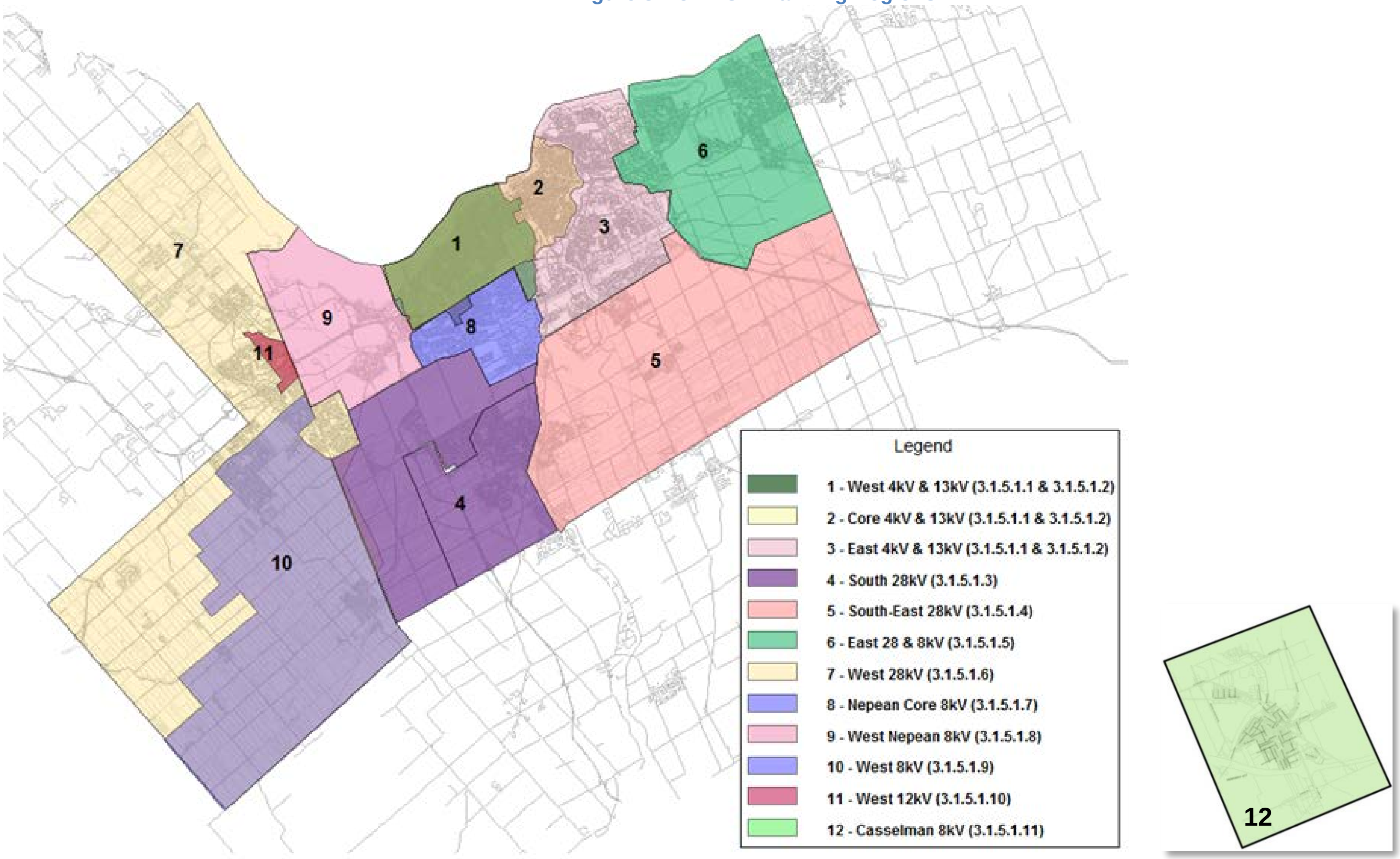
HOL plans system and feeder capacity based on coincident peak loading and single (N-1) contingency. The station and area contingency is considered to be the loss of the largest element, typically either a substation transformer or supply circuit. Under a single contingency, the system is planned to maintain the loading within the remaining equipment's top rating (either 10 day Limited Time Rating (LTR) or allowable flat rating). HOL plans a one-to-one backup arrangement for feeders, this means that circuits have contingency pairs so that for the loss of any one circuit the entire load can be recovered by its back-up thereby reducing the number of switching operations (and time) for recovery of full load. With this arrangement any one circuit must only be loaded to half of its 8 hour emergency rating. Refer to section 1.3.1.4 System Operations Performance for more details on the determination of planning and rated capacities for stations and feeders.

Load for each substation supplying HOL customers is forecasted separately using the previous year's summer coincident peak as the starting point for the forecast. An average annual load growth rate is calculated using the station's historic load levels. This rate is used to predict the baseline load growth over the next twenty years, and reflects typical addition of new customers and the load maturation of existing customers. Additional adjustments are made to the forecast to account for known City of Ottawa and developer plans, forecasted load transfers and other local events that are expected to impact the load forecast. Loading is weather normalized and a one in ten year heat wave adjustment is used as a worst case planning scenario.

Growth in the City is currently being driven by new residential developments in previously rural areas, infill and intensification in many established areas, as well as major projects like the Ottawa Light Rail Transit (OLRT) system.

HOL distribution system is composed of several subsystems, which are segregated by operating voltage, geographical boundaries, and historic political boundaries (see Figure 3.1.5 - HOL Planning Regions). Each of these subsystems undergoes an extensive review annually, as part of the Capacity Planning Process (Section 2.1.2), and a forecast is produced over a twenty year horizon. The following sections details the forecasted subsystem needs.

1 **Figure 3.1.5 - HOL Planning Regions**

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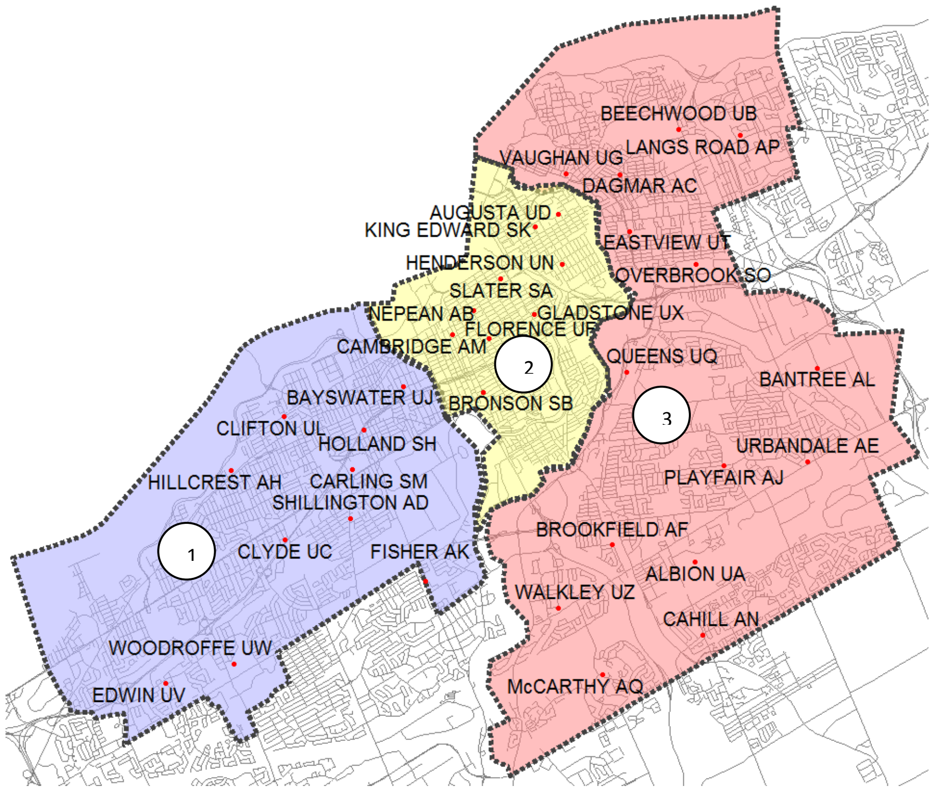
#### 3.1.5.1.1 4 kV System

HOL 4kV supply region (Figure 3.1.6) is comprised of three main areas:

1) The West 4kV supply region covers West of Rochester Street, East of Bayshore Drive, and North of Baseline Road. This region is supplied by the Edwin UV, Shilington AD, Fisher Park AK, Clyde UC, Carling SM, Holland SH, Hillcrest AH, Clifton UL, Bayswater UJ.
2) The Core 4kV supply region covers East of Rochester Street and is bounded West and North of the Rideau River. This region is supplied by the Bronson SB, Nepean AB, Gladstone UX, Augusta UD, Cambridge AM, Slater SA, Henderson UN, Florence UF, Riverdale SR, King Edward SK.
3) The East 4kV supply region covers West of Blair Road, East of the Rideau River, and North of Hunt Club Road. This region is supplied by the Vaughan UG, Bantree AL, Albion UA, Eastview UT, Playfair AJ, Cahill AN, Dagmar AC, Urbandale AE, McCarthy AQ, Beechwood UB, Brookfield AF, Walkley UZ, Queens UQ, Langs Road AP, Overbrook SO, Church AA.

These 4kV substations are supplied from twelve 13kV stations and provide electricity for much of the residential load in the region (See 3.1.5.1.2 13kV System).

**Figure 3.1.6 - 4kV Supply Region**




Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification. Many new developments are converting from low-rise apartments to larger high density condos and apartment buildings. As a result, most of the 4kV substations are experiencing decreasing loads as customers upgrade their electrical supply and transfer to being supplied directly from the 13kV system.

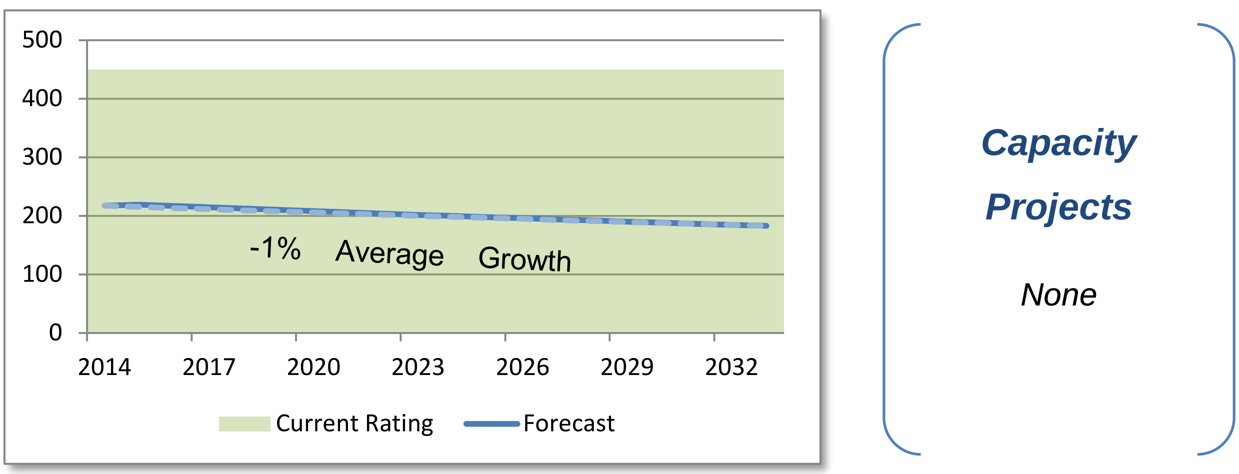
This decrease in load among the stations reduces their financial usefulness due to the fixed maintenance and replacement costs required that is independent of load. In areas that have seen a large transition of their load being supplied by 13kV stations and where the 4kV substation's equipment is nearing end of life, it may be financially advantageous to convert the existing customers to a 13kV supply while decommissioning the 4kV substation.

Currently, HOL is undergoing a voltage conversion project where the 4kV system fed from the substation Woodroffe UW is being decommissioned. The customers that were supplied from this system are being transitioned to the 13kV system fed from Woodroffe TW. This project was mainly driven by the Woodroffe UW assets nearing their end of life, but also due to the decreasing load on the substation. A business case was developed concluding that it made financial sense to undergo the voltage conversion. The end date of this project will be December 2015.

Stations which are forecasted to have diminished asset utilization due to decreased load are identified as potential candidates for voltage conversion projects. Stations for consideration in the short term include: Slater SA and Cahill AN. These stations were identified based on their loading, however, detailed business cases will be required to ultimately determine whether a voltage conversion makes economic sense.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.7.

**Figure 3.1.7 - 4kV Load Forecast**

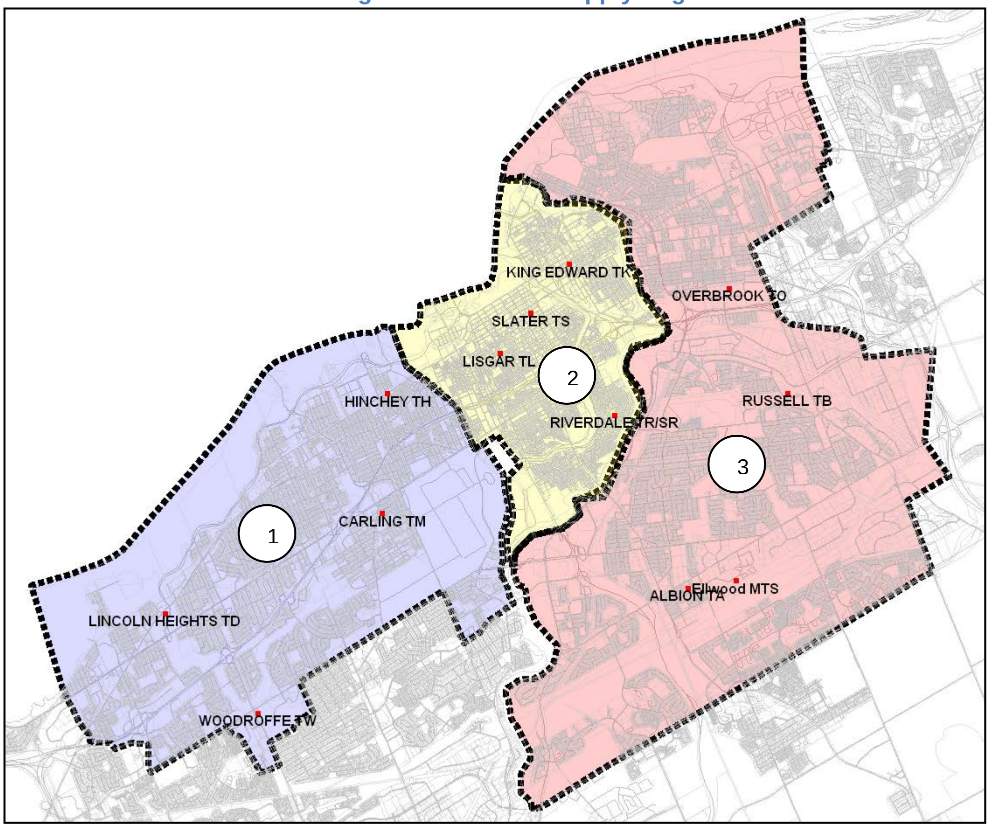


#### 3.1.5.1.2 13kV System

The HOL 13kV supply region is composed of 3 main areas, as shown in Figure 3.1.8. These zones correspond to the 4kV system mentioned in 3.1.5.1.1 above. The three areas are:

1. The West 13kV supply region covers from Bayview Yards and west of Preston Street to Bayshore Drive, north of Baseline Road. This region is supplied by Hinchey TH, Carling TM, Woodroffe TW and Lincoln Heights TD. Hinchey TH also supports the Core 13kV supply region.
2. The Core 13kV area follows the Rideau River to the East and covers to LeBreton Flats in the West. This region is supplied by King Edward TK, Slater TS, Lisgar TL, Hinchey TH, and Riverdale TR. Riverdale TR and King Edward TK also support the East and Core 13kV supply regions.
3. The East 13kV supply region includes the eastern portion of the Old City of Ottawa. This region is supplied by the Russell TB, Albion TA, Ellwood TS, Overbrook TO, Riverdale TR and King Edward TK. Riverdale TR and King Edward TK also support the East and Central 13kV supply regions.

**Figure 3.1.8 - 13kV Supply Region**




Much of the residential load in these regions is not directly supplied from the 13kV system, but rather from a total of thirty-five 4kV substations (see 3.1.5.1.1 4 kV System) which are supplied from the 13kV system.

Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification. This impacts the 13kV system as it covers mostly established areas. Many new developments are trading in low-rise apartments for larger, high density condos. This will reduce the load of the 4kV network through conversion onto the 13kV system.

The majority of the load growth on the 13kV system is from new infrastructure projects and City driven Community Design Plans. More detailed information can be found in Appendix E.

- The West 13kV new loads include the Ottawa Light Rail Transit (OLRT), Tunney's Pasture, Bayview Yards, Centrepointe, Richmond Road, and Preston-Carling Area.

- The Core 13kV is seeing large new loads such as the Ottawa Light Rail Transit (OLRT), the Cliff Street Heating/Cooling Plant (CHCP), Lansdowne Park, LeBreton Flats, Bayview Yards and Transit Oriented Development (TOD).
- The East 13kV new loads include the Ottawa Light Rail Transit (OLRT), the reconstruction of Rockliffe CFB, Transit Oriented Developments (TOD), the Bank Street CDP and the Beechwood CDP.

In the short term, there is a requirement for capacity upgrades and the construction of station interconnections to transfer load at opportune times in order to manage the growth. Longer term planning relating to the IRRP is meant to deal with transmission upgrade plans.

Major capacity infrastructure upgrades on this system include the Hinchey TH Expansion, the Lisgar TL Upgrade, the Overbrook TO upgrade, the King Edward TK upgrade, and the Russell TB upgrade.

**Hinchey TH Expansion**

The capacity expansion of Hinchey TH substation began in 2012. The two transformers at Hinchey TH will have their tertiary winding brought out and allow for the installation of a new bus. The capacity at Hinchey TH will increase from 42 MVA to 99 MVA and will provide 12 new breaker positions. The project is expected to be completed in 2015. Feeder expansions out of Hinchey TH will also be required to transfer load from Lisgar TL to accommodate new growth. Currently 4 feeder expansions are planned for 2014-2015, more will proceed as necessary.

Hinchey TH is currently limiting generation connection capacity based on its minimum load. This expansion will allow for increased generation capacity by providing the ability to transfer more load to the station, plus, the nature of the power transformers will allow some reverse flow capability.

**Lisgar TL Upgrade**

To accommodate the new load to the west of downtown, upgrading the capacity at Lisgar TL is required to support Hinchey TH. This project will increase the limited time rating (LTR) capacity from 83 MVA to 133 MVA. HONI is currently working on preparing estimates for this work.

This upgrade will allow for increased generation capacity availability by upgrading the equipment capacity which currently has a thermal restriction for any new generation connections.

**Overbrook TO Upgrade**

The total transformer capacity at Overbrook TO will be upgraded to 144MVA from 82MVA. The transmission supply to the substation will need to be upgraded to facilitate the increased capacity of this station. This is currently being studied under the IRRP being conducted by HONI, HOL and the OPA (now IESO). This upgrade will be required in or about 2016.

**King Edward TK Upgrade**

The two transformers at King Edward TK substation are currently mismatched in capacity, limiting the overall available capacity. This project would see the replacement of the undersized transformer thereby increasing the available LTR of the station from 80 MVA to 136 MVA. The increased capacity will relieve Slater TS and support the Light Rail Transit (LRT) project. The timelines for this project may be affected by the on-going IRRP with the OPA (now IESO) and Hydro One. The study is currently reviewing the A4K 115kV transmission line which has been identified as having a thermal overload in N-1 contingency loss of the A5RK. The project need has been identified for 2021.

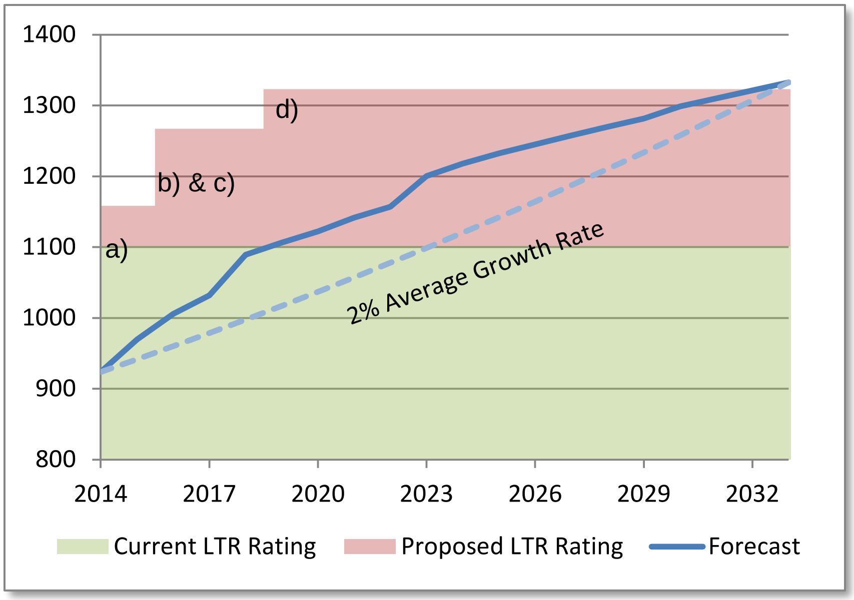
King Edward TK is currently limiting generation connection capacity based on its minimum load. This expansion will allow for increased generation capacity by providing the ability to transfer more load to the station. Also, generation connection capacity can be increased if the power transformers are specified for reverse flow capability.

**Russell TB Upgrade**

Russell TB will need to be upgraded to 144MVA from the current 77MVA. There are no known transmission limitations that should cause delays in this project and will be required in or about 2024.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.9.

Figure 3.1.9 - 13kV Load Forecast




***Capacity Projects***

*Committed:*

(a) *Hinchey TH – 57MVA (2014)*

*Planned:*

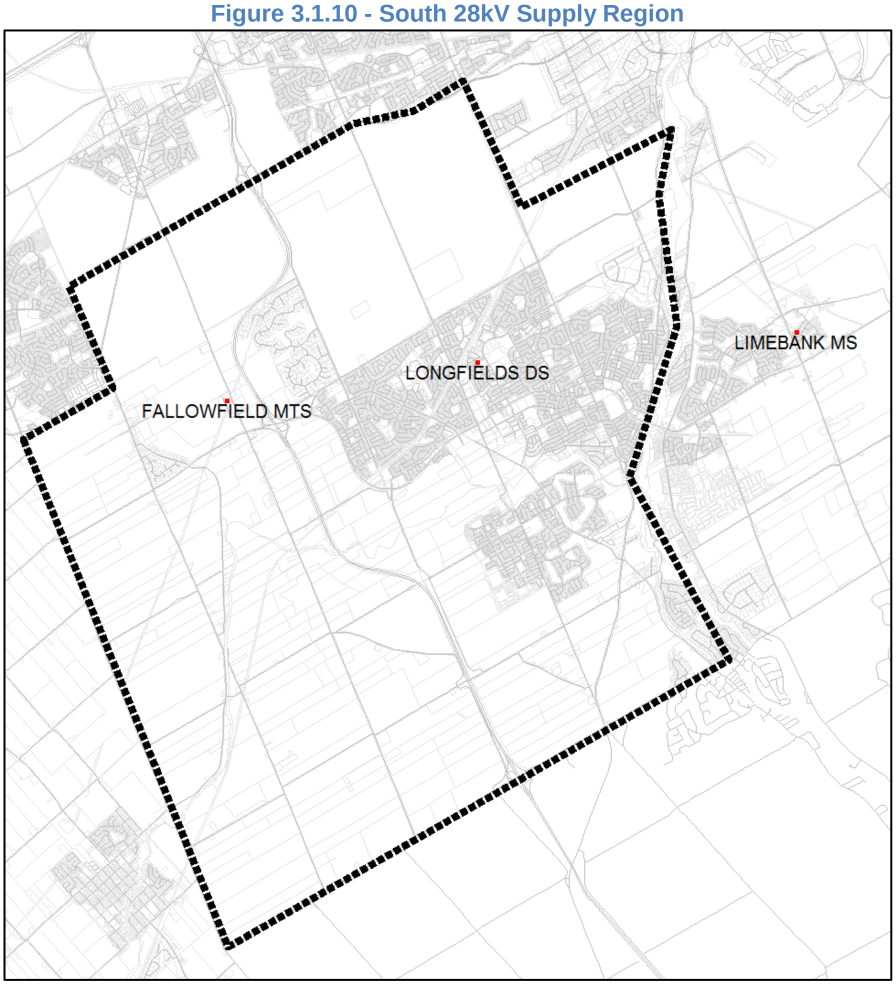
(b) *Lisgar TL – 53MVA (2016)*
(c) *Overbrook TO – 55.6MVA (2016)*
(d) *King Edward TK – 56MVA (2019)*
(e) *Slater TS – 50MVA (2025)*

1

### 3.1.5.1.3 South 28kV System

The South 28kV supply region includes the southern portions of Nepean. This region is supplied by the Fallowfield DS and Longfields DS 28kV substations as well as two feeders from Limebank MS 28kV substation, located in the South-East supply region. Figure 3.1.10 shows the supply region of the South 28kV System.

**Figure 3.1.10 - South 28kV Supply Region**




Despite the physical barrier of the Rideau River between Nepean and Gloucester, the Limebank MS station plays an essential role in supplying both sides of the river.

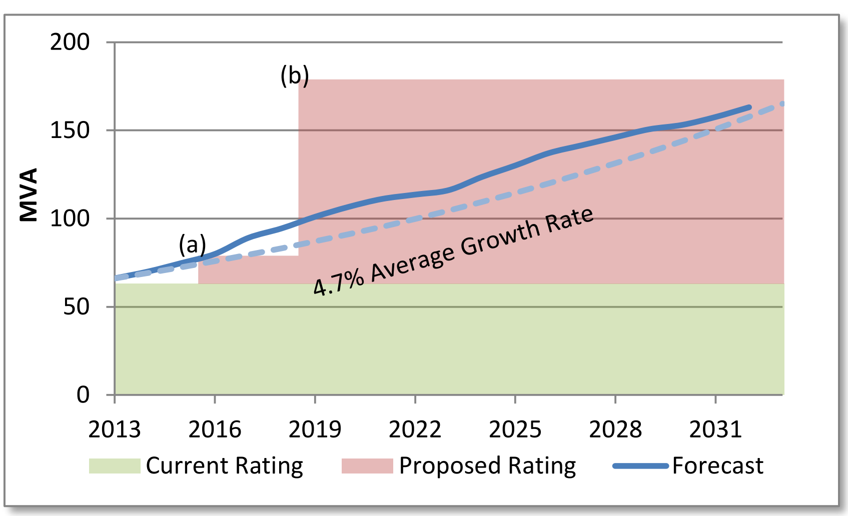
Growth in the south supply region is driven by the ongoing expansion of suburban residential developments, the Nepean Town Centre and the Strandherd Business Park. In addition, rural areas south of the Jock River which are currently fed by the 8KV system will be transferred to the 28kV system as 28kV feeders are introduced in the area to supply new suburban developments.

Overall, the existing south 28kV area is supplied by a strong network of trunk feeders. However, there is the need to expand the system to cover areas seeing growth, as well as strengthen the interconnections to the south of the Jock River. These issues will be addressed by the introduction of a new substation that will support the growth in the Fallowfield DS supply area for the expected load growth.

Based on the projected load growth, an additional station is required to supply the expected load in the South 28kV area. It is planned to build the new station with 2 X 75 MVA transformers with a need date of 2019. The planned new station will solve the overloading issues in normal operating conditions as well as the N-1 contingency situations to the end of the study period. Currently, capacity in this area is being evaluated under the Regional Planning Study which evaluated the various options to meet the capacity needs and resulted in the next step of determining the location of the new station and transmission connection. Details can be found in the project business case found in Attachment B-1(A).

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.11.

**Figure 3.1.11 - South Nepean 28KV load forecast**




***Capacity Projects***

*Planned:*

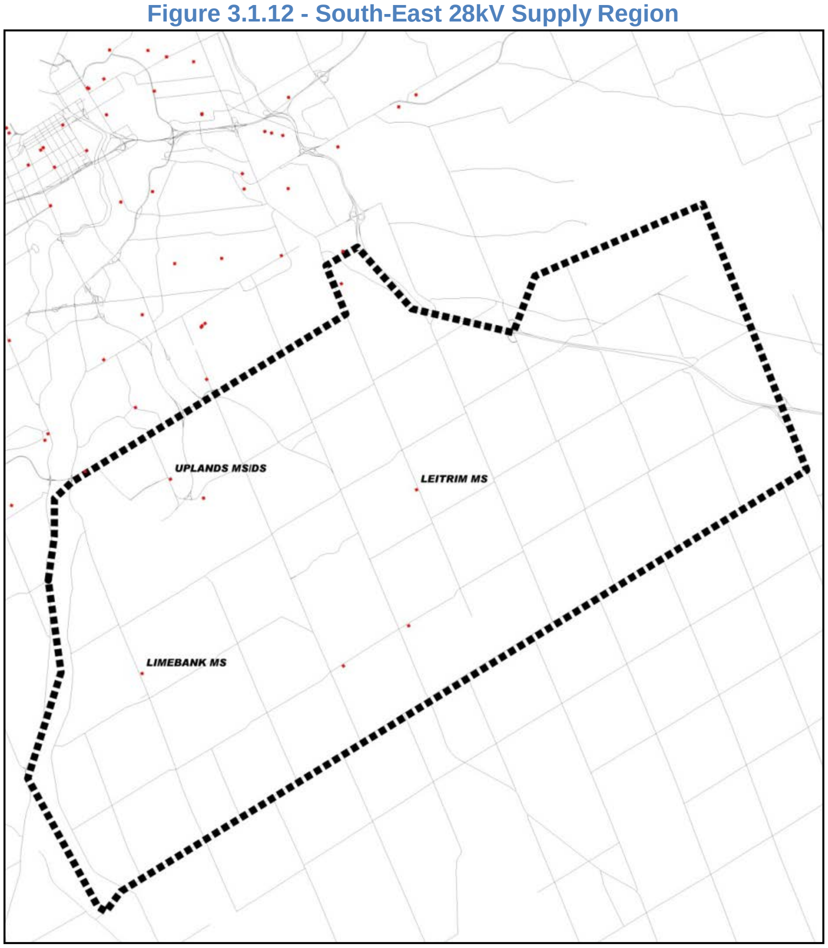
(a) *Added Capacity from Limebank-16MVA(2016)*

(b) *New 28kV Station – 100 MVA (2019)*

### 3.1.5.1.4 South-East 28kV System

The South-East 28kV supply region includes the southern portions of Gloucester. This region is supplied by the Limebank MS, Uplands MS and Leitrim MS 28kV substations, as well as a small pocket supplied by 8kV feeders from the Hydro One owned South Gloucester substation. Despite the physical barrier of the river between Nepean and Gloucester, the Limebank MS station plays an essential role in supplying both sides of the river, creating interdependence between the South 28kV and the South East 28kV systems. Figure 3.1.12 shows the supply region of the South-East 28kV System.

**Figure 3.1.12 - South-East 28kV Supply Region**




New load growth in this area is driven by commercial development in the land surrounding the airport and residential and mixed-use developments in the Riverside South and Leitrim community areas.

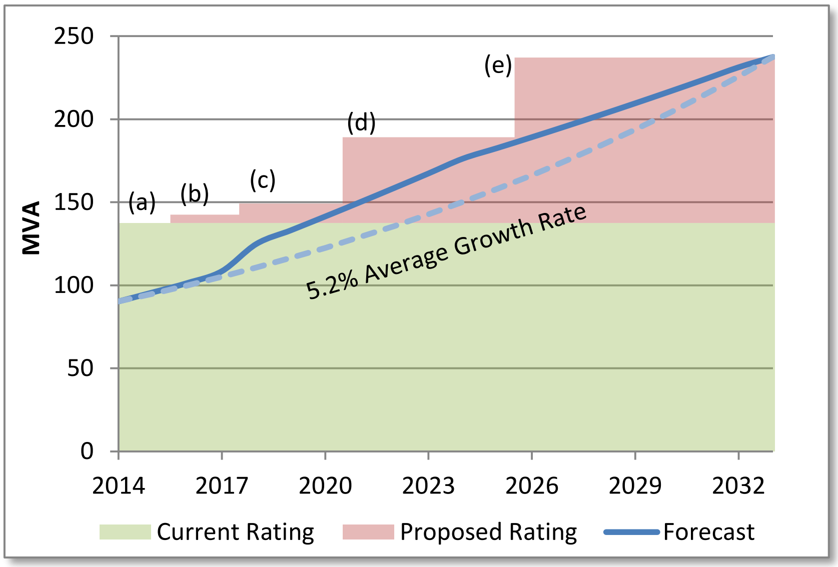
Both Uplands MS and Leitrim MS substations have single supplies and single transformers. With such configurations it is paramount that sufficient distribution circuit ties are maintained to transfer load to adjacent stations under contingency. Circuit ties exist for Uplands MS, although station capacity is currently a limitation to adequately backup capacity for the loss of transformers or supply at Uplands MS.

Regional capacity will require significant increase in order to keep pace with forecasted growth. Upgrades are currently underway at Limebank MS to add a third transformer and make provisions for a fourth transformer, currently projected to be required between 2018 and 2021. In or about 2018, Uplands MS will require an additional transformer to support growth in the region as well. Supply capacity in the region is anticipated to lag growth through the second half of the planning period. The load growth during this period is expected to be met by planned additional upgrades in the South 28kV Region.

While it only results in minor increases to the overall firm capacity in the area, additional transformers are required at both Leitrim MS and Uplands MS in 2016 and 2018 respectively. These units will improve the specific region contingencies and station capacity. As load continues to grow in the Leitrim MS supply area the potential of creating a new transmission connected substation should be evaluated as the existing 44kV supply is limited and it will be costly to add a second 44kV supply.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.13.

**Figure 3.1.13 - South East Load Growth**




## *Capacity Projects*

*Committed:*

*(a) Limebank MS – 40MVA (2014)*

*Planned:*

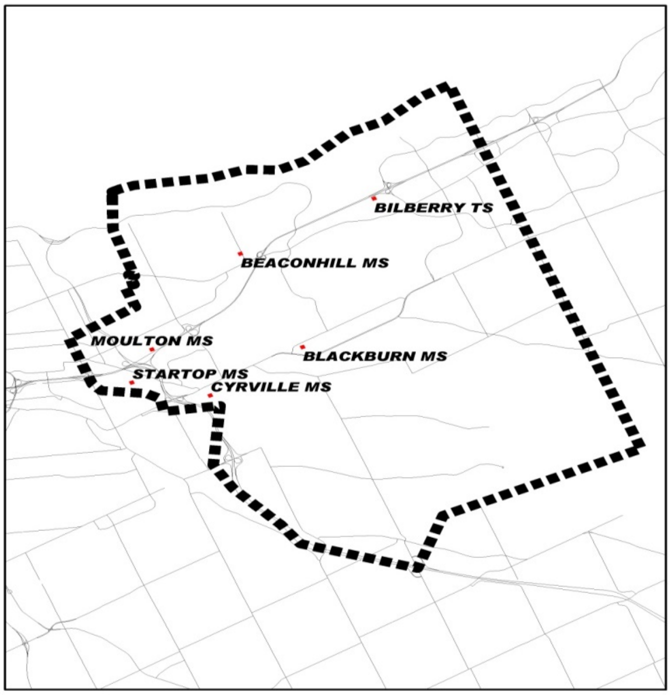
*(b) Leitrim (2nd Tx) – 5 MVA (2016)*
*(c) Uplands (2nd Tx) – 40MVA (2018)*
*(d) Limebank MS – 46MVA (2021)*
*(e) South 28kV Support (2026)*

1

## East 8kV & 28kV System

The East 28kV and 8kV supply area is bounded by the old Gloucester & Ottawa municipal boundary and Highway 417 in the south. Supply to the region includes 28kV transmission connected stations: Cyrville MTS, Bilberry TS and Moulton MS as well as 44kV sub transmission supplied 8kV substations: Startop MS, Blackburn MS and Beaconhill MS. Figure 3.1.14 shows the supply region of the East 28kV and 8kV System.

**Figure 3.1.14 - East 28kV and 8kV Supply Region**




The East 28/8kV system is seeing two main pockets of growth: the East Urban Community, a combination of residential and mixed-use areas, and Light Rail Transit related load developing in the vicinity of the split between highways 417 and 174.

The 28kV & 8kV trunk network provides acceptable coverage of the region; however, expansion of the Cyrville MTS trunk circuits to the east (currently underway) will be required to supply the south of Orleans as it develops.

From a regional point of view there is sufficient capacity to address forecasted load growth. Minor changes to address localized load growth will be required over the next 20 years.

**Startop MS Transformer Upgrades**

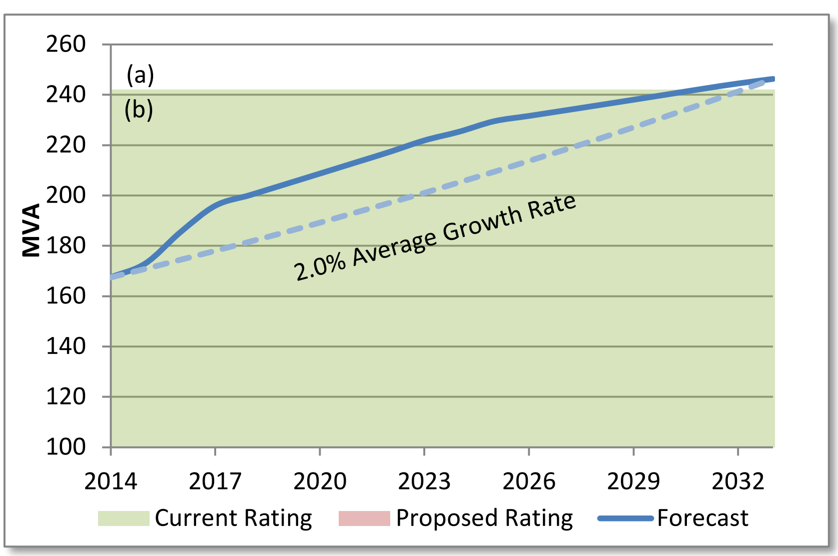
While overall regional capacity is sufficient for future load growth, the local loading on the Startop MS substation is currently above the station rating. Due to the distance between substations this load cannot be effectively supplied from the other 8kV stations in the area. The upgrade of these transformers will be coordinated with primary protection upgrades and automation work occurring on the 44kV subtransmission in the east. The new station transformers will increase the station capacity from 15MVA to 20MVA and will be completed in 2015.

**HONI Orleans TS Construction**

HONI is constructing a new 28kV station, Orleans TS, in the vicinity of Mer Bleue Road and Innes Road. HOL has requested ownership of a single circuit, providing for 16MVA of capacity. The new Orleans TS feeder will tie into the system currently supplied from the Cyrville F1, reducing the load on Cyrville MTS and possibly Bilberry TS and provide additional redundancy to the area. The new feeder will be tied into the Mer Bleue Road line and open points introduced along Renaud Road and Navan Road. It is anticipated that this circuit will be in service in 2015.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.15.

**Figure 3.1.15 - East 8kV & 28kV Load Growth**




***Capacity Projects***

*Committed:*

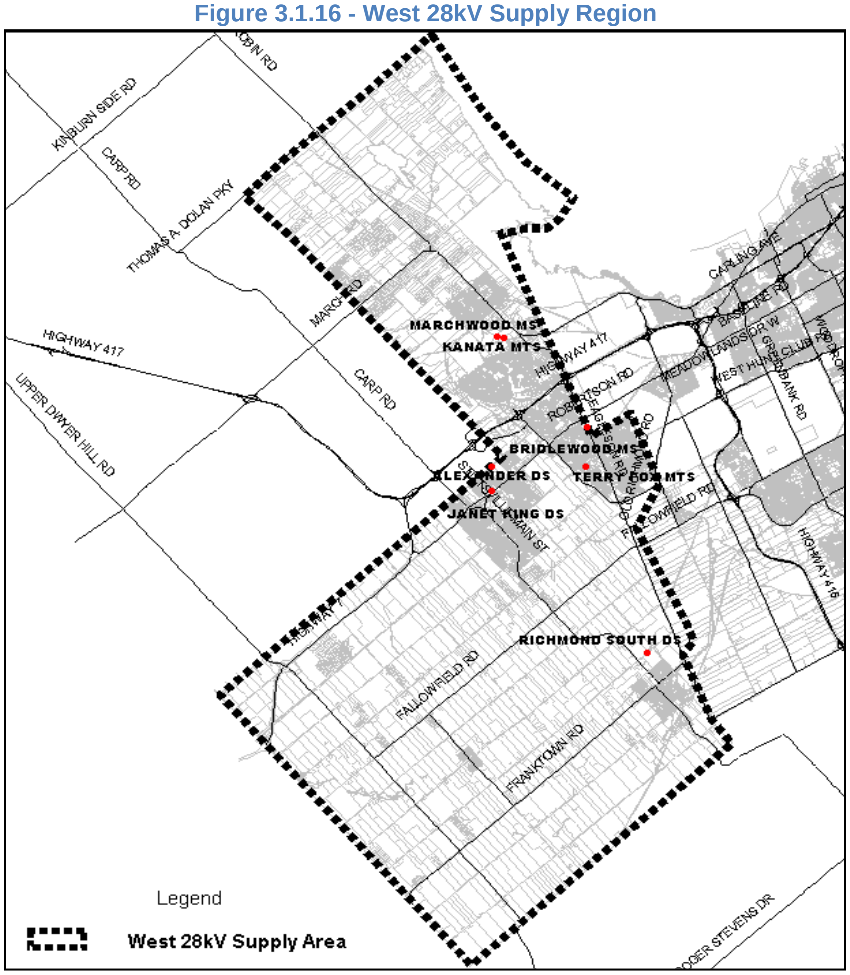
*(a) Startop MS – 5MVA (2014)*
*(b) Orleans TS – 16MVA (2014)*

### 3.1.5.1.5 West 28kV System

The West 28kV supply region includes Kanata and Stittsville. The region is bounded by HOL's service boundary in the west, south and north. Eagleson Road has been utilized as the main boundary to the east, with the exception of the Bridlewood Area. The majority of this service territory is fed at 28kV; however, there are pockets fed at 12kV and 8kV. The 28kV region is supplied by the Kanata MTS, Marchwood MS, Bridlewood MS, Alexander DS, Janet King DS and the Terry Fox MTS 28kV substations.

Figure 3.1.16 shows the supply region of the West 28kV System.

**Figure 3.1.16 - West 28kV Supply Region**




Growth in the west supply region is driven by the ongoing expansion of suburban residential developments, and associated mixed-use centres.

Projected load growth in the Kanata and Stittsville areas is expected to be supplied from the recent addition to the system, Terry Fox MTS. Terry Fox MTS is located on Michael Cowpland Drive along the 230kV right-of-way and will mainly supply the areas of new growth, and act as a backup for Bridlewood MS and Janet King DS. Terry Fox MTS will also be used to off-load the Stittsville load from the Hydro One owned substation Alexander DS which will allow Hydro One to have available capacity for growth in their service territory.

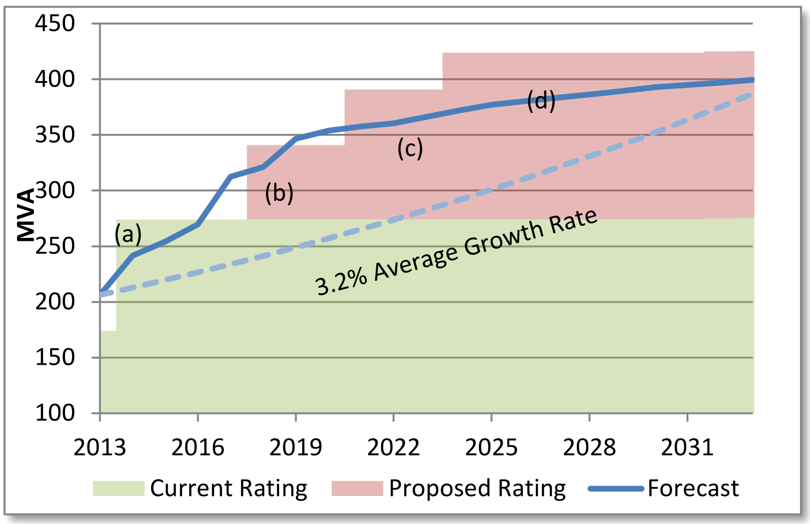
The anticipated growth in the Village of Richmond has prompted the upgrade and voltage conversion of the Richmond South DS substation. Construction is anticipated to begin in 2016 and will increase capacity to accommodate the expected growth and will increase the capacity of Richmond South DS by 1100%.

Overall, the existing west 28kV area is supplied by an adequate network of trunk feeders. There is however the need to expand the system to cover areas seeing growth, as well as to transfer the HOL load off of Alexander DS. Back-up solutions are also required in the south section of the Stittsville community as well as create a backup loop across the south-western part of the region including Richmond. These issues will be addressed by the introduction of six feeders from Terry Fox MTS and the four new feeders planned from Richmond South DS.

There is a need in the short term to increase capacity in the Richmond area as well as increase the transformation at Bridlewood MS and Marchwood MTS to meet the N-1 planning criteria at the station level. Distribution transfer capabilities can however be maintained allowing station transformers to remain below capacity in an N-1 situation delaying the need date for capacity upgrades. Due to the future anticipated capacity demand expected from the Richmond area, Richmond South DS will require an upgrade with voltage conversion to be capable of meeting this demand. The rebuild is planned to replace the existing 8kV transformer with two 28kV 45/60/75 MVA units. Based on the forecasted station growth and the assumed ability to maintain feeder transfer during a station N-1 contingency it is planned to completely rebuild the Bridlewood MS substation by replacing the existing four transformers supplying both 8kV and 28kV, with two 75 MVA units supplying solely 28kV in 2019. In order to maintain supply capacity within the north 28kV supply territory it is planned to replace the 33 MVA transformers at Marchwood MS with 30/40/50 MVA units (with an assumed LTR of 66 – 1.33 x 50) by 2026.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.17.

**Figure 3.1.17 - West 28kV Load Growth**




***Capacity Projects***

*Committed:*

*(a) Terry Fox MTS – 100MVA (2014)*

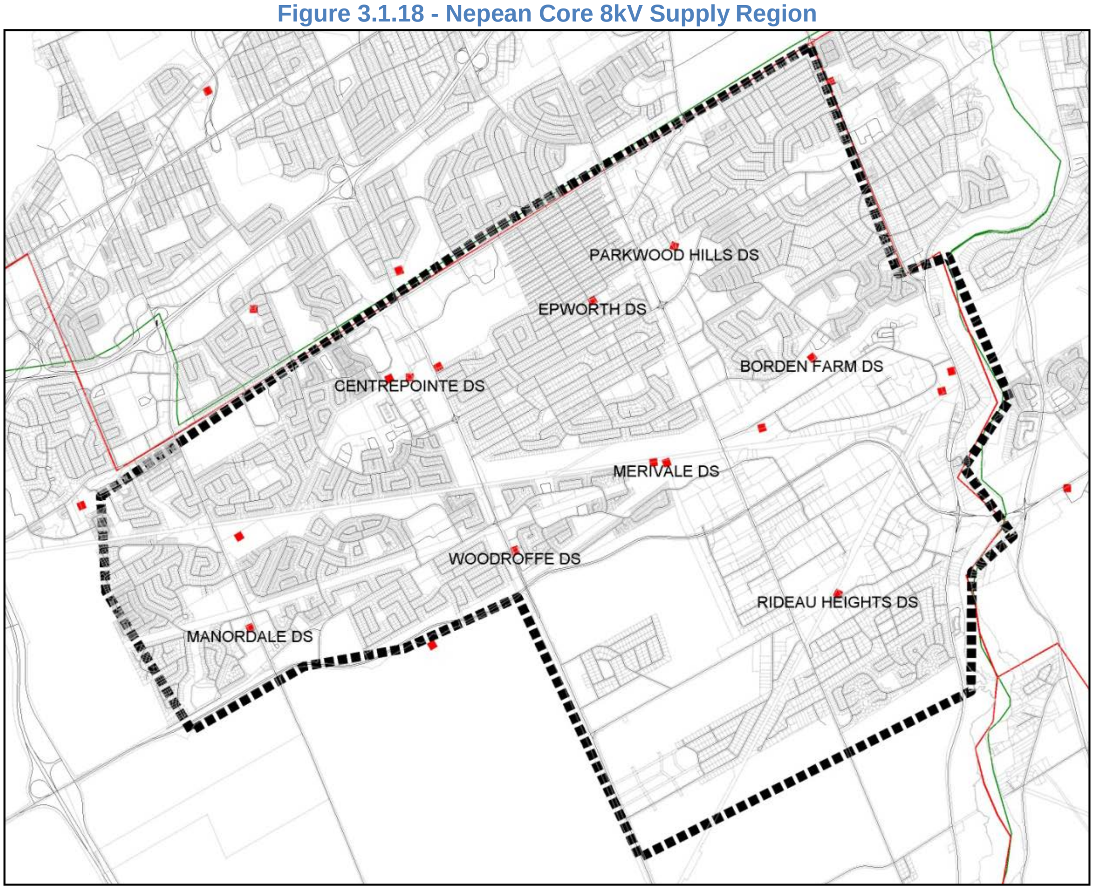
*Planned:*

*(b) Richmond South DS – 67MVA (2016)*
*(c) Bridlewood MS – 50MVA (2019)*
*(d) Marchwood MS – 33MVA (2022)*

### 3.1.5.1.6 Nepean Core 8kV System

The Nepean Core 8kV supply region includes the northern portions of Nepean. This region is supplied by the Manordale DS, Centrepointe DS, Woodroffe DS, Epworth DS, Merivale DS, Parkwood Hills DS, Borden Farms DS and Rideau Heights DS 8kV substations. Figure 3.1.18 shows the supply region of the Nepean Core 8kV System.

**Figure 3.1.18 - Nepean Core 8kV Supply Region**




Growth in the 8kV Nepean supply region is driven by ongoing commercial developments and associated mixed-use centers, two major areas of development are the Nepean Employment Area (located around Hunt Club Road between Merivale Road and Prince of Wales Drive) and Centrepointe that involves the expansion of Algonquin College and the relocation of the existing Transit Station.

The existing 8kV Nepean area is above the capacity limitations. The area of main concern is the Nepean employment area in which the trunk feeders are approaching their capacity limitations and the existing circuit interconnections are limited.

Over the next 20 years, significant growth is expected for the employment area in the Nepean region. The expected growth will push the stations and feeders to their capacity limits. The transformers at Merivale DS and Borden Farm DS are at the end of their useful lifetime, work at Borden Farm is currently in progress and expected to be completed by 2015. By 2021, new 28KV feeders will need to be introduced in this area along Hunt Club Road and Prince of Wales Drive where a high concentration of load is expected. In addition, major circuit reconfiguration and new interconnection ties need to be built in order to maintain a reliable system for this area.

**Borden Farm DS Transformers Replacement**

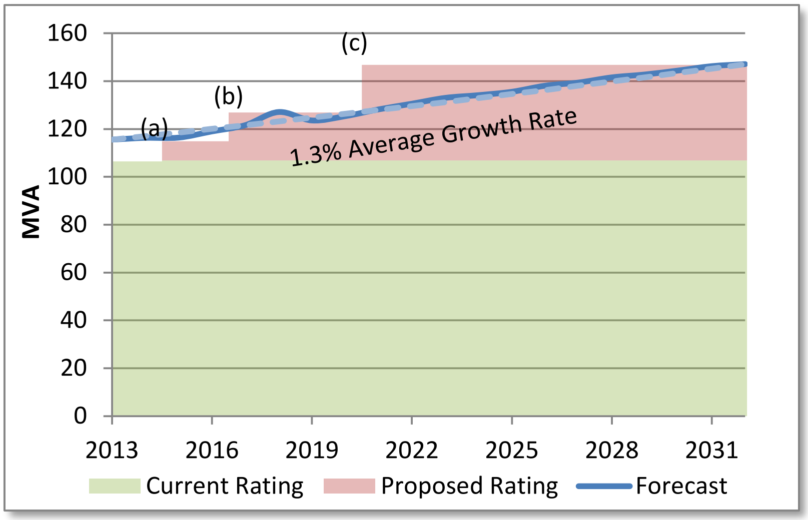
The transformers at this station have reached the end of their life and are in need of immediate replacement. In 2013, a project was started to replace the transformers and it will be completed by 2015. As mentioned in this report, the exiting transformer size would not be able to supply the additional proposed load in the next 8 years. It is recommended that the transformation at the station be upgraded to 2 x 15MVA.

**New Merivale DS Station**

This station is at the end of its life and it is planned for replacement with design starting in 2015 with completion in 2016. Additional capacity is required in order to service the proposed additional load. It is planned that the transformation be upgraded to 2x20 MVA transformers and four feeders per bus.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.19.

**Figure 3.1.19 - Nepean 8kV Load Growth**




### Capacity Projects

Planned:

(a) Borden Farm DS – 8MVA (2015)

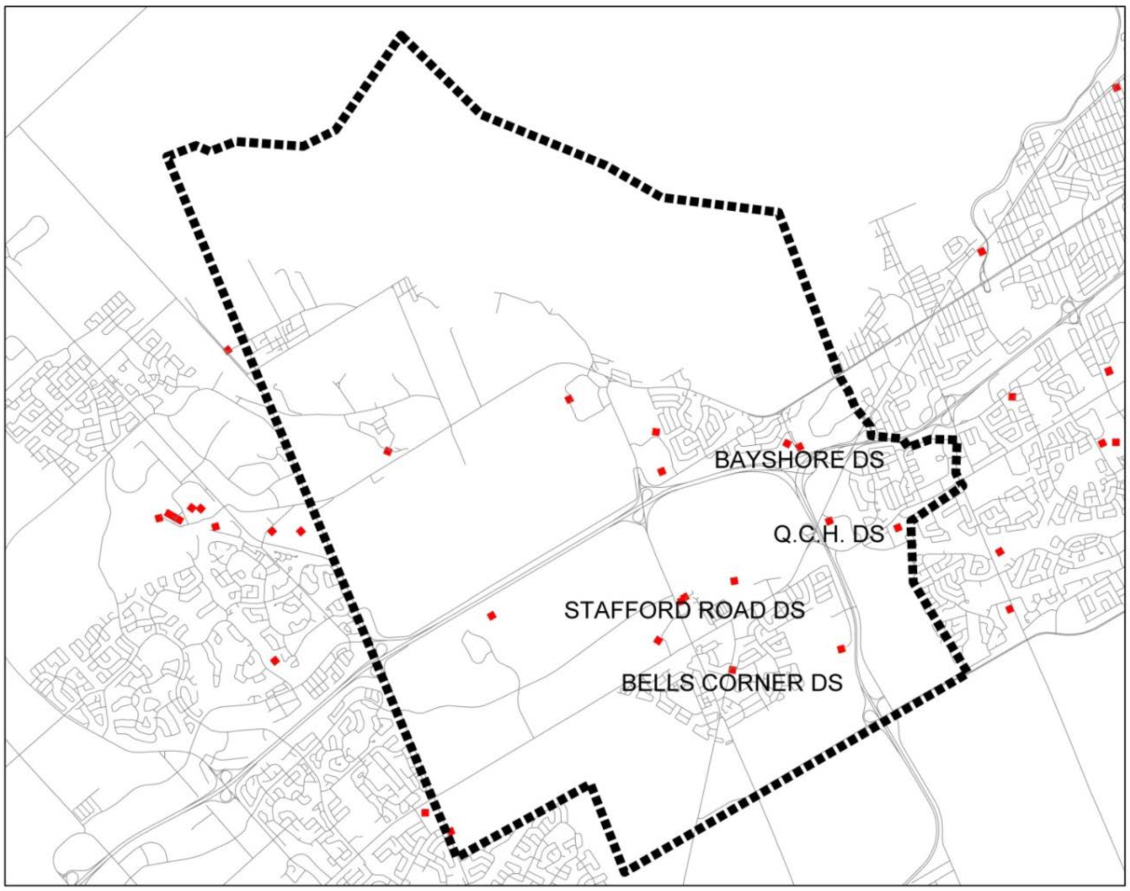
(b) Merivale MS – 12MVA (2017)

(c) New 27KV

## West Nepean 8kV System

The West Nepean 8kV supply region includes the north-west portions of Nepean. This region is supplied by the Bayshore DS, QCH DS, Stafford Road DS and Bells Corners DS 8kV substations. Figure 3.1.20 shows the supply region of the West Nepean 8kV System.

**Figure 3.1.20 - West Nepean 8kV Supply Region**




Growth in the 8kV West Nepean supply region has been very slow in the last couple of years. This trend is expected to continue since no major projects for this area have been identified, except for the Bayshore Mall expansion which is expected to bring an additional demand of 2MVA in the next 1-2 years.

The existing 8kV West Nepean area is below the capacity limitations. No major issues have been identified in this area of Nepean; however, the transformers at these stations are approaching end of life and will need replacement during the duration of this study period.

Over the next 20 years, very little growth is expected for the west area of the Nepean region. The expected growth will not push the stations and feeders to their capacity limits.

**Bayshore T1**

The T1 transformer at this station will be reaching end of life by 2018. Currently, the transformers at this location do not match in size. It is recommended that the transformation at the station be upgraded to 15MVA. The planned capacity upgrade will improve the supply availability under a contingency scenario.

**Bells Corners DS**

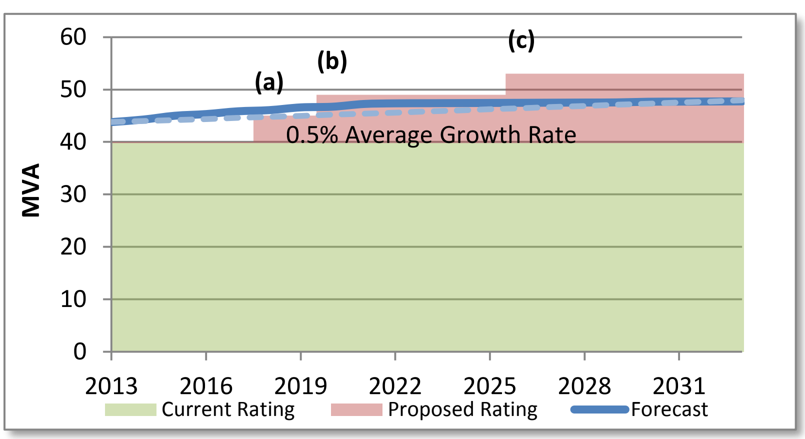
The transformers at this station will be reaching end of life by 2020. It is recommended that the transformation at the station be upgraded to 2 x 12MVA.

**QCH DS**

The transformers at this station will be reaching end of life by 2026. It is recommended that the transformation at the station be upgraded to 2 x 12MVA.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.21.

**Figure 3.1.21 - West Nepean 8kV Load Growth**




***Capacity Projects***

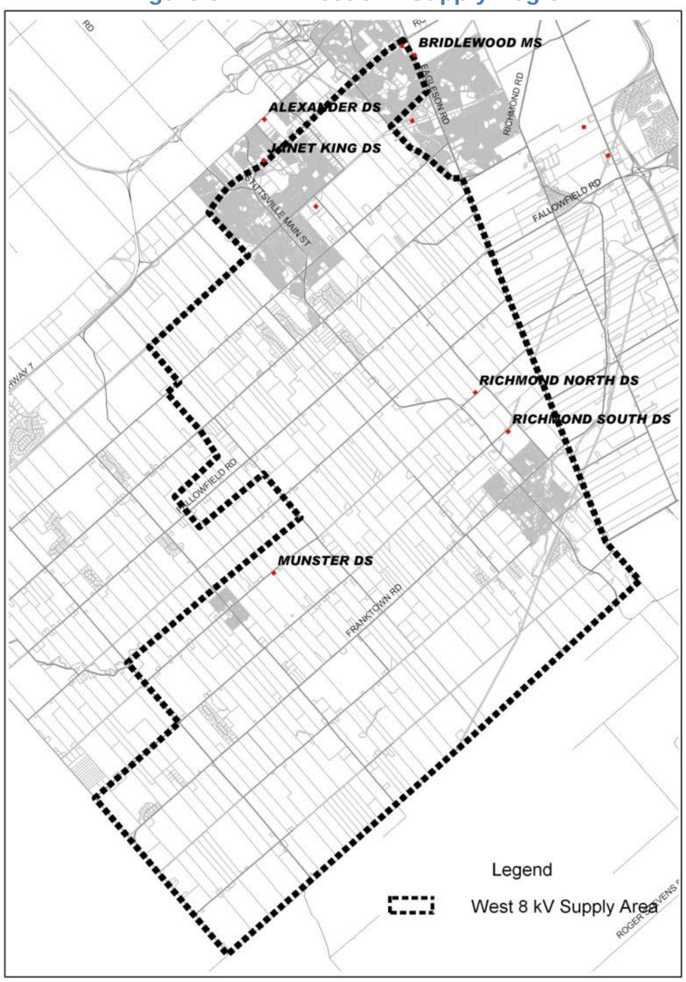
*Planned:*

*(a) Bayshore T1 – 5MVA (2018)*
*(b) Bells Corners DS– 4MVA (2020)*
*(c) QCH DS – 4MVA (2026)*

###### 3.1.5.1.7 West 8kV System

The West 8kV supply region includes South Kanata, Stittsville, the Village of Richmond and Munster Hamlet. This region is supplied by the Bridlewood MS, Janet King DS, Munster DS, Richmond North DS and Richmond South DS 8kV substations as well as by the 28kV substations Alexander DS, Beckwith DS and Janet King DS through the use of distribution step-down transformers (28kV to 8kV). Figure 3.1.22 shows the supply region of the West 8kV System.

**Figure 3.1.22 - West 8kV Supply Region**




Growth in the west 8kV supply region is driven primarily by the growth in the Village of Richmond. Based on the Village of Richmond, City of Ottawa plans and available information from other agencies, the key developments which will continue to drive growth in this supply region are all centered in Richmond and detailed in the Village of Richmond Community Design

Plan (CDP). The Village of Richmond CDP outlines the expansion of industrial and commercial areas as well as an increase of 2,850 – 3,950 dwelling units.

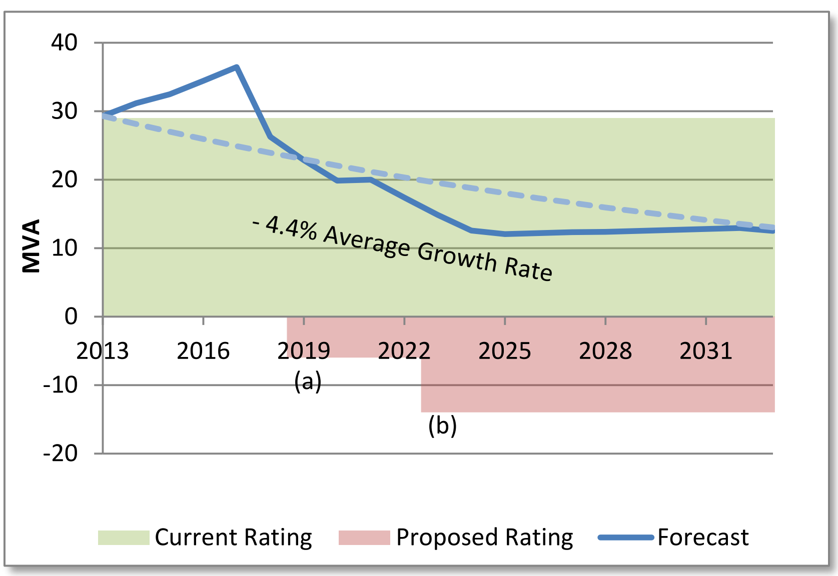
Overall, the existing west 8kV area is supplied by an adequate network of trunk feeders. There is however the need to expand the system to cover areas seeing growth. As there are very few 8kV feeders (9) that span a vast geographic region there are limits to capacity as well as the ability to restore under contingency.

Based on the load growth predicted in the Village of Richmond as well as capacity demand for Trans Canada's Energy East Pumping Station, there is a need in the short term to increase capacity with voltage conversion at Richmond South DS.

Due to aging infrastructure in the Glen Cairn community and at Bridlewood MS substation, reliability has been greatly impacted and has prompted a station rebuild. This project is planned to completely rebuild the substation by replacing the existing four transformers supplying both 8kV and 28kV, with two 75 MVA units supplying solely 28kV in 2019.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.23.

**Figure 3.1.23 - West 8kV Load Growth**




***Capacity Projects***

*Planned Voltage Conversions:*

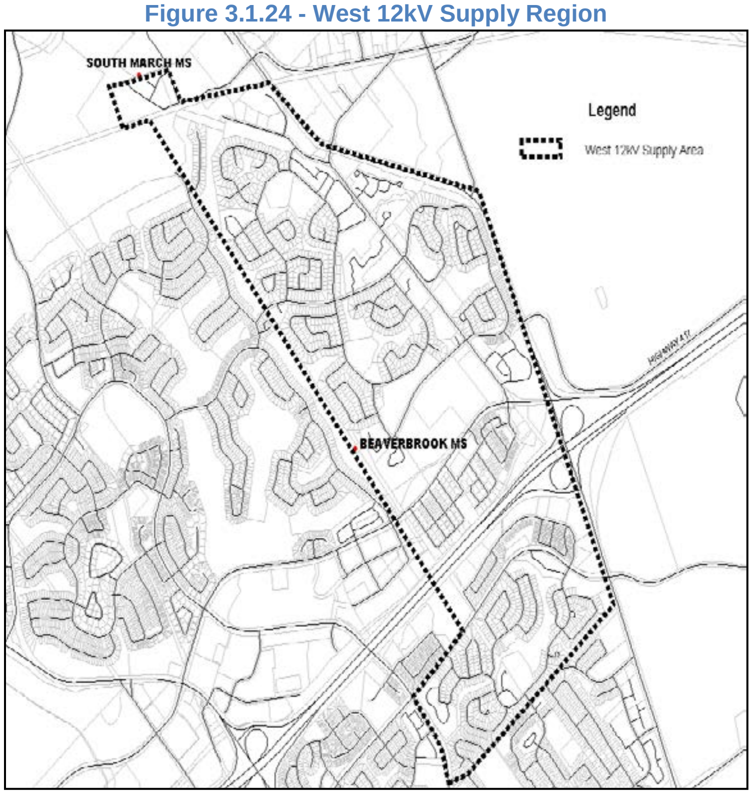
*(a) Richmond South DS Reduction of 6 MVA (2016)*

*(b) Bridlewood MS*

### 3.1.5.1.8 West 12kV System

The West 12kV supply region is located in central Kanata, including the communities of Katimavik and Beaverbrook. This region is supplied by the Beaverbrook MS, and South March MS substations. Figure 3.1.24 shows the supply region of the West 28kV System.

**Figure 3.1.24 - West 12kV Supply Region**



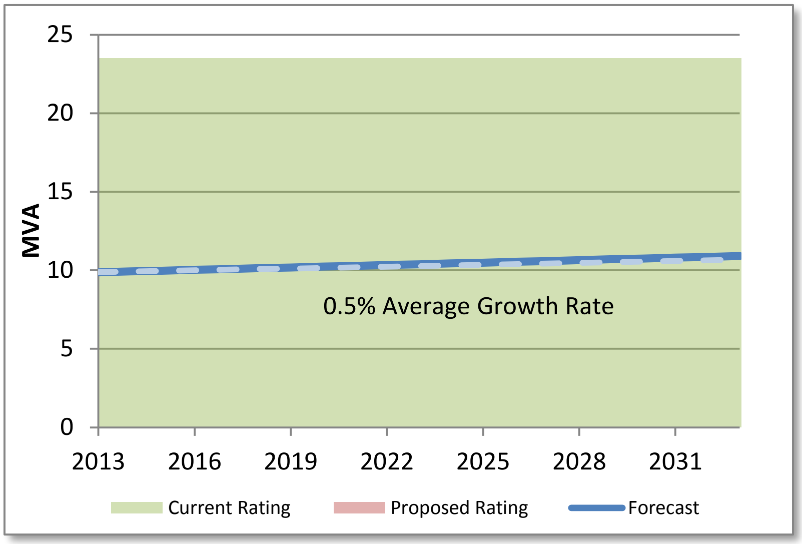

The West 12kV area is bounded by 28kV supplied areas on all sides and is anticipated that all future growth will be supplied from 28kV sources.

Overall, the existing West 12kV area is supplied by an adequate network of trunk feeders and can be recovered in N-1 contingency circumstances.

Based on only infill load growth predicted in the west 12kV supply area, the system will only require regular inspection and maintenance to continue providing the demanded capacity.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.25.

**Figure 3.1.25 - West 12kV Load Growth**



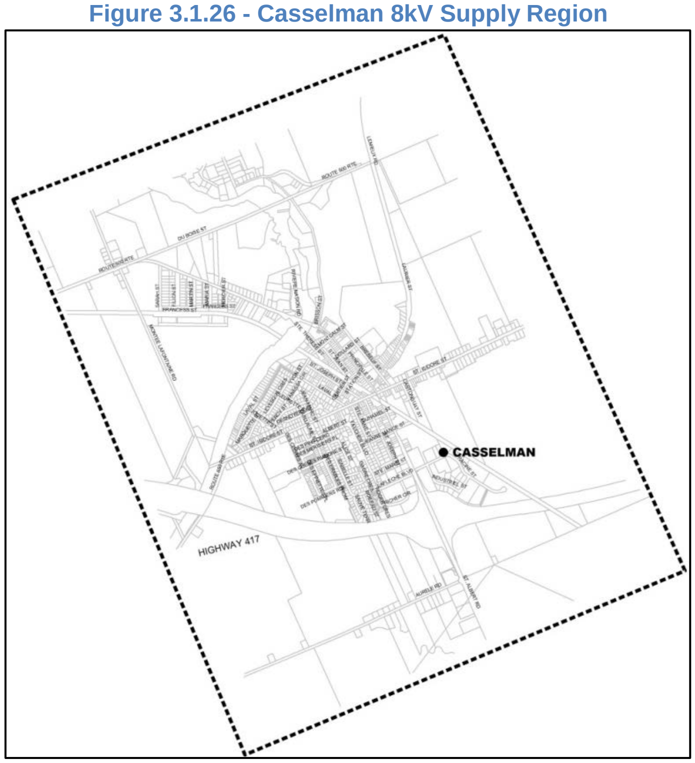

***Capacity Projects***

*None*

#### 3.1.5.1.9 Casselman 8kV System

The Village of Casselman is supplied from a single station, Casselman MS at 8.32kV from three circuits. Figure 3.1.26 shows the Casselman supply area.

**Figure 3.1.26 - Casselman 8kV Supply Region**

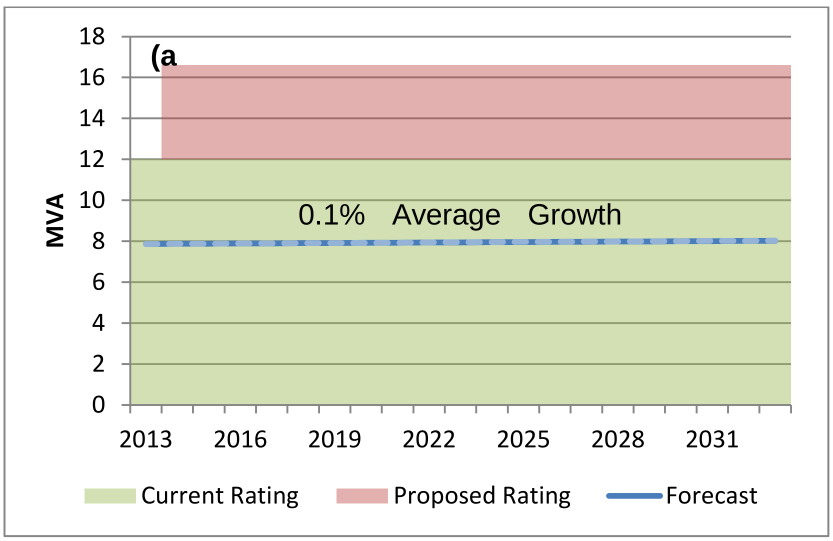


Overall, the Casselman area is supplied by an adequate network of trunk circuitry, however there is no redundancy at the station level since it is a single transformer with a single supply. In order to provide redundancy for contingency situations, a second transformer is planned to improve reliability to the area.

Growth within the Village of Casselman has been slow, and there are no major developments anticipated in the region over the next 20 year forecast period.

The forecasted 20 year load growth along with planned is shown in Figure 3.1.27.

**Figure 3.1.27 - Casselman 8kV Load Growth**




***Capacity Projects***

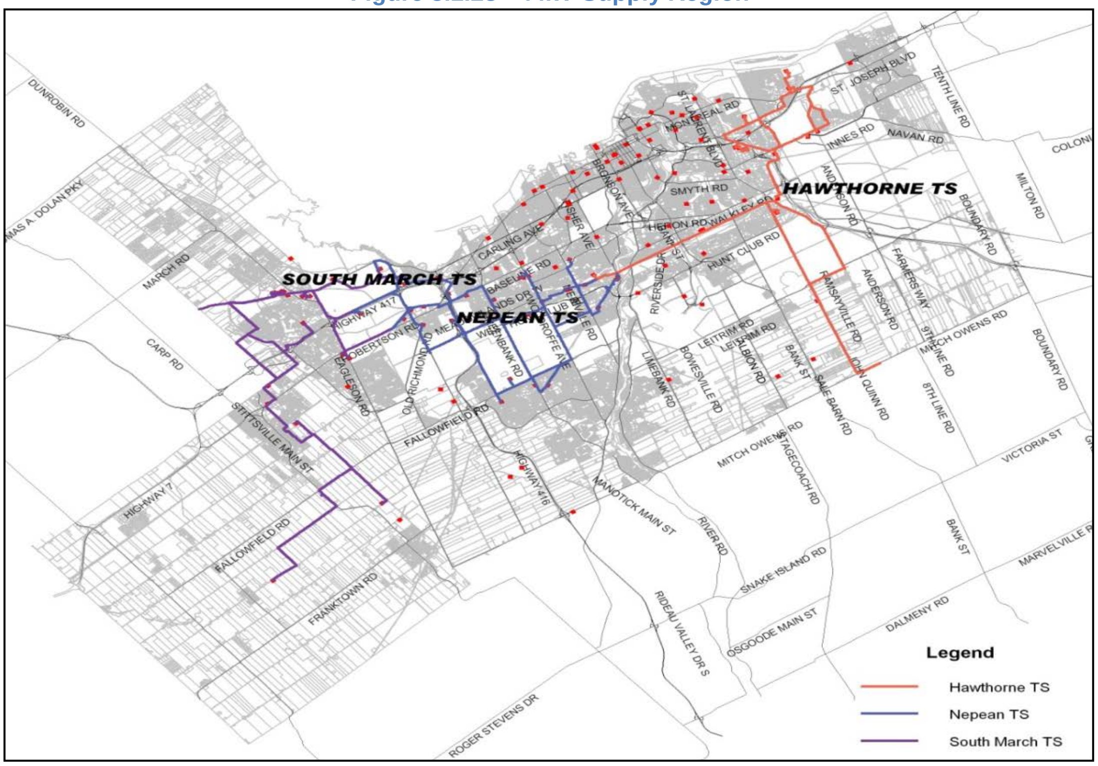
*Planned:*

*(a) Casselman T2 – 5MVA (2014)*

### 3.1.5.1.10 Citywide 44kV System

The 44kV system spans the entire service area and is supplied from three stations: Hawthorne TS, Nepean TS and South March TS. This system supplies a number of large industrial customers as well as 44kV to 28kV and 44kV to 8.32kV HOL substations. Figure 3.1.28 outlines the trunk circuit routing from each of these three stations.

**Figure 3.1.28 - 44kV Supply Region**




Each station area is essentially independent of the others with limited connections between South March TS and Nepean TS and between Hawthorne TS and Nepean TS.

Based on the vast area that these stations cover and their independent nature, they have been studied as separate stations as opposed to as a single region. Through the Regional Planning Study currently under way with the OPA (now IESO) and HONI, the load forecast for each of the stations has been developed.

In order to improve reliability performance in the East end of the City the loop of feeders from Hawthorne TS will be automated, the details of which can be found in the Reliability Plan Report as part of the 2014 Annual Planning Report, Attachment B-1(B).

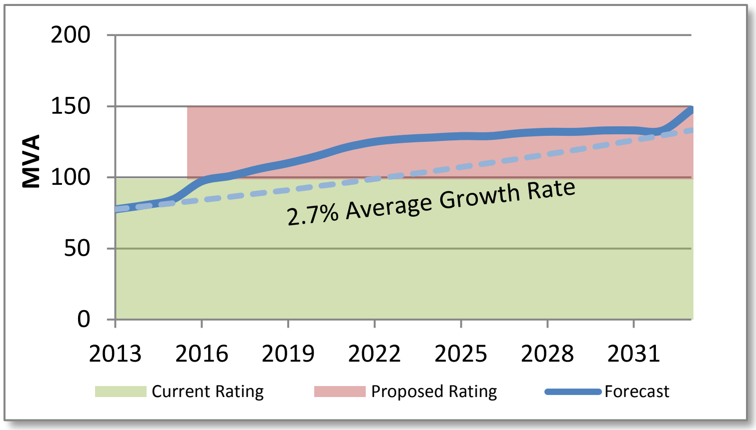
The Nepean TS 44kV system is built in a network configuration and at this time there are no significant issues identified with the distribution arrangement.

The 44kV trunk network from South March TS is adequate, except for the single radial feeder (A9M3) that runs south of Maple Grove Road. The radial section of A9M3 supplies three 44/8kV stations: Janet King DS, Richmond North DS and Munster DS. In order to improve reliability performance the 22M25 out of Nepean TS will be extended into the southern part of the West service territory to serve as a backup to these stations. Construction is anticipated and to begin in 2015 and be operational in 2017.

Additional capacity is required at Hawthorne TS in the near term and at South March TS in the long term, after the end of the study period. HONI is currently replacing the T7 and T8 230kv-44kV transformers with an expected LTR of 152MVA and in service date of 2017. An additional 44kV station is being proposed in the Richmond area which will create dual supplies to some of the rural 44kV supplied substations, create additional feeder ties for contingency operability and will help off-load the heavily loaded feeders from South March TS and Nepean TS.

The forecasted 20 year load growth along with planned capacity upgrade projects for each station are shown in Figure 3.1.29, Figure 3.1.30, and Figure 3.1.31.

**Figure 3.1.29 - Hawthorne TS Load Growth**

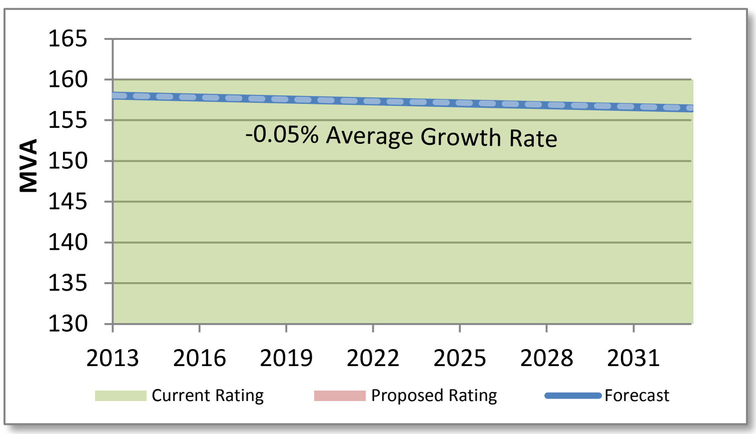



***Capacity Projects***

*Planned:*

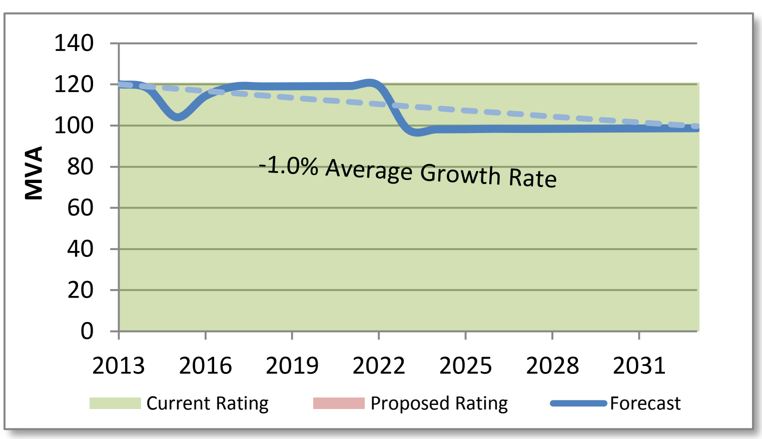
*(a) Hawthorne TS – 51MVA (2017)*

**Figure 3.1.30 - Nepean TS Load Growth**




*There are no capacity issues forecasted at Nepean TS. The load forecast shows a decreasing trend based on the conversion of 8kV load (fed from 44/8kV stations) to the 28kV system.*

**Figure 3.1.31 - South March TS Load Growth**




*There are no capacity issues forecasted at South March TS during the study period. The load forecast shows a decreasing trend based on load transfers to transmission connected stations.*

#### *3.1.5.2 Ability to Connect New Generation*

System ability to connect distributed generation is limited by several factors such as:

1. **Station Loading** – some station transformers have limited or no capability for reverse power flow. At these stations, total connected generation cannot exceed either 60% of top transformer rating plus minimum loading, or in the most restrictive case where there is no reverse flow capability, generation is limited to the minimum station loading. This limit has been adopted from HONI's evaluation tool for generation connection assessment.
2. **Feeder Thermal Rating** – the feeder ampacity rating must be respected to not overheat the conductors and connected equipment. For distributed generation, the available thermal capacity is the full feeder ampacity rating less contingency loading.
3. **Short Circuit Rating** – connection of distributed generation will increase the available current that flows through the system during faults. The total available current during faults cannot exceed the equipment ratings.
4. **Power Quality** – four concerns arise when connecting distributed generation:
    a. harmonics caused by inverter based generation;
    b. phase imbalance caused by single-phase generators;
    c. voltage instability caused by generators connected at various points along a feeder, or by induction generators requiring reactive power; and
    d. flicker caused by generators intermittently turning on and off – they can affect the voltage on the circuit impacting the quality of supply to HOL customers.
5. **Anti-Islanding** – distributed generation may introduce safety and power quality issues in the event of continued generation after loss of supply from the distribution system. The installation of transfer trips and other anti-islanding methods are used to limit islanding.

The generation connected to both feeders and station must be managed to prevent adverse impact to existing HOL load and generation customers.

As of July 30, 2014, HOL's Service Area was no longer under a transmission constraint due to the short circuit rating of 115kV transmission breakers located at the Hydro One Networks Inc. (HONI) owned Hawthorne TS. As a result, 300MW of generation capacity is now available.

Despite this, some stations remain restricted from any generation connection regardless of size and are discussed in the sections that follow.

**Core 13kV**

Currently, there are connection restrictions at the Slater TS, and one bus at Lisgar TS. Slater TS is limited due to short circuit levels at the station, whereas Lisgar TS is currently limited by the minimum normal loading on the station bus. Proposed upgrades at Lisgar TS substation will allow loading at this station to increase, which is anticipated to alleviate the current restriction at this location.

HOL has discussed with a few proponents their interest in large size district heating & cooling, hydro-generation, or energy storage within this region. With the coming load growth and planned station upgrades it is anticipated that capacity will be available to accommodate these requests.

**East 13kV**

There are currently no regional substation restrictions for the connection of distributed generation at the East 13kV substations; however; there are proposed upgrades at King Edward TK substation that may result in a constraint due to an increased fault current from the larger substation transformers.

**West 13kV**

Presently, the Lincoln Heights TS B1B2 bus pair is restricted to allow connection of only renewable micro-generation due to thermal limitations.

The OPA (now IESO) has approved a 29.35MW large hydro generation facility that will connect to Carling TS with an anticipated in service date of 2017.

As per the manufacturer’s recommendation, HONI is presently restricting reverse flow through the existing Hinchey TH transformers to the minimum station load. The planned station upgrade will allow for more loading of Hinchey TS, and reverse flow of 60% of the top transformer rating plus minimum load with the requirement to keep the loading (with and without generation) on the secondary windings balanced.

**South 28kV**

Currently, the T1 half of Fallowfield MTS is restricted due to thermal limitations as well as a zero reverse flow capability. The T2 side of the station was built with reverse flow capability allowing the connection of generation dependant on remaining capacity available as applications currently exist for large generation to make partial use of this capacity.

**South-East 28kV**

There are currently no station restrictions for the connection of distributed generation at the South-East 28kV stations.

**East 8kV & 28kV**

There are currently no station restrictions for the connection of distributed generation at the East 28kV & 8kV stations.

**West 28kV**

There are currently no station restrictions for the connection of distributed generation at the West 28kV stations. HOL is attending to a proponent with a 4MW IESO energy storage offer-of-contract for transmission grid support. This project will connect to the Terry Fox MTS.

**Nepean Core 8kV**

There are currently no station restrictions for the connection of distributed generation at the Nepean Core 8kV stations.

**West Nepean 8kV**

There are currently no station restrictions for the connection of distributed generation at the West Nepean 8kV stations. All these stations are supplied from HONI High Voltage Distribution Stations (HVDSs), either South March TS or Nepean TS.

**West 8kV**

There are currently no station restrictions for the connection of distributed generation at the West 8kV stations.

**West 12kV**

There are currently no station restrictions for the connection of distributed generation at the West 12kV stations.

**City Wide 44kV**

There are currently no station restrictions for the connection of distributed generation at the 44kV Stations.

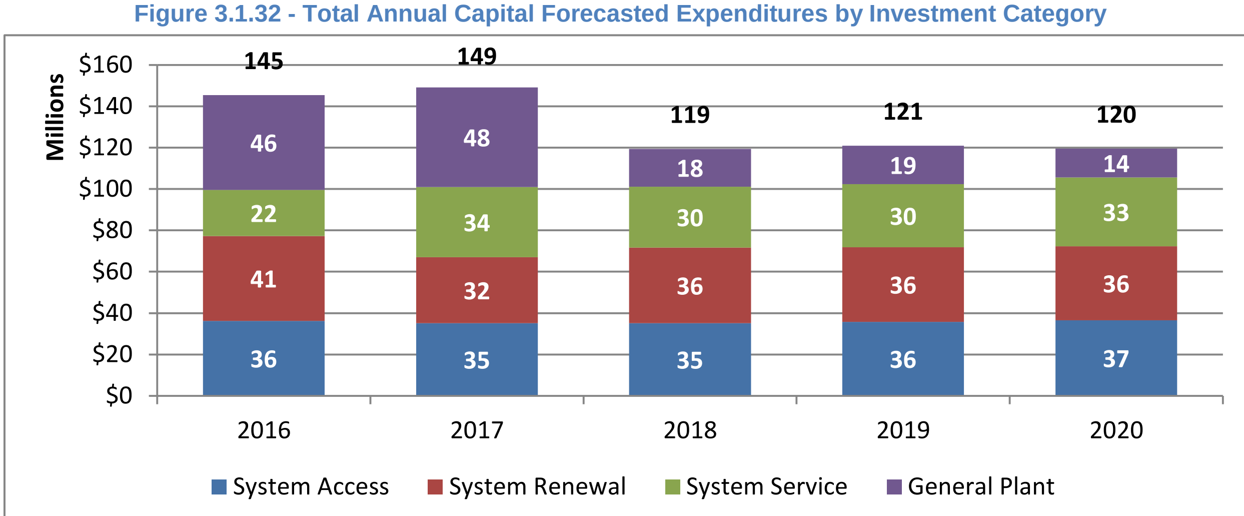
### 3.1.6 Total Annual Capital Expenditures by Category

HOL's total annual capital forecasted expenditure by investment category is shown in Table 3.1.6 and Figure 3.1.32.

**Table 3.1.6 - Total Annual Capital Forecasted Expenditures by Investment Category**

| Investment Category | $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| System Access (Gross) | 36,263 | 35,156 | 35,132 | 35,835 | 36,551 |
| System Renewal | 41,033 | 31,823 | 36,491 | 35,980 | 35,718 |
| System Service | 22,235 | 33,957 | 29,518 | 30,473 | 33,314 |
| General Plant | 45,899 | 48,138 | 18,276 | 18,695 | 13,954 |
| **Grand Total** | **145,430** | **149,073** | **119,418** | **120,982** | **119,538** |

**Figure 3.1.32 - Total Annual Capital Forecasted Expenditures by Investment Category**



### 3.1.7 Capital Expenditures Description by Category

HOL's capital expenditures are driven by the Asset Management planning process which is described in section 2.1 Asset Management Process Overview. The following sections describe, by investment category, how the outputs of the planning process tie into the allocation of the capital budgets.

#### *3.1.7.1 System Access*

System Access capital expenditures are driven by HOL's mandate to connect customers to the distribution system and to meet the service obligations of the Distribution System Code. The System Access Budget Programs are: Plant Relocation & Upgrade, Residential Subdivisions, Commercial Development, System Expansion, Embedded Generation, Infill Service (Res & Small Com), and Damage to Plant (see section 3.1.1 for a brief definition of the Budget Programs). System Expansion Demand contributions are determined though the application of the Board's prescribed economic evaluation methodology.

The capital planning process has minimal impact on System Access Capital Expenditures since these expenditures are demand/customer driven and are therefore typically considered to be mandatory.

Forecasted annual spending takes into consideration a number of variables:

- Historic spending levels – trending of each category;
- Known large future developments;
- City plans and projects; and
- Economic indicators

Where efficiencies are identified in combining activities, system renewal or system service projects are considered to allow all work in one area to take place together. System access projects may in some cases require a system renewal or service project to be delayed due to physical restrictions in the work area or system operability restrictions. In these circumstances, the risk to the system is evaluated and an optimal solution is determined with regards to work timing and prioritization.

### *3.1.7.2 System Renewal*

System Renewal investments include sustainment programs that replace or refurbish assets which are nearing or have reached the end of their useful lives. The System Renewal Budget Programs are: Stations Transformer Replacement, Stations Switchgear Replacement, Stations Plant Failure, Stations Enhancements, Pole Replacement, Insulator Replacement, Elbow & Insert Replacement, Distribution Transformer Replacement, Vault Rehab or Removal, Civil Rehabilitation, Cable Replacement, Switchgear New & Rehab, O/H Equipment New & Rehab, and Distribution Plant Failure (see section 3.1.2 for a description of the Budget Programs).

Capital expenditures for System Renewal are sustainment investments that are determined as an output of the Asset Investment Strategy (Section 2.1 Asset Management Process Overview) and are captured annually in the Annual Planning Report (Attachment B-1(B)). The primary planning pieces which impact System Renewal investments are the Asset Management Plan and the Testing, Inspection & Maintenance Plan. The Asset Management Plan provides strategic guidance on replacement and investment forecasts, manages priorities, and identifies process gaps. The Testing, Inspection, and Maintenance Plan outputs data used in the development of asset condition assessment and aims to optimize maintenance practices and therefore, overall asset lifecycle.

Full details on how System Renewal Investments are determined and prioritized can be found in section 2.1 Asset Management Process Overview.

### *3.1.7.3 System Service*

System Service investments include sustainment programs that address capacity, reliability, and power quality issues on the distribution system. The System Service Budget Programs are: Stations New Capacity, Line Extensions, System Reliability, Distribution Enhancements, Distribution Automation, Substation Automation, SCADA Upgrades, and RTU Additions (see section 3.1.3 for a description of the Budget Programs).

Capital expenditures for System Service are investments that are determined as an output of the Asset Investment Strategy (Section 2.1 Asset Management Process Overview) and are captured annually in the Annual Planning Report (Attachment B-1(B)).The primary planning pieces which impact System Renewal are the System Capacity Plan and the Reliability Plan.

The System Capacity Plan identifies milestones for required system upgrades to ensure a reliable supply is maintained. The Reliability Plan provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

#### *3.1.7.4 General Plant*

General Plant investments include payments to Hydro One under Connection & Cost Recovery Agreements, facility and fleet requirements, Information Technology system upgrades, and new initiatives. The General Plant Budget Programs are: Facilities Management, Fleet Replacement, Tools Replacement, IT Life Cycle and On-going Enhancements, IT New Initiatives, ERP System, Customer Service, and Operation Initiatives.

Forecasted annual spending takes into consideration a number of variables:

- Identification of lifecycle optimization, examples including building facilities, vehicles, and tools. The objective is to determine the optimal replacement to minimize overall costs but also maintain a safe work environment;
- Identification of any IT system upgrades required to continue with vendor support and maintain data integrity;
- All new Operation initiatives must align to business plan priorities, help achieve approved performance targets, and support the four key areas of focus (Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship). Funding must be justified and supported by business case and approved by Executive Management Team (EMT).

### 3.1.8 Forecasted Material Capital Expenditures

The following section outlines the material capital expenditures, by category, planned over the forecast period, which exceed the materiality threshold of $750k.

#### *3.1.8.1 Committed Investment*

Annual budgets for 2015 and 2016 have been prepared and identify projects by Investment Category, Capital Program and Budget Program. Table 3.1.7 and Table 3.1.8 list the projects executing in 2015 and 2016 that exceed the materiality threshold. It should be noted that this

1 number represents the total project cost and therefore may incorporate project expenditures
2 which fall outside of the 2015-2020 window (either before or after). The full justifications of these
3 projects can be found in Attachment B-1(A).

4 **Table 3.1.7 - Material Capital Expenditures for 2015 and 2016 Projects (1/2)**

| Investment Category | Capital Program | Budget Program | Project | Total Budget $'000 |
|---|---|---|---|---|
| System Renewal | Station Assets | Station Trans. Replace. | Merivale DS Rebuild | 17,126 |
| | | | Bronson T1 & T2 Replacement | 3,223 |
| | | | Longfields T2 | 4,340 |
| | | | Albion UA T1, T2 & T3 Replacement | 2,970 |
| | | Station Switchgear Replacement | Epworth T1 Primary Fuse to Circuit Switcher | 1,149 |
| | | | Woodroffe TW 13kV Switchgear Replacement | 7,346 |
| | | | Borden Farms Switchgear Replacement | 7,269 |
| | | | Bayshore Primary Circuit Switcher | 3,782 |
| | | | Overbrook TO Switchgear Replacement | 7,130 |
| | | | Startop Protection Upgrade | 4,768 |
| | Distribution Assets | Pole Replacement | Centretown East Pole Replacement | 7,416 |
| | | | South East Kilborn Area Pole Replacement | 1,054 |
| | | | Riverside South Pole Replacement | 4,565 |
| | | | Grandview Road Pole Replacement | 1,086 |
| | | | Centretown West Pole Replacement | 6,681 |
| | | | Alphabet Ave Pole Replacement | 1,224 |
| | | | Prince of Wales & Greenbank | 2,456 |
| | | Dist Trans Replace | OH TXF – PCB Regulatory Compliance | 1,473 |
| | | Civil Rehab. | Civil on Carling from Bronson to Sherwood | 2,602 |
| | | Cable Replacement | 48M4 & 48M5 Cable Replacement | 841 |
| | | | Butyl Rubber Craig Henry | 1,604 |
| | | | Stittsville Main Cable Replacement | 2,868 |
| | | | Blackburn 4F8 | 1,611 |
| | | | Butyl Rubber Tanglewood | 2,540 |

| Investment Category | Capital Program | Budget Program | Project | Total Budget $'000 |
|---|---|---|---|---|
| | | O/H Equipment New & Rehab | SMD-20 Switch Replacement | 1,250 |
| | | Metering | Remote Disconnect Smart Meters | 6,800 |

**Table 3.1.8 - Material Capital Expenditures for 2015 and 2016 Projects (3/2)**

| Investment Category | Capital Program | Budget Program | Project | Total Budget $'000 |
|---|---|---|---|---|
| System Service | Stations Capacity | Stations New Capacity | New South 28kV Substation | 21,255 |
| | | | Hinchey New Switchgear Lineup | 11,280 |
| | | | Lisgar TL Transformer Upgrade | TBD* |
| | | | Limebank Transformer Upgrade | 8,360 |
| | | | Leitrim T1 | 3,050 |
| | | | Casselman T1 | 4,740 |
| | | | Richmond South DS | 17,657 |
| | Distribution Enhancements | Line Extension | TM1AH Capacity Upgrade | 880 |
| | | | Alta Vista Tie | 1,658 |
| | | | Orleans TS Feeder | 4,546 |
| | | | Fernbank Rd Line Extension | 1,533 |
| | | | West 44kV Line Extension | 6,243 |
| | | | Springbrook Drive Trunk Extension | 2,363 |
| | | | Abbott Street Trunk | 1,023 |
| | | System Voltage Conversion | Woodroffe UW Voltage Conversion | 15,835 |
| | | | Prince of Wales Voltage Conversion | 1,475 |
| | | | Rideau Valley Voltage Conversion | 1,035 |
| | | | Richmond Voltage Conversion | 8,320 |
| | | | Goulbourn St Voltage Conversion | 802 |
| | Auto-mation | Dist. Auto. | Telecommunications Master Plan | 17,000 |
| | | SCADA Upgrade | SCADA Replacement | 2,800 |

*Note – the budget for Lisgar TL Transformation Upgrade is currently being prepared by Hydro One.

### *3.1.8.2 2017-2020 Investments*

For the 2017-2020 forecasted years, total Budget Program level spending has been projected, as shown in Table 3.1.9, Table 3.1.10, Table 3.1.11, and Table 3.1.12. Note that all programs are shown including those that do not exceed the materiality threshold of $750k. Project specific investments will be identified on an on-going basis, always looking out three years at a time. Project and Budget Program Justifications can be found in Attachment B-1(A).

1 Table 3.1.9 - Forecasted Capital Expenditures by Budget Program – System Access

| Investment Category | Capital Program | Budget Program | $'000 | | | |
|---|---|---|---|---|---|---|
| | | | 2017 | 2018 | 2019 | 2020 |
| System Access | Plant Relocation | Plant Relocation & Upgrade | 7,773 | 7,928 | 8,087 | 8,248 |
| | Residential | Residential Subdivision | 7,027 | 7,167 | 7,311 | 7,457 |
| | Commercial | New Commercial Dev | 13,042 | 12,576 | 12,827 | 13,084 |
| | System Expansion | System Expansion Demand | 2,366 | 2,413 | 2,462 | 2,511 |
| | Stations Embedded Gen | Embedded Generation | 384 | 392 | 400 | 408 |
| | Infill & Upgrade | Infill Service (Res & Small Com) | 3,223 | 3,288 | 3,353 | 3,420 |
| | Damage To Plant | Damage to Plant | 1,171 | 1,195 | 1,219 | 1,243 |
| | Metering | Metering – Re-verification | - | - | - | - |
| | | Smart Meters | - | - | - | - |
| | | Suite Metering | 170 | 173 | 177 | 180 |
| | Total | | 35,156 | 35,132 | 35,835 | 36,551 |

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**Table 3.1.10 - Forecasted Capital Expenditures by Budget Program – System Service**

| Investment Category | Capital Program | Budget Program | $'000 | | | |
|---|---|---|---|---|---|---|
| | | | 2017 | 2018 | 2019 | 2020 |
| System Service | Stations Capacity | Stations New Capacity | 15,272 | 10,464 | 14,441 | 15,626 |
| System Service | Distribution Enhancements | Line Extensions | 6,180 | 7,132 | 6,455 | 6,739 |
| System Service | Distribution Enhancements | System Voltage Conversion | 4,964 | 5,729 | 5,185 | 5,413 |
| System Service | Distribution Enhancements | System Reliability | 445 | 513 | 464 | 485 |
| System Service | Distribution Enhancements | Dist. Enhancements | 694 | 801 | 725 | 757 |
| System Service | Automation | SCADA Upgrades | 1,011 | 556 | 51 | 51 |
| System Service | Automation | SCADA - RTU Additions | 76 | 87 | 79 | 82 |
| System Service | Automation | Distribution Automation | 4,719 | 3,548 | 2,449 | 3,510 |
| System Service | Automation | Stations Automation | 597 | 689 | 624 | 651 |
| System Service | Total | | 33,957 | 29,518 | 30,473 | 33,314 |

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1 Table 3.1.11 - Forecasted Capital Expenditures by Budget Program – System Renewal

| Investment Category | Capital Program | Budget Program | $'000 | | | |
|---|---|---|---|---|---|---|
| | | | 2017 | 2018 | 2019 | 2020 |
| System Renewal | Stations Asset | Stations Transformer Replacement | 4,620 | 6,533 | 8,225 | 7,965 |
| | | Stations Switchgear Replacement | 7,088 | 7,408 | 6,871 | 6,114 |
| | | Stations Plant Failure | 107 | 107 | 107 | 107 |
| | Stations Refurbishment | Stations Enhancements | 634 | 731 | 662 | 691 |
| | Distribution Asset | Pole Replacement | 6,592 | 7,608 | 6,886 | 7,189 |
| | | Insulator Replacement | 168 | 194 | 176 | 183 |
| | | Elbow & Insert Replacement | 190 | 219 | 198 | 207 |
| | | Dist. Transformer Replacement | 808 | 933 | 844 | 881 |
| | | Civil Rehabilitation | 636 | 734 | 664 | 694 |
| | | Cable Replacement | 5,262 | 6,073 | 5,496 | 5,738 |
| | | Switchgear New & Rehab | 376 | 434 | 393 | 410 |
| | | O/H Equipment New & Rehab | 902 | 1,041 | 942 | 983 |
| | | Plant Failure Capital | 2,893 | 2,893 | 2,893 | 2,893 |
| | Metering | Remote Disconnected Smart Meter | 1,547 | 1,584 | 1,623 | 1,662 |
| | Total | | 31,823 | 36,491 | 35,980 | 35,718 |

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Table 3.1.12 - Forecasted Capital Expenditures by Budget Program – General Plant

| Investment Category | Capital Program | Budget Program | $'000 | | | |
|---|---|---|---|---|---|---|
| | | | 2017 | 2018 | 2019 | 2020 |
| General Plant | Buildings – Facilities | Buildings – Facilities | 509 | 408 | 323 | 243 |
| | Customer Service | Customer Service | 2,361 | 1,148 | 6,658 | 1,139 |
| | ERP System | ERP System | 354 | 350 | 354 | 1,061 |
| | Fleet Replacement | Fleet Replacement | 1,209 | 1,452 | 1,480 | 1,876 |
| | Info Serv & Tech New Initiatives | Info Serv & Tech New Initiatives | 1,166 | 1,006 | 1,218 | 1,203 |
| | IT Life Cycle & Ongoing Enhancement | IT Life Cycle & Ongoing Enhancement | 1,737 | 1,905 | 2,232 | 1,816 |
| | Operation Initiatives | Operation Initiatives | 452 | 405 | 892 | 1,069 |
| | Tools Replacement | Tools Replacement | 521 | 530 | 539 | 548 |
| | Hydro One Payments | Hydro One Payments | 5,000 | 5,000 | 5,000 | 5,000 |
| | Facilities Implementation Plan | Facilities Implementation Plan | 34,829 | 6,073 | - | - |
| | Total | | 48,138 | 18,276 | 18,695 | 13,954 |

### 3.1.9 Regional Planning Process

HOL is currently participating in the Integrated Regional Resource Planning process (IRRP) with Hydro One Network Inc., Hydro One Distribution, and the Independent Electricity System Operator (IESO) as described in 1.2.1.1 Integrated Regional Resource Planning Process. The IRRP began in 2011 and continues to be developed by the working group, with the IESO leading the process. The IESO has issued a hand off letter to Hydro One Networks Inc. initiating development work on near and mid-term transmission solutions to meet the identified needs. As per the hand off letter, found in Appendix B, two transmission solutions have been identified that impact HOL's capital expenditure plan: rebuilding of the existing 115 kV single-circuit A6R and upgrading a section of 115 kV S7M. It has been determined that to increase the available capacity of the Hydro One circuit S7M HOL overhead line that passes beneath it must be lowered by 2.5 feet through the crossing. The costs associated with the work is budgeted at approximately $10k and is scheduled for completion in 2015.The plan for the Hydro One circuit A6R upgrade will be developed and implemented by Hydro One Networks Inc. Currently, the date and cost is not known, no estimate has been provided, and there is potential that the costs of this work will fall within HOL's forecast years. As the timeline and costs of this work are beyond the control of HOL, any work will be integrated into the current plan through reprioritization of work following the planning process. HOL will continue to provide updates as more information becomes available.

### 3.1.10 Customer Engagement Activities

As an overview, this section outlines the activities HOL undertakes to solicit feedback from customers. Some examples of outcomes are provided in section 3.2.4 Customer Engagement

Each year, HOL engages an external research firm to conduct an annual Customer Satisfaction Survey. The survey helps HOL understand the satisfaction levels of HOL customers relative to Ontario comparators. It also reveals how customer perceptions, issues and concerns are evolving over time. The types of questions posed to customers in this annual survey include:

- LDC Knowledge, integrity, involvement and trust;
- Overall Customer Satisfaction scores;
- % of respondents indicating they had a blackout or outage issue in the past 12 months;

- % of respondents indicating they had a Billing problem in the past 12 months;
- What customers think of electricity costs;
- Level of customer engagement;
- Company Image; and
- Customer view of importance to pursue implementation of “SMART Grid”

The survey results factor into the setting of annual performance objectives and the establishment of relative priorities.

In addition to the annual survey described above, HOL also conducts monthly telephone surveys of customers who have recently called HOL’s call center. This survey measures factors such as:

- Call Center level of Satisfaction;
- Level of knowledge of the staff who dealt with the customer;
- Level of courtesy of the staff who dealt with the customer; and
- The ability to deal with the customer’s issue (First Call Resolution)

Use of these two surveys helps to determine if HOL is improving performance, from the customer’s perspective, year over year. Further, these surveys help identify emerging issues which influence planning and resolution priorities. Annual plans are more informed and aligned as a result of customer feedback generated from these two surveys.

### 3.1.11 System Development Expectations

This section describes how HOL anticipates the system to develop over the next five years, including in relation to load and customer growth, smart grid development and the accommodation of forecasted renewable energy generation projects.

#### *3.1.11.1 Load and Customer Growth*

HOL’s system capacity is lagging behind the load growth – currently 15% of substations are above their specified planning rating (see2.2.4 Capacity of the Existing System Assets). Over the next five years, HOL is expecting growth to continue as previous rural areas are changed to urban areas and the City’s plan for intensification continues.

Overall, the City of Ottawa is seeing continued growth, primarily focused in four regions: the downtown core, Nepean & Riverside South, South Kanata & Stittsville and Orleans. This growth is being seen through the development of new mixed retail/residential communities as well as intensification of existing communities and the Light Rail Transit developments. Moving forward, significant investment in capacity for the system, at both the station and distribution level, will be required to catch up to and maintain pace with the demand. In addition, there are a number of distribution expansions which will be required to bring power from the substations to the customer site. These capacity upgrade projects are identified through the Capacity Planning process and the needs are described in Section 3.1.5.1 Ability to Connect New Load.

There are several upgrades of transmission interties within the City which may be necessary over the next 20 years to maintain adequate and reliable supply from the bulk system. HOL is currently involved in an IRRP (section 1.2.1.1 Integrated Regional Resource Planning Process) that is evaluating the transmission capacity and infrastructure requirements in the Ottawa region. The final report is expected by Q1 2015. Preliminary findings indicate required upgrades to address the following needs:

- Post-contingency thermal overload of the 115 kV double circuits in Downtown Ottawa M4G and M5G ;
- Additional station capacity needed in Downtown Ottawa area;
- Additional supply capacity needed in the south of Nepean area to support the growth;
- Post-contignecy thermal overload of one Merivale autotransformer; and
- The need for bulk transfer capability between Hawthorne and Merivale.

### *3.1.11.2 Smart Grid Development*

HOL's Smart Grid Development is detailed in the Grid Transformation Action Plan (GTAP) report, found in Attachment B-1(C).

The term "Smart Grid" means different things to different people depending on their perspective and knowledge of the power system. One statement that captures the essence of Smart Grid is the following:

"The integration and application of real-time monitoring, advanced sensing, communications, analytics, and control, enabling the dynamic flow of both energy and information to accommodate existing and new forms of supply, delivery, and use in a secure, reliable and efficient electric power system, from generation source to end-user."

In addition to the challenge of distributed generation, consumers are very aware of the increasing cost of electricity and are demanding greater control over their usage. At the same time they expect a high level of electricity supply reliability.

Governments are also keenly aware that demand control can play a significant role towards reducing overall cost in delivering electricity service in the future. The Grid Transformation Action Plan report is the first step in preparing HOL for the future Smart Grid.

Refusing to make progress in developing a smarter grid is not an option. At the same time HOL must not be reckless in the transformation plans. Being on the bleeding edge of technology is not something that many of our customers would value for HOL. A middle of the road approach of making prudent investments in proven technology will enable us to bring greatest returns to our customers.

HOL has identified a number of fundamental building blocks for the Smart Grid that requires study to ensure they will meet our future needs. Communication Infrastructure, data capture, storage and sharing, IT systems and cyber security are some of the fundamentals that are required to ensure a solid foundation for future projects.

HOL treats "Smart Grid" development activities within the regular processes to identify capital expenditures. It is anticipated that more focus will be placed on automation, including a robust communication infrastructure, in the coming years to allow for more efficient system operability and transparency.

#### *3.1.11.3 Accommodation of forecasted renewable energy generation projects*

HOL is predicting a continued interest in the installation of REG within the service territory, over the five year forecast period. Based on the current ability of the system to connect new REG (Section 3.1.5.2), there are no constraints at the anticipated connecting stations for the forecasted connections. For more detailed information on accommodation of forecasted renewable energy projects in the next five years, please refer to 3.3 System Capability Assessment for Renewable Energy Generation.

### 3.1.12 Impact of Customer Preferences, Technology, and Innovation on Total Capital Cost

HOL uses the information gathered from customer engagement activities (section 3.2.4) to help meet customer preferences through the use of technology and innovation. The use of smart switches and enhanced communication systems to improve restoration times are two examples of the use of technology.

#### *3.1.12.1 Response to customer preferences*

See section 3.2.4 Customer Engagement.

#### *3.1.12.2 Technology Based Opportunities*

Over the next five years, HOL will continue implementing grid technologies to improve the reliability and efficiency of the distribution system. Ongoing targeted installation of automated devices is planned. Currently, targeted projects are the East 44kV automation, which will deploy automatic restoration to this sub-transmission loop that supplies 3% of HOLs' customers. In addition, automation plans are being deployed in the quickly growing South Nepean/Barrhaven area, as well as targeted annual installation to address the Worst Performing Feeders (1.3.2.1.3 Worst Feeder Analysis). Continued investment in the communication infrastructure will be essential to support current automation plans while maintaining the flexibility to integrate the technologies of tomorrow.

Starting in 2015, with a completion of installation in 2018, HOL's Supervisory Control and Data Acquisition (SCADA) is being upgraded. SCADA supports system reliability by providing system operators with real-time access to system status and control, reducing time required to identify service disruptions, locate system faults, and operate the system to restore customers. As more and more distribution assets are connected to the SCADA system, the Operator's situational awareness improves, resulting in a more focused and effective restoration effort.

In early 2014, HOL initiated a pilot project to deploy a small WiMAX network using the 1800 – 1830MHz band that has been reserved by Industry Canada for use in the management of the electricity system. It is the goal of this project to evaluate the technology for use in distribution automation as well as SCADA and metering applications. While the WiMAX network will not provide the throughput of 3G/LTE systems, it does provide lower latency and a cost structure that will be more compatible with a utility budgetary framework.

HOL continues to evaluate the best mix of technologies to support increased communications across both distribution and substation equipment. Over the course of 2014, HOL engaged a leading utility communications consulting firm to develop a telecommunications master plan. This plan (completed in August of 2014) provides a complete picture of the core Wide Area Network which will accommodate all HOL communications needs. With this plan completed, a detailed investment roadmap has been crafted which describes the necessary investments and outcomes over the next 10 years. These investments will bring the HOL communications infrastructure from a disparate patchwork of costly services to a single cost efficient, secure, reliable, and effective communications network. By building a private communications infrastructure, HOL will reduce the ongoing burden of third-party service charges while at the same time providing connectivity and capacity exactly where it is needed.

#### *3.1.12.3 Innovative Processes, Services, Business Models, or Technologies*

In 2014, HOL acquired Copperleaf C55, an industry-leading and established Asset Investment Planning tool. This planning tool will enable the development of a strategic framework, improved asset analytics, investment decision optimization, and performance management. Copperleaf C55 will achieve the objectives of value creation through better decision making, improved efficiency in the planning process, and meeting the standards set by the OEB's performance-based Renewed Regulatory Framework. Implementation of Copperleaf C55 was completed in December 2014.

## 3.2 Capital Expenditure Planning Process Overview

The Capital Expenditure Planning Process Overview section outlines HOL's planning objectives, how non-distribution alternatives for relieving capacity and operational constraints are evaluated, a description of how HOL identifies, selects, prioritizes and paces investments, and the mechanisms used to engage customers.

### 3.2.1 Capital Expenditure Planning Objectives

HOL's capital expenditure Planning Objectives are as follows:

- To align with HOL's Corporate Strategic Objectives as outlined in Section 1.0.1: Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship;
- To optimize projects by ranking investment criteria and comparing project benefits;
- To ensure that investments are financially viable in terms of the approved budget and required resources;
- To provide high quality customer service by evaluating customer value and striving to increase reliability;
- To maximize cost efficiency by considering timing, resource allocation and contingency scenarios;
- To analyze previous investments to improve future investment decisions; and
- To pace expenditures to minimize rate impact.

These objectives align with HOL's Asset Management Objectives in that the Planning Objectives define the selection and prioritization process for project investments. The Asset Management Objectives are: Health & Safety, Asset Management, Reliability & Customer Impact, Environment and Regulatory Compliance. They are detailed in section 2.1.1 Asset Management Objectives. Whereas HOL's Asset Management Objectives provide a focus on identifying the asset needs and enhancing the distribution system, the capital planning objectives aim to maximize the outcome of the invested capital, based on the available budget.

Both the Planning Objectives and the Asset Management Objectives revolve around HOL's primary area of focus: delivering customer value. As a company that provides an essential service to the public, the ability to deliver value to its customers is critical to HOL's. The fundamentals of customer value in the electricity business are quality and cost — delivering a reliable service, while operating efficiently and effectively to minimize rate impact. HOL is consistently among the top performers in Ontario in both these areas, but the customer's place within the electricity system is also evolving. Customers are no longer just consumers of electricity, but also generators of electricity and managers of energy conservation, thereby making them integral and active participants in the management of the electricity system.

In order to meet and exceed the diverse expectations of the customer base, HOL is focussing on service quality and responsiveness, assisting customers in managing their energy consumption and electricity costs, and maintaining/improving overall system reliability.

HOL's approach includes:

- A focus on detailed customer knowledge to guide the company in understanding, anticipating and responding to customer needs;
- The revision of the conditions of service —operating practices, levels of service and connection policies — to be more customer-centric; and
- The effective and innovative use of technology and communication to enhance the customer experience, and provide solutions to help customers conserve energy and manage costs.

HOL also focuses on accommodating and implementing proposals for customer distribution generation projects. This includes solar generation projects under the Feed-In-Tariff (FIT) or microFIT programs. HOL works with the customer in the preparation of their connection proposal, ensuring that the equipment and design meets all required standards and regulations. A Connection Impact Assessment is completed by HOL as a formal response to the proposal, verifying that connection at the proposed location is viable and that the proposed generation will not negatively impact the grid.

### 3.2.2 Non-Distribution System Alternatives

HOL does not have a policy governing the treatment of non-distribution system alternatives to relieve capacity or operational constraints. HOL is currently involved in an Integrated Regional

Resource Planning process (IRRP) as developed by the IESO and updated by the OEB. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC), and develops regionally integrated solutions to address needs that are identified. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. HOL continues to work with Hydro One, and the IESO in developing optimal solutions to the transmission and bulk system needs within the Ottawa area. Refer to section 1.2.1.1 Integrated Regional Resource Planning Process for more details.

### 3.2.3 Prioritization Process, Tools and Methods

HOL's process, tools, and methods used to identify and prioritize projects are described in 2.1.2 Asset Management Process Components.

The pace at which HOL plans project execution is dependent on three criteria:

- Customer service requests;
- Rate impact to customers; and
- System requirements – safety, reliability & capacity

Investments are scheduled and paced according to customer requirements and are coordinated to meet regulatory requirements based on crew availability.

The annual planning process as part of the Annual Planning Report (see Attachment B-1(B)), identifies a gap between the forecasted investment required for the distribution system, and the funding currently identified. That gap exists to some degree due to resource constraints including operational and capacity, and affordability constraints. The pattern of increased capital investment has placed pressure on rate impacts and financing capability. A balance must be found that ensures sufficient investment in the distribution system to enhance reliability and improve productivity and customer service, while achieving the deemed funding level through rates. Projects and new initiatives must be reviewed and prioritized to ensure the most essential investments with the greatest value to the customers are funded on a timely basis, within all the constraints.

### 3.2.4 Customer Engagement

HOL undertakes various customer engagement activities of which the following relate directly to the implementation of the Distribution System Plan.

**Annual Customer Satisfaction Survey**

Each year, HOL conducts a customer satisfaction survey which solicits customer feedback on the utility and the various services the utility provides. In 2014, 805 telephone interviews were conducted with a wide range of questions covering such topics as: system reliability performance, investment to improve reliability, acceptable length of outages, design of the system (overhead versus underground) and willingness to pay more for system enhancements.

Key results of the survey, including percentage of responses:

- Provides consistent, reliable electricity – 90%
- Not willing to pay for further improvements – 51%
- Willingness to pay at least something to better their electricity system – 43%
- Acceptable duration of an outage during extreme conditions:
    - None, the power should not go out – 7%
    - Less than 2 hours – 11%
    - 2 to 4 hours – 17%
    - 12 to 18 hours – 7%
    - 1 day – 10%
    - 1 to1.5 days – 5%
    - 1.6 to2 days – 5%
    - More than 2 days – 4%

Based on the survey results, HOL customers indicated that reliability be maintained or improved, at minimal or no increased cost. As a result, HOL has created a capital plan that paces investments in order to minimize rate impacts, while continuously improving efficiencies and productivity with respect to distribution planning and implementation. HOL is continuing to improve capital project prioritization, specifically in the areas of data collection and risk management.

**Customer Consultations on Major Projects**

HOL regularly consults customers with regards to major projects that will potentially impact customer property or neighbourhoods, such as cable replacement or distribution transformer replacement.

The consultation process first involves informing the potentially impacted customers of the pending work, followed by a customer open house aimed at creating open dialog. During the open houses, HOL staff informs customers on the scope, schedule and the general process to be undertaken to perform the work. It is also a venue for customers to provide their feedback and voice their concerns that staff can then immediately address. The open house strategy was developed based on feedback received from customers in the past and have since proven to enable a productive and successful project for both the customers and HOL. HOL believes, and it has been proven from these sessions that strong and open communication is essential with our customers. Customers have commented that they appreciate these consultation sessions as they provide a forum for discussion and airing their concerns, while allowing HOL to inform them of project needs and the concept of reliability.

**Participation with Electrical Contractor Association**

HOL actively communicates with the Electricity Contractor Association (ECA) of Ottawa to ensure strong communications between HOL and the numerous contractors that work in Ottawa. This need was identified by the ECA as part of the customer persona activity that HOL initiated in 2013. As a result, HOL now ensures any and all questions are answered and actively communicates new information to the ECA. Topics such as changes to the Conditions of Service are explained and discussed to ensure clear understanding of requirements. Feedback received in this continuous manner allows HOL planners to better understand future needs, timing of developments and issues and concerns around design standards and planning practices.

**HOL Website**

Customers are solicited for their direct feedback on HOL's corporate website, as well as, on the secured customer portal known as "My Hydro Link". Customers can send in their complaints and inquiries, the resolution of which, are tracked and managed by a complaint management application. The use of complaint management software helps identify complaint trends and opportunities for improvement. As an example, one of HOL's previously rural areas was developed into a dense residential community. The rural area previously made use of a protection scheme known as fuse saving, which allowed a distribution circuit to experience momentary outages rather than longer sustained outages caused by factors such as animal contacts. As a result, long outages were avoided, but identifying the exact location and cause of the outage was more difficult. Based on customer feedback, HOL learned that these customers preferred experiencing a longer outage in order to determine the associated root causes and put in place location specific risk mitigation measures, such as animal guards. This highlighted that customers in different areas have different preferences and tolerances for dealing with outages. Regarding this particular issue, a dedicated feeder more suited for the now urban area was installed in late 2014 to provide improved reliability.

### 3.2.5 Prioritization of REG Investments

HOL prioritizes Renewable Energy Generation (REG) investments based on customer requests and follows regulated timelines for response and connection.

HOL strives to integrate all proposed residential and commercial customer generation projects into the grid. Several projects are proposed every year (see Table 3.3.1 for connected and committed generation) and HOL works with project managers and the customer to integrate the proposed generation into the distribution system. The process for accepting these projects involves: analyzing the generation capacity of the connecting feeder and interface transformer; verifying that the relevant station transformer can accept reverse flow; ensuring that the short circuit changes and voltage fluctuations will cause no material impacts on either the distribution or transmission grid; and reviewing the proposed single line diagram, electrical protection scheme and site plan for adherence to all HOL, ESA and OPA (now IESO) standards and requirements (Refer to 3.1.5.2 Ability to Connect New Generation). In the event that the proposed generation connection is not possible, HOL works with the customer to provide a solution. This solution may involve expanding the distribution system to meet customer needs or relocating the project to a more fitting property. Where work on the distribution system is required for the connection, the project is coordinated to ensure regulatory timelines are met while optimizing crew time.

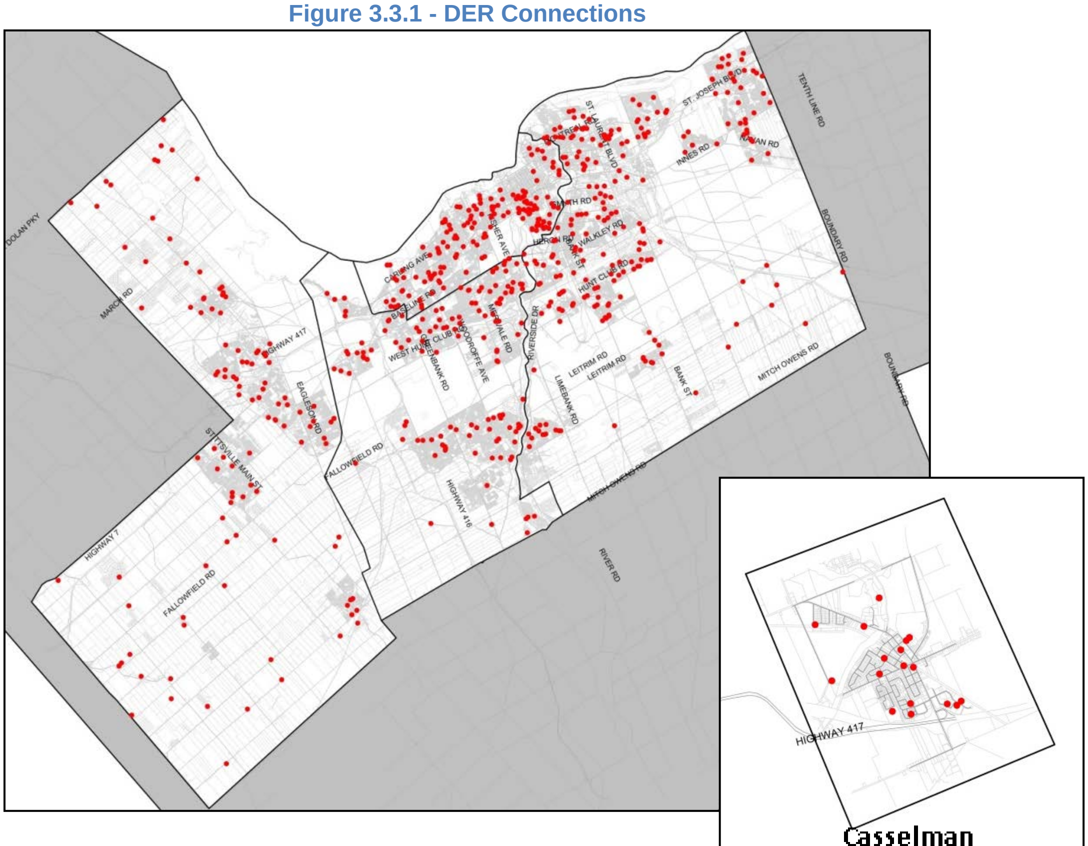
## 3.3 System Capability Assessment for Renewable Energy Generation

This section describes HOL's system capability to accommodate all Distributed Energy Resources (DER) including its the sub-set of Renewable Energy Generation (REG).

HOL is required by the Distribution System Code to assess generator connection requests of all fuel types, not just those defined as "renewable" in the Electricity Act, regardless of contract or program categories.

HOL currently has a number of connected generation facilities within the service area. These facilities have been connected and continue to be connected under various programs such as the OPA (now IESO) programs (FIT, HCI, PSUI-CDM, RESOP, HESOP), Net-Metering and Load Displacement. HOL also conducts system evaluations to accommodate a much broader group of generation connections classified as Distributed Energy Resources (DER), like large energy storage such as batteries and co-generation plants. The existing DER connections within HOL's service territory are shown in Figure 3.3.1.

**Figure 3.3.1 - DER Connections**



By the end of 2014 it is anticipated that HOL will have 678 DER connections of various sizes. The detail on number and total kilowatts of DERs connected by size and program are provided in Table 3.3.1.

**Table 3.3.1 - 2014 DER Connections**

| Program / DSC Category | Large kW (qty) | Medium kW (qty) | Small kW (qty) | Micro kW (qty) | Total kW (qty) |
|---|---|---|---|---|---|
| **Non-Renewable** | | | | | |
| **Load Displacement** | | 9,249 (5) | | | **9,249 (5)** |
| **Renewable** | | | | | |
| **FIT** | - | - | 10,792 (88) | - | **10,792 (88)** |
| **HIC** | - | 18,080 (4) | 500 (1) | - | **18,580 (5)** |
| **Load Displacement** | - | - | 70 (1) | 6 (3) | **76 (4)** |
| **microFIT** | - | - | - | 4,619 (569) | **4,619 (569)** |
| **Net-metered** | - | - | - | 18 (4) | **18 (4)** |
| **RES 1** | | 6,378 (1) | | | **6,378 (1)** |
| **RESOP** | - | 10,700 (2) | - | - | **10,700 (2)** |
| **Stand Alone** | - | 2,736 (1) | - | - | **2,736 (1)** |
| **Total** | **-** | **47,143 (13)** | **11,362 (90)** | **4,643 (576)** | **63,148 (679)** |

Where the generation categories are defined in the Ontario Energy Board Distribution System Code (August 21, 2014), section 1.2 Definitions as:

**Micro-embedded generation facility**: name-plate rated capacity of 10kW or less

**Small embedded generation facility**: is not a micro-embedded generation facility with a name-plate rated capacity of 500kW or less in the case of a facility connected to a less than 15kV line and 1 MW or less in the case of a facility connected to a 15kV or greater line

**Medium embedded generation facility**: name-plate rated capacity of 10 MW or less and is more than 500kW in the case of a facility connected to a less than 15kV line and more than 1 MW in the case of a facility connected to a 15kV or greater line

**Large embedded generation facility**: name-plate rated capacity of more than 10MW

### 3.3.1 Applications Over 10kW

By the end of 2014, HOL will have a total of 102 connected DERs over 10kW, totalling 64.3 MW peak nameplate capacity. See Table 3.3.1, columns Large, Medium and Small.

### 3.3.2 Renewable Generation Forecast

Interest in generation projects within HOL's service territory has been steady over the historic years, and is anticipated to continue into the future. The trend has shown an increasing interest in Net-Metering and Load Displacement projects of various fuel types.

HOL has performed initial consultations or is currently (November 2014) completing assessments for:

- 69.35 MW of hydro-electric generation;
- 38 MW of co-generation (natural gas);
- 18.3 MW of solar photovoltaic ; and
- 16 MW of synthetic gas generation.

HOL is aware of 33 potential new projects under final FIT3 OPA evaluation totalling 8.68 MW of nameplate capacity. Currently, no existing restrictions are in place at the requested substation that would prevent connection.

Forecasts for DER connections are provided in Table 3.3.2 and are based on initial consultations and executed CIAs received and completed to date (November 2014). The initial consultations include those made with demonstrated higher level of intent under Net-Metering, Load-Displacement, IESO Energy Storage Procurement Request for Proposal (RFP) (one 4 MW applicant has been approved), and the OPA (now IESO) programs such as the PSUI, FIT 3, or Large FIT RFP. The executed CIAs have been for applicants under the OPA (now IESO) HESOP or PSUI program.

Table 3.3.2 - Forecasted DER Connections

| Type | 2015 (kW) | 2016 (kW) | 2017 (kW) | 2018 (kW) | 2019 (kW) | 2020 (kW) |
|---|---|---|---|---|---|---|
| Co-Generation | 9,723 | 3,250 | - | - | 25,000 | - |
| Hydro-Electric | - | - | 29,350 | - | - | 40,000 |
| Solar PV | 6,302 | 12,000 | - | - | - | - |
| Synthetic Gas | - | - | 16,000 | - | - | - |
| Total | 16,025 | 15,250 | 45,350 | 0 | 25,000 | 40,000 |

Capacity of the System to Connect DER as shown in Table 3.3.3 (last update December 5th, 2014) illustrates the capacity availability to connect Distributed Energy Resources at each HOL owned High Voltage Distribution Stations (HVDS). Note that if an HVDS has an open bus-tie switch capacity is provided per bus, and where the bus-tie is normally closed, it is provided by bus pair.

Overall, where HOL station limitations exist, they are limited by thermal capacity and not short circuit capacity, with the exception of Ellwood MTS and Nepean Epworth DS. When transformers are identified as having reverse flow capability, by manufacturer specification, (Bridlewood Q and Fallowfield Q) the limiting factor is the transformer capacity plus minimum station load. Otherwise, the limiting factor is simply the station minimum load.

Typically, more capacity at the stations is available for inverter based generation as opposed to spinning generation for two reasons:

- When reverse flow is the limiting factor, the minimum station load is higher between the 10AM to 3PM – the same period the solar generation nameplate capacity will likely be reached and the facility nameplate in capacity calculation is considered; and
- Short circuit contribution of inverter based generators is by rule of thumb 1.2 times the full load current and for spinning generation is considered to be 5 times the full load current.

The column label Connected & Committed represents all non-standby DER (renewable and non-renewable), that is already connected to the grid, committed for connection due to having an IESO or OPA contract, or HOL has issued a CIA and tentatively allocated, allocated, or reserved capacity.

**Table 3.3.3 - Capacity for Generation at HOL HVDS**

| Station | Bus | Connected & Committed (kW) | Remaining Generation Capacity (kW) | | Limiting Factor |
|---|---|---|---|---|---|
| | | | Equivalent Inverter Based Generation | Equivalent Spinning Generation | |
| Bridlewood MTS | B1 | 515 | 3,009 | 3,009 | Minimum load |
| | Q | 454 | 7,031 | 6,670 | Transformation + Minimum load |
| Centrepointe DS | B1 | 45 | 1,730 | 736 | Minimum load |
| | B2 | 30 | 882 | 167 | Minimum load |
| Cyrville MTS | JQ | 339 | 2,389 | 1,625 | Minimum load |
| Ellwood MTS | JQ | 335 | 1,905 | 457 | Short Circuit |
| Fallowfield DS | J | 9,131 | 0 | 2,454 | Minimum load |
| | Q | 9,224 | 11,614 | 5,292 | Transformation + Minimum load |
| Kanata MTS | B1B2 | 1,124 | 18,475 | 17,317 | Minimum load |
| Limebank MS | B1 | 87 | 3,485 | 2,408 | Minimum load |
| | B2 | 468 | 6,238 | 4,616 | Minimum load |
| Manordale DS | B1 | 23 | 1,493 | 639 | Minimum load |
| | B2 | 34 | 1,808 | 823 | Minimum load |
| Marchwood MS | J | 865 | 7,420 | 5,425 | Minimum load |
| | Q | 295 | 7,519 | 6,654 | Minimum load |
| Merivale MS | B1 | 84 | 1,667 | 644 | Minimum load |
| | B2 | 22 | 1,878 | 1,385 | Minimum load |
| Moulton MS | B1 | 80 | 5,638 | 3,729 | Minimum load |
| | B2 | - | 4,614 | 4,099 | Minimum load |
| Nepean Epworth DS | B | 20 | 1,201 | 288 | Short Circuit |
| | Q | 12 | 2,398 | 1,112 | Minimum load |
| Richmond South DS | B | 300 | 1,628 | 866 | Minimum load |
| Terry Fox MTS | J | 4,105 | 0 | 1,929 | Minimum load |
| | Q | 24 | 2,450 | 1,959 | Minimum load |
| Uplands MS | Z | 228 | 9,219 | 8,388 | Minimum load |

Notes:

- Total Connected and Committed includes a reserve for future micro-generation projects;
- Committed projects are those that have an OPA Offer-of-Contract, received a CIA or have received and paid for a DER connection.

### 3.3.3 Constraints

Constraints to capacity for the connection of DER can occur due to legacy station power transformers not being able to accommodate reverse power flows as well as the short circuit capability of the station protection devices. To increase the short circuit limitations of the equipment, replacement is required with devices with higher ratings. Some station transformers have been operating for over 50 years and were intended to pass electricity only one way: from the transmission grid to the distribution system. At best, many of these units can allow connection of generation capacity up to the minimum of supplied load thereby not allowing electricity to flow back through the transformer and into the transmission grid. To eliminate this constraint, minimum load on the station transformer can be increased or the station transformer(s) can be replaced with newer, reverse flow capable units. As part of HOL's asset management plan, new or upgraded transformers being installed are standardized to allow for reverse flow in order to help eliminate the constraint through normal business practices.

There are currently six stations within HOL's service area that are either restricted or constrained for the connection of DER:

**Slater TS**

- HONI owned station
- Restricted due to short circuit handling capability being exceeded
- HOL is currently unaware of any plans to alleviate the restriction

**Lisgar TS**

- HONI owned station
- JY bus-pair is restricted due to thermal capacity being exhausted
- As a result of the IRPP Lisgar TS was identified for transformer replacement which will include transformers with reverse flow capability.

**Hinchey TH**

- HONI owned station
- Constrained by the legacy station transformers – no reverse flow capability
- HONI will be completing transformer replacements and station upgrade in 2016

- HONI has assured HOL that the newer transformers will be capable of some reverse flow

**Lincoln Heights TD**

- HONI owned station
- B bus-pair is constrained due to thermal capacity being exhausted for all but micro-generation projects
- HOL is currently unaware of any plans to alleviate the restriction

**Fallowfield DS**

- The J bus (half the station) is restricted to any further generation connection due to reverse flow limitations
- Remaining capacity has been reserved for an existing large generation customer that is currently undergoing the connection process
- Continued load growth at Fallowfield DS will increase the capacity available at the station
- Note that only half of the station is constrained as the second transformer was installed in 2013 and therefore has reverse flow capabilities, whereas the other, older unit does not.

**Leitrim MS**

- HOL owned single transformer station
- The station is thermally and short circuit constrained
- There is a 10 MW solar farm connected to this station
- Starting in 2015 HOL is undertaking station upgrades which will alleviate these constraints with the addition of a second transformer

### 3.3.4 Constraints for an Embedded Distributor

HOL does not have any embedded distributors within the service territory.

## 3.4 Capital Expenditure Summary

This section provides the overview of HOL's total capital expenditures for the period from 2011 through 2020, along with discussions on yearly and trend variances.

### 3.4.1 Capital Spending Overview

Overall capital expenditures are outlined in Table 3.4.1, showing the budget and actuals for the years 2011 through 2020.

HOL plans and budgets work by Capital Program (see section 3.1); therefore, the variances described in the following sections will be explained in terms of these Capital Programs.

The tables outlined in the following sections list the capital expenditures for the period 2011 through 2020. At the time of writing (November 2014) the final numbers for 2014 actuals are not available and have therefore been based on Q2 forecast: 6 months of actual costs and 6 months of forecasted costs. For the 2015 costs, no actual expenditures have been included in this report.

**Table 3.4.1 - Capital Expenditure Summary**

| Category | Historical (Previous Plan & Actual) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | | | 2012 | | | 2013 | | | 2014 Q2* | | | 2015 | | |
| | Plan | Act. | Var | Plan | Act. | Var | Plan | Act. | Var | Plan | Act. | Var | Plan | Act. | Var |
| | $M | | % | $M | | % | $M | | % | $M | | % | $M | | % |
| System Access | 30.2 | 31.6 | 5% | 34.5 | 30.9 | -2% | 36.9 | 37.7 | -11% | 40.7 | 39.0 | -8% | 35.3 | - | - |
| System Renewal | 26.7 | 27.8 | 4% | 27.4 | 29.6 | 10% | 23.4 | 29.5 | 8% | 32.8 | 37.0 | -7% | 40.0 | - | - |
| System Service | 25.5 | 26.7 | 5% | 21.5 | 21.4 | 20% | 25.1 | 23.9 | -1% | 23.1 | 21.8 | -10% | 20.8 | - | - |
| General Plant | 20.6 | 10.2 | -50% | 35.9 | 27.2 | -24% | 43.6 | 40.5 | -24% | 22.8 | 18.7 | -11% | 20.9 | - | - |
| **Total** | **103.1** | **96.3** | **-7%** | **119.3** | **109.0** | **-9%** | **129.0** | **131.6** | **9%** | **119.4** | **116.5** | **-9%** | **117.0** | **-** | **-** |
| **System O & M** | N/A | N/A | N/A | N/A | 24.9 | N/A | N/A | 25.2 | N/A | N/A | 27.1 | N/A | 29.5 | N/A | N/A |

*Note that 2014 Actuals are based on Q2 forecast

**Table 3.4.2 - Capital Expenditure Forecasted Spend**

| Category | Forecast (Planned) | | | | |
|---|---|---|---|---|---|
| | 2016 (test) | 2017 | 2018 | 2019 | 2020 |
| | $M | $M | $M | $M | $M |
| System Access | 36.3 | 35.2 | 35.1 | 35.8 | 36.6 |
| System Renewal | 41.0 | 31.8 | 36.5 | 36.0 | 35.7 |
| System Service | 22.2 | 34.0 | 29.5 | 30.5 | 33.3 |
| General Plant | 45.9 | 48.1 | 18.3 | 18.7 | 14.0 |
| **Total** | **145.4** | **149.1** | **119.4** | **121.0** | **119.5** |
| **System O & M** | 30.9 | N/A | N/A | N/A | N/A |

### 3.4.2 System Access

System Access investments are "modifications (including asset relocation) to a distributor's distribution system that a distributor is obligated to perform to provide a customer (including a generation customer) or group of customers with access to electricity services via the distribution system" as *per Section 5.1.1 of Chapter 5*.

Spending in the System Access Capital Programs is focused around:

- Relocation of existing plant due to third party agency (the cities of Ottawa and Casselman, Ministry of Transportation of Ontario, National Capital Commission) infrastructure projects;
- Costs associated with the connection of new residential and commercial customers;
- Expansion of HOL's distribution system to meet a specific customer or developer's needs;
- Connection of new generation customers under various provincial programs such as microFIT, FIT and RESOP;
- Connection of one-off residential and small commercial infill connection requests that do not fall under the dedicated Residential and Commercial Capital Programs;
- Replacement of damaged assets caused by a third party; and
- New and replacement meter installations.

Details of these Capital Programs have been outlined in section 3.1.1.

#### *3.4.2.1 Historic Expenditures*

The following section outlines HOL's System Access Capital Programs and projects from 2011 through 2020 and discusses the variance in spending over the 10 years. As mentioned in section 3.1.1 System Access.

System Access expenditures are mandated by legislation. While HOL strives to ensure the expenses in this Investment Category are completed as efficiently as possible, HOL does not control the timing of projects. While every attempt is made to predict and budget the expenses, the actual implementation is not within HOL's control. Budgeting is based off of historical spending and known large projects or changes in legislative requirements (e.g. Green Energy Act).

**Table 3.4.3 - System Access Expenditure Summary**

| Investment Category / Capital Program | 2011 | | 2012 | | 2013 | | 2014 | | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | Act. | Var. | Act. | Var. | Act. | Var. | Act.* | Var. | Plan |
| | $'000 | % | $'000 | % | $'000 | % | $'000 | % | $'000 |
| **System Access** | **31,635** | **5%** | **30,868** | **-11%** | **37,675** | **2%** | **39,010** | **-4%** | **35,275** |
| Plant Relocation | 7,743 | 39% | 5,942 | -24% | 10,005 | -13% | 9,437 | -19% | 7,814 |
| Residential | 7,247 | 35% | 6,278 | 34% | 6,573 | 37% | 5,985 | -1% | 6,720 |
| Commercial | 9,159 | 25% | 11,892 | 99% | 10,634 | 47% | 9,342 | -1% | 12,279 |
| System Expansion | 3,276 | -28% | 1,675 | -86% | 5,710 | -30% | 10,144 | 8% | 3,727 |
| Stations Embedded Generation | 190 | 204% | 1,181 | 2680% | 64 | -81% | 277 | 2% | 376 |
| Infill & Upgrade | 3,081 | -1% | 2,731 | -10% | 3,178 | -3% | 2,857 | -2% | 3,075 |
| Damage To Plant | 826 | -5% | 798 | 4% | 1,349 | 64% | 840 | -2% | 1,120 |
| Metering | 112 | -97% | 370 | -31% | 160 | -81% | 130 | -3% | 163 |

Historical spending in System Access has steadily increased from 2011 through 2014. While some Capital Programs have remained consistent, others have seen considerable growth causing the overall trend to show a steady increase in spending in the category. While attempts are made to budget for both the historical trending and known major projects in System Access, variances from the budget do occur on a regular basis, and are typically offset by the other Capital Programs within this category.

**Plant Relocation**

HOL has seen a steady increase in the spending for Plant Relocation mainly due to the City of Ottawa's Light Rail Transit project (LRT). This project was budgeted based off of the City of Ottawa's LRT project schedule, which has seen a number of revisions and project changes over the course of HOL's involvement. The changes in project plan have been due to decisions made by the City of Ottawa and not HOL, but these changes have impacted both the timing and scope of work required.

**Residential**

Historically, residential subdivisions in HOL's territory have followed a 7-10 year rolling trend that has been consistent with the provincial and national averages since amalgamation, with the noted exception of 2011. Ottawa's territory trending has been slightly higher than the provincial and national average. As of 2012, and into 2013, subdivision development is in a flat line state and will likely continue until 2014 when the City of Ottawa finalizes its review of the Official Plan regarding development lands. There has also been a shift in development housing trends over this timeline due to intensification policies: there are more blocks within subdivisions being used for high density housing (Stacked Townhomes) on private streets.

**Commercial**

New Commercial Development has remained strong in Ottawa in recent years, including 2013 as actual costs are expected to exceed the budget by approximately 5 million dollars due to developer demand. The recent economic downturn in Canada has had little effect on Ottawa as it is largely government and high tech based. 2014 is expected to remain fairly consistent with 2013 results, new commercial development is still increasing as a result of developer demand.

**System Expansion**

The actual costs for system expansion have varied over the 5 year time frame as requests have been made to HOL. The budgets for system expansion are based on historical trends and expected projects. HOL works with the relevant City of Ottawa departments, as outlined in section 3.1.11.1, to ensure that the forecasts are in line with the City of Ottawa. The timing of these projects, and therefore the actual costs are driven by the third parties and not controlled by HOL. HOL works with the third parties to determine realistic estimates for timing; however, delays do occur due to external reasons and cannot always be controlled by HOL.

**Embedded Generation**

Costs associated with distributed generation connections have shown a steady increase since 2011 with the exception of 2012. Work associated with OPA's (now IESO) FIT program and the

Green Energy Act had been fairly low at the start of the program but has been steadily increasing with all projects associated with FIT 1.0 to be completed in 2015 which has caused the increase in spend in 2013 and 2014. HOL has not received any projects under the FIT 2.0 release. A large RESOP project for the Green Soldiers 10MW solar farm was located just beyond HOL's service territory and included the construction of a new 27.6kV overhead pole line and communication tower at Leitrim MS station to allow for protection upgrades. In order to serve the customer, a service area amendment was completed with Hydro One. This project represented a cost of $1.2M in 2011 and 2012 which is more than all other distributed generation projects from 2011 to 2015 combined.

**Infill & Upgrade**

Infill services remain strong due to the City's Official Plan which encourages urban infill developments. HOL anticipated that the demand for these installations would remain strong through 2015. The actual cost for infill services has remained consistent over the 5 year time frame as Ottawa has been isolated from any slowing of the home market. The budgets for infill services are based on historical trends and expected projects. HOL works with the relevant City of Ottawa departments, as outlined in section 3.1.11.1, to ensure that our forecasts are in line with the City of Ottawa. The timing of these projects, and therefore the actual costs are driven by the third parties and are not controlled by HOL. HOL works with the third parties to determine realistic estimates for timing, however delays do occur due to external reasons and cannot always be controlled by HOL.

**Damage to Plant**

Due to the largely unknown and variable nature of the Damage to Plant Capital Program historical trends are used as the basis for budgeting and forecasting. Since 2007, Damage to Plant expenditures have remained relatively stable year over year. The vast majority of damages consistently occur to overhead and underground transformers, and to wooden poles. The impact of increasing material and labour costs has offset gains made in reducing volumes and/or severity of incidents. As such, 2014 & 2015 volumes and costs are expected to remain consistent with prior years.

**Metering**

The work consists of recertification of meters to ensure their accuracy and extend either the meter's serviceable life or that of a representative sample of meters through compliance sampling. This work all but disappeared through the smart meter installation years from 2006-2011 and into 2012. Metering has been proactively pre-inspecting compliance sample lots to attest to their quality and in 2014 compliance sample testing will be conducted on those meters installed in 2006 to extend their life beyond the initial seal period of 10 years. HOL does this in advance of the 2016 seal expiry period to flatten out production as one third of the whole system meter population was installed with contractors in the fall of 2006, representing 96,000 meters.

### *3.4.2.2 Forecast Trend*

**Table 3.4.4 - System Access Forecasted Spend**

| Investment Category / Capital Program | Forecast (Planned) $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| **System Access** | **36,263** | **35,156** | **35,132** | **35,835** | **36,551** |
| Plant Relocation | 7,620 | 7,773 | 7,928 | 8,087 | 8,248 |
| Residential | 6,889 | 7,027 | 7,167 | 7,311 | 7,457 |
| Commercial | 13,423 | 13,042 | 12,576 | 12,827 | 13,084 |
| System Expansion | 3,479 | 2,366 | 2,413 | 2,462 | 2,511 |
| Stations Embedded Generation | 377 | 384 | 392 | 400 | 408 |
| Infill & Upgrade | 3,160 | 3,223 | 3,288 | 3,353 | 3,420 |
| Damage To Plant | 1,148 | 1,171 | 1,195 | 1,219 | 1,243 |
| Metering | 167 | 170 | 173 | 177 | 180 |

The forecasted spending in the System Access category is expected to remain at consistent levels through to 2020. HOL expects that the economy in Ottawa will remain steady over the next five years, and work associated with the System Access Category will remain at the levels seen since from 2011 through 2015.

- Plant Relocation costs are expected to remain at the elevated costs seen since 2013 as a result of the LRT project. This project has represented a large increase in the relocation costs for HOL. While the first phase of LRT is expected to be completed in

2018, the City of Ottawa has expressed plans to continue directly into the second phase of the project. This combined with a continued focus on infrastructure investments by the City and other agencies HOL expects the spending to remain at the current levels through to 2020 and beyond.

- With the continued strength of the Ottawa community, HOL is expecting that the customer connection needs in Residential, Commercial and Infill & Upgrade Capital Programs will remain consistent with the levels from 2011 through 2015.
- System Expansion is expected return to historical values seen in 2011 and2012. With the completion of the Phase 1 of the City of Ottawa's LRT project expected in 2018, HOL plans on completing the required work for this project in 2016. Following that, for future phases, there are no details of the requirements for HOL, and as a result no costs have been budgeted past 2016.
- Stations Embedded Generation is expected to remain at the consistent levels experienced in 2014 and 2015. With the transmission constraints removed from the Ottawa area by Hydro One, it is expected that the level of interest for these connections will remain at the current levels.

### 3.4.3 System Renewal

System Renewal investments "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services" as per Section *5.1.1* of Chapter 5. Projects outlined in the System Renewal Investment Category have been identified as part of HOL's Asset Management Process.

Spending in the System Renewal Capital Programs is outlined in section 3.1.2 and are focused around:

- Replacement of end of life and obsolete station equipment such as power transformers, switchgear and protection devices;
- Refurbishment of station building structures and facility systems;
- Replacement of end of life distribution assets such as poles, distribution transformers, cables and switches;

- Replacement of in service failed assets through the Plant Failure Capital Program; and
- Upgrades to end of life meters and meter technology.

### 3.4.3.1 Historic Expenditures

The following section outlines the capital expenditures in the System Renewal category from 2011 through 2020. Projects contained in the in System Renewal and System Service categories are determined through HOL's capital expenditure planning process outlined in section 3.2. variances in this category are tracked and approved though HOL's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows HOL to track and adjust the progress of the sustainment project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the asset management plan on track.

Table 3.4.5 - System Renewal Historical Spend

| Investment Category / Capital Program | 2011 | | 2012 | | 2013 | | 2014 | | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | Act. | Var. | Act. | Var. | Act. | Var. | Act.* | Var. | Plan |
| | $'000 | % | $'000 | % | $'000 | % | $'000 | % | $'000 |
| **System Renewal** | **27,778** | **4%** | **29,628** | **8%** | **29,540** | **26%** | **36,997** | **13%** | **40,048** |
| Stations Asset | 5,097 | -9% | 8,475 | 10% | 9,154 | 48% | 14,493 | 11% | 17,200 |
| Stations Enhancement | 2,046 | -7% | 1,067 | -66% | 906 | -38% | 825 | -16% | 679 |
| Distribution Asset | 20,512 | 9% | 19,701 | 22% | 18,992 | 23% | 21,263 | 16% | 21,756 |
| Metering | 122 | 37% | 385 | -6% | 488 | 33% | 416 | 1% | 412 |

Historical spending in the System Renewal has fluctuated over the past five years, but overall has seen an increase in the spending trend, as in the other capital categories. Both of the largest Capital Programs (Station Assets and Distribution Asset) are for the replacement of existing aging infrastructure. The need for these projects has been outlined in section 2.3 Asset Lifecycle Optimization Policies and Practices.

**Stations Asset**

The investments in Stations Asset have seen a marked increase year over year in the past 5 years. While attempts to maintain overall spending on major station projects (Stations Capacity, Transformer Replacement and Switchgear Replacement) consistent year over year, it is not possible to smooth the spending over all years of the Capital Programs. The individual projects are budgeted in an attempt to maximize the efficiency of the project and can cause the timing of costs required for these multiyear projects to fluctuate.

**Stations Enhancement**

The investments in Stations Enhancements have seen a reduction from 2011 to 2013 with the completion of the Stations Transformer Cooling Fan and Porcelain Insulator projects. The spending levels in 2014 and 2015 are planned remain consistent trough to 2020.

**Distribution Asset**

The spending in Distribution Assets has shown a more consistent increase over the 5 years. Spending in the Capital Program has continued to focus on Pole and Cable Replacement Projects along with the Plant Failure projects.

Spending in System Renewal in 2011 was within 4% of the budgeted amount, but some variances did occur in various Capital Programs.

- Stations Asset was 9% below original budget due to contractor and vendor delays causing spending on two Station Switchgear Replacement projects (Richmond North DS and Bridlewood Breaker Refurbishment) to be delayed and pushed these costs forward one year into 2012.
- Distribution Assets was 9% off of budget, however under this Capital Program there were a number of larger variances over and under the planned budget. In the pole replacement program a number of projects were completed under the estimated amount which caused a decrease in the expenditures compared to the budget. The Pole Replacement, Elbow and Insert Replacement and Distribution Transformer replacement

programs were faced with contractor and labour restrictions that caused some of the work to be pushed into 2012.

- Offsetting these decreases in spend in System Renewal in 2011 was the spending in Plant Failure which saw a year end cost 141% above the original budget. Spending on Plant Failure is due to assets that are not replaced proactively before they reach their functional end of life and fail while in service. As outlined in section 2 Asset Management Process, many of the HOL's assets are reaching end of life. Even though HOL is increasing spend on proactive asset replacement to offset the anticipated equipment reaching end of life and levelize replacement spend, HOL continues to experience failure of in service equipment. The spending of $5.1M has been seen in 2011 through 2014; however, HOL has continued to budget at a lower amount. HOL focuses on replacing assets in a proactive manner through planned projects as outlined in our Asset Management Process in Section 2.1. This focus on proactive replacement is expected to reduce the required spend on plant failure. The lower budget also allows planning for an adequate amount of sustainment work for our crews to meet available labour hours, allowing for readjustment if there is an increase in the Plant Failure work that cannot be handled within the capital budget or labour and contractor availability. The level of plant failure spend is continuously monitored throughout the year and the capital budgeted projects are adjusted accordingly.

Spending in 2012 was 8% over budget for the System Renewal category.

- Stations Assets spending was 10% above budget mainly due to increased spending in stations transformers. Scope Increases associated with the transformer replacement at Clyde UC and Barrhaven DS were the main reasons for the Capital Program tracking over the original budget. Increased civil construction costs at Clyde US were caused by unforeseen removal of legacy underground structures and increased safety requirements. It was determined that the Barrhaven DS project could be done more efficiently if the timing of the project was condensed, which pulled costs into 2012 that were originally planned for 2013.
- Costs associated to the Stations Refurbishment Capital Program for protection and equipment upgrades associated to the Green Energy Act (GEA) were originally

budgeted to the System Renewal Investment Category. The budgeting was done early on in the GEA implementation when the true requirements of the program were not yet known. It was later determined that the upgrades required at the stations were already part of HOL's Stations Asset Capital Program and the costs therefore would not be required.

- Distribution Asset spending was over the original budget by 22% and again was mainly due to spending in the Plant Failure Capital Program, for similar reasons as those discussed for 2011.

System Renewal spending in 2013 was 26% above the original budget; this was offset by under spending in both General Plant and System Service. Sustainment (System Renewal and System Service) as defined by HOL was 11% over the original budget as a whole.

- Stations Assets was over spent by 48% in 2013 mostly due to increased spending in the Stations Transformer Replacement Budget Program. Carry over associated with the Clyde UC transformer replacement project was the main contributing factor. This was a direct result of the increased scope that was highlighted in the 2012 spending. For the Beechwood UB transformer project, the feeder reconfiguration project that was identified for future years was added to the station project scope. This combined with higher contractor costs than anticipated also contributed to the increased spending in the Stations Replacement Budget Program.
- Distribution Asset spending was over the original budget by 23% and similarly to 2011 and 2012, was mainly due to spending in the Distribution Plant Failure Budget Program. The reasons for this are the same that were discussed for 2011. Spending was in line with the values that have been experienced from 2011 through 2014.

2014 spending in the System Renewal Investment Category is expected to be 13% over the original budget. This is based off of the 6 months of actuals and 6 months of forecasted expenditures. Sustainment (System Renewal and System Service) as defined by HOL was only 5% over the original budget as a whole.

- The majority of the forecasted spending variance is due to spending in Station Plant Failure in the Stations Asset Capital Program which is expected to be 11% over the original budget. The one station transformer at Leitrim MS was required to be replaced due to failure, as identified through dissolved gas analysis. This replacement is expected to continue into 2015.
- Distribution Asset spending was over the original budget by 16% and similarly to 2011 through 2013, was primarily due to spending in the Plant Failure Budget Program. The reasons for this are the same as those discussed for 2011. Spending was in line with the values that have been experienced for the past three years.

### *3.4.3.2 Forecast Trend*

Table 3.4.6 - System Renewal Forecasted Spend

| Investment Category / Capital Program | Forecast (Planned) $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| **System Renewal** | **41,033** | **31,823** | **36,491** | **35,980** | **35,718** |
| Stations Asset | 16,338 | 11,815 | 14,048 | 15,203 | 14,186 |
| Stations Enhancement | 597 | 634 | 731 | 662 | 691 |
| Distribution Asset | 23,683 | 17,828 | 20,128 | 18,492 | 19,179 |
| Metering | 415 | 1,547 | 1,584 | 1,623 | 1,662 |

Overall, when combined, spending in System Renewal and System Service is expected to increase at 3% annually from 2016 through 2020. The main driving factor for fluctuations in the category spend over the 5 years is due to timing of the major station projects. The decrease in spend in 2017 is due to the increased spending in the Stations New Capacity Budget Program in order to maintain overall sustainment spending consistent year over year. A continued focus will be seen through to 2020 and beyond on replacements of the critical assets as outlined in section 2.2.3 Asset Demographics and Condition. HOL will continue to replace major station and distribution assets on a focused basis as has previously been the case.

- Station transformers and switchgear will remain consistent with the spending levels seen since 2011;

- Distribution asset including poles, cable and switches will also remain consistent. A large civil infrastructure project along Carling Avenue is planned for 2016 which will see a one year increase in HOL's Civil Rehabilitation Budget Program.
- An increased focus on spending for the Remote Disconnect Smart Meter Budget Program is planned for 2017 and will continue through to 2020.

### 3.4.4 System Service

System Service investments are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future electricity service requirements" as per Section *5.1.1* of Chapter 5.

Spending in the System Service Investment Category is focused around:

- Stations Capacity Upgrades covers the building of new or rebuilding of stations for the addition of transformation capacity or supply;
- Distribution Enhancements includes a range of system betterment projects. Included in this Capital Program are Line Extensions and System Voltage Conversions projects; and
- HOL's Automation Capital Program which include upgrades to the SCADA systems and installation of automated switches in the distribution and devices in stations.

#### *3.4.4.1 Historic Expenditures*

The following section outlines the capital spending in the System Service category from 2011 through 2020. Projects contained in the in System Renewal and System Service categories are determined through HOL's capital expenditure planning process outlined in section 3.2. Variances in this category are tracked and approved though HOL's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows HOL to track and adjust the progress of the sustainment project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the asset management plan on track.

Table 3.4.7 - System Service Historical Spend

| Investment Category / Capital Program | 2011 | | 2012 | | 2013 | | 2014 | | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | Act. | Var. | Act. | Var. | Act. | Var. | Act.* | Var. | Plan |
| | $'000 | % | $'000 | % | $'000 | % | $'000 | % | $'000 |
| **System Service** | **26,716** | **5%** | **21,362** | **-1%** | **23,917** | **-5%** | **21,753** | **-6%** | **20,806** |
| Stations Capacity | 19,170 | 16% | 11,838 | -2% | 13,198 | -13% | 6,223 | 30% | 2,187 |
| Distribution Enhancements | 6,226 | -12% | 8,375 | 23% | 10,319 | 13% | 14,961 | -16% | 15,176 |
| Automation | 1,320 | -33% | 1,150 | -58% | 400 | -52% | 569 | 3% | 3,444 |

Historical spending in the System Service category has fluctuated within each Capital Program over the past five years, but overall has shown a steady trend. The largest contributor to the costs in System Service category can be attributed to Stations Capacity and Distribution Enhancements Capital Programs. These programs are designed to build out the distribution system to efficiently serve the customer at the best possible value. The need for these projects has been outlined in 3.1.3 System Service.

**Stations Capacity**

The investments in Stations Capacity has decreased over the past five years which is due to the completion of three major station builds at Ellwood MTS, Beacon Hill DS and Terry Fox MTS. These projects are in addition to the expansion of a number of other stations through the installation of additional transformers. While attempts to maintain overall spending on major station projects (Stations Capacity, Transformer Replacement and Switchgear Replacement) consistent year over year, it is not possible to smooth the spending over all years of the Budget Programs. The individual projects are budgeted in an attempt to maximize the efficiency of the project and can cause the timing of costs required for these multiyear projects to fluctuate.

**Distribution Enhancements**

The spending in Distribution Enhancements has increased gradually since 2011. The largest increase has been seen because of increased spending in the Voltage Conversion Budget Program which has been focused in the Woodroffe TS, Kilborn DS and South Nepean areas. Line Extensions have fluctuated over the 5 years since 2011, but the majority of these projects are tied to the timing of the completion of Station New Capacity projects. Details on these projects can be found in section 3.5 Justifying Capital Expenditures.

**Automation**

The Automation Capital Program have decreased in 2013 and 2014 as automation switch installations have become part of our normal course of business. 2015 is the first year of HOL Telecom Plan implementation. The details of this project are outlined in Attachment B-1(A). This project will continue to 2024.

Spending in System Service in 2011 was 6% below the budgeted amount, but some larger variances did occur in various Capital Programs.

- Distribution Enhancements was 12% under the budgeted amount for 2011, with the majority of the variances being in the Line Extensions Budget Program. The variance in this Budget Program was due to both efficiencies in construction and a portion of the work being pushed into 2012.
- The Automation Capital Program spending was below budget due to the cancelation of one project in the SCADA Upgrade Budget Program. The MyOASIS project was canceled after a detailed review revealed that it was not going to deliver the desired outcomes.

2012 System Service spending was very close to budget at 1% below the budgeted amount of $21M.

- Distribution Enhancements was 23% over the original budget in 2012 due to carry over of projects from 2011 in the Line Extension Budget Program and an increase in the scope for the voltage conversion project at Upland DS.
- The Automation Capital Program spending was below budget due to delays on the SCADA Upgrade Budget Program and delays of control boxes for automated distribution switches.

2013 System Service spending was again close to budget at 5% below the original amount.

- Progress payments for the new Switchgear at Limebank MTS and contractor delays for the construction of the expanded Casselman DS led to the spending in Station Capacity to be 13% below the original budgeted amount of $15M.
- The reasoning for the increase in the spending for Distribution Enhancements was due to an increase in the scope for the Woodroffe Voltage Conversion project. Some of this increase was offset by the delays in three line extension projects. Delays in the City of Ottawa's Strandherd Bridge project delayed the installation of new feeder ties across the Rideau River and Work along the Alta Vista Transit Corridor was delayed to 2014 due to HOL budget and resource constraints.

The forecasted spending for 2014 is expected to be in line with the budget with a 6% variance from the budget.

- Stations Capacity spending is forecasted to be over budget. The majority of these costs are due to the carryover of in spending from Hinchey TH from 2013. An increased scope in the Casselman DS project to upgrade the second bank has also led to a large increase in the Stations Capacity Capital Program.
- A number of Line Extension projects have been delayed due to coordination with the City of Ottawa's LRT project. The planned work for the LRT has caused a delay to the completion of a number of projects to ensure HOL work coincides with the City's plans.

#### *3.4.4.2 Forecast Trend*

**Table 3.4.8 - System Service Forecasted Spend**

| Investment Category / Capital Program | Forecast (Planned) $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| **System Service** | **22,235** | **33,957** | **29,518** | **30,473** | **33,314** |
| Stations Capacity | 5,676 | 15,272 | 10,464 | 14,441 | 15,626 |
| Distribution Enhancements | 11,290 | 12,282 | 14,175 | 12,829 | 13,394 |
| Automation | 5,269 | 6,403 | 4,880 | 3,202 | 4,295 |

Overall, when combined, spending in System Renewal and System Service is expected to increase at 3% annually from 2016 through 2020. The main driving factor for fluctuations in the category spend over the 5 years is due to timing of the major station projects. Spending in the System Service category is expected to increase in 2017 and continue at the elevated levels through 2020. The requirement for the Stations Capacity and Distribution Enhancement Capital Programs has been outlined in section 3.1.3

HOL will continue to build and enhance our stations while developing distribution feeders and ties as we have been since before 2011 including:

- Station capacity upgrades including the rebuild of Richmond South DS, building of a new transmission station in the south region to supply the growing City along with additional transmission upgrades to improve reliability;
- Build new and extend feeders to connect the new capacity with the customers and load, while focusing on removing stations and their associated distribution assets through targeted voltage conversions;
- Continuation of the Telecom Plan project started in 2015 through 2020 with completion in 2024. The details of this project are outlined in Attachment B-1(A).

### 3.4.5 General Plant

General Plant investments are "modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities" as *per Section 5.1.1* of Chapter 5.

In General Plant, there are two major funding requirements:

1) Life cycle funding requirements for fleet replacement, facilities, tools, and information technology asset replacement have also been forecast to 2020. The investments are essential to meet the operational needs.
2) New technology initiatives have been identified in the 2015 to 2020 planning horizon. The business case for each initiative have been reviewed and approved by the Executive Management Team. Examples include mobile workforce management software, asset planning software, JD Edwards system upgrades, and automated power outage system upgrades. Each of these initiatives is required to maintain the integrity of

our data, to facilitate productivity improvements through automation, and/or to position HOL for the next phase of smart grid transformation in the planning horizon.

The following section outlines the capital spends in the General Plant from 2011 through 2020.

#### *3.4.5.1 Historic Expenditures*

The following section outlines HOL's System General programs from 2011 through 2020 and discusses the variance in spending over the 10 years. Expenditures and variances are tracked regularly by HOL's management team and are adjusted to align with any changes in the Corporate Strategic Objectives.

**Table 3.4.9 - General Plant Expenditure Summary**

| Investment Category / Capital Program | 2011 | | 2012 | | 2013 | | 2014 Q2* | | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | Act. | Var. | Act. | Var. | Act. | Var. | Act. | | Plan |
| | $'000 | % | $'000 | % | $'000 | % | $'000 | | $'000 |
| **General Plant** | **10,215** | **-50%** | **27,190** | **-24%** | **40,484** | **-7%** | **18,742** | | **20,850** |
| Buildings - Facilities | 767 | -51% | 380 | -60% | 380 | -52% | 426 | | 688 |
| Customer Service | 3,818 | -65% | 10,365 | 0% | 13,389 | 2% | 5,839 | | 2,450 |
| ERP System | 950 | -29% | 933 | -28% | 478 | -24% | 329 | | 1,547 |
| Fleet Replacement | 2,024 | -15% | 2,542 | -5% | 3,056 | -26% | 1,441 | | 1,537 |
| IT New Initiatives | 296 | -55% | 578 | -19% | 57 | -95% | 1,584 | | 2,111 |
| IT Life Cycle & Ongoing Enhancement | 1,122 | -43% | 2,440 | 19% | 3,076 | 33% | 2,821 | | 1,970 |
| Operations Initiatives | 356 | -44% | 683 | 54% | 242 | -67% | 3,011 | | 2,756 |
| Tools Replacement | 580 | -17% | 568 | -18% | 539 | -19% | 386 | | 512 |
| Hydro One Payments | - | - | 1,116 | N/A | 6,358 | 11% | 2,453 | | 2,347 |
| Facilities Implementation Plan | 302 | -20% | 7,586 | -54% | 12,909 | -10% | 453 | -91% | 4,933 |

*Note that 2014 Actuals are based on Q2 forecast

Historical spending in the General Plant investments has seen a marked increase from 2011 through 2015 from the implementation of HOL's Facilities Implementation Plan which is outlined below. Outside of this program the spending has remained consistent over the past 5 years with the exception of 2011 and 2013. Spending in 2011 was significantly below budget due to timing of cost of service application and the pending rate approval. All General Plant capital spending was cut to a bare bone. 2013 saw an increase in spending in the Customer Service Capital Program which is outlined below. Overall the General Plant Investment Category has had little variance to budget with the exception of the Facilities Implementation Plan which has been under budget for the past years. The details of these variances are outlined below.

**Buildings – Facilities**

Spending in the Building – Facilities Capital Program have been pared back due to the implementation of the Facilities Implementation Plan.

**Customer Service**

The largest contributor to the costs in General Plant was attributed to the Customer Care and Billing System (CC&B) Upgrade started in late 2010, went live in 2014. The Customer Information System was going to reach end of life in 2013 and no longer supported by its vendor. Therefore the company invested on the upgrade of the new system to ensure billing is properly supported. Spending variance from budget was due to timing of project milestones and delivery.

**ERP System**

Spending in the ERP System Capital Program remained relatively consistent over the past 5 years. There is an increase in spending in the ERP Capital Program in 2015. The Enterprise Architecture Program is a multi-year project to connect all the individual software applications and improve operational effectiveness and the JDE Application Upgrade will begin (details can be found in Attachment B-1(A)). In the past three years, the spending for ERP System was below budget due to internal resource issue. Several key enhancements are reprioritized for the upcoming ERP Upgrade.

**Fleet Replacement**

Life cycle replacements were steady with a slight increase in 2013. The spending in 2014 and 2015 reduced due to the vehicle end of life schedule caught up with the increase in 2013. Some vans and trucks ordered in 2013 were delivered in 2014, therefore 2013 spending was below budget.

**IT New Initiatives**

This program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System. The introduction of Document Management System to ensure documents for legal, business, health, safety, environmental are managed in accordance with legislative compliance and ISO requirement. The Asset Planning software is to improve capital planning process and ensure the most optimized capital investment decisions are made for the company and the customers. The project is expected to be complete in 2015. Historical spending was below budget due to internal resources redeployed for other IT Life Cycle & Ongoing Enhancement projects.

**IT Life Cycle & Ongoing Enhancements**

The IT Life Cycle & Ongoing Enhancements Capital Program has a slight increase over the past 5 years. 2012 and 2013 spending exceeded budget due timing of spending i.e. 2011 projects implemented in 2012. Also some of the new initiative components were embedded into the ongoing enhancements. Combined the two programs, the spending was in line with budget projection.

**Operations Initiatives**

Operations Initiatives have remained constant from 2011 through to 2013. The spending is planned to increase in 2014 and 2015 with the focus on the next productivity initiative –Mobile Workforce Management software (project details can be found in Attachment B-1(A)). 2011 spending was low due to the Radio System Replacement project budgeted in 2011, but completed in 2012. 2013 variance is mainly explained by a planned GIS (OMS-AMI Meter Ping) project cancellation due to some technical issues with AMI communication infrastructure.

**Tools Replacement**

The Tools Replacement Capital Program has remained relatively unchanged over the past 5 years with spending being at a consistent level under the budget.

**Hydro One Payments**

Starting in 2012, capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects accounted for under the General Plant account. Prior to 2012, costs associated with these investments were tracked under the separate System Renewal or System Service budgets. These budget amounts and timelines for these projects are based off of the original signed contracts between Hydro One and HOL, but timing can move these payments out of the budgeted year. The only payment in 2012 was for HOL's Hinchey TH project which was originally budgeted under Stations Capacity in the System Service category.

2014 spending was well under the budget. This was due to the delay of two projects. The Lisgar TL upgrade payment was delayed into 2015, only the study agreement payment was completed in 2014. The original schedule from Hydro One was to complete Orleans TS in 2014 and this has now been updated to spring 2015, which has delayed the final milestone payment until that time.

**Facilities Implementation Plan**

The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities. An amount for the purchase of land for the construction of new facilities was included in HOL's 2012 rate base used to calculate distribution rates resulting from its last cost of service rate case (EB-2011-0054). Details of the spending are outlined in Table 3.4.10.

**Table 3.4.10 - Facilities Implementation Plan Historic Spend**

| Facility | | $'000 | | | | |
|---|---|---|---|---|---|---|
| | | 2011 Act. | 2012 Act. | 2013 Act. | 2014 Q2* Act. | 2015 Plan |
| East Ops & Campus | Land | - | 250 | 10,002 | 21 | - |
| | Building | 234 | 492 | 287 | 432 | 3,835 |
| South Ops | Land | - | 6,704 | 2,537 | - | - |
| | Building | 68 | 140 | 83 | - | 1,098 |
| Total | | 302 | 7,586 | 12,909 | 453 | 4,933 |

The 2011-2014 budget to actual variances are the result of delays in the schedule for the purchase of land and construction of Hydro Ottawa's new facilities. More specifically, the 2011 variance is the result of underspending on the services provided by Hydro Ottawa's real estate advisors. Spending in 2012 and 2013 was significantly lower than forecasted due to delays in the project. Actual spend reflects the purchase of the two land parcels whereas the budget had also set aside monies for the construction of the facilities.

### *3.4.5.2 Forecast Trend*

**Table 3.4.11 - General Plant Forecasted Spend**

| Investment Category / Capital Program | Forecast (Planned) $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| **General Plant** | **45,899** | **48,138** | **18,276** | **18,695** | **13,954** |
| Buildings - Facilities | 688 | 509 | 408 | 323 | 243 |
| Customer Service | 3,740 | 2,361 | 1,148 | 6,658 | 1,139 |
| ERP System | 5,043 | 354 | 350 | 354 | 1,061 |
| Fleet Replacement | 1,455 | 1,209 | 1,452 | 1,480 | 1,876 |
| IT New Initiatives | 2,127 | 1,166 | 1,006 | 1,218 | 1,203 |
| IT Life Cycle & Ongoing Enhancement | 1,424 | 1,737 | 1,905 | 2,232 | 1,816 |
| Operations Initiatives | 1,074 | 452 | 405 | 892 | 1,069 |
| Tools Replacement | 512 | 521 | 530 | 539 | 548 |
| Hydro One Payments | 4,575 | 5,000 | 5,000 | 5,000 | 5,000 |
| Facilities Implementation Plan | 25,262 | 34,829 | 6,073 | - | - |

Over the period 2016-2020 Hydro Ottawa General Plant investments will be addressing Operational Effectiveness and Customer Value. Life cycle investments remain flat while there are increases in spending in the Customer Service Capital Program in 2019, details of this change is outlined in the Materials Investments section 3.6.

The forecasted trend for Hydro One Payments is expected to remain consistent over the next 5 years. This will represent an increase from the $3M average from 2012 through 2015 due to the increased amount of work associated and existing agreements. The actual expenditures forecasted are expected to change as agreements with HONI are finalized, and therefore it remains difficult to determine the expected costs for new projects or true-up payments.

New agreements are expected to be signed for a number of transmission connected stations and jointly owned HOL/Hydro One stations through 2020. Below is a list of projects that have been identified to start by the end of 2016 that will have new agreements with Hydro One issued. These projects may or may not require a capital contribution by HOL, and this will only be known once Hydro One completes the evaluation of the projects and a contract is signed, timelines of which have not yet been determined.

- Merivale DS Rebuild;
- Woodroffe TW 13kV Switchgear Replacement ;
- Overbrook TO Switchgear Replacement;
- New South 28kV Substation;
- Lisgar TL transformer Upgrade;
- Richmond South DS Rebuild; and
- 2nd 230kV Supply to Terry fox MTS

There has been an increase in the number of agreements signed with Hydro One over the last five years and as a result HOL has obligations under these agreements to complete true-up reviews on five year increments. These reviews may require that payments be made for any short fall of revenue generated by Hydro One as a result of the forecasted load from HOL not materializing. While HOL does attempt to maintain the loading committed to in the CCRA agreements, shortfalls do occur. Table 3.1.11 outlines the existing CCRA contracts that have true-up reviews over the 2016-2020 timeframe.

**Table 3.4.12 - Hydro One CCRA True-up Dates**

| Station | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Hawthorne 115kV Lines Upgrade | | | | | X |
| Cyrville MTS | | | | X | |
| Ellwood MTS | | | | | X |
| Terry Fox MTS | | | X | | |
| Orleans TS | | | | | X |
| Hawthorne TS | | | | | X |
| Overbrooke TS | X | | | | |
| Limebank MS | | | | | X |

Spending in the Facilities Implementation Plan is set to be completed by 2018. Table 3.4.13 below sets out HOL's forecasted expenditure for its new Eastern Operations & Campus and its Southern operation/warehouse centre facilities. The capital expenditure for the construction of the new facilities is a once in a generation investment. This investment was identified almost fifteen years ago at amalgamation as necessary to consolidate administrative functions; to better locate the operation centres; to modernize the work environment and to provide for future growth. HOL's existing facilities are between 45 and 60 years old and were designed and built in an era and are now beyond their end of life. These costs can be broken down by the two proposed projects.

**Table 3.4.13 - Facilities Implementation Plan Forecasted Spend**

| Facility | | Forecast (Planned) $'000 | | | | |
|---|---|---|---|---|---|---|
| | | 2016 | 2017 | 2018 | 2019 | 2020 |
| East Ops & Campus | Land | - | - | - | - | - |
| | Building | 19,642 | 25,818 | 6,073 | - | - |
| South Ops | Land | - | - | - | - | - |
| | Building | 5,620 | 9,011 | - | - | - |
| Total | | 25,262 | 34,829 | 6,073 | - | - |

### *3.4.5.3* Y Factor Treatment

HOL proposes to recover the costs associated with the construction of new head office and operations buildings via a Y factor. Y factors are mechanisms available under incentive regulation to accommodate revenue requirement pass throughs. HOL proposes to use a Y factor to pass along the costs associated with the construction of the administrative and operational buildings to ratepayers in the years that said costs are incurred. HOL proposes to use the Y factor rather than embed the full costs into revenue requirement because HOL does not know at this point in time a) the precise amount of costs that is to be recovered; b) when (ie. the year) said costs will be incurred and hence recoverable. HOL proposes to record the expenses incurred with the construction of its new facilities in a Y Factor Account.

### *3.4.5.4* Proceeds of Sale of Existing Facilities

Following the move to its new facilities, HOL's existing Albion Street, Merivale Road and Bank Street facilities will be marketed for sale. At this time, HOL does not know the final sale price for the land and buildings at each location nor the year in which the sale will occur.

HOL proposes to credit ratepayers with the entire value of the after tax proceeds of sale for the buildings and for 50% of the after tax proceeds for the sale of the lands. The 50% share of the after tax proceeds for the sale of the lands recognizes that land is an undepreciated asset. HOL is proposing to establish a deferral account to record the after tax proceeds from the sale of the buildings and lands and will bring forward the deferral account for clearance in a future proceeding once the buildings and lands have been sold.

## 3.5 Justifying Capital Expenditures

The following section provides the data, information and analysis to support the forecasted capital expenditures as proposed by HOL.

### 3.5.1 Overall Plan

The Overall Plan section provides comparative data from the historic period of 2011-2015 and the forecast period of 2016-2020 by Investment Category and by primary driver.

#### *3.5.1.1 Historic Expenditures by Category*

Table 3.5.1 and Figure 3.5.1 depict the expenditures by investment category over the historic period of 2011-2015 and the projected expenditures for the forecast period of 2016-2020.

**Table 3.5.1 - Expenditures by Investment Category in $'000**

| Investment Category | $'000 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Historical | | | | | | Forecast | | | | | |
| | 2011 | 2012 | 2013 | *2014 | **2015 | Avg. | 2016 | 2017 | 2018 | 2019 | 2020 | Avg. |
| System Access | 31,635 | 30,868 | 37,675 | 39,010 | 35,275 | 34,892 | 36,263 | 35,156 | 35,132 | 35,835 | 36,551 | 35,787 |
| System Renewal | 27,778 | 29,628 | 29,540 | 36,997 | 40,048 | 32,798 | 41,033 | 31,823 | 36,491 | 35,980 | 35,718 | 36,209 |
| System Service | 26,716 | 21,362 | 23,937 | 21,753 | 20,806 | 22,915 | 22,235 | 33,957 | 29,518 | 30,473 | 33,314 | 29,899 |
| General Plant | 10,215 | 27,191 | 40,484 | 18,743 | 20,850 | 23,497 | 45,899 | 48,138 | 18,276 | 18,695 | 13,954 | 28,992 |
| Grand Total | 96,343 | 109,049 | 131,635 | 116,503 | 116,979 | 114,102 | 145,430 | 149,073 | 119,418 | 120,982 | 119,538 | 130,888 |

Note: *2014 actuals are based on the Q2 forecast **2015 based on budget

**Figure 3.5.1 - Expenditures by Investment Category**

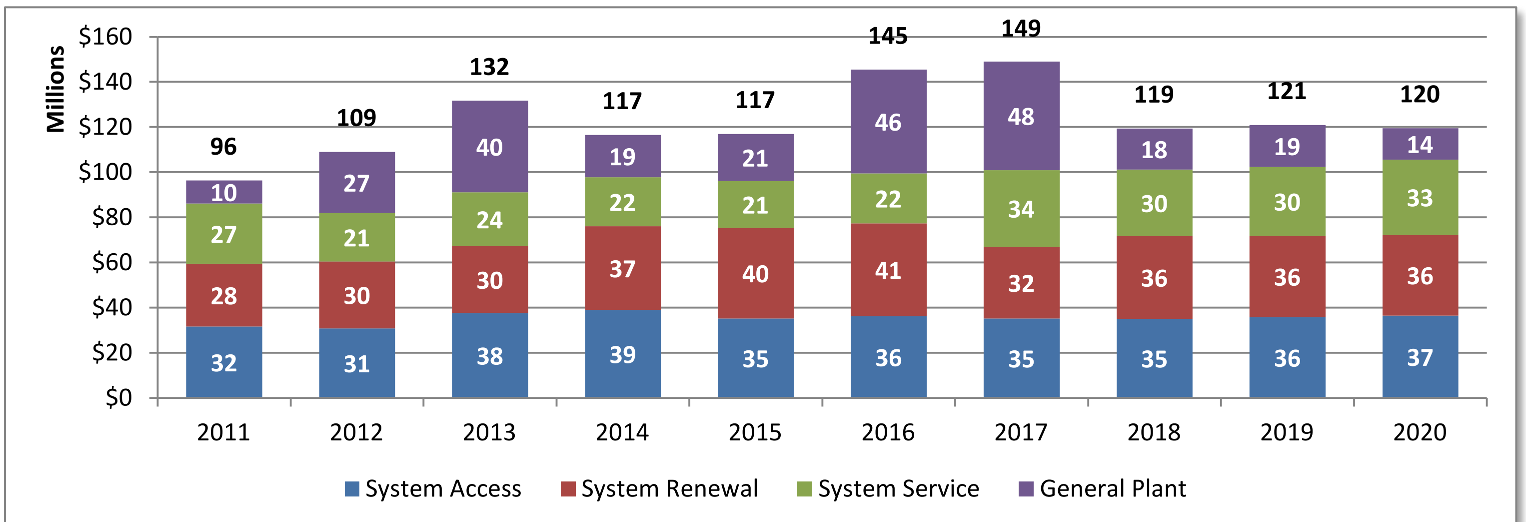
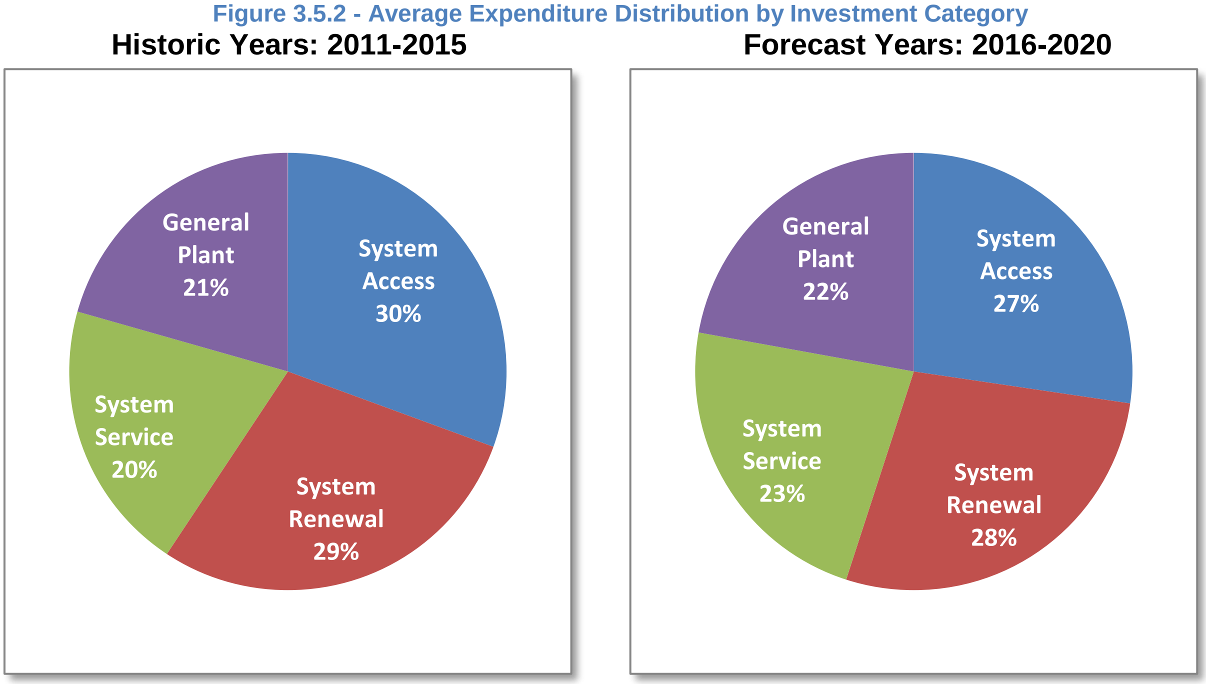


Figure 3.5.2 shows the average percent contribution of annual expenditure to each of the Investment Categories over the historic period of 2011-2015 compared to the forecast period of 2016-2020.

Figure 3.5.2 - Average Expenditure Distribution by Investment Category




### *3.5.1.2 Impact on O&M Costs*

Impacts to operation and maintenance costs vary by Investment Category, as described below.

**System Access**

System Access projects can introduce new assets to the system resulting in an increase of equipment requiring maintenance, and additional potential failure points within the grid. These projects can also involve expanding the communication infrastructure, and as a result could incur ongoing licencing fees.

**System Service**

System Service investments represent the costs associated with growing the distribution system, thereby increasing the number of assets to maintain and introducing additional potential failure points within the system. These projects can also involve expanding the communication infrastructure, and as a result could incur ongoing licencing fees.

**System Renewal**

System Renewal Investments target the replacement of ageing infrastructure. As an asset ages, the costs associated with maintenance increases as the activities become more onerous. When an asset is replaced, maintenance is still required, but typically involves less time and resources, resulting in lower O&M expenses in comparison. As well, as an asset ages and its condition deteriorates to the point of failure, there are resulting O&M costs associated with the emergency work required to respond and restore power. Through pro-active replacement, these additional costs can be avoided.

As HOL replaces assets, new technologies are introduced. There are benefits to such improvements, such as reduced crew travel time, but other costs such as communication licencing, software licencing, increased communication infrastructure and a need for device specific training can increase O&M costs.

### *3.5.1.3 Drivers by Investment Categories*

The drivers by investment category are expected to remain constant from the historic period moving through the forecast period and have been summarized in Table 3.5.2. For the definitions of the drivers refer to Section 2.1.1 Asset Management Objectives.

**Table 3.5.2 - Drivers by Investment Category**

| Investment Category | Driver(s) |
|---|---|
| **System Access** | • 3rd Party Requirements<br>• Customer Service Request<br>• Mandated Service Obligation |
| **System Renewal** | • Assets at end of Service Life<br>  o Failure Risk<br>  o Failure<br>  o High Performance Risk<br>  o Substandard Performance |
| **System Service** | • Capacity Constraint<br>• Reliability |

| | |
|---|---|
| | • System Efficiency |
| **General Plant** | • System Capital Investment Support<br>• System Maintenance Support<br>• Business Operations Efficiency<br>• Non-System Physical Plant |

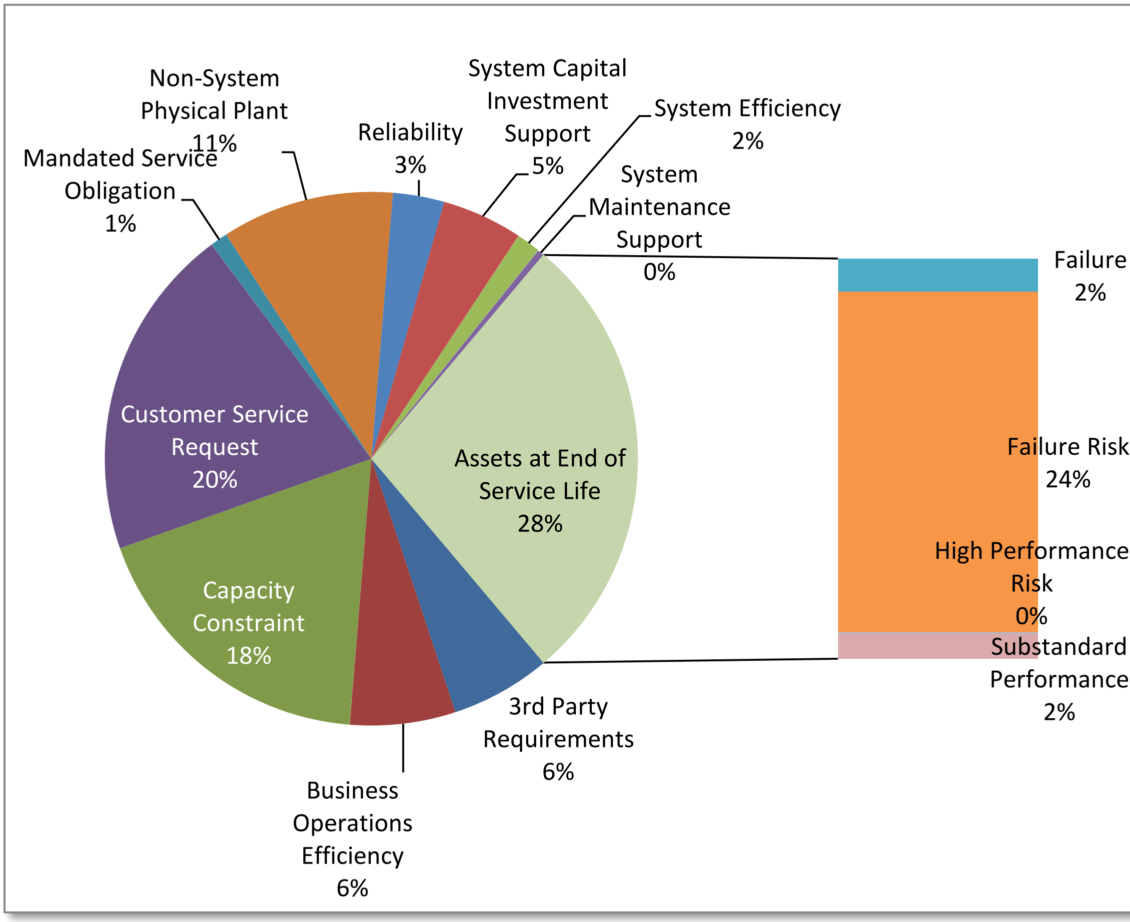
Table 3.5.3 shows the forecasted expenditures by driver and Figure 3.5.3 shows the distribution by driver of the total expenditures over the forecast period.

1

**Table 3.5.3 - Forecasted Expenditures by Driver**

| Investment Category | Driver | $'000 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011A | 2012A | 2013A | 2104A | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| System Access | 3rd Party Requirements | 6,542 | 14,998 | 17,242 | 13,583 | 10,833 | 7,620 | 7,773 | 7,928 | 8,087 | 8,248 |
| | Customer Service Request | 767 | 380 | 380 | 426 | 688 | 27,328 | 26,042 | 25,836 | 26,352 | 26,880 |
| | Mandated Service Obligation | 2,024 | 3,658 | 9,414 | 3,894 | 3,885 | 1,315 | 1,341 | 1,368 | 1,395 | 1,423 |
| System Renewal | Failure | 580 | 568 | 539 | 386 | 512 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 |
| | Failure Risk | 302 | 7,586 | 12,909 | 453 | 4,933 | 36,732 | 26,284 | 30,763 | 30,321 | 29,975 |
| | High Performance Risk | 7,743 | 5,942 | 10,005 | 9,437 | 7,814 | - | 168 | 194 | 176 | 183 |
| | Substandard Performance | 22,207 | 23,031 | 25,661 | 28,410 | 26,178 | 1,301 | 2,370 | 2,534 | 2,483 | 2,560 |
| System Service | Capacity Constraint | 1,684 | 1,895 | 2,008 | 1,163 | 1,283 | 15,955 | 26,416 | 23,325 | 26,082 | 27,778 |
| | Reliability | 6,146 | 5,186 | 5,322 | 6,493 | 2,991 | 4,282 | 5,164 | 4,061 | 2,913 | 3,995 |
| | System Efficiency | 16,648 | 22,078 | 22,494 | 28,889 | 35,219 | 1,998 | 2,377 | 2,133 | 1,478 | 1,541 |
| General Plant | Business Operations Efficiency | 403 | 150 | 303 | 326 | 319 | 13,407 | 6,070 | 4,814 | 11,352 | 6,288 |
| | Non-System Physical Plant | 3,066 | 2,214 | 1,421 | 1,514 | 1,519 | 688 | 509 | 408 | 323 | 243 |
| | System Capital Investment Support | 24,496 | 19,081 | 22,436 | 20,018 | 16,004 | 6,030 | 6,209 | 6,452 | 6,480 | 6,876 |
| | System Maintenance Support | 856 | 1,010 | 394 | 921 | 3,305 | 512 | 521 | 530 | 539 | 548 |
| | Non-System Physical Plant | 1,363 | 1,272 | 1,107 | 814 | 1,498 | 25,262 | 34,829 | 6,073 | - | - |
| **Total** | | **94,829** | **109,050** | **131,635** | **116,727** | **116,979** | **145,430** | **149,073** | **119,418** | **120,982** | **119,538** |

**Figure 3.5.3 - Contribution to Total Forecasted (2016-2020) Expenditures by Driver**




### 3.5.1.4 System Capability Assessment

Over the period 2016-2020 HOL will be addressing three stations that currently have restrictions for the connection of REG within the capital expenditures: Lisgar TL by contributing to the transformer upgrade being completed by HONI, Hinchey TH by contributing to the transformer upgrade being completed by HONI, and Leitrim MS by adding a second transformer at the station. Further details of the system capability assessment for REG connections can be found in section 3.3. As well, whenever station transformers are identified for replacement through the Asset Management Process (2 Asset Management Process) due to either reaching their end of life or capacity constraints, the new units will have reverse flow capabilities specified to eliminate the potential restriction to the connection of REG.

### 3.5.2 Material Investments

This section describes HOL's Budget Programs and projects specifically those that meet the materiality threshold of $750k in each of the four investment categories (System Access, System Renewal, System Service, and General Plant) for the forecast years of 2016 through 2020.

#### *3.5.2.1 System Access*

System Access investments are "modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generation customer) or group of customers with access to electricity services via the distribution system" as *per Section 5.1.1* of Chapter 5.Table 3.5.4 details HOL's full expenditures by Capital Program within System Access from 2016 through 2020.

**Table 3.5.4 - System Access Forecast Expenditure by Capital Program**

| Capital Program | Budget Program | $'000 | | | | |
|---|---|---|---|---|---|---|
| | | 2016 | 2017 | 2018 | 2019 | 2020 |
| Plant Relocation | Plant Relocation & Upgrade | 7,620 | 7,773 | 7,928 | 8,087 | 8,248 |
| Residential | Residential Subdivision | 6,889 | 7,027 | 7,167 | 7,311 | 7,457 |
| Commercial | New Commercial Development | 13,423 | 13,042 | 12,576 | 12,827 | 13,084 |
| System Expansion | System Expansion Demand | 3,479 | 2,366 | 2,413 | 2,462 | 2,511 |
| Stations Embedded Generation | Embedded Generation | 377 | 384 | 392 | 400 | 408 |
| Infill & Upgrade | Infill Service (Res & Small Com) | 3,160 | 3,223 | 3,288 | 3,353 | 3,420 |
| Damage To Plant | Damage to Plant | 1,148 | 1,171 | 1,195 | 1,219 | 1,243 |
| Metering | Suite Metering | 167 | 170 | 173 | 177 | 180 |
| Total | | 36,263 | 35,156 | 35,132 | 35,835 | 36,551 |

##### 3.5.2.1.1 Plant Relocation

The HOL Plant Relocation Capital program is in response to the Ontario Energy Board's *Distribution System Code (August 21, 2014)* (DSC), *section 3.4 – Relocation of Plant*, *3.4.1*, which states that “When requested to relocate distribution plant, a distributor shall exercise its rights and discharge its obligations in accordance with existing legislation such as the *Public Service Works on Highways Act*, regulations, formal agreements, easements and common law. In the absence of existing arrangements, a distributor is not obligated to relocate the plant. However, the distributor shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility or infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.”

#### 3.5.2.1.2 Residential, Commercial, System Expansion and Infill & Upgrade

HOL’s Residential, Commercial, System Expansion, and Infill & Upgrade Capital Programs are driven by the requirements as set out in the DSC, s*ection 6 – Distributors’ Responsibilities, 6.1 – Responsibilities to Load Customers, 6.1.1,* which states that “A distributor shall make every reasonable effort to respond promptly to a customer’s request for connection. In any event a distributor shall respond to a customer’s written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made”.

#### 3.5.2.1.3 Stations Embedded Generation

The HOL Stations Embedded Generation Capital Program is driven by the DSC requirement from s*ection 6.2 – Responsibilities to Generators, 6.2.4* that states “Subject to all applicable laws, a distributor shall make all reasonable efforts in accordance with the provisions of section 6.2 to promptly connect to its distribution system a generation facility which is subject of an application for connection”.

#### 3.5.2.1.4 Damage to Plant

HOL’s Damage to Plant Capital Program covers costs associated with damage to HOL owned plant which is caused by a third party. HOL targets 100% recovery of the costs from the third party; however, where tracking information is not available, HOL absorbs the cost or may attempt at recovery from the insurer.

#### 3.5.2.1.5 Metering

The HOL Metering Capital Program is driven by the DSC requirement from *section 5.1 – Provision of Meters and Metering Services, 5.1.1* that states “A distributor shall provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor’s distribution system…”.

HOL forecasts expenditures within System Access using a number of factors:

- Analysis of historic trends;
- Forecasted economic and population statistics;
- Known developments; and
- City of Ottawa plans;

Details from City of Ottawa plans used in the forecasting of expenditures are explained below.

**City of Ottawa Official Plan**

All information within this section has been obtained from the City of Ottawa Official Plan, Section2 – Strategic Directions, Figure 2.2.

**Table 3.5.5 - Project Growth in Population, Households & Employment, City of Ottawa, 2006 to 2031**

| Population | | | | |
|---|---|---|---|---|
| **Area** | **2006** | **2011** | **2021** | **2031** |
| **Inside the Greenbelt** | 533,000 | 540,000 | 562,000 | 591,000 |
| **Outside Greenbelt, Urban** | 252,000 | 291,000 | 367,000 | 432,000 |
| **Rural** | 86,000 | 91,000 | 102,000 | 113,000 |
| **Total** | **871,000** | **923,000** | **1,031,000** | **1,136,000** |

| Households | | | | |
|---|---|---|---|---|
| **Area** | **2006** | **2011** | **2021** | **2031** |
| **Inside the Greenbelt** | 228,000 | 237,000 | 258,000 | 278,000 |
| **Outside Greenbelt,** | 88,000 | 106,000 | 140,000 | 168,000 |

| | | | | |
|---|---|---|---|---|
| Urban | | | | |
| Rural | 30,000 | 32,000 | 38,000 | 43,000 |
| Total | 346,000 | 376,000 | 436,000 | 489,000 |

| Employment | | | | |
|---|---|---|---|---|
| Area | 2006 | 2011 | 2021 | 2031 |
| Inside the Greenbelt | 432,000 | 457,000 | 482,000 | 506,000 |
| Outside Greenbelt, Urban | 72,000 | 95,000 | 128,000 | 162,000 |
| Rural | 25,000 | 26,000 | 30,000 | 35,000 |
| Total | 530,000 | 578,000 | 640,000 | 703,000 |

Table 3.5.5 shows that growth within the City of Ottawa is expected to continue into the future and that the total average annual growth rates from 2011 to 2021 are:

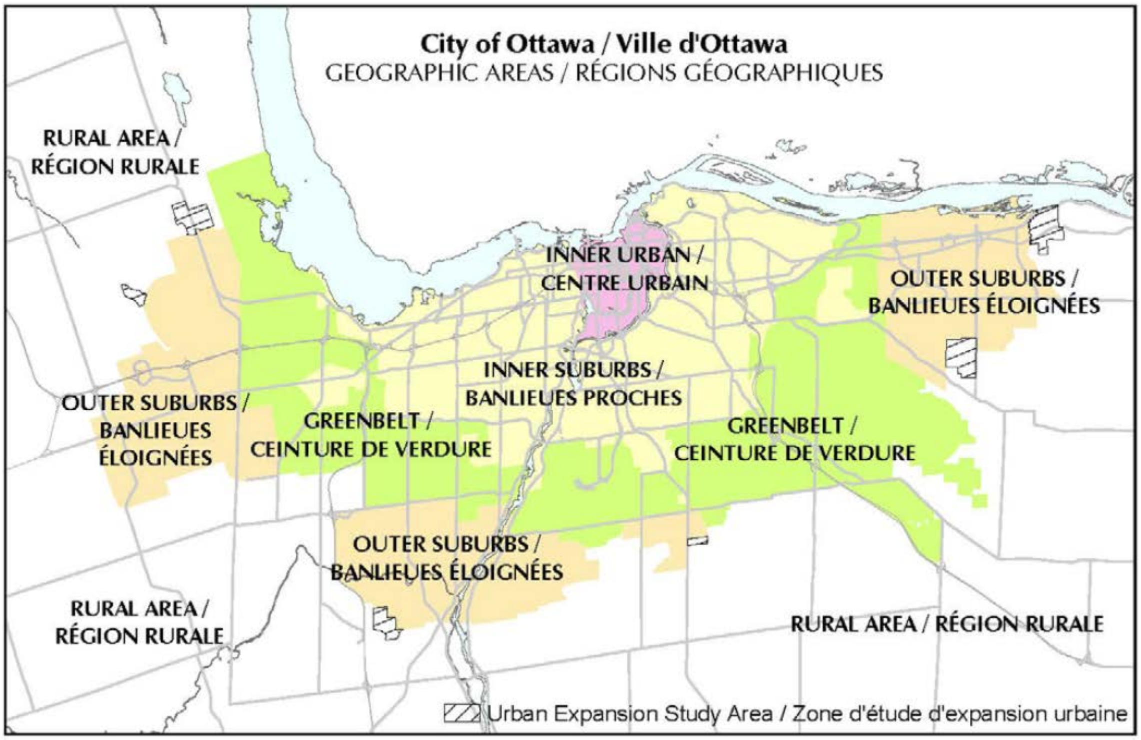
- Population – 1.11%
- Households – 1.49%
- Employment – 1.02%

Therefore, HOL expects the continuing trend of requests for connection of residential subdivisions and the associated mixed-use centres, along with employment centres.

**City of Ottawa Transportation Master Plan**

The City of Ottawa's Transportation Master Plan identifies the transportation facilities and services that are required to meet the needs of the growing City. HOL utilizes this information to help forecast customer connection requests and to plan the sustainment of the distribution system. The following figure and table depict the increasing requirements by region, within the City of Ottawa out to 2031.

Figure 3.5.4 - Location of Inner Area, Inner Suburbs & Outer Suburbs - City of Ottawa




**Source: City of Ottawa Transportation Master Plan, 2013 – Exhibit 2.1*

**Table 3.5.6 - Population & Employment: 2011 Actual & 2031 Projections**

| Area | Population | | | Employment | | |
|---|---|---|---|---|---|---|
| | 2011 | 2031 | Growth and distribution | 2011 | 2031 | Growth & distribution |
| **Inner Area** | 97,200 | 116,400 | 19,200 (9%) | 170,600 | 201,800 | 31,200 (23%) |
| **Inner Suburbs** | 432,500 | 459,300 | 26,800 (13%) | 287,400 | 355,300 | 67,900 (49%) |
| **Kanata/ Stittsville** | 105,200 | 162,000 | 56,800 (27%) | 51,300 | 62,500 | 11,200 (8%) |
| **Barrhaven** | 71,200 | 107,400 | 36,200 (17%) | 11,100 | 21,800 | 10,700 (8%) |
| **Riverside South/Leitrim** | 15,900 | 35,800 | 19,900 (9%) | 4,000 | 7,800 | 3,800 (3%) |
| **Orléans** | 108,200 | 143,400 | 35,200 (16%) | 20,600 | 33,000 | 12,400 (9%) |
| **Rural Ottawa** | 91,400 | 111,700 | 20,300 (9%) | 20,000 | 20,900 | 900 (1%) |
| ***Total*** | ***922,000*** | ***1,135,900*** | ***213,900 (100%)*** | ***564,900*** | ***703,200*** | ***138,100 (100%)*** |

**Source: City of Ottawa Transportation Master Plan, 2013 – Exhibit 2.10*

Within the Transportation Master Plan, the City of Ottawa has developed an “Affordable Road Network” planned out to 2031. This “Affordable Road Network” is the prioritized City projects based on the expected funding levels, and as such, is the most reasonable list of projects to base future road work projections which is used to forecast Plant Relocation spending levels.

The “Affordable Road Network” projects have been broken out by phases, and are listed in Table 3.5.7, showing only those projects planned until 2025, and graphically in Figure 3.5.5.

**Table 3.5.7 - City of Ottawa Affordable Road Network - Projects by Phase**

**Currently Under Construction**

| Sector | Project | Description |
|---|---|---|
| Southeast | Alta Vista Transportation Corridor | New two-lane road between Riverside Drive and the Ottawa Hospital |
| Southwest | Greenbank Road | Widening from two to four lanes between Malvern Drive and Strandherd Drive |
| Southeast | Hunt Club Road Extension | Eastward extension of Hunt Club road to Highway 417 |
| East | St. Joseph Boulevard | Widening from two to four lanes between Old Tenth Line Road and Trim Road |
| Southwest | Strandherd-Earl Armstrong Bridge | New bridge crossing between Strandherd Drive and Earl Armstrong Road |
| East | Trim Road | Widening from two to four lanes between North Service Road and Innes Road |

**Phase 1: 2014-2019**

| Sector | Project | Description |
|---|---|---|
| Southeast | Airport Parkway (1) | Widen from two to four lanes between Brookfield Road and Hunt Club Road |
| East | Blackburn Hamlet Bypass Extension (1) | New four-lane road between Orléans Boulevard and Navan Road |
| East | Brian Coburn Boulevard Extension | New two-lane road (ultimately four-lane) between Navan Road and Mer Bleue Road |
| West | Campeau Drive | New four-lane road between Didsbury Road and Huntmar Drive |
| Rural | Country Club Road | New two-lane road between eastern terminus of Golf Club Way and Jenkinson Road |
| West | Earl Grey Drive Underpass | New underpass of Terry Fox Drive |
| Southwest | Greenbank Road Extension | New four-lane road between Cambrian Road and Jockvale Road |
| West | Old Richmond/West Hunt Club | Widen Old Richmond Road/ West Hunt Club Road from two to four lanes between Hope Side and Highway 416 |
| West | Stittsville North-South Arterial (1) | New two-lane road between Fernbank Road and Abbott Street |
| West | Klondike Road | Urbanize existing two-lane rural cross section between March Road and Sandhill Road |
| East | Mer Bleue Road | Widen from two to four lanes between Brian Coburn Boulevard and Renaud Road |
| West | Palladium Drive Realignment | Realign in vicinity of Huntmar Road to new north-south arterial |
| Southwest | Strandherd Drive (1) | Widen from two to four lanes between Fallowfield Road and Maravista Drive |

| Phase 2: 2020-2025 | | |
|---|---|---|
| **Sector** | **Project** | **Description** |
| **Southeast** | Bank Street | Widen from two to four lanes between Earl Armstrong Road extension and south of Leitrim |
| **East** | Blackburn Hamlet Bypass Extension (2) | New four-lane road between Innes Road and Orléans Boulevard |
| **West** | Carp Road | Widen from two to four lanes between Highway 417 and Hazeldean Road |
| **Southwest** | Chapman Mills Drive | New four-lane road between Strandherd Drive and Longfields Drive |
| **West** | Eagleson Road | Widen from two to four lanes between Cadence Gate and Hope Side Road |
| **Southwest** | Jockvale Road | Widen from two to four lanes between Cambrian Road and Prince of Wales Drive |
| **West** | Kanata Avenue | Widen from two to four lanes between Highway 417 and Campeau Drive |
| **West** | Stittsville North-South Arterial (2) | New four-lane road between Palladium Drive (at Huntmar) and Abbott Street |
| **Southeast** | Lester Road | Widen from two to four lanes between Airport Parkway and Bank Street |
| **Southwest** | Strandherd Drive (2) | Widen from two to four lanes between Maravista Drive and Jockvale Road |
| **East** | Tenth Line Road | Widen from two to four lanes between Harvest Valley Road and Wall Road |

**Source City of Ottawa Transportation Master Plan, 2013 – Exhibit 7.2*

**City of Ottawa Community Design Plans**

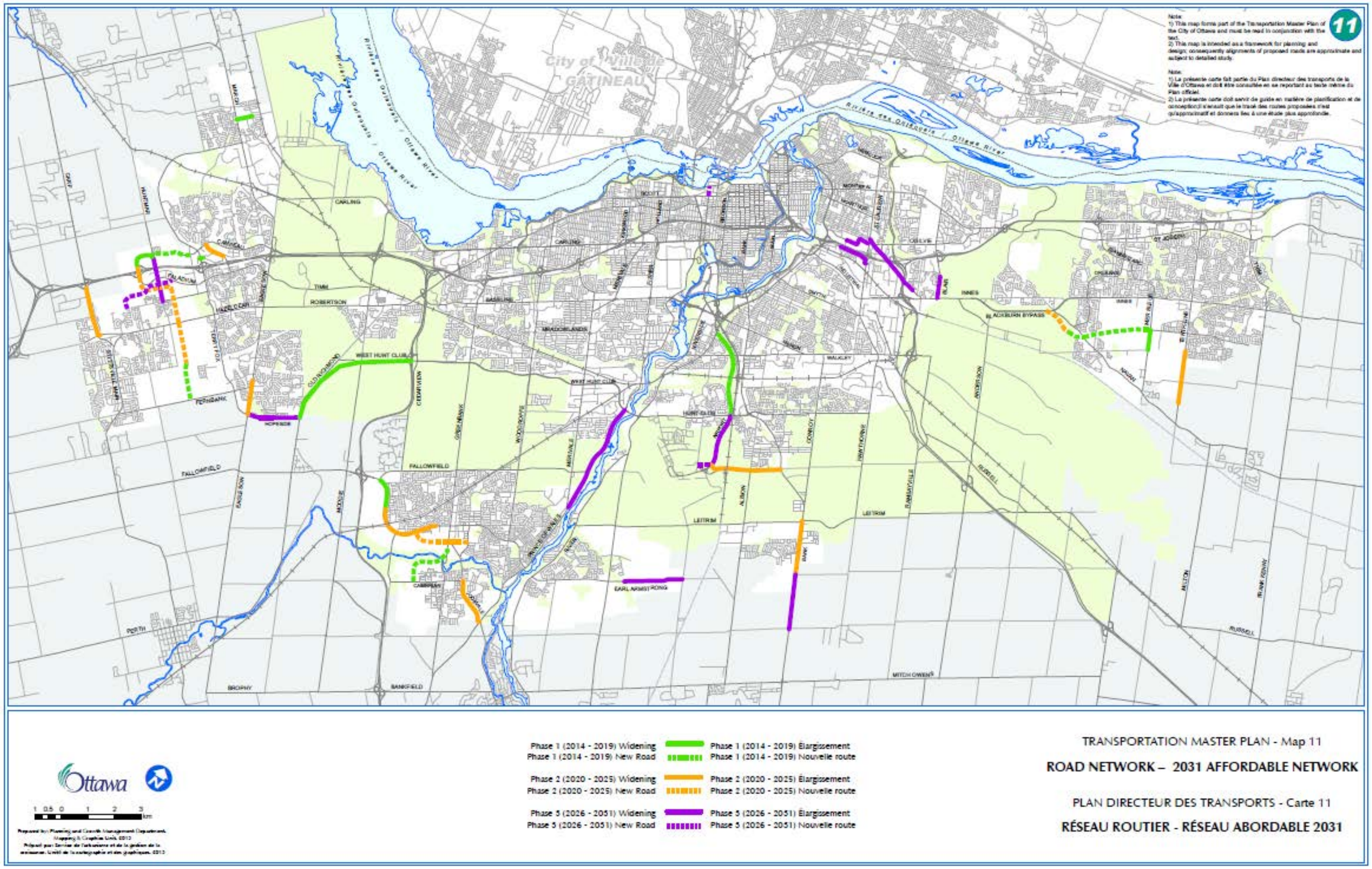
HOL also references published Community Design Plans from the City of Ottawa to forecast future residential and mixed-use centres.

Currently, there are 32 Community Design Plans published on the City of Ottawa's website which describe a mix of development types. A summary of the CDPs can be found in Table 3.5.8 and is based upon information provided within each study. Further details from the City of Ottawa CDPs have been captured in Appendix E.

1 Table 3.5.8 - City of Ottawa Community Design Plans Summary

| Study | Study Area (ha) | GFA (ha) | No. Res. Units | Land Use Type |
|---|---|---|---|---|
| Barrhaven South CDP | 500 | 188.9 | 6,862 | Mixed-Use |
| Bank Street CDP | 101 | | | Mixed-Use |
| Bayview Station District CDP | 29.5 | 55 | | Mixed-Use |
| Bayview/Somerset Area Secondary Study | 89.7 | | 1,590 | Mixed-Use |
| Beechwood CDP | 22 | | 819 | Mixed-Use |
| Cardinal Creek Village Concept Plan | 208 | 95 | 3,500 | Mixed-Use |
| Carp Road Corridor CDP | 2475 | | 0 | Commercial |
| Village of Carp CDP | 49.5 | | 543 | Mixed-Use |
| Village of Constance Bay Community Plan | 114 | | 204 | Mixed-Use |
| Downtown Ottawa Urban Design Strategy | | | | |
| East Urban Community (Phase 1 Area) CDP | 570 | | 3,498 | Mixed-Use |
| East Urban Community (Phase 2 Area) CDP | 240 | | 1,726 | Mixed-Use |
| Escarpment Area District Plan | | | | Mixed-Use |
| Fernbank CDP | 674 | 310 | 11,000 | Mixed-Use |
| Greely CDP | 1276 | | 729 | Mixed-Use |
| Leitrim CDP | 500 | 362.3 | 5,300 | Mixed-Use |
| Mer Bleue CDP | 160 | 113.7 | 3,000 | Mixed-Use |
| Kanata West Concept Plan | 887 | | 5,000 | Mixed-Use |
| North Gower CDP | 278 | 208 | 520 | Mixed-Use |
| Old Ottawa East CDP | 158 | | 2,250 | Mixed-Use |
| Orleans Industrial Park Study | 316 | 18.7 | 0 | Commercial |
| Queensway Terrace North | 140 | | | |
| Richmond Road/Westboro CDP | 270 | | 3,970 | Mixed-Use |
| Richmond Road/Westboro Transpo Plan | | | | |
| Riverside South CDP | 1800 | 1450 | 18,300 | Mixed-Use |
| Scott Street CDP | 57.7 | | 1,500 | Mixed-Use |
| South Nepean Town Centre CDP | 165 | 35 | 11,000 | Mixed-Use |
| St. Joseph Boulevard Corridor Study | 67.3 | | | Mixed-Use |
| Uptown Rideau CDP | 21 | | | Mixed-Use |
| Transit-Oriented Development (TOD) Plans | | | | |
| Village of Richmond CDP | 879 | | | Residential |
| Wellington Street West CDP | 232 | | 950 | Mixed-Use |

**Figure 3.5.5 - City of Ottawa Transportation Master Plan, 2013-2031 Affordable Network**




**Source: City of Ottawa Transportation Master Plan – Map 11*

### *3.5.2.2 System Renewal*

System Renewal investments "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services" as per Section *5.1.1* of Chapter 5.

The following section details HOL's System Renewal Budget Programs and projects from 2016 through 2020 that meet the materiality threshold of $750k. Table 3.5.9 shows the full Budget Program expenditures over the forecast period.

**Table 3.5.9 - System Renewal Forecast Expenditure by Program**

| Capital Program | Budget Program | $'000 | | | | |
|---|---|---|---|---|---|---|
| | | 2016 | 2017 | 2018 | 2019 | 2020 |
| **Stations Asset** | Stations Transformer Replacement | 10,729 | 4,620 | 6,533 | 8,225 | 7,965 |
| | Stations Switchgear Replacement | 5,424 | 7,088 | 7,408 | 6,871 | 6,114 |
| | Stations Plant Failure | 185 | 107 | 107 | 107 | 107 |
| **Stations Refurbishment** | Stations Enhancements | 597 | 634 | 731 | 662 | 691 |
| **Distribution Asset** | Pole Replacement | 8,641 | 6,592 | 7,608 | 6,886 | 7,189 |
| | Insulator Replacement | - | 168 | 194 | 176 | 183 |
| | Elbow & Insert Replacement | 289 | 190 | 219 | 198 | 207 |
| | Dist. Transformer Replacement | 804 | 808 | 933 | 844 | 881 |
| | Civil Rehabilitation | 3,153 | 636 | 734 | 664 | 694 |
| | Cable Replacement | 5,974 | 5,262 | 6,073 | 5,496 | 5,738 |
| | Switchgear New & Rehab | 1,222 | 376 | 434 | 393 | 410 |
| | O/H Equipment New & Rehab | 785 | 902 | 1,041 | 942 | 983 |
| | Plant Failure Capital | 2,815 | 2,893 | 2,893 | 2,893 | 2,893 |
| **Metering** | Remote Disconnected Smart Meter | 415 | 1,547 | 1,584 | 1,623 | 1,662 |
| **Total** | | **41,033** | **31,823** | **36,491** | **35,980** | **35,718** |

#### 3.5.2.2.1 Stations Transformer Replacement

Details on the Stations Transformer Replacement Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.2 Stations Switchgear Replacement

Details on the Stations Switchgear Replacement Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.3 Stations Plant Failure

The Station Plant Failure Budget Program is set up to capture costs associated with station assets that have failed or that have substandard performance and are no longer meeting the requirements and require immediate refurbishment to extend the service life or replacement.

#### 3.5.2.2.4 Stations Enhancements

Costs associated with the Stations Enhancement Budget Program cover the replacement of non-distribution equipment such as, building assets, station batteries, and cable racking when they have reached end of functional life. For building assets the costs are associated with sustaining civil, electrical, mechanical, structural and security/life safety assets, such as, work on roof, windows, doors, fencing and security equipment.

#### 3.5.2.2.5 Pole Replacement

Details on the Pole Replacement Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.6 Insulator Replacement

The Insulator Replacement Budget Program is designed for the replacement of overhead insulators typically when they have been deemed to have a high performance risk, or categorized as having a high probability of failure. Currently, there are four types of insulators that have been identified for proactive replacement:

- “WART” type porcelain post insulators;
- Canadian Porcelain pin type 28/46kV insulators;
- Horizontally installed porcelain pin type insulators; and
- Ohio Brass porcelain insulators on standoff brackets.

#### 3.5.2.2.7 Elbow & Insert Replacement

The Elbow & Insert Replacement Budget Program was initiated for the replacement of 28kV non-vented elbows and inserts on distribution transformers to eliminate the safety hazard associated with switching below $0^{o}C$. Annually, a specific neighbourhood, or region, is identified to undergo full replacements, creating great efficiencies for labour utilization and future system operability.

#### 3.5.2.2.8 Distribution Transformer Replacement

Details on the Distribution Transformer Replacement Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.9 Civil Rehabilitation

Details on the Civil Rehabilitation Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.10 Cable Replacement

Details on the Cable Replacement Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.11 Switchgear New & Rehabilitation

Details on the Switchgear New & Rehabilitation Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.12 Overhead Equipment New & Rehabilitation

Details on the Overhead Equipment New & Rehabilitation Budget Program can be found in Attachment B-1(A).

#### 3.5.2.2.13 Distribution Plant Failure

The Distribution Plant Failure Budget Program is set up to capture costs associated with distribution assets that have failed or that have substandard performance and are no longer meeting the requirements and require immediate refurbishment to extend the service life or replacement.

#### 3.5.2.2.14 Remote Disconnected Smart Meter

Details on the Remote Disconnected Smart Meter Budget Program can be found in Attachment B-1(A).

### *3.5.2.3 System Service*

System Renewal investments are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future electricity service requirements" as per Section *5.1.1 Investment Categories* of the *OEB Filing Requirements for Electricity Distribution Rate Applications*, published July 17th, 2013.

The following section details HOL's System Service Budget Programs and projects from 2016 through 2020 that meet the materiality threshold of $750k.Table 3.5.10 shows the full Budget Program expenditures over the forecast period.

**Table 3.5.10 - System Service Forecast Expenditure by Budget Program**

| Capital Program | Budget Program | $'000 | | | | |
|---|---|---|---|---|---|---|
| | | 2016 | 2017 | 2018 | 2019 | 2020 |
| Stations Capacity | Stations New Capacity | 5,676 | 15,272 | 10,464 | 14,441 | 15,626 |
| Distribution Enhancements | Line Extensions | 7,522 | 6,180 | 7,132 | 6,455 | 6,739 |
| | System Voltage Conversion | 2,758 | 4,964 | 5,729 | 5,185 | 5,413 |
| | System Reliability | 329 | 445 | 513 | 464 | 485 |
| | Dist. Enhancements | 682 | 694 | 801 | 725 | 757 |
| Automation | SCADA Upgrades | 1,011 | 1,011 | 556 | 51 | 51 |
| | SCADA - RTU Additions | 169 | 76 | 87 | 79 | 82 |
| | Distribution Automation | 3,953 | 4,719 | 3,548 | 2,449 | 3,510 |
| | Stations Automation | 136 | 597 | 689 | 624 | 651 |
| **Total** | | **22,235** | **33,957** | **29,518** | **30,473** | **33,314** |

#### 3.5.2.3.1 Stations New Capacity

The expenditures under the Stations New Capacity Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.5.1 Ability to Connect New Load.

#### 3.5.2.3.2 Line Extensions

The expenditures under the Line Extensions Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.4.1 Ability to Connect New Load.

#### 3.5.2.3.3 System Voltage Conversion

The expenditures under the System Voltage Conversion Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.4.1 Ability to Connect New Load.

#### 3.5.2.3.4 System Reliability

The expenditures under the System Reliability Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Reliability Planning process) and include projects identified through evaluation of the Worst Feeders (section 1.3.1.1.3).

#### 3.5.2.3.5 Distribution Enhancements

Distribution Enhancement projects are targeted at making improvements to the existing distribution system in terms of reliability and/or operability and are typically targeted towards areas or equipment that are deemed problematic.

#### 3.5.2.3.6 SCADA Upgrades

The SCADA Upgrades Budget Program covers expenditures related to upgrading and/or renewing SCADA equipment that has reached end of life or has become obsolescent.

#### 3.5.2.3.7 SCADA RTU Additions

The SCADA RTU Budget Program covers expenditures related to upgrading and/or renewing SCADA remote terminal units that have reached end of life or has become obsolescent.

#### 3.5.2.3.8 Distribution Automation

The expenditures under Distribution Automation are aimed at making the distribution system "smarter" and improving reliability and operability through the installation of remotely operable devices and sensors.

#### 3.5.2.3.9 Substation Automation

The expenditures under Substation Automation are aimed at increasing visibility into the distribution system and improving reliability and operability through increasing remote operability and reporting/alarms.

### *3.5.2.4 General Plant*

General Plant investments are "modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities" as per Section *5.1.1* of Chapter 5.

Over the period 2016-2020 HOL's General Plant investments will be addressing Operational effectiveness and Customer value. Life cycle investments remain flat. The major initiatives include:

- Facilities Implementation Plan;
- CC&B Enhancements;
- Outage Communication System;
- JDE Application Upgrade;
- Fleet Replacement;
- Enterprise Architecture Program; and
- Mobile Workforce Management.

Further details of these initiatives can be found in Attachment B-1(A).

1

**Table 3.5.11 - General Plant Expenditures by Capital Program**

| Capital Program | $'000 | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| Hydro One Payments | 4,575 | 5,000 | 5,000 | 5,000 | 5,000 |
| Buildings – Facilities | 688 | 509 | 408 | 323 | 243 |
| Customer Service | 3,740 | 2,361 | 1,148 | 6,658 | 1,139 |
| ERP System | 5,043 | 354 | 350 | 354 | 1,061 |
| Fleet Replacement | 1,455 | 1,209 | 1,452 | 1,480 | 1,876 |
| IT New Initiatives | 2,127 | 1,166 | 1,006 | 1,218 | 1,203 |
| IT Life Cycle & Ongoing Enhancement | 1,424 | 1,737 | 1,905 | 2,232 | 1,816 |
| Operation Initiatives | 1,074 | 452 | 405 | 892 | 1,069 |
| Tools Replacement | 512 | 521 | 530 | 539 | 548 |
| **Total** | **20,637** | **13,309** | **12,203** | **18,695** | **13,954** |

2

## 3.6 Material Investments

The details on the Budget Programs and projects that meet the materiality threshold of $750k have been included in a separate document which can be found in Attachment B-1(A).

# Appendix A

## Integrated Regional Resource Planning – Load Forecast

## Medium Planning Forecast

Updated July 31, 2014

| Weather Correction Values | | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Source: Hydro One | Norm | 0.944 | 0.91 | 0.942 | 0.930 |
| | Extren | 1.001 | 0.970 | 0.999 | 0.987 |

Latest Forecast

| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Preliminary | Source | 10-Day LTRs? (MVA) | 10-Day LTRs (MW) | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Downtown A | CARLING | 84 | 80 | 78 | 80 | 86 | 79 | 80 | 76 | 80 | H1 | 103 | 93 | 80 | 81 | 82 | 83 | 84 | 85 | 86 | 86 | 87 | 88 | 93 | 94 | 95 | 96 | 96 | 97 | 98 | 99 | 99 | 100 |
| | LINCOLNHTS | 45 | 45 | 41 | 42 | 48 | 46 | 45 | 43 | 39 | H1 | 79 | 71 | 45 | 45 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 49 | 49 | 49 | 49 | 49 | 48 | 48 | 48 | 48 | 48 |
| | WOODROFFE | 37 | 33 | 32 | 32 | 34 | 36 | 34 | 32 | 32 | H1 | 102 | 92 | 33 | 39 | 39 | 40 | 41 | 42 | 42 | 43 | 43 | 44 | 53 | 53 | 54 | 54 | 55 | 55 | 56 | 56 | 56 | 57 |
| Downtown - A Total | | 167 | 159 | 150 | 153 | 168 | 161 | 159 | 150 | 151 | | | 256 | 159 | 165 | 166 | 168 | 170 | 172 | 173 | 173 | 175 | 176 | 196 | 196 | 198 | 199 | 200 | 200 | 202 | 203 | 203 | 204 |
| Downtown B | HINCHEY | 42 | 46 | 43 | 44 | 48 | 46 | 44 | 42 | 47 | H1 | 86 | 77 | 44 | 44 | 47 | 50 | 52 | 56 | 58 | 60 | 62 | 64 | 67 | 69 | 71 | 73 | 75 | 77 | 79 | 81 | 83 | 85 |
| | SLATER | 113 | 110 | 116 | 121 | 113 | 108 | 99 | 93 | 112 | H1 | 131 | 118 | 100 | 101 | 102 | 103 | 104 | 105 | 104 | 103 | 103 | 103 | 103 | 102 | 102 | 102 | 101 | 101 | 101 | 101 | 100 | 100 |
| | LISGAR | 59 | 64 | 56 | 59 | 66 | 61 | 61 | 58 | 62 | H1 | 82 | 74 | 61 | 61 | 74 | 78 | 81 | 85 | 85 | 85 | 86 | 86 | 87 | 87 | 88 | 89 | 90 | 90 | 90 | 90 | 90 | 89 |
| | KINGEDWARD | 76 | 79 | 71 | 71 | 85 | 84 | 78 | 74 | 76 | H1 | 79 | 71 | 77 | 76 | 77 | 79 | 81 | 83 | 83 | 84 | 84 | 85 | 86 | 86 | 87 | 87 | 86 | 86 | 86 | 85 | 86 | 86 |
| Downtown - B Total | | 290 | 299 | 286 | 294 | 312 | 300 | 283 | 266 | 297 | | | 340 | 282 | 283 | 301 | 309 | 318 | 329 | 330 | 331 | 336 | 339 | 343 | 344 | 348 | 350 | 352 | 353 | 356 | 357 | 359 | 360 |
| Downtown C | RUSSELL TS | 61 | 60 | 58 | 73 | 79 | 82 | 61 | 58 | 68 | H1 | 77 | 69 | 61 | 61 | 61 | 63 | 65 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| | OVERBROOK | 77 | 74 | 74 | 76 | 80 | 75 | 78 | 74 | 77 | H1 | 144 | 130 | 80 | 81 | 85 | 87 | 89 | 95 | 97 | 98 | 103 | 104 | 105 | 105 | 106 | 107 | 107 | 108 | 109 | 109 | 110 | 110 |
| | ALBION | 108 | 100 | 95 | 100 | 109 | 104 | 99 | 93 | 67 | H1 | 98 | 88 | 71 | 71 | 72 | 72 | 73 | 73 | 73 | 73 | 74 | 74 | 74 | 74 | 75 | 75 | 75 | 76 | 76 | 76 | 77 | 77 |
| | ELLWOOD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 32 | H.O. | 65 | 59 | 27 | 27 | 27 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 |
| | RIVERDALE | 84 | 83 | 77 | 68 | 73 | 70 | 92 | 87 | 84 | H1 | 117 | 105 | 94 | 97 | 99 | 102 | 105 | 117 | 118 | 119 | 121 | 122 | 124 | 124 | 125 | 126 | 126 | 127 | 128 | 128 | 129 | 129 |
| Downtown - C Total | | 331 | 317 | 304 | 317 | 342 | 331 | 330 | 311 | 328 | | | 451 | 334 | 337 | 344 | 352 | 361 | 387 | 388 | 389 | 397 | 401 | 404 | 404 | 407 | 409 | 410 | 411 | 414 | 416 | 417 | 418 |
| Downtown TOTAL | | 788 | 775 | 741 | 764 | 822 | 792 | 772 | 727 | 777 | | | | 774 | 785 | 811 | 829 | 849 | 888 | 891 | 894 | 907 | 916 | 942 | 945 | 953 | 958 | 963 | 965 | 971 | 976 | 980 | 982 |

Latest Forecast with consideration of HOL's transfer capability

| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Preliminary | Source | 10-Day LTRs? (MVA) | 10-Day LTRs (MW) | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Downtown A | CARLING | 84 | 80 | 78 | 80 | 86 | 79 | 80 | 76 | 80 | H1 | 103 | 93 | 80 | 81 | 82 | 83 | 84 | 85 | 86 | 86 | 87 | 88 | 93 | 94 | 95 | 96 | 96 | 97 | 98 | 99 | 99 | 100 |
| | LINCOLNHTS | 45 | 45 | 41 | 42 | 48 | 46 | 45 | 43 | 39 | H1 | 79 | 71 | 45 | 45 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 49 | 49 | 49 | 49 | 49 | 48 | 48 | 48 | 48 | 48 |
| | WOODROFFE | 37 | 33 | 32 | 32 | 34 | 36 | 34 | 32 | 32 | H1 | 102 | 92 | 33 | 39 | 39 | 40 | 41 | 42 | 42 | 43 | 43 | 44 | 53 | 53 | 54 | 54 | 55 | 55 | 56 | 56 | 56 | 57 |
| Downtown - A Total | | 167 | 159 | 150 | 153 | 168 | 161 | 159 | 150 | 151 | | | 256 | 159 | 165 | 166 | 168 | 170 | 172 | 173 | 173 | 175 | 176 | 196 | 196 | 198 | 199 | 200 | 200 | 202 | 203 | 203 | 204 |
| Downtown B | *HINCHEY* | 42 | 46 | 43 | 44 | 48 | 46 | 44 | 42 | 47 | H1 | 86 | 77 | *44* | *44* | *58* | *60* | *62* | *66* | *68* | *70* | *72* | *75* | *67* | *69* | *71* | *73* | *75* | *77* | *79* | *81* | *83* | *85* |
| | *SLATER* | 113 | 110 | 116 | 121 | 113 | 108 | 99 | 93 | 112 | H1 | 131 | 118 | *100* | *105* | *106* | *113* | *114* | *116* | *115* | *114* | *114* | *113* | *113* | *112* | *112* | *112* | *112* | *111* | *111* | *111* | *110* | *110* |
| | *LISGAR* | 59 | 64 | 56 | 59 | 66 | 61 | 61 | 58 | 62 | H1 | 120 | 108 | *61* | *61* | *64* | *67* | *71* | *74* | *74* | *75* | *75* | *76* | *87* | *87* | *88* | *89* | *90* | *90* | *90* | *90* | *90* | *89* |
| | *KINGEDWARD* | 76 | 79 | 71 | 71 | 85 | 84 | 78 | 74 | 76 | H1 | 79 | 71 | *77* | *69* | *70* | *67* | *69* | *75* | *75* | *75* | *76* | *76* | *77* | *77* | *78* | *78* | *77* | *77* | *77* | *77* | *78* | *77* |
| Downtown - B Total | | 290 | 299 | 286 | 294 | 312 | 300 | 283 | 266 | 297 | | | 374 | 282 | 280 | 298 | 307 | 316 | 330 | 332 | 333 | 337 | 340 | 344 | 346 | 350 | 352 | 354 | 355 | 357 | 359 | 361 | 361 |
| Downtown C | RUSSELL TS | 61 | 60 | 58 | 73 | 79 | 82 | 61 | 58 | 68 | H1 | 77 | 69 | 61 | 61 | 61 | 63 | 65 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| | *OVERBROOK* | 77 | 74 | 74 | 76 | 80 | 75 | 78 | 74 | 77 | H1 | 144 | 130 | *80* | *81* | *85* | *91* | *94* | *100* | *101* | *102* | *108* | *109* | *110* | *110* | *111* | *111* | *112* | *113* | *113* | *114* | *114* | *115* |
| | ALBION | 108 | 100 | 95 | 100 | 109 | 104 | 99 | 93 | 67 | H1 | 98 | 88 | 71 | 71 | 72 | 72 | 73 | 73 | 73 | 73 | 74 | 74 | 74 | 74 | 75 | 75 | 75 | 76 | 76 | 76 | 77 | 77 |
| | ELLWOOD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 32 | H.O. | 65 | 59 | 27 | 27 | 27 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | 28 |
| | *RIVERDALE* | 84 | 83 | 77 | 68 | 73 | 70 | 92 | 87 | 84 | H1 | 117 | 105 | *94* | *100* | *102* | *99* | *102* | *111* | *112* | *112* | *114* | *116* | *118* | *118* | *119* | *120* | *120* | *120* | *121* | *122* | *123* | *123* |
| Downtown - C Total | | 331 | 317 | 304 | 317 | 342 | 331 | 330 | 311 | 328 | | | 451 | 334 | 340 | 347 | 353 | 362 | 385 | 387 | 388 | 396 | 400 | 403 | 403 | 406 | 408 | 409 | 410 | 412 | 414 | 416 | 417 |
| Downtown TOTAL | | 788 | 775 | 741 | 764 | 822 | 792 | 772 | 727 | 777 | | | | 774 | 785 | 811 | 829 | 849 | 888 | 891 | 894 | 907 | 916 | 942 | 945 | 953 | 958 | 963 | 965 | 971 | 976 | 980 | 982 |

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| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Prelimina | Source | 10-Day LTRs? | 10-Day LTRs | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | (MVA) | (MW?) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Ottawa - East | MOULTON | 42 | 40 | 39 | 39 | 36 | 34 | 31 | 29 | 23 | H.O. | 33+33 | 34 | 31 | 31 | 31 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 34 | 34 |
| | CYRVILLE | 0 | 0 | 0 | 0 | 6 | 17 | 21 | 19 | 19 | H.O. | 65 | 59 | 27 | 24 | 24 | 30 | 35 | 35 | 37 | 38 | 40 | 41 | 42 | 42 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| | BILBERYCREEK - H.O. | 63 | 61 | 56 | 56 | 64 | 54 | 53 | 50 | 55 | H1 | 94 | 85 | 53 | 53 | 53 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |
| | BILBERYCREEK - H1 | 34 | 35 | 22 | 24 | 39 | 26 | 26 | 25 | 28 | H1 | 94 | 85 | 30 | 31 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | ORLEANS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | H1 | 113 | 102 | 0 | 5 | 86 | 90 | 92 | 92 | 94 | 96 | 96 | 98 | 99 | 100 | 100 | 102 | 103 | 105 | 105 | 107 | 107 | 109 |
| Ottawa - East Total | | 140 | 135 | 117 | 119 | 145 | 132 | 131 | 124 | 124 | | | 279 | 141 | 144 | 195 | 205 | 212 | 214 | 217 | 219 | 222 | 225 | 228 | 229 | 232 | 233 | 234 | 236 | 237 | 240 | 240 | 242 |

| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Prelimina | Source | 10-Day LTRs? | 10-Day LTRs | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | (MVA) | (MW?) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Kanata | MARCHWOOD | 34 | 36 | 21 | 36 | 27 | 46 | 42 | 40 | 40 | H.O. | 33+33 | 34 | 34 | 33 | 34 | 34 | 34 | 35 | 34 | 34 | 34 | 34 | 35 | 35 | 34 | 35 | 35 | 34 | 35 | 35 | 35 | 35 |
| | KANATA | 58 | 54 | 62 | 54 | 73 | 49 | 50 | 47 | 55 | H.O. | 61 | 54 | 46 | 47 | 46 | 47 | 47 | 47 | 47 | 46 | 47 | 47 | 47 | 47 | 48 | 47 | 48 | 47 | 48 | 48 | 48 | 48 |
| | BRIDLEWOOD | 29 | 34 | 33 | 30 | 35 | 39 | 32 | 30 | 26 | H.O. | 33+8 | 37 | 24 | 22 | 22 | 22 | 23 | 22 | 22 | 22 | 23 | 39 | 39 | 40 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| | TERRY FOX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | H.O. | 100 | 90 | 0 | 25 | 39 | 50 | 78 | 83 | 65 | 65 | 64 | 64 | 63 | 64 | 63 | 63 | 62 | 62 | 61 | 61 | 60 | 60 |
| Kanata Total | | 121 | 124 | 116 | 120 | 135 | 134 | 125 | 118 | 121 | | | 215 | 104 | 127 | 141 | 153 | 181 | 186 | 169 | 166 | 168 | 184 | 185 | 185 | 185 | 184 | 184 | 183 | 183 | 182 | 182 | 182 |

| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Prelimina | Source | 10-Day LTRs? | 10-Day LTRs | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | (MVA) | (MW?) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Kanata - South | SOUTHMARCH - H.O. | 38 | 34 | 33 | 36 | 39 | 34 | 42 | 40 | 39 | H1 | 121 | 109 | 43 | 43 | 43 | 43 | 43 | 43 | 42 | 42 | 42 | 27 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 25 |
| | SOUTHMARCH- H1 | 59 | 56 | 52 | 56 | 54 | 56 | 61 | 57 | 58 | H1 | 121 | 109 | 61 | 68 | 73 | 67 | 72 | 76 | 80 | 84 | 89 | 92 | 96 | 76 | 78 | 78 | 77 | 77 | 78 | 78 | 78 | 78 |
| | RICHMOND | 6 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | H.O. | 6 | 5 | 6 | 8 | 9 | 10 | 11 | 13 | 31 | 34 | 36 | 35 | 36 | 37 | 37 | 37 | 38 | 38 | 39 | 39 | 38 | 38 |
| Kanata - South Total | | 103 | 93 | 88 | 96 | 98 | 95 | 108 | 101 | 102 | | | 114 | 110 | 119 | 125 | 120 | 126 | 132 | 154 | 160 | 167 | 154 | 159 | 139 | 141 | 141 | 141 | 142 | 143 | 143 | 142 | 141 |

| | Reference | Historical (Actuals) | | | | | | | Weather Corrected | Prelimina | Source | 10-Day LTRs? | 10-Day LTRs | Forecast | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Group | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2012 | 2013 | | (MVA) | (MW?) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Nepean South | FALLOWFIELD | 27 | 20 | 23 | 21 | 26 | 27 | 30 | 28 | 29 | H.O. | 25+25 | 26 | 29 | 31 | 36 | 39 | 38 | 41 | 49 | 51 | 54 | 55 | 58 | 59 | 61 | 66 | 67 | 70 | 71 | 74 | 76 | 79 |
| | LIMEBANK | 46 | 45 | 24 | 29 | 40 | 41 | 40 | 38 | 33 | H.O. | 33+33 | 68 | 42 | 43 | 44 | 47 | 49 | 52 | 54 | 56 | 59 | 61 | 64 | 67 | 70 | 73 | 76 | 79 | 82 | 85 | 89 | 88 |
| | UPLANDS | 6 | 9 | 25 | 28 | 26 | 23 | 23 | 21 | 22 | H.O. | 33 | 30 | 24 | 25 | 25 | 26 | 26 | 27 | 27 | 27 | 27 | 28 | 28 | 28 | 29 | 29 | 29 | 30 | 30 | 30 | 30 | 30 |
| Nepean - South Total | | 79 | 75 | 72 | 78 | 93 | 91 | 93 | 87 | 84 | | | 124 | 95 | 99 | 105 | 111 | 114 | 119 | 129 | 134 | 140 | 144 | 150 | 154 | 160 | 168 | 173 | 179 | 183 | 189 | 195 | 198 |

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# Appendix B

## Integrated Regional Resource Planning – Near-Term Needs Hand Off Letter

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June 27, 2014

Mr. Bing Young
Director, System Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Ottawa Area Regional Planning – Initiating Study or Development Work on Near and Mid-Term Transmission Solutions

Dear Bing,

The purpose of this letter is to:

- Hand off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the near-term transmission components of the Ottawa Region Integrated Regional Resource Planning (IRRP) process to Hydro One, and
- Request Hydro One Networks to initiate the development of wires solutions or implement the near-term transmission component of the integrated plan to meet the near- and medium-term reliability needs of the Ottawa Area.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulator Framework for Electricity.

The Ottawa Area Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and Hydro Ottawa, has been conducting an Integrated Regional Resource Planning (IRRP) process for the Ottawa Area since 2011. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC) and develops integrated solutions to address any needs that are identified.

While the IRRP process is not yet complete, a number of supply capacity and reliability issues in the near (within 5 year) and mid (5 to 10 years) term have been identified as not meeting the ORTAC planning standards in the Ottawa area. Furthermore, because of feasibility and the nature of the identified reliability issues, it has also been determined that wires solutions are the only reasonable means of addressing the identified needs. In such a situation, the Ontario Energy Board's (OEB) endorsed regional planning process provides for a "hand off" letter from the OPA to the lead transmitter, in this case Hydro One Networks, to initiate the development of wires solutions. This will permit Hydro One to develop and implement wires solutions to address the near-term needs in a timely fashion and commence early work associated with these solutions for their Regional Infrastructure Plan for the Ottawa area in advance of the completion of the IRRP.

Summarized below are four near-term needs along with proposed wires solutions identified for the Ottawa area by the Working Group for implementation by Hydro One.

1. Improve the reliability performance of Almonte TS and Terry Fox MTS by installing an in-line circuit breaker at Almonte TS on 230 kV circuit M29C between Cherrywood TS and Merivale TS. This work was identified early in the IRRP and is currently underway with a scheduled in-service date of Q2 2015.

2. Provide additional 230/115 kV autotransformation capacity at Hawthorne TS so as to relieve overloading of the existing autotransformers T5 and T6 there. The preferred alternative is to replace these lower rated units with standard 250 MVA units. The increased capacity is required now.

3. Provide increased supply capability for the downtown Ottawa 115 kV network to relieve overloading of the 115 kV circuit A4K from increased demand on this system. The preferred alternative is to rebuild the existing 115 kV single-circuit A6R to a double-circuit and extend it to Overbrooke TS. The need date is 2017.

4. Upgrade a section of 115 kV circuit S7M (the tap to Fallowfield TS) to increase its supply capability in order to supply a large customer load connecting to this circuit in the south Nepean area. The need date is 2019 or earlier.

In addition to the above, Hydro One has advised that the transformers and protection facilities at Bilberry Creek TS are approaching their end of life. Based on a 2020 end of life date for these facilities, a transmission and distribution development plan is required to supply the load served by Bilberry Creek TS either by refurbishing the station or alternately decommissioning the station and serving the load from other stations in the area.

The Working Group has identified these projects to address near- and mid-term needs. However, more detailed study and development work is required before these projects can be implemented. Continued development of these projects is best accomplished by Hydro One leading this effort as a lead transmitter and working with any relevant LDCs, guided by the information and requirements provided below from the IRRP process.

To facilitate the development of the wires solution, the OPA will provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

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We look forward to receiving information, results, recommendations and deliverables related to these four near and mid-term projects for the Ottawa area, as part of the Ottawa Working Group activities and continue to work with and support Hydro One on the implementation of these projects.

Best Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC Working Group members:

**Hydro Ottawa**
Jim Pegg
Jenna Van Vliet
Morgan Barnes

**Hydro One Distribution**
Ashley Lebel
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Mike Falvo
Mauro Facca

## Attachment 1 – Project Objectives and Scope

### Project 1: Hawthorne 115 kV System Autotransformer Upgrade

The 115 kV network in Ottawa area is connected to the 230 kV system through two autotransformer stations, Hawthorne TS, which serves the east half of the Ottawa area and Merivale TS, which serves the west half. The purpose of this project is to increase the 230/115 kV transfer capability at Hawthorne TS in order to meet the forecast load demand in the area while providing a level of reliability consistent with the IESO's ORTAC reliability standards.


There are currently four 230/115 kV autotransformers at Hawthorne TS. They supply about 630 MW of demand in east Ottawa. The 230/115 kV transformation capability at Hawthorne TS is limited by two of the existing autotransformers, T5 and T6. These two autotransformers are smaller in size, each with a rating of 225 MVA, while the other two autotransformers are rated at 250 MVA. Even at today's load level, planning studies done for this IRRP indicate that, following an outage of one of the autotransformers at Hawthorne TS, overload would result on the remaining T5 or T6 transformer under peak demand conditions. Orleans TS, which comes in service in 2015 and transfer some load from the 115 kV to the 230 kV system, does not provide enough relief for the overloaded autotransformers. After that, continued load growth on the Hawthorne 115 kV system will worsen the overload.

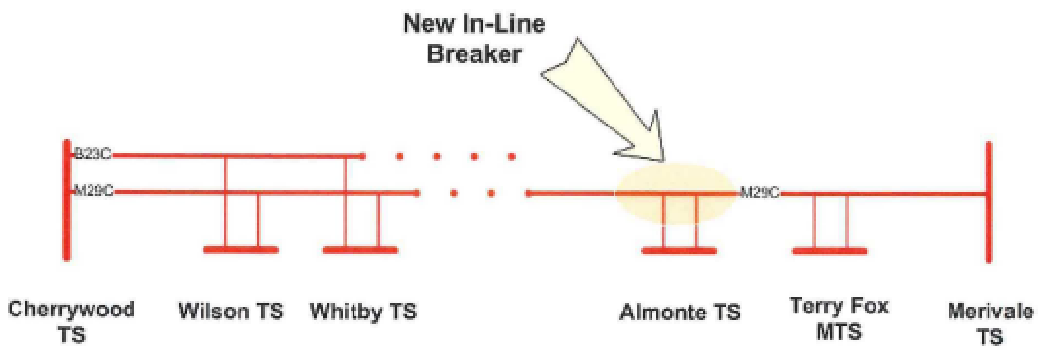
Since the overloading problem exists with today's load level, local generation option, which requires longer lead time, is not considered viable to address this need. Options of additional CDM were considered. However, significant demand reduction on the 115 kV system in the area will be required to provide sufficient relief for the overloaded autotransformers. 200 MW demand reduction can only provide roughly 10-year of relief on T5 and T6. On the other hand, both T5 and T6 are approaching 60-year-old in next few years. Replacement of these equipments is likely necessary in the near-term. Therefore, with support from the Working Group, the OPA recommends replacing the T5 and T6 autotransformers with 250 MVA units, with an estimated cost of $14 million. The estimated in-service date is 2017.

**Project 2: Almonte in-line Breaker**

Circuit M29C is a 320km long line that links Merivale TS in Ottawa to Cherrywood TS in Pickering. The line supplies two DESNs in the GTA, Wilson TS and Whitby TS; and two in Eastern Ontario, Almonte TS and Terry Fox MTS.

While Whitby TS and Wilson TS have a second 230kV supply from circuit B23C, both Almonte and Terry Fox MTS are on single line supply from circuit M29C. Any outage on the circuit - occuring about 7-10 times per year - means a complete interruption of supply to load customers at these two stations.

The Working Group identified the need for a breaker at Almonte early in the IRRP study and Hydro One is currently proceeding with the installation of a 230 kV breaker. This project will improve the reliability of the transmission supply to Terry Fox MTS and Almonte TS by eliminating the exposure of these stations to lightning related outages west of Almonte TS and is expected to reduce the probability of transmission-line related outages at these stations by about 80%.

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The Working Group noted that the breaker option does not protect against outages occurring on M29C on the Merivale side of the breaker. However, it does provide substantial improvement in reliability that can be achieved relatively quickly. It does not preclude development of other options that may be considered in the context of a long-term plan for the Nepean/Kanata area.

The reliability problem is due to the system configuration in this area, and is not driven by load growth. Therefore, additional CDM and local generation were not considered viable options to meet this need. This project is scheduled to be in service by Q2-2015, with an estimated cost of under $5 million.

**Project 3: Downtown Transmission Line Rebuild**

Downtown Ottawa is supplied by two 115 kV systems as shown in the figure below:

- from Merivale TS in the west through M4G and M5G
- from Hawthorne TS in the east through A4K, A5RK, A6R and A3RM


With forecasted load growth in the downtown area, the main section of A4K, from Hawthorne TS to Blackburn JCT, will exceed planning criteria starting 2017. Upon the contingency of losing the companion circuit A5RK, A4K will experience thermal overload.

This transmission line refurbishment project involves rebuilding a section of A5RK, between Overbrook TS and the junction with A6R, from a single circuit to a double-circuit line, and reconfiguring the supply to Overbrook TS to relieve the A4K circuit.

The Working Group also discussed upgrading the main section of A4K to increase the supply capability of this circuit. However, this would involve upgrading a section that is proximately 8 km in length. In addition, due to the ampacity rating of the existing main section of A4K, upgrading may not provide significant incremental supply capacity to the area. For these reasons, the Working Group did not pursue the option of upgrading A4K.

Other non-wire options were considered. A 29 MW new hydroelectric facility was recently contracted through the OPA's Hydroelectric Standard Offer Program (HESOP). This is a run-of-the-river facility and hence based on planning assumption for run-of-the-river hydroelectric, very little capacity of the facility will be available during peak load condition. In addition, this HESOP facility has the milestone date for commercial operation of 2022. As the overload on A4K starts to arise in 2017, local generation option with this HESOP facility is not considered viable.

Additional CDM, such as Demand Response (DR) was also considered. However, to entirely address this need, over 30 MW of demand reduction will be required in the next 10 years and over 40 MW will be needed by 2032. Since the transmission option involves only refurbishing a short section of an existing line (less than 2 km in length), it would have a lower cost as compare to CDM options.

Therefore, with the support from the Working Group, the OPA recommends that Hydro One initiate work on the project. The cost of this project is currently estimated between $5 million and $6 million. Detailed project costs and in-service date will be determined as part of this work.

**Project 4: S7M Upgrade**

S7M is a 115 kV single circuit originated from Merivale TS. It supplies the Nepean / Kanata area in the west Ottawa. With forecasted load growth in the Nepean south area, the S7M tap to Fallowfield DS is expected to exceed its thermal capacity by 2019. This includes a large customer of Hydro Ottawa with bulk load of 20 MW who has recently requested connection at Richmond DS which is also supplied by the S7M tap, south of Fallowfield DS.

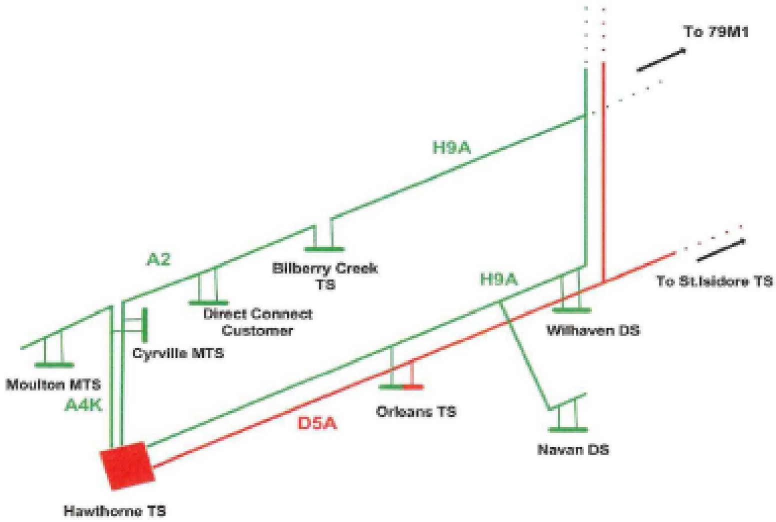
While the Working Group continues to develop options for additional supply to the Nepean south area for the longer-term, upgrading the existing S7M tap to Fallowfield DS is needed in the near-term in order to accommodate the connection of the bulk load customer. With the support from the Working Group, the OPA recommends that Hydro One work with Hydro Ottawa to determine the optimal upgrade configuration and proceed with the development work to upgrade the S7M circuit between STR 673 N JCT and Fallowfield DS.

**Development of Transmission Options for Addressing the End-of-Life at Bilberry Creek TS**

Bilberry Creek TS is a medium size 115 kV stepdown station located in East Ottawa. It was built in 1964 and is currently supplying about 80 MW of Hydro One Distribution and Hydro Ottawa
1 customer load. Hydro One Transmission, who owns the station, informed the Working Group

that the two transformers and the associated protection system at this station are near their end-of-life. For planning purpose, the end-of-life date is 2020. A decision is needed now to either refurbish the station and maintain the 115 kV system in the area, or decommission the station and transfer its load to other stations in the area by 2020.

Below is a figure showing the current supply arrangement for the East Ottawa / Orleans area.




The primary issue is to replace an end-of-life facility and is not related to load growth. Therefore, other options such as CDM and local generation are not viable to address this need. However, these other options will be considered as part of the integrated solutions for the area in the long-term, after the decision on addressing Bilberry Creek TS end-of-life is made. At this time, more detailed cost and technical information is required by the Working Group in order to make that decision. The Working Group agrees that the study work be handed-off to Hydro One at this time so that more detailed studies can be carried out by Hydro One.

1 # Appendix C

2 ## IESO Letter of Comment – REG Investments Plan

# IESO Letter of Comment

## Hydro Ottawa Limited

## Renewable Energy Generation Investments Plan

Date: January 20, 2015

Independent Electricity System Operator

**Introduction**

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority [1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

**Hydro Ottawa Limited – Distribution System Plan**

On October 23, 2014 Hydro Ottawa Limited ("HOL") provided its Renewable Energy Generation Investments Information ("Plan") to the Ontario Power Authority as part of its 5-year Distribution System Plan. The IESO has reviewed HOL's Plan and has provided its comments below.

*OPA FIT/microFIT Applications Received*

Hydro Ottawa Limited indicates that presently it has connected 569 microFIT projects totalling 4,619 kW, and 88 FIT projects, totalling 10,792 kW. According to the IESO's information, as of November 2014, the OPA had offered contracts to 573 microFIT projects totalling 4,611 kW of capacity. The OPA contracted a total of 95 FIT projects, 88 of which have reached commercial operation or the Notice to Proceed stage ("NTP"). The remaining seven contracts have not yet reached NTP. The renewable energy generation connections information in HOL's Plan is therefore consistent with that of the IESO.

*Additional Renewable Generation Procurement*

Hydro Ottawa Limited also indicates that it has connected five facilities, with a total capacity of 18,580 kW, which were contracted as part of the Hydroelectric Contract Initiative; one facility, with a capacity of 6,378 kW, which was contracted as part of the RES I procurement; and two facilities, with a

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.



Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

capacity of 10,700 kW, which were contracted as part of the RESOP procurement. This information is consistent with the IESO's records of previous OPA procurement programs.

In addition, Hydro Ottawa has noted that it has additional renewable and non-renewable generation connected to the distribution system (in the form of load displacement, net-metered and stand alone projects) which is not related to previous OPA procurement programs and which therefore cannot be verified by the IESO.

*Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans*

Hydro Ottawa Limited has been active in the Greater Ottawa regional planning process which has been ongoing since 2011. This regional planning process has now been merged into the Ontario Energy Board's regional planning process and is part of "Group 1" of the Board's 21 Ontario regions. The Integrated Regional Resource Plan ("IRRP") for this region is due to be completed in April, 2015.

Hydro Ottawa Limited identified six stations within their service territory that are restricted or constrained for additional renewable generation connection, four of which are owned by Hydro One, and two of which are owned by Hydro Ottawa. For Fallowfield DS, Hydro Ottawa has indicated that load growth in the area will be a mitigating factor, allowing additional renewable generation connections to the portion of the station which is currently constrained. For Leitrim MS, Hydro Ottawa has indicated the planned station investment which will remove the constraint.

The IESO looks forward to continuing to work with Hydro Ottawa Limited to complete an Integrated Regional Resource Plan for the Ottawa area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.



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# Appendix D

## Worst Feeder Evaluation Methodology

| HydroOttawa | | TITLE: Worst Feeder Analysis | |
|---|---|---|---|
| RECOMMENDED: | Jenna Van Vliet | NO: | REV: 0 |
| APPROVED: | | | |
| REV. DATE: | 2011-08-30 | | |

# Worst Feeder Analysis

See Hydro Ottawa's Intranet site
for the latest revisions

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## REVISION SHEET

| Revision | Description of Change | Date | Initial |
|---|---|---|---|
| 0 | Original Document | 2011-08-30 | jvv |

## TABLE OF CONTENTS **PAGE**

## 1. Introduction

The basis for the evaluation of the Worst Feeders is to track and highlight priority areas that are consistently seeing issues, to then identify solutions to improve the reliability performance.

## 2. References

Canadian Electricity Association

## 3. Scope

This document describes the methodology used to determine and track the worst performing feeders on an annual basis. It does not describe methods used to improve feeder reliability.

## 4. Definitions

**Interruption:** The loss of service to one or more customers.

**Loss of Supply:** Customer interruptions due to problems in the bulk electricity supply system.

**Momentary Interruption:** An interruption with a duration of less than 1 minute.

**Scheduled Outage:** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

## 4. Definitions

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**Scheduled Outage:** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

## 5. Worst Feeder Evaluation

In order for HOL to be able to directly impact the reliability performance, only the causes for outages that can be reduced or eliminated by HOL intervention are included in the Worst Feeder Evaluation. This means that outages caused by Loss of Supply and Scheduled Outages are not included in the evaluation.

Four metrics are used in the evaluation process: the number of customers interrupted, customer hours of interruption, the number of interruptions a feeder sees annually and the number of momentary interruptions a feeder sees annually. The worst feeders are defined by those with: the highest number of customers interrupted (SAIFI), the highest number of customer hours interrupted (SAIDI), the highest number of interruptions (FEMI) and the highest number of momentary interruptions (MAIFI). In the evaluation, the metrics are each given a weighting according to their impact on a feeder's overall reliability. The number of customers interrupted, the number of customer hours of interruption and the number of interruptions are all equally weighted by a factor of 1, while the number of momentary interruptions is given a weighting of ½. This weighting is based on the fact that not all of the reclosing devices in the system are monitored and therefore we currently do not report on MAIFI.

To calculate each metric, the maximum number of customers, the total number of customer hours, the number of outages and momentary outages seen has to be determined for each feeder in the system for the previous 3 years. The 3-year average for the four categories, for each feeder, is then calculated based on the 3 year period. From the 3-year average, a per-unit value is then calculated. To calculate the per-unit value for the 3-year average of the maximum number of customers and the total number of customer hours, the 3-year average values are divided by 30,000. The 30,000 is based on an assumption that no feeder should contribute more than 10% towards the corporate target of 1.0 for both the 3-Year average SAIDI and SAIFI values with a total customer count of 300,000. The 3-year average number of outages is divided by 10, since HOL reports on $FEMI_{10}$, to determine the per-unit value for each feeder. The 3-year average number of momentaries is divided by 25, since no feeder has seen more than 25 momentary outages annually to date. This number may be adjusted as a specific target for momentary outages is chosen. To attain the overall feeder rating the four per unit values are multiplied by their associated weighting (1 for customers interrupted, 1 for customer hours, 1 for number of outages and ½ for number of momentaries) and then summed.

The score of each feeder gives a picture of the feeder's performance over the last three year period, but does not take into consideration whether the feeder's reliability has been improving or deteriorating. To determine whether the feeder's reliability is improving the feeder's Score (weighted per-unit ranking as outlined above) is evaluated over the previous three year period. When the Score is plotted for the three year period, if the overall trend is increasing (positive slope) then the feeder's reliability has been deteriorating, if the overall trend is decreasing (negative slope) then the feeder's reliability has been improving and if the slope is relatively flat, then the reliability has remained consistent. See Figure 1 below, Feeder 1 has deteriorating reliability, Feeder 2 has improving reliability and Feeder 3 has had relatively consistent reliability.



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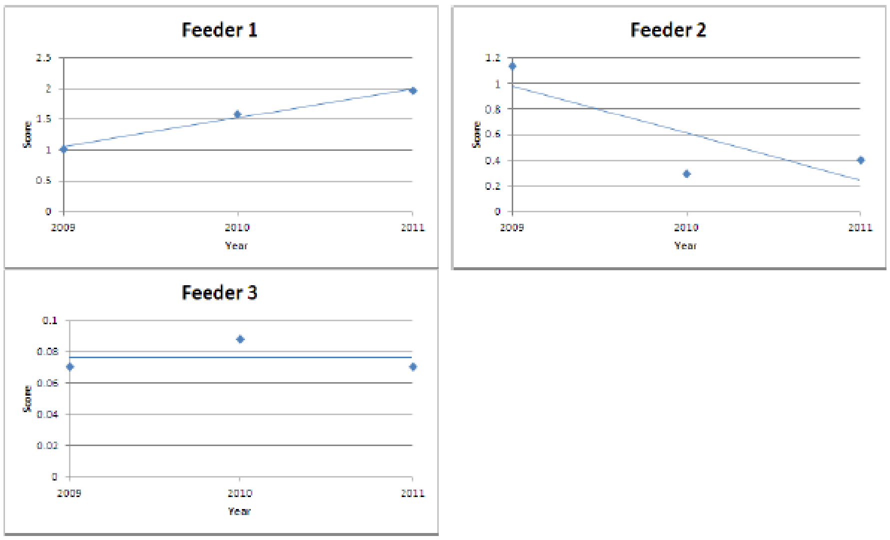
Figure 1: Feeder Score




To incorporate whether the feeder's reliability is improving or deteriorating, the linear slope of the Score for the previous three years is calculated. This is accomplished by determining the Least Squares Fit to the Score for the three year period. The formula assumed is shown below.

$$m = \frac{\sum x \cdot y - 3\overline{x}\,\overline{y}}{\sum x^2 - 3\overline{x}^2}$$

Where,
$m =$ Slope – Least Squares Fit
$x =$ Year
$y =$ Score

The slopes for Feeder 1, Feeder 2, and Feeder 3 from the charts above are calculated below.

$$m_{Feeder1} = \frac{[(2009 \cdot 1.02) + (2010 \cdot 1.59) + (2011 \cdot 1.97)] - 3[(2009 + 2010 + 2011)/3] \cdot [(1.02 + 1.59 + 1.97)/3]}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder1} = \frac{9206.75 - 9205.80}{12120302 - 12120300}$$

$$m_{Feeder1} = \frac{0.95}{2.00}$$

$$m_{Feeder1} = 0.48$$

$$m_{Feeder2} = \frac{[(2009 \cdot 1.13) + (2010 \cdot 0.30) + (2011 \cdot 0.41)] - 3[(2009 + 2010 + 2011)/3] \cdot [(1.13 + 0.30 + 0.41)/3]}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder2} = \frac{9970.25 - 9971.89}{2.00}$$

$$m_{Feeder2} = \frac{-0.72}{2.00}$$

$$m_{Feeder2} = -0.36$$

$$m_{Feeder3} = \frac{[(2009 \cdot 0.07) + (2010 \cdot 0.09) + (2011 \cdot 0.07)] - 3[(2009 + 2010 + 2011)/3] \cdot [(0.07 + 0.09 + 0.07)/3]]}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder3} = \frac{14095.99 - 14095.73}{2.00}$$

$$m_{Feeder3} = \frac{0.00}{2.00}$$

$$m_{Feeder3} = 0.00$$

The slopes are then unitized based on a scale from -1 to +1. This implies that the feeder with the fastest improving reliability will have a Trend closest 0, while the feeder with the quickest deterioration will have a trend closest to 1 and feeders who's reliability has remained consistent will sit near 0.5. The unitizing is done with the following equation.

$$Trend = \frac{m - Min(m)}{Max(m) - Min(m)}$$

$$Trend = \frac{m - (-1)}{1 - (-1)}$$

$$Trend = \frac{m + 1}{2}$$

The Trends for Feeder 1, Feeder 2 and Feeder 3 are calculated below.

$$Trend_{Feeder1} = \frac{0.48 + 1}{2}$$

$$Trend_{Feeder1} = 0.74$$

$$Trend_{Feeder2} = \frac{-0.36 + 1}{2}$$

$$Trend_{Feeder2} = 0.32$$

$$Trend_{Feeder3} = \frac{0.00 + 1}{2}$$

$$Trend_{Feeder3} = 0.50$$

To determine the overall Rank for each feeder the Trend is multiplied by the Score. The Rank for the feeders is then sorted from highest to lowest score, which sorts the feeders from worst reliability performer to best.

To visually inspect the Worst Feeders, a plot of Trend versus Score can be used. See the example in Figure 2 on the following page.

Since Trend is the unitized slope value, between 0 and 1, a Trend between 0 and 0.5 implies a negative slope, or improving reliability, and a Trend between 0.5 and 1 implies a positive slope, or deteriorating reliability. It can be seen in Figure 2 that the majority of the feeders fall within a Score from 0 and 0.5 (Approx. 95%) and a Trend around 0.5. It can therefore be interpreted that the feeders that need to be evaluated can be determined by eliminating the feeders with a Score below 0.5, and a Trend below 0.5 See Figure 3.

Figure 2: Feeder Rank - Overall

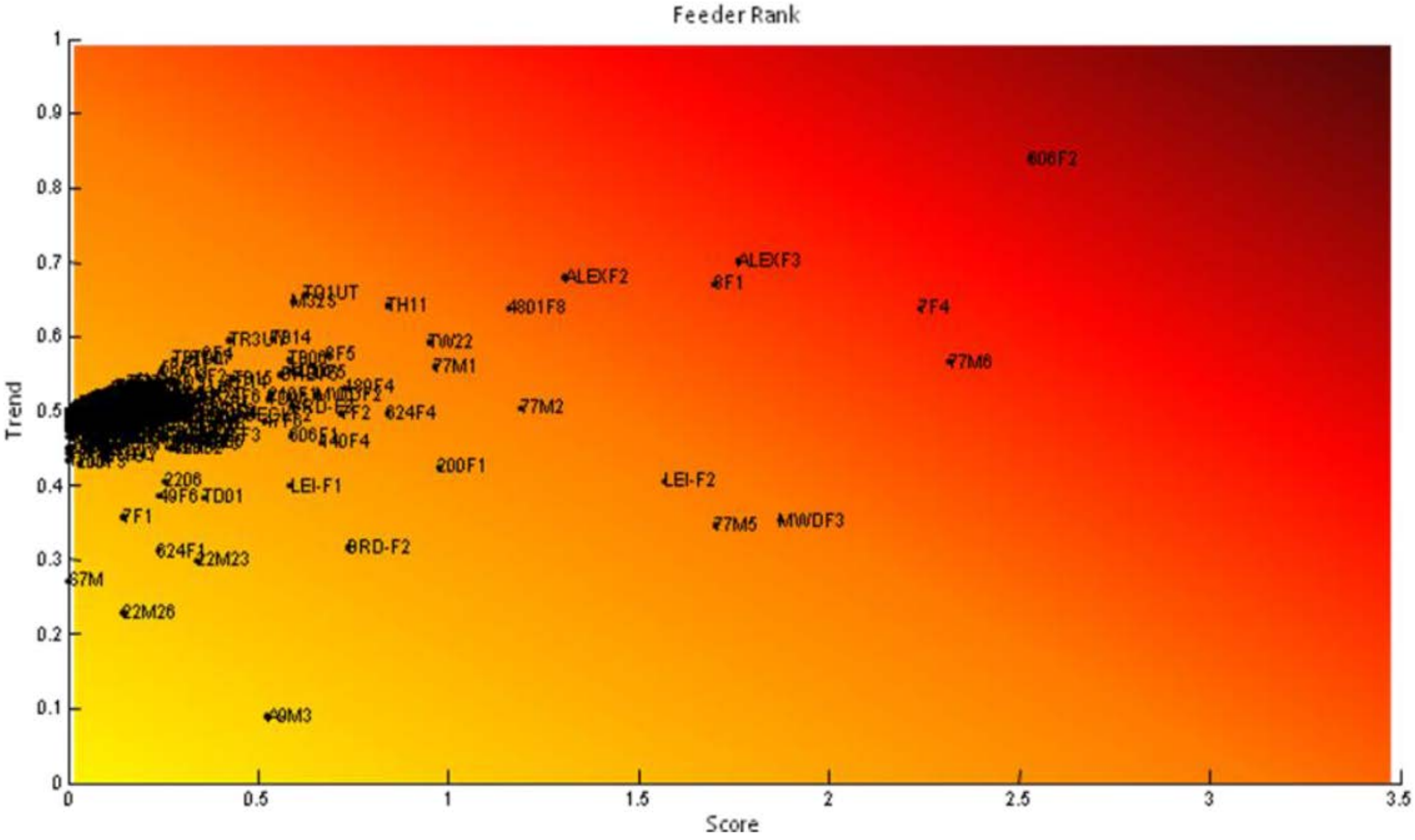



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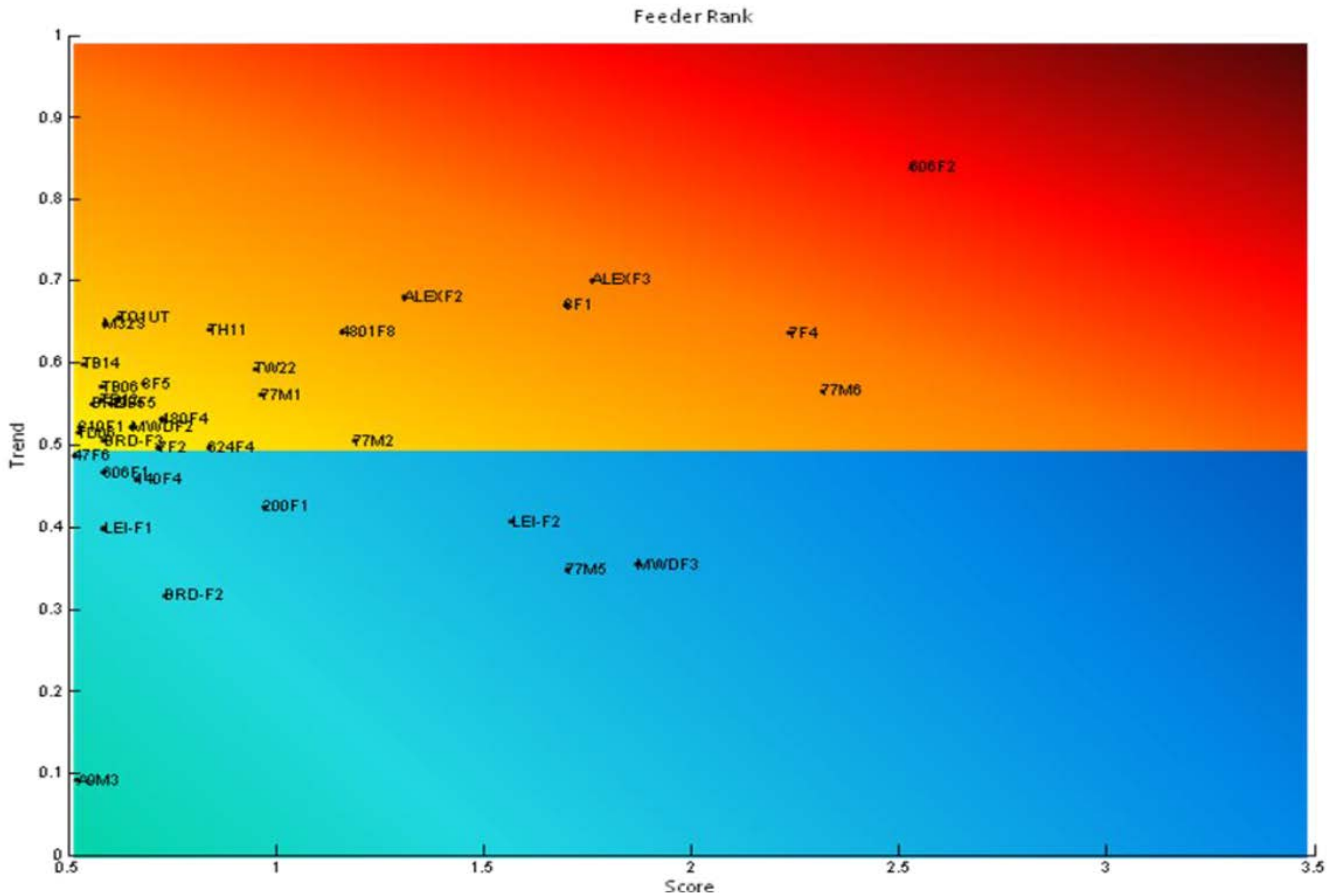
Figure 3: Feeder Rank – Feeders Requiring Evaluation



## 6. Worst Feeder Evaluation Process

The following section outlines the steps to determine the Worst Feeder List.
*See Table 1 for the referenced rows and columns for steps 1-4.*

1. Determine the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruptions for all feeders.
    - Fill in the information for Columns C, D, E & H, I, J & M, N, O & R, S, T
2. Calculate the 3-year average for the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruptions for all feeders.
    - (Value Year 1 + Value Year 2 + Value Year 3) / 3
    - Calculate columns F & K & P & U
    - Ex: *F1 = (C1+D1+E1)/3*
3. Calculate the per unit values for the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruption for all feeders.
    - 3 Year Average / Maximum Allowable Value
    - Maximum Allowable Value:
        i. Number of Outages: 10
        ii. Number of Momentary Outages: 25
        iii. Maximum Customers Interrupted: 30,000
        iv. Total Customer Hours of Interruption: 30,000
    - Calculate Columns G & L & Q & V
    - Ex: *G1 = F1/Max Allowable Value)*
4. Calculate the Score for all feeders
    - (Per Unit Number of Outages) + 0.5*(Per Unit Number of Momentary Outages) + (Per Unit Maximum Customers Interrupted) + (Per Unit Customer Hours of Interruptions)
    - Calculate Column B

- Ex: *B1 = G1 + 0.5*L1 + Q1 + V1*

*See Table 2 for the referenced rows and columns for steps 5-8.*

5. Calculate the slope for each feeder using the Least Squares Fit Method.

   - $m = \dfrac{\sum x \cdot y - 3\overline{xy}}{\sum x^2 - 3\overline{x}^2}$ Where, m = slope, x = year and y = score
   - Calculate Column E
   - Ex: *E1 =(SUMPRODUCT(C1:E1,C2:E2)-3*AVERAGE(C1:E1)*AVERAGE(C2:E2))/(SUMSQ(C1:E1)-3*AVERAGE(C1:E1)^2)*

6. Calculate the Trend for each feeder, unitizing to a scale of -1 to +1.

   - $$Trend = \frac{m - Min(m)}{Max(m) - Min(m)}$$
     $$Trend = \frac{m-(-1)}{1-(-1)}$$
     $$Trend = \frac{m+1}{2}$$
   - Calculate Column F
   - Ex: *F1 =(E1+1)/2*

7. Calculate the Rank for each feeder.

   - $Rank = Score \;\; x \; Trend$
   - Calculate Column G
   - Ex: *G2 = D2*F2*

8. Arrange the Rank in descending order, for largest to smallest.

   - Arrange Column G in descending order – This arranges the feeders from worst performer to best performer.

Table 1: 2010 Feeder Score

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Score | Number of Interruptions | | | | | Number of Momentary Interruptions | | | | | Customer Hours | | | | | Maximum Customers | | | | |
| | Feeder | 2010 | 2008 | 2009 | 2010 | Average | Per Unit | 2008 | 2009 | 2010 | Average | Per Unit | 2008 | 2009 | 2010 | Average | Per Unit | 2008 | 2009 | 2010 | Average | Per Unit |
| 1 | Worst Feeder 1 | 2.91 | 35 | 24 | 12 | 23.67 | 2.37 | 2 | 1 | 4 | 2.33 | 0.09 | 12317 | 13439 | 1755 | 9170.33 | 0.31 | 6796 | 7562 | 2835 | 5731.00 | 0.19 |
| 2 | Worst Feeder 2 | 1.59 | 5 | 8 | 5 | 6.00 | 0.60 | 11 | 4 | 1 | 5.33 | 0.21 | 9295 | 13457 | 18374 | 13708.67 | 0.46 | 5245 | 12572 | 20522 | 12779.67 | 0.43 |
| 3 | Worst Feeder 3 | 2.06 | 13 | 18 | 8 | 13.00 | 1.30 | 6 | 7 | 3 | 5.33 | 0.21 | 1261 | 20479 | 453 | 7397.67 | 0.25 | 4483 | 31754 | 239 | 12158.67 | 0.41 |
| 4 | Worst Feeder 4 | 1.86 | 15 | 14 | 13 | 14.00 | 1.40 | 1 | 16 | 12 | 9.67 | 0.39 | 1447 | 4469 | 983 | 2299.67 | 0.08 | 838 | 10366 | 5627 | 5610.33 | 0.19 |
| 5 | Worst Feeder 5 | 1.61 | 14 | 12 | 18 | 14.67 | 1.47 | 1 | 1 | 0 | 0.67 | 0.03 | 648 | 7671 | 661 | 2993.33 | 0.10 | 233 | 1840 | 956 | 1009.67 | 0.03 |
| 6 | Worst Feeder 6 | 1.77 | 11 | 14 | 15 | 13.33 | 1.33 | 6 | 0 | 0 | 2.00 | 0.08 | 8883 | 1903 | 8468 | 6418.00 | 0.21 | 11497 | 2467 | 2676 | 5546.67 | 0.18 |
| 7 | Worst Feeder 7 | 1.40 | 8 | 8 | 7 | 7.67 | 0.77 | 1 | 0 | 6 | 2.33 | 0.09 | 7140 | 9270 | 15841 | 10750.33 | 0.36 | 3482 | 5795 | 11161 | 6812.67 | 0.23 |
| 8 | Worst Feeder 8 | 1.13 | 8 | 9 | 6 | 7.67 | 0.77 | 2 | 3 | 2 | 2.33 | 0.09 | 1204 | 2032 | 6514 | 3250.00 | 0.11 | 4638 | 4719 | 8978 | 6111.67 | 0.20 |
| 9 | Worst Feeder 9 | 0.99 | 7 | 14 | 6 | 9.00 | 0.90 | 1 | 0 | 0 | 0.33 | 0.01 | 279 | 3376 | 667 | 1440.67 | 0.05 | 140 | 2342 | 535 | 1005.67 | 0.03 |
| 10 | Worst Feeder 10 | 2.10 | 32 | 7 | 8 | 15.67 | 1.57 | 1 | 2 | 0 | 1.00 | 0.04 | 17456 | 3894 | 1680 | 7676.67 | 0.26 | 17890 | 4262 | 749 | 7633.67 | 0.25 |

Table 2: 2010 Feeder Slope, Trend & Rank

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| | | Score | | | Slope | Trend | Rank |
| | Feeder | 2008 | 2009 | 2010 | 2010 | 2010 | 2010 |
| 1 | Worst Feeder 1 | 2.50 | 2.80 | 2.91 | 0.21 | 0.60 | 1.76 |
| 2 | Worst Feeder 2 | 0.62 | 1.02 | 1.59 | 0.48 | 0.74 | 1.18 |
| 3 | Worst Feeder 3 | 1.79 | 2.16 | 2.06 | 0.14 | 0.57 | 1.17 |
| 4 | Worst Feeder 4 | 1.44 | 1.79 | 1.86 | 0.21 | 0.60 | 1.12 |
| 5 | Worst Feeder 5 | 1.10 | 1.33 | 1.61 | 0.26 | 0.63 | 1.02 |
| 6 | Worst Feeder 6 | 1.75 | 1.84 | 1.77 | 0.01 | 0.51 | 0.90 |
| 7 | Worst Feeder 7 | 1.06 | 1.00 | 1.40 | 0.17 | 0.58 | 0.82 |
| 8 | Worst Feeder 8 | 0.55 | 0.88 | 1.13 | 0.29 | 0.64 | 0.72 |
| 9 | Worst Feeder 9 | 0.70 | 0.91 | 0.99 | 0.14 | 0.57 | 0.57 |
| 10 | Worst Feeder 10 | 3.02 | 2.52 | 2.10 | -0.46 | 0.27 | 0.56 |

## 7. Worst Feeder Trending

In order to determine whether or not improvements are being seen on the worst feeders from one year to the next – as a feeder may appear in the top ten for a few years as the rating is based on a 3-year average – trending from year to year must be evaluated.

For three years following the first time a feeder is seen on the Top Ten listing the slope is tracked to determine whether or not the reliability performance is improving. Three years is used since any improvements to the feeder will be implemented in the following budget year, then results can be tracked for the next two years.

As described above, if the overall linear trend is decreasing for the following three years, then improvements are being seen on the feeder, if the overall trend is increasing or remaining constant, then further evaluation, and possible intervention is required.

# Appendix E

## City of Ottawa Community Design Plan Summary

Hydro Ottawa Limited

# Community Design Plans

## Approved by City Council for Implementation

Annie Williams

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This document contains a summary of all Community Design Plans approved by the City of Ottawa as of October 2014. The purpose of this report is to demonstrate the expected growth in the city over the next few years. Some projects may already be underway while others are planned for the long term. This report is specifically focused on the consequences of City expansion projects to Hydro Ottawa's electrical distribution system.

Each CDP summary states the boundaries of the study area, any relevant transportation projects within the study area that may affect Hydro Ottawa's assets, and a brief description of the development proposed for the area. Full CDP documents are available on the City of Ottawa's website at http://ottawa.ca/en/city-hall/planning-and-development/community-plans-and-design-guidelines/community-plans-and-studi-0.

It is expected that there will be more than 214MW of load growth in the City of Ottawa over the next 20 years. Hydro Ottawa's distribution system does not currently have the capacity to supply these additional loads in some areas. System expansion and relocation will need to occur alongside these City plans and additional station capacity is being considered.

## Table of Contents





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## CDP Summary

| Study | Study Area (ha) | GFA (ha) | No. Res. Units | Land Use Type | Expected Load (MW) | MVA (PF=0.9) |
|---|---|---|---|---|---|---|
| Barrhaven South CDP | 500 | 188.9 | 6,862 | Mixed-Use | 14,253 | 15,837 |
| Bank Street CDP | 101 | | | Mixed-Use | 0 | 0 |
| Bayview Station District CDP | 29.5 | 55 | | Mixed-Use | 4,146 | 4,607 |
| Bayview/Somerset Area Secondary Study | 89.7 | | 1,590 | Mixed-Use | 3 | 4 |
| Beechwood CDP | 22 | | 819 | Mixed-Use | 2 | 2 |
| Cardinal Creek Village Concept Plan | 208 | 95 | 3,500 | Mixed-Use | 7,168 | 7,965 |
| Carp Road Corridor CDP | 2475 | | 0 | Commercial | 0 | 0 |
| Village of Carp CDP | 49.5 | | 543 | Mixed-Use | 1 | 1 |
| Village of Constance Bay Community Plan | 114 | | 204 | Mixed-Use | 0 | 0 |
| Downtown Ottawa Urban Design Strategy | | | | | 0 | 0 |
| East Urban Community (Phase 1 Area) CDP | 570 | | 3,498 | Mixed-Use | 7 | 8 |
| East Urban Community (Phase 2 Area) CDP | 240 | | 1,726 | Mixed-Use | 3 | 4 |
| Escarpment Area District Plan | | | | Mixed-Use | 0 | 0 |
| Fernbank CDP | 674 | 310 | 11,000 | Mixed-Use | 23,390 | 25,989 |
| Greely CDP | 1276 | | 729 | Mixed-Use | 1 | 2 |
| Leitrim CDP | 500 | 362.3 | 5,300 | Mixed-Use | 27,321 | 30,356 |
| Mer Bleue CDP | 160 | 113.7 | 3,000 | Mixed-Use | 8,577 | 9,530 |
| Kanata West Concept Plan | 887 | | 5,000 | Mixed-Use | 10 | 11 |
| North Gower CDP | 278 | 208 | 520 | Mixed-Use | 15,680 | 17,422 |
| Old Ottawa East CDP | 158 | | 2,250 | Mixed-Use | 5 | 5 |
| Orleans Industrial Park Study | 316 | 18.7 | 0 | Commercial | 1,410 | 1,566 |
| Queensway Terrace North | 140 | | | | 0 | 0 |
| Richmond Road/Westboro CDP | 270 | | 3,970 | Mixed-Use | 8 | 9 |
| Richmond Road/Westboro Transpo Plan | | | | | 0 | 0 |
| Riverside South CDP | 1800 | 1450 | 18,300 | Mixed-Use | 109,338 | 121,486 |
| Scott Street CDP | 57.7 | | 1,500 | Mixed-Use | 3 | 3 |
| South Nepean Town Centre CDP | 165 | 35 | 11,000 | Mixed-Use | 2,660 | 2,956 |
| St. Joseph Boulevard Corridor Study | 67.3 | | | Mixed-Use | 0 | 0 |
| Uptown Rideau CDP | 21 | | | Mixed-Use | 0 | 0 |
| Transit-Oriented Development (TOD) Plans | | | | | 0 | 0 |
| Village of Richmond CDP | 879 | | | Residential | 0 | 0 |
| Wellington Street West CDP | 232 | | 950 | Mixed-Use | 2 | 2 |

*Expected load should be greater than shown in table due to lack of information

## Barrhaven South CDP

**Boundaries:** Jock River, Highway 416, Barnsdale Rd, Jockvale Rd & Greenbank Rd
**Transportation projects:** Relocation and widening of Greenbank Rd (also upgrade to 4-lanes south of Cambrian Rd), New 4-lane structure over Jock River, Cambrian Rd widening

The area currently contains a few farms and rural residential homes. The plan is to create a complete residential community that contains a full range of housing choices and a broad complement of support services and facilities. This will include residential housing, commercial buildings, community centres and schools.

## Bank Street CDP

**Boundaries:** Bank St - Rideau River to Ledbury Park (ie. Riverside Dr to CN Rail Line)
**Transportation Projects:** 2 Transitway stations + LRT station within walking distance, 3 Intersection modifications

The current land uses along Bank St are predominantly commercial, with some residential, office and industrial uses. The Bank St corridor will become a vibrant mixed use area with diverse housing, shops and services. The goal is to transform the area from a retail strip into a central spine for a new higher-density community.

## Bayview Station District CDP

**Boundaries:** Revolves around Bayview Station, Bayview Rd, Albert St, City Centre Ave, Somerset St W
**Transportation Projects:** LRT station, Existing O-Train line to become major LRT route (BRT to LRT)

A large portion of the study area is publicly owned, such as the rail corridor and the Tom Brown Arena. The area also contains some smaller-scale residential and commercial properties. The focus is on transit-oriented development in the area around Bayview Station. It will include residential buildings, mixed-use commercial and small scale industrial buildings. The CDP notes that existing underground utilities do not follow municipal rights-of-way and development will need to consider avoiding or relocating these services. It is not specified whether these utilities include Hydro.

## Bayview/Somerset Area Secondary Study

**Boundaries:** Lebreton Flats to Tunney's Pasture, Bayview Road, Canadian Pacific Railway, Transitway, Ottawa River Parkway
**Transportation Projects:** Traffic circle at Burnside/Bayview

The site is currently occupied by a number of City operations such as snow disposal. Bayview Road will become the community's main street, and there will be a mix of medium density housing forms as well as retail space. It should be noted that many properties in the study area have soil contamination.

## Beechwood CDP

**Boundaries:** Beechwood Ave - St. Patrick St Bridge to Beechwood Cemetery
**Transportation Projects:** No Relevant Projects

Beechwood Avenue currently has a wide variety of shops. The public prefers low-rise or medium-rise building heights. It is mentioned that hydro poles and wires should be removed, if possible. It is anticipated that there will be a new grocery store, other small stores, residential buildings and urban plazas.

## Cardinal Creek Village Concept Plan

**Boundaries:** Ottawa Road 174 & Ottawa River, Cardinal Creek, Frank Kenny Rd/Ted Kelly Ln
**Transportation Projects:** Rapid Transit Corridor may be extended into study area

These lands currently have large lot rural residential, institutional and nursery/landscape uses. 50% of the area is pasture. The intent is to create a complete residential community with a full range of housing choices that is complemented and supported by appropriate community facilities such as parks and schools, while providing opportunities to work and shop in close proximity to the residential neighbourhoods. A 'center' to the village was considered an important community-defining element of the plan and accordingly, the intersection of the proposed north-south major collector road and Old Montreal Road was identified as a central area. In this location, a variety of land uses (such as local commercial uses, higher density residential uses and a neighbourhood park) have been provided to create an active, interesting and diverse 'Village Core'. The 'Village Core' will be supported by the creation of a traditional main street character along Old Montreal Road, and will support potential future transit service along this road. Hydro Ottawa has confirmed that there is plant in reasonable proximity to the study area.

## Carp Road Corridor CDP

**Boundaries:** Carp Rd - Rothbourne Rd to March Rd
**Transportation Projects:** Carp Rd widening to 4 lanes (Stittsville boundary to Richardson Side Rd)

The Carp Road Corridor currently contains country lot residential subdivisions, a golf course, commercial and agricultural properties. The objective is to promote the corridor as a rural employment area which is an attractive base for a wide range of industrial and commercial uses.

## Village of Carp CDP

**Boundaries:** Carp River, Carp Hills
**Transportation Projects:** Former CN Rail line protected as corridor for future public transit

There are 2 areas being discussed: the Village Core and the residential areas. The Village Core contains heritage buildings, and will be the primary focus of Carp's economic activity. The predominant uses in the Core will be commercial, recreational and institutional, with residential uses being encouraged as part of a mixed-use development. Commercial and retail uses will not be permitted in the residential areas.

## Village of Constance Bay Community Plan

**Boundaries:** Ottawa River
**Transportation Projects:** Road links from Allbirch to Kilmaurs Side Rd (to provide 2nd access into area)

There is limited potential for growth, but the Village will grow slowly over the next 20 years in two ways: new subdivision in the undeveloped land, and the conversion of cottages to permanent homes. Constance Bay will be a residential-focused area, with some commercial development in the Village. This includes a new shopping area, medical centre and day care.

## Downtown Ottawa Urban Design Strategy

**Boundaries:** Ottawa's Downtown Core
**Transportation Projects:** This document encompasses many upcoming transportation projects

Over the next 20 years, this design strategy will help set the stage for a renewed physical environment for the downtown core. This is a strategic document that can be used by several parties as a tool to guide future development projects in the downtown area. The strategy sets the proper priorities on improvements for realization over the 20-year time frame.

## East Urban Community (Phase 1 Area) CDP

**Boundaries:** Mer Bleue Rd, Former Canadian Pacific Railway line, NCC Greenbelt, Hydro corridor
**Transportation Projects:** Alignment of the future Blackburn Hamlet By-pass Extension, Navan Rd and Mer Bleue Rd widening to 4-lane divided arterials, Belcourt Boulevard Extension, 2 LRT stations

There are existing structures in the study area, but the land is largely undeveloped. The Orleans projected population is expected to increase steadily over the next 15 years to approximately 20,000 more people. More housing is needed for this additional population. There are several Official Plan (OP) targets for residential development that should be met, such as: achieve a density of 29 units/net ha for singles, semis and towns, requirement of 10% apartments, at least 30% multiples, and maximum 60% singles and semi-detached dwellings. There are 2 proposed transit stations and a Mixed Use Centre (700-850 units).

## East Urban Community (Phase 2 Area) CDP

**Boundaries:** Former Canadian Pacific Railway line, Mer Bleue Rd, Renaud Rd, Phase 1 boundary
**Transportation Projects:** Mer Bleue Rd realignment, Future VIA Rail high-speed passenger train

The majority of the study area is currently covered with open pasture or wooded areas. Existing structures are predominantly residential dwellings, with some small commercial uses. The East Urban Community's designation as a Developing Community in the City of Ottawa Official Plan sets the requirement for the completion of a CDP for the lands. There will be more residential housing, commercial sites, 3 elementary schools, and a fire station. It should be noted that there are multiple statements in the CDP regarding burying hydro lines along particular roads.

## Escarpment Area District Plan

**Boundaries:** Lebreton Flats, Garden of the Provinces, Bay Street, Laurier Avenue
**Transportation Projects:** New roads (no impact on existing/proposed transit system)

Over the next 15 years, the Escarpment District will develop into a diverse and attractive downtown community. This will include new residential developments (various types – ex. high rise buildings), commercial buildings, and an Ottawa Technical High School. It is noted that hydro services are located adjacent to the study area, and that Hydro Ottawa will be contacted in advance of site plan approval to confirm the adequacy and availability to service the proposed development.

## Fernbank CDP

**Boundaries:** Stittsville, Carp River, Terry Fox Dr, South of Hazeldean Rd to Fernbank Rd
**Transportation Projects:** Widening of Hazeldean Rd, Terry Fox Dr, Kanata West road network, Extension of Western Transitway, Extension of rapid transit corridor & north-south arterial

The study area currently contains rural and agricultural uses, including 2 transmission corridors. Development will include residential and commercial uses. It has been noted that Hydro Ottawa has confirmed that there is plant in reasonable proximity of the study area, and that there is adequate supply to service the Fernbank community.

## Greely CDP

**Boundaries:** Mitch Owens, Sale Barn, Fox Valley, Snake Island Rd
**Transportation Projects:** Updated Road Network

The objectives of this CDP are to provide more residential dwellings, and to develop the Village Core, which will include residential, commercial and institutional uses. There will be a shopping centre. Note that the CDP mentions an expansion of utility services which will be installed efficiently to minimize disruptions.

## Leitrim CDP

**Boundaries:** Leitrim Rd, Bank St, Albion Rd
**Transportation Projects:** Future LRT Station (North-South LRT Corridor) and Park & Ride Lot, 4-lane Bank St & Albion Rd, 2-lane Leitrim Rd & Earl Armstrong Dr Extension

The majority of Leitrim is presently undeveloped, but there are existing commercial, institutional, industrial and residential uses throughout the area. The plan involves adding 3 mixed use centres along Bank Street to accommodate commercial, institutional, residential and service uses. There will be 4 elementary schools, higher density residential uses and 10 residential neighbourhoods.

## Mer Bleue CDP

**Boundaries:** Hydro Corridor, Mer Bleue Rd, Tenth Line Rd, Southern Urban Boundary
**Transportation Projects:** East-West Transit Expansion along northern boundary (Stations at Mer Bleue & Tenth Line), Blackburn Hamlet By-pass Extension, Innes Rd Widening 4-lanes

The CDP area is part of the Orleans Expansion Area. There are currently residential and rural uses, developing commercial uses and a HONI corridor. The plan will potentially involve 2 new schools, as well as residential, commercial and mixed-use development. The CDP notes that private utilities shall be permitted in all land use designations, utilities must confirm the ability to provide service prior to development, and developers should consult with utilities early on.

## Kanata West Concept Plan

**Boundaries:** Highway 417, former: Township of West Carleton, Township of Goulbourn, City of Kanata
**Transportation Projects:** Transit Corridor Extension (Kanata Town Centre to CTC), Highway 417 widening 6/8 lanes, Terry Fox Dr Widening (Upgrade Interchange), Hazeldean Rd Widening, Eagleson Rd Widening, Construct Castlefrank Rd Interchange
Existing uses within the area are limited, but include the Canadian Tire Centre (CTC) and related offices, the City of Ottawa Works Yards, the Wesleyan Church of Canada, and some residential dwellings. The concept plan involves creating office uses, housing, retail, institutional and entertainment uses. The Mixed Use area is the heart of this new community with 3 integrated land use concepts – the Community Core Zone, the Major Facilities Zone, and the Institutional/Corporate Campus Zone. There will also be a Prestige Business Park, and 2 residential areas. The plan notes that the proposed development area is split between HONI and HOL, and it states that HONI will act as the lead representing both utility companies. It is stated that there is adequate capacity to serve initial loads, and new sources will be brought into the area as loads exceed capacity.

## North Gower CDP

**Boundaries:** Centered on crossing of 3 roads: Prince of Wales, Roger Stevens, Fourth Line
**Transportation Projects:** Multi-Use Pathway Plan (including new sidewalks), Future Local Road Network

North Gower is a vibrant farming community in a rural setting. There are currently some small commercial uses in the Village Centre. The goal of the CDP is to provide a variety of business to support the community, and to provide more housing for residents. There will be added commercial uses. It is noted that some residents would like overhead lines buried within the Village Centre. They would like to see upgraded street lighting for safety purposes, along certain streets such as Prince of Wales, Roger Stevens and Fourth Line. They would also like to see lighting throughout new subdivisions and on the bridges.

## Old Ottawa East CDP

**Boundaries:** Rideau River, Rideau Canal, Riverdale, Highway
**Transportation Projects:** Widen Sidewalks (Main St, Lees Ave), Roundabout at Main/Riverdale Intersection, Narrow Main St from 4 to 3 lanes

The study area primarily focuses on Main Street, along which there are some clusters of retail uses. A large percentage of the land is occupied by institutions and there is a large portion of residential space.

The plan involves intensifying lots in a mixed-use format, adding residential and commercial uses, and enhancing a mixed-use centre precinct at the east end of Lees Ave (near Ottawa University campus). The CDP notes that priority will be given to the burial of overhead wires in some locations.

## Orleans Industrial Park Study

**Boundaries:** Innes Rd, Hydro Corridor, Pagé Rd, Tenth Line Rd
**Transportation Projects:** Innes Rd Expansion 4-lanes, Widening of Mer Bleue Rd & Tenth Line Rd

The study area currently contains residential and commercial uses. There is a HONI Transmission Corridor on the south border of the study area. Proposed development includes a 45 $m^2$ commercial development and an 18.7 ha snow disposal facility. The industrial park will be modified without disturbing the surrounding residential areas.

## Queensway Terrace North

**Boundaries:** Carling Ave, Transitway, Queensway, Pinecrest Rd
**Transportation Projects:** No Relevant Projects
This study was undertaken in response to increasing community concerns over the number of residential triplex conversions within the area, which are not in compliance with Zoning By-law 1998. The goal of this study was to conduct a review of the likely forms, locations and appropriate levels of intensification, the ability of existing infrastructure to accommodate growth, and the potential impact of evolving City Council intensification policies on this neighbourhood. The results of this study do not appear to directly affect Hydro Ottawa or any of its assets.

## Richmond Road/Westboro CDP

**Boundaries:** Ottawa River, Island Park Dr, Byron Ave, Ottawa River Parkway Extension
**Transportation Projects:** Potential Transitway Station in New Orchard Area

This CDP was undertaken because neighbouring residential communities were concerned with several rezoning applications for substantial increases in maximum building height. They viewed increased building heights as being incompatible with the existing character of Richmond Road. The study area currently contains a mix of residential housing types, retail, office, institutional, commercial and industrial uses. The study area has been divided into several sectors. Between all of them, there will be new residential communities with commercial mixed-use buildings, offices, institutional and industrial development. The CDP also mentions the installation of pedestrian-oriented street lighting, and the possibility of placing overhead wires underground.

## Richmond Road/Westboro Transportation Management Plan

**Boundaries:** Ottawa River, Island Park Dr, Byron Ave, Ottawa River Parkway Extension
**Transportation Projects:** Making Transit More Accessible, Improve Sidewalks, Bike Lanes

The purpose of this plan is to promote a shift to more sustainable modes of transportation in the Richmond Road/Westboro community over the next 15 years. The peak period auto modal share must decrease by 13% to avoid the need for additional roadway capacity. This plan includes designating bike lanes, sidewalk improvement projects, and making public transit more accessible.

## Riverside South CDP

**Boundaries:** Ottawa Macdonald-Cartier International Airport, Rideau River
**Transportation Projects:** Rapid Transit Corridor + Stations

The northwest portion of the site is currently developed as a residential subdivision, and the CDP focuses on the surrounding area east of the river. This plan involves development of a rapid transit corridor, residential areas and an employment area. The subdivision will be expanded to include a variety of uses and housing types.

## Scott Street CDP

**Boundaries:** Northwestern Ave, Bayview Rd, West Wellington St, North of Burnside Ave
**Transportation Projects:** Confederation LRT to Tunney's Pasture, Extend Sir Frederick Banting north to connect to Sir John A. Macdonald Parkway, Extend Goldenrod Driveway

This CDP is intended to guide future change in the area surrounding the Tunney's Pasture Transit Station. This involves 4 established neighbourhoods: Mechanicsville, Hintonburg, Wellington Village and Champlain Park. Development will include commercial uses, residential uses, institutional and cultural uses. Apartment neighbourhoods will be expanded. The CDP acknowledges that there is an existing hydro substation on Scott Street, and there are no changes proposed for the zoning of these sites.

## South Nepean Town Centre CDP

**Boundaries:** Strandherd Dr, Jock River
**Transportation Projects:** 2 Rapid Transit Routes, LRT & BRT Alignments

The Town Centre is intended to be a compact, mixed-use, walkable, pedestrian-scaled, and transit-supportive community. It will include a shopping district, retail, office and residential uses.

## St. Joseph Boulevard Corridor Study

**Boundaries:** Montreal Rd in Vanier, Rideau in downtown Ottawa, Wellington St in front of Parliament
**Transportation Projects:** ---

St. Joseph Boulevard is one of the City's major arterial roads, and is classified as a commercial strip. The purpose of this study is to create a lively, vibrant and diverse district with a mix of places to live, work, shop and play. The study area is divided into 4 basic districts: industrial, neighbourhood commercial, main street, and residential hinterland. Development will involve industrial uses, commercial, office and community uses. There will also be more residential uses, retail uses and government facilities. The Study mentions that there are overhead utility poles along St. Joseph Boulevard and both sides of the street, as well as crossing the road. The City currently has no plans to bury the utility lines, but sees underground hydro service as a long term goal.



1

## Uptown Rideau CDP

**Boundaries:** Rideau St (between King Edward Ave, Cummings Bridge)
**Transportation Projects:** Sidewalk Widening (eliminate OH hydro plant)

There are currently a mix of retail/office uses and retail/residential uses along the street. The goal is to transform the street into a green, pedestrian streetscape of the highest quality in a compact urban setting, framed with 3-6 storey buildings on both sides of the street. The mainstreet will serve a mix of residential, commercial, institutional, and entertainment functions. The community would like the hydro poles and overhead wires to be removed, as a first priority. This should be done in conjunction with street reconstruction.

## Transit-Oriented Development (TOD) Plans

Ottawa's Light Rail Transit (LRT) project runs east-west from Tunney's Pasture in the west to Blair Road in the east. The LRT system includes 12.5 km of new rail, 13 stations and a tunnel through the downtown core. Ten of the stations are a conversion or reconstruction of existing bus rapid transit stations to accommodate light rail and the other three stations are new underground stations in the downtown area. The final design phase and construction will be undertaken over the next few years with system opening day scheduled for 2018.

In anticipation of land development pressure in proximity to the LRT stations, City Council has established priority areas for the creation of transit-oriented development (TOD) plans. The TOD plans set the stage for future transit-supportive, or "intensified", land development by adding in appropriate locations opportunities for additional land use types and densities. The first three TOD studies for land surrounding the "Train", "St. Laurent" and "Cyrville" future LRT stations were approved by City Council on November 14, 2012.

The following concerning Hydro Services is noted:
*The main findings and recommended upgrades are as follows:*

- *Substation spare capacity is currently limited, especially at Overbrook, Russell, and Moulton.*
- *Overbrook, Russell, and Moulton are already planned to be enlarged by Hydro-Ottawa.*
- *Circuit capacity will have to be upgraded by addition of new lines, especially Russell, and to a lesser extent, Riverdale and Moulton.*

*Assuming a slightly lower build-out rate of 25% of eventual build-out within 20 years, the Hydro Ottawa substation build-out plans are not significantly altered. It may only delay the trigger points where additional circuit capacity must be added for development loading. Most of the developer related circuit build-out costs are triggered within the first 10 years using initially proposed build-out rates plans.*

## Village of Richmond CDP

**Boundaries:** South of Kanata on either side of Jock River
**Transportation Plans:** Sidewalk Widening

This CDP involves redeveloping the shopping centre in the village, new residential buildings and possibly small commercial buildings. The plan mentions moving buildings closer to the street while adhering to overhead setbacks. The plan seems to be more visually oriented, rather than large expansion.

## Wellington Street West CDP

**Boundaries:** Wellington St (Holland Ave, Parkdale Ave, Spencer St)
**Transportation Plans:** Road Reconstruction Project (surface and sub-surface infrastructure)

This CDP contains the following goals: to enhance the existing mix of land uses, to establish a clear network of people spaces, to strengthen the traditional built form and spaces through respect and innovation, to capture the opportunities of mainstreet gateways and nodes, to encourage views and vistas, to link the varied character areas together as a unified corridor, and to promote a pedestrian and transit friendly environment. The plan involves adding more residential and commercial uses.


HydroOttawa

# Distribution System Plan 2016

# Material Investments

# System Renewal

# 1 Station Transformer Replacement

## 1.1 Project/Program Summary

Station transformers are critical assets operating within HOL's distribution system. They provide voltage transformation from transmission line voltage to a lower voltage to distribute throughout the city.

Station transformers are unique assets due to a number of factors including replacement costs ranging from $300,000 to $2,500,000; a failure will have medium to major consequence, and a replacement is a six to twenty-four months project cycle. In addition, station transformer replacements may require additional upgrades such as oil containment, ground grid upgrades, cable replacement, and protection & control upgrades. In some cases a full substation upgrade (switchgear and transformers) may be triggered by a transformer replacement.

## 1.2 Project/Program Description

### 1.2.1 Assets in Scope

HOL's replacement policy is to replace transformers with a standard capacity rating that is rated equal or greater than the existing capacity rating. Note that the HOL's Capacity Plan will be consulted to determine if an upgraded capacity rating is required.

If the transformer is part of a sub-transmission system, considerations for a voltage conversion will be reviewed as an alternative to replacing the transformer.

HOL plans to replace 21 power transformers over the 2015-2020 period. The equivalent estimated yearly cost of the proposed station transformer replacement program is $8 million per year. Over the 2011-2014 period, HOL has replaced an average of 3 power transformers per year. The proposed approach to replacement represents a 0.5% increase in units replaced per year. Increase in the number of power transformers replaced during the rate filing period to 3.5 from 3 in 2015 eliminates a risk of operating assets beyond useful life in the 5-10 year horizon. Operating these assets beyond useful life increases risks to reliability and is detrimental to system performance.

Historically, power transformer replacements have been prioritized based on age and health index. Transformers prioritized in the 2016-2020 period have been assessed using a similar approach. As such, poor and critical condition transformers are scheduled for replacement while further inspection and condition assessments continue to identify high priority power transformers for replacement.

The station transformers targeted for replacement in 2015 and 2016 are identified in the specific projects listed in Section 8 of this program narrative. These transformers were identified using HOL's transformer health assessment detailed in subsequent sections. HOL will continue to conduct power transformer inspections and improve in-service asset demographics to continually improve asset identification for replacement.

### 1.2.2 Asset Life Cycle and Condition

HOL owns and operates 170 station transformers distributed over primary voltages: 103 at 13.2kV, 39 at 44kV, 22 at 115kV and 6 at 230kV. These voltages are stepped down to 27.6kV, 12.8kV, 8.32kV, and 4.16kV.

The age demographic of station transformers is illustrated below in Figure 1. A large distribution of assets in the 40-45 year range is attributed to rapid economic development in HOL's service area in the past. The majority of these transformers have primary voltages of 13.2kV or 44kV. Given that the expected useful life of a station transformer is 50 years, and many are approaching end of life in the 5-10 year horizon, there are currently 6 transformers that have reached end of life and there will be a total of 16 by the end of 2020. HOL plans to replace additional transformers that are approaching end of life in order to reduce the impact of the large amount of transformers build or re-built in the 1970s.

To manage this aging asset group, HOL implemented an active inspection and maintenance program to maintain acceptable operating conditions and provide information to prioritize replacement projects. To further enhance monitoring capabilities, monitoring units that provide information on key gas generation, moisture, and oil temperature will be installed on many transformers. Information will be communicated back through the SCADA network.

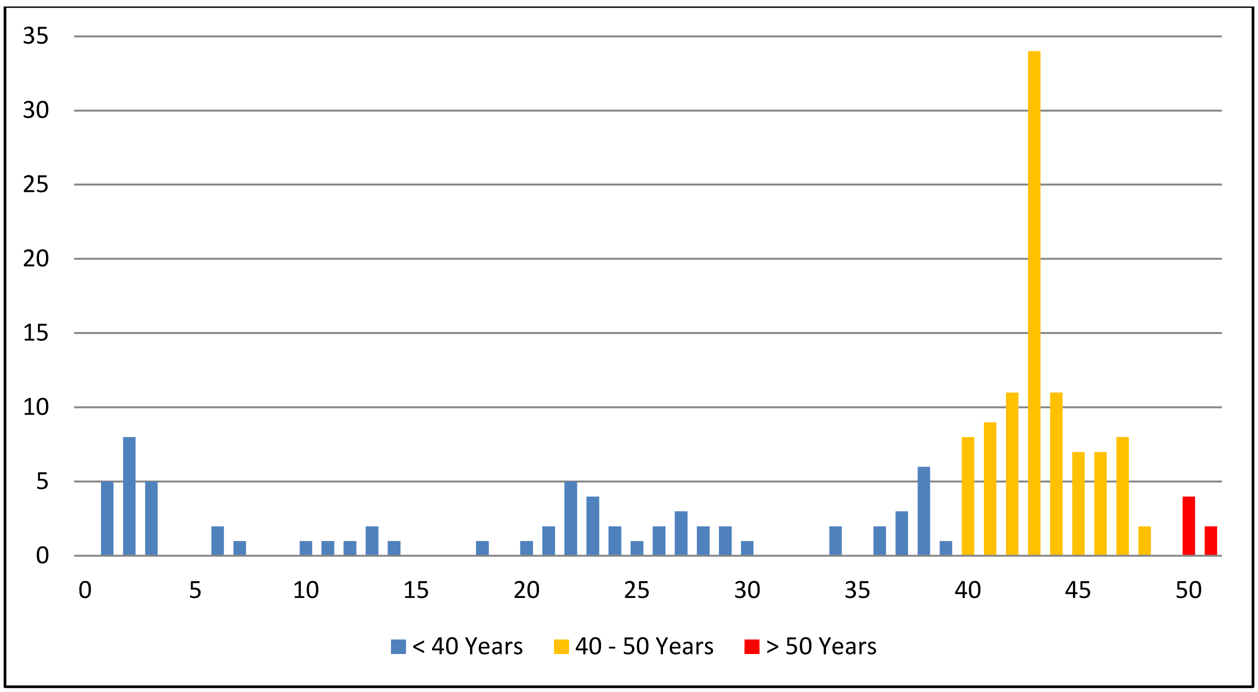



**Figure 1 - Station Transformer Demographics**

The health of a transformer can be broken down into three main components: thermal, electrical, and mechanical stresses.

- Thermal stresses occur due to internal heating or local overheating due to short-time overload. They can be measured using dissolved gas analysis, paper deterioration, and infra-red scanning.

- Dielectric stresses occur due to system overvoltages, transient impulse conditions or internal resonances within the windings. They can be measured through oil analysis, partial discharge, and power factor tests.
- Mechanical stresses can occur between conductors, windings, or leads due to short-term overcurrents, faults, and inrush currents. They can be measured through frequency response analysis, capacitance, and inductance measurements.

HOL currently tracks the health index through results from dissolved gas analysis. The transformer health index is based on the dissolved gas condition, the generation rate of these dissolved gases and the oil or fluid condition, given by the following equation.

$$Health\,Index = \left(\frac{Gas\,Score + Rate\,Score + Fluid\,Score}{3}\right) \times 5$$

The following figure provides an indication of the condition of the station transformer population calculated using the above equation.

| Category | Health Index (HI) |
|---|---|
| **Good** | HI = 0 |
| **Fair** | 0 < HI <=1 |
| **Requires Attention** | HI > 1 |

**Table 1 - Station Transformer Health Index Rating**

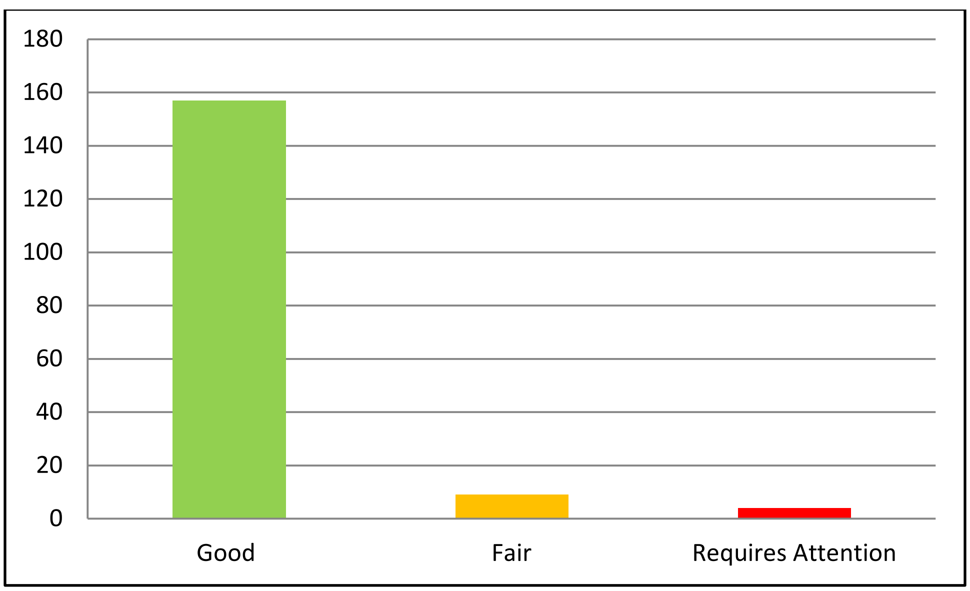



**Figure 2 - Station Transformer Health**

Transformer failures occur due to contamination in mineral oil, degradation of winding insulation as well as windings themselves. Failures have an extreme negative impact on reliability and can result in system operating without contingency in place.

### 1.2.3 Consequence of Failure

Station transformers have a large consequence of failure as they are an integral component to the distribution system. Station transformer failure will have reliability, safety and environmental consequences.

Substations are designed with contingencies in the event of a transformer failure. However, with long lead times and projects with high complexities, identifying and prioritizing station transformers that are at end of life before failure is critical. Capacity constraints are also a factor when a contingency unit is required to support the entire load of a station. Aging or overloaded transformers are at a higher risk of failure and can have high consequences if they fail.

Transformers that fail catastrophically have the potential to damage other surrounding equipment, even damage the transformer that will be used as contingency to restore power.

Historical reliability for station transformer defective equipment is provided in the graph below.

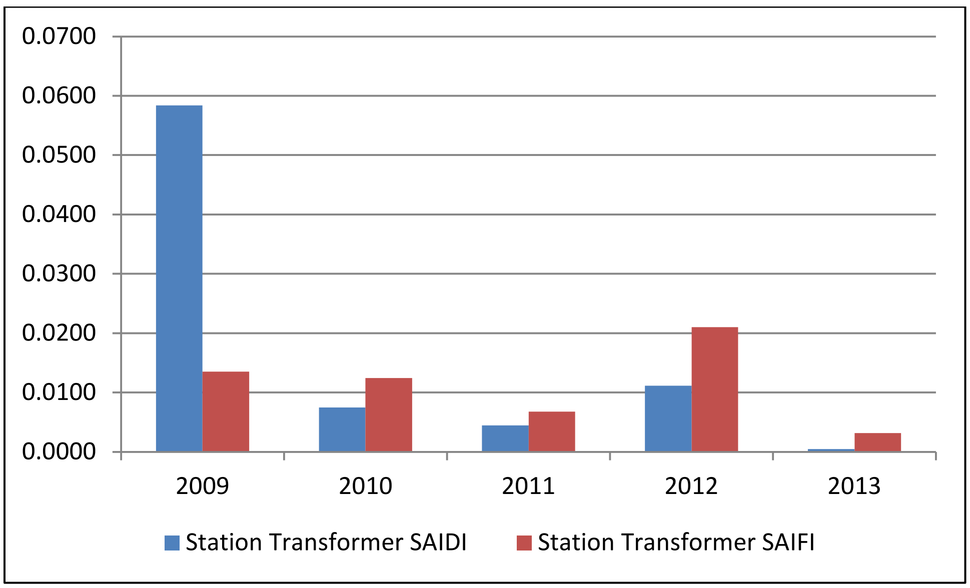



**Figure 3 - Historical SAIDI and SAIFI, Station Transformer Defective Equipment**

Additional failure impacts include environmental issues resulting from contamination of soil. HOL reports to the Ministry of the Environment information on oil spilled and the cost of remediation. In 2009, a large amount of mineral oil was released due to the failure at Beacon Hill substation. This emphasizes the importance of active inspection and replacement of station transformers to mitigate this environmental impact.

### 1.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | 6 transformer units have passed end of life criteria that will grow to 16 by the end of rate filing period 2020. |
| **Secondary** | **Reliability** | Station transformer has a direct impact on system reliability, as all customers connected will experience a power outage in the event of a failure.<br>Increasing number of power transformer failures impact on SAIFI and SAIDI |

**Table 2 - Station Transformers Main Drivers**

### 1.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the station transformer replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

## 1.3 Project/Program Justification

### 1.3.1 Alternatives Evaluation

#### 1.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program HOL considered four alternatives for the replacement policy. All the alternatives stabilize the replacement amount at the same level beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of power transformers
- Replace 1 power transformer per year
- Replace 3 power transformers per year
- Replace 5 power transformers per year

#### 1.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resource** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favourable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 3 – Alternative Evaluation Criteria**

#### 1.3.1.3 *Preferred Alternative*

The preferred alternative is to replace 3 transformers per year. It is expected that this option will maintain the condition of the asset class, therefore, to maintain the current failure rate by managing the risk of an aging demographic.

**Failure / Reliability**

HOL performed an analysis to calculate the projected failure rate, using historical failure data and the probability of failure at a particular age. Based on a probability of failure, a predictive analysis can be completed depicting the future failure rate of the asset. Active replacements can be incorporated into this analysis to show the effects of varying replacement rates on failures. This analysis is shown in Figure 4.

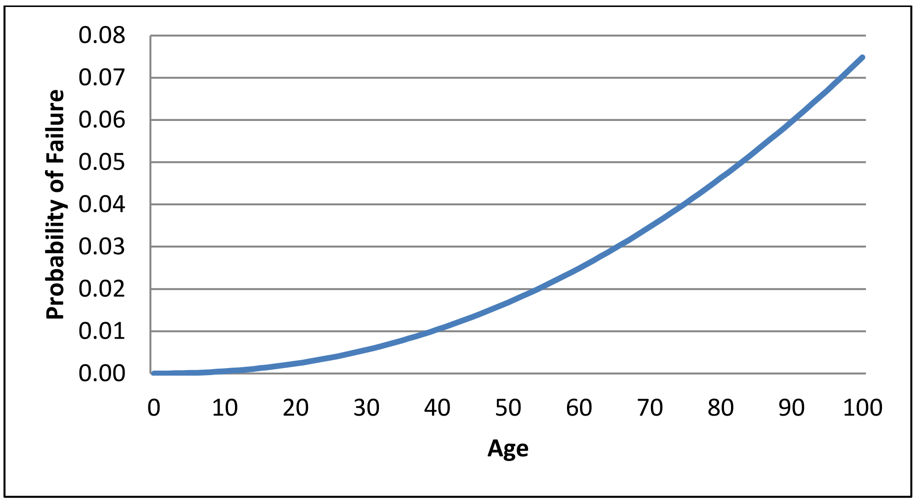



**Figure 4 - Station Transformer Failure Probability**

The failure curve used in the analysis is a calculated Weibull probability based on the total age demographic and the age at failure. The Weibull distribution is used industry wide for electrical equipment. This allows a curve to be built not only on failure data but incorporates the surviving population. As inspection processes develop and failure data is recorded in more detail, the failure curve will be updated to more accurately represent long term projected failures. Projected failure rates for various levels of replacements are presented in Figure 5.

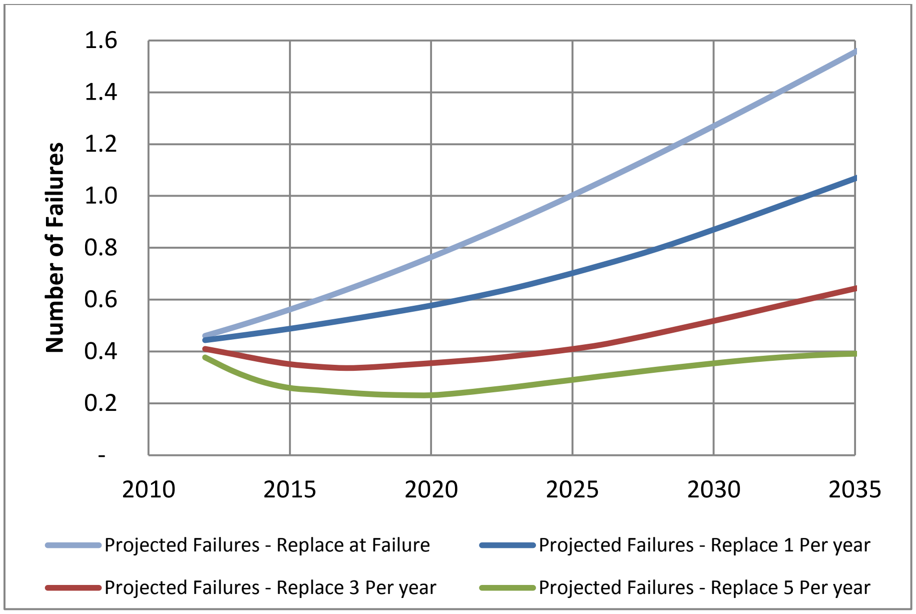



**Figure 5 - Station Transformer Replacement Policy Failure Rates per Year**

**Safety**

With a more aggressive approach to station transformer replacement end of life assets will be reduced at an accelerated pace. In instances where risk to the workforce is a catastrophic station transformer failure - this will be mitigated.

**Resources**

With assets on the system continuing to age and deteriorate, inadequate planned replacements of end of life assets will lead to accumulation of poor/critical assets and potential increase in unplanned replacements that will stress the available resources of HOL at its current staffing level.

**Financial**

The costs associated with replacing transformers in an emergency situation are higher than planned replacements as temporary measures will need to be put into place to restore contingencies until the transformer is replaced. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact.

Replacing unscheduled failed transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

### 1.3.2 Project/Program Timing & Expenditure

Table 4 provides information on the expenditures and station transformer units replaced that was completed in the historical period. The average cost per transformer replaced in projects completed from 2010 to 2012 is provided by TX size:

- 5MVA: $430k

- 9MVA: $900k
- 30MVA: $1,990k
- 45MVA: $2,590k

| | Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| **Total Expenditure** | $2.5 | $5.79 | $3.74 | $4.16 | $10.77 | $10.73 | $4.62 | $6.53 | $8.23 | $7.97 |

**Table 4 - Expenditure History of Comparative Projects**

HOL has replaced 12 station transformers between 2011 and 2014. 21 are planned for replacement between 2015 and 2020.

Station Transformer replacement projects vary depending on the criticality and the ability to supply load. Some projects require a staged approach such that the new transformer is constructed while keeping the existing transformer in-service. Once constructed, the connections are transferred to the new transformer with minimal interruption to the customers.

### 1.3.3 Benefits

Key benefits that will be achieved by implementing the station transformer replacement program are summarized in Table 5 below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | Other assets are typically replaced in conjunction with these projects such as: protections and control upgrade, new egress cables, monitoring devices, disconnect switches and breakers. This collaboration of asset replacement has been found to be cost-effective. |
| **Customer** | Improved reliability due to decreased transformer failures and availability of redundant systems.<br>Improved reliability and safety due to upgraded protection and control systems, and monitoring. |
| **Safety** | Station transformers have potential to fail catastrophically if the mineral oil were to reach its flash point. Replacing the transformer reduces this risk. Upgraded protection and control systems allow for better internal fault detection, which will isolate the transformer from potential catastrophic failure. |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | For station transformer replacement projects that involve transmission connection requirements, HOL coordinates with Hydro One to complete the transmission connection. |
| **Economic Development** | HOL hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources. |
| **Environment** | HOL aims to minimize oil spills by the installation of an oil containment unit underneath each transformer. |

**Table 5 – Station Transformer Program benefits**

## 1.4 Prioritization

### 1.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increase in station transformer failures per year.

Deferral of station transformer replacements will also create a backlog of poor condition power transformers that will require an increased level of investment in the future. As evident in Figure 6 below, if increase in station transformer replacements is deferred until 2020 the asset demographics show a higher level in poor condition.

### 1.4.2 Priority

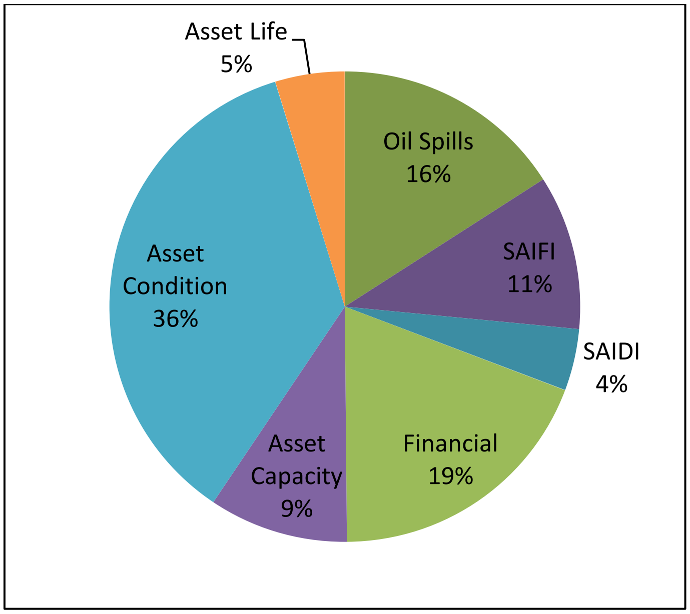



**Figure 6 - Typical Project Score - Station Transformer Replacement**

Typical station transformer replacement project score: 1.257

## 1.5 Execution Path

### 1.5.1 Implementation Plan

HOL is planning for the following transformer replacements in 2015-2016:

- Merivale DS, 2 transformers
- Longfields DS, 1 transformer
- Albion DS, 3 transformers
- Bronson DS, 2 transformers

Station transformer replacement projects typically span over 2-3 years. The project starts with the design, followed by equipment procurement, installation, and commissioning.

### 1.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Coordinating activities in areas where multiple parties are working;<br>• Adherence to schedules;<br>• Material compatibility with existing station equipment;<br>• Quality of materials | HOL has dedicated project managers who oversee the project to ensure that risk is managed accordingly. |

**Table 6- Station Transformer Risks to Completion and Mitigation Strategies**

### 1.5.3 Timing Factors

Transformer projects are typically planned to include any civil construction outside of the winter months to avoid issues with concrete. Construction timing at the manufacture plant typically dictates the schedule of the project.

### 1.5.4 Cost Factors

Cost factors that affect replacement projects are:

- Project creep with including additional assets to be replaced. Most are identified early on in the project.
- Delays in the project schedule.
- Compatibility with existing equipment.

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

## 1.6 Renewable Energy Generation

HOL's station transformer purchasing standard includes designing new transformers with the ability to have reversed current flow through the transformer. This will reduce restrictions due to thermal overloading of transformers for new generation connections.

## 1.7 Leave-To-Construct

(Not applicable for this program)

## 1.8 Project Details and Justification

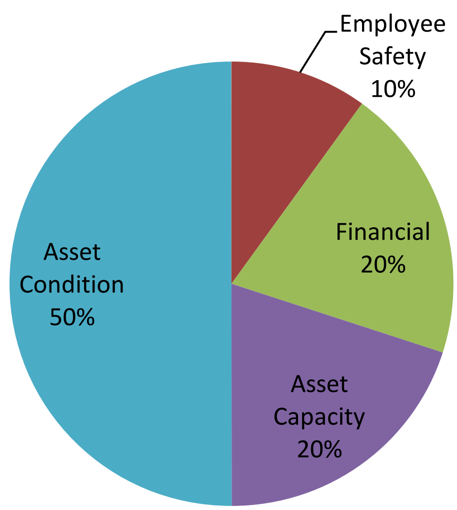
### 1.8.1 Merivale DS Rebuild

| | |
|---|---|
| **Project Name:** | Merivale DS Rebuild |
| **Project Number:** | 920084859 |
| **Capital Cost:** | $17,125,785 |
| **O&M:** | N/A |
| **Start Date:** | February 2014 |
| **In-Service Date:** | August 2018 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1600 customers/50 MVA |

**Project Scope**

The project is to replace two end of life transformers, 72T1 and 72T2, at Merivale DS. The new transformers will also provide upgraded capacity of 15/20/25MVA each. There will be replacement transformer foundations and oil containment, upgraded circuit breakers, reclosers, disconnect switches, metalclad switchgear, new Protection and Control (P&C) equipment and a new P&C house. While not being in the scope of this project, the upgraded station capacity will allow an additional feeder and a duct bank will be put in place to prepare for this future egress. This project takes place within the boundaries of the Hydro One Networks Inc-owned Merivale transmission station at 31 Woodfield Drive. It is important to note that although Hydro One owns the land upon which the station resides, HOL Limited owns the equipment pertaining to its distribution station, and it is anticipated that this project will receive official permission from Hydro One to move forward.

**Priority**




Project Score = 1.01

| Work Plan |
|---|
| HOL Limited is awaiting official permission from Hydro One Networks Inc. to do this station work on Hydro One's property. HOL Limited owns the station equipment at Merivale distribution station and expects approval to do this work. Hydro One is fully aware of the plans for this project.<br>Once all procurement is complete, construction will begin with the demolition of existing electrics to allow the removal of both station transformers. With the transformers removed, the foundations and oil containment will be constructed. The new transformers will be installed, followed by the upgraded circuit breakers, reclosers, disconnect switches and metalclad switchgear. New P&C equipment will be installed and finally, commissioning and energization will take place.<br>Any necessary station outages should be coordinated with the 92008497 Prim Fuse to C-Switcher – Epworth T1 and the 92006413 Borden Farms Switchgear Replacement projects. This will ensure that there will be adequate station capacity to supply the load in the area while this work is being done. |
| **Customer Impact** |
| The main driver of this project is to enhance reliability by replacing two station transformers which have both surpassed the end of their service life. The secondary driver of this project is to upgrade the capacity of the station so that it can meet the current and future demands required of it. It is estimated that Merivale DS requires additional capacity within the next 10-20 years to supply the proposed load, but the end of life transformers require replacement within the next two years. The oil containment will be replaced which ensures that the station's environmental impact will be kept to a minimum. |

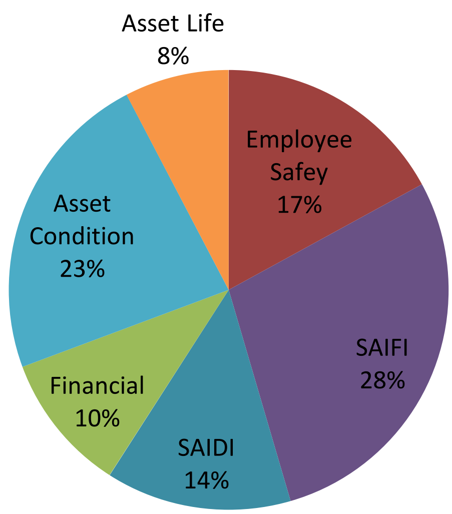
### 1.8.2 Bronson T1 & T2

| | |
|---|---|
| **Project Name:** | Bronson T1 & T2 |
| **Project Number:** | 92008661 |
| **Capital Cost:** | $3,223,099 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2017 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1000 customers/2.5 MVA |

**Project Scope**

Replace 2 end of life transformers at Bronson Substation located at 247 Glebe Avenue.
New 13.2kV 6.7 MVA ONAF transformers will be installed. Replace oil containment as it will be demolished during removal of existing transformers. Install new Protection & Control equipment.
Station capacity and number of feeders are not affected by this project.

**Priority**




Score = 1.173

**Work Plan**

- Demolition of existing oil containment around SBT1 and SBT2 transformers
- Removal of existing transformers
- Construction of replacement foundations for new transformers
- Installation of new transformers
- Construction of new oil containment pit
- Installation of new instrumentation transformers and new Protection & Control equipment

**Customer Impact**

Reliability improvements due to replacement of end of life assets with new equipment.

### 1.8.3 Longfields Transformer Base Replacement – Including CS/CB

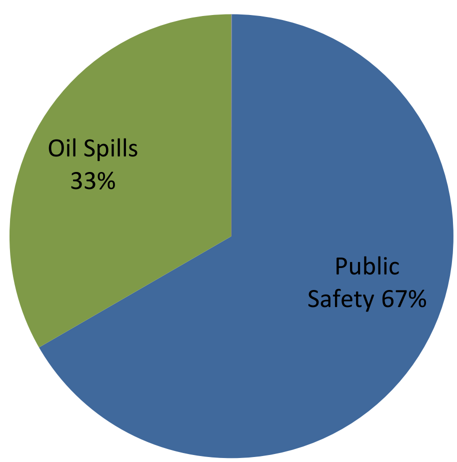
| | |
|---|---|
| **Project Name:** | Longfields XFRM Base Rpl- Including CS/CB |
| **Project Number:** | 92008491 |
| **Capital Cost:** | $4.34 M |
| **O&M:** | N/A |
| **Start Date:** | March 2015 |
| **In-Service Date:** | 2016 – Q1 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,535 customers/ 20MVA |

**Project Scope**

This project involves replacing and upgrading assets at Longfields DS and will include:

- Building a temporary station using one of the current station transformers. The temporary station will be used to service customers while the new transformer base is in construction.
- Construction of T2 transformer base and oil containment
- Upgrade fuse protection to circuit switchers/breakers. New 44kV air break switches, circuit breakers, bus, and all associated structures and foundations. New 27.6kV circuit breakers, tie switch, load break disconnect switches, instrument transformers, and all associated structures and foundations.
- New P&C outdoor panels, SCADA, ground grid, lightning protection, AC and DC station service, cable trenches, cable duct, noise abatement, and privacy fence.

**Priority**




Project Score: 0.9

**Work Plan**

| |
|---|
| The work plan for this project is as follows:<br>• Design and major equipment procurement started in 2014, to be completed in 2015.<br>• Civil construction for temporary station occurring in March 2015.<br>• Electrical construction for temporary station (currently planned to be completed by HOL electricians and technicians) occurring in March 2015.<br>• Civil construction for new station occurring in 2015 (starting end of Q2, ending end of Q4)<br>• Electrical construction for new station (currently planned to be completed by HOL station electricians and technicians) occurring in 2016 (starting in Q1).<br>• New station (T1 and T2) to be energized in 2016. |
| **Customer Impact** |
| The primary driver of this project is to prevent risk of failure by creating protection and environmental upgrades. This project upgrades the primary protection of the station, transformer base and oil containment. These upgrades result in a more reliable and safe station. |

### 1.8.4 Transformer Replacement – 13/4.16kV Albion UA T1, T2 & T3

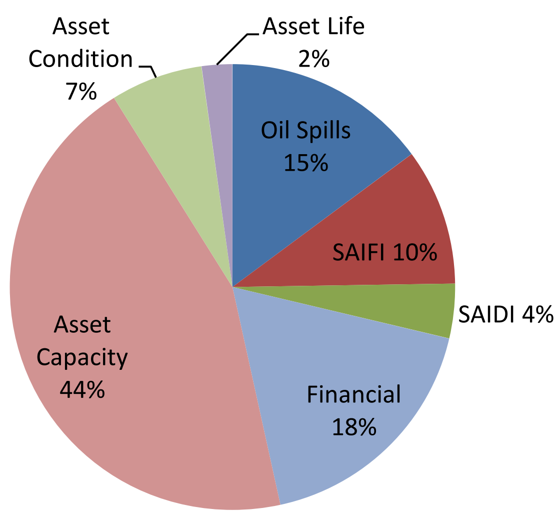
| | |
|---|---|
| **Project Name:** | TFX Repl- 13/4.16kV Albion UA T1&T2&T3 |
| **Project Number:** | 92008579 |
| **Capital Cost:** | $2.97M |
| **O&M:** | N/A |
| **Start Date:** | 2015 |
| **In-Service Date:** | 2016 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 3,688 customers/ 9.6MVA |

**Project Scope**

This project involves replacing and upgrading assets at Albion UA and will include:

- The replacement of 3 existing 5.6MVA 13.2-4.16kV transformers
- New transformer foundation and oil containment
- New primary and secondary cables

**Priority**




Project Score: 1.347

**Work Plan**

The work plan for this project is as follows:

- Design and major equipment procurement occurring in 2015
- Delivery of equipment, and construction to begin in 2016
- Project to be completed by Q4 2016

**Customer Impact**

The primary driver of this project is to prevent risk of failure due to aging assets. Replacement of the aged transformers with new units mitigates the failure risk.

# 2 Station Switchgear Replacement

## 2.1 Project/Program Summary

Station switchgears are commonly employed at substations to provide protection for electrical equipment, and to allow control and isolation during faults and planned maintenance activities. Station switchgears, therefore, have a direct impact on the reliability of electricity supply to customers. Station switchgear failure will have reliability, safety and environmental consequences. The station switchgear replacement program targets the planned replacement of switchgears based on their age and qualitative information to maintain system reliability and safety in the most cost-effective manner.

## 2.2 Project/Program Description

### 2.2.1 Assets in Scope

HOL's station switchgear asset class consists of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation, and fuses. The base unit of this asset class is a switchgear assembly, which includes bus work, feeder breakers, and appurtenances. HOL's current standard is to install arc resistant switchgears. This standard has not always been in place and has been incorporated to minimize safety risks.

The station switchgears targeted for replacement by 2017 are shown in Table 7.

| Switchgear | Year | Scope of the replacement | Reason for Replacement |
|---|---|---|---|
| **Woodroffe UW** | 2016 | Switchgear being decommissioning, customers to be supplied by Woodroffe TW | At end of life. |
| **Woodroffe TW** | 2017 | Switchgear being replaced | Condition. |
| **Bayshore Primary CS** | 2012-2015 | Replace switch and fuse protection with differential. Replace circuit switcher with breaker. | Protection Upgrade. |
| **Borden Farms Switchgear** | 2013-2015 | Installation of new metal clad switchgear. Replace fuses with breakers. Add differential protection. | Switchgear installation and protection upgrade. |
| **Epworth T1 CS** | 2014-2015 | Primary fuse being replaced with circuit switcher. Differential protection added. | Protection upgrade. |
| **Overbrook TO Switchgear** | 2016 | Replace the existing switchgear and breakers. Install new protection and control and cable work. | Condition. |
| **Bells Corners** | 2014-2015 | Replacement of reclosers and controllers. Replace low side protection for AC/DC services with modern load center and fusing blocks. | At end of life. Protection upgrade. |

**Table 7 - Planned Station Switchgear Replacements**

HOL recommends a replacement rate of 3-5 station's switchgear assemblies a year. Under this scenario the expected number of switchgear failures will be reduced and kept constant.

### 2.2.2 Asset Life Cycle and Condition

HOL currently manages switchgear assemblies in 83 substations containing a total of 936 breakers and 67 reclosers. These substations range in operating voltage from 5kV to 27.6kV.

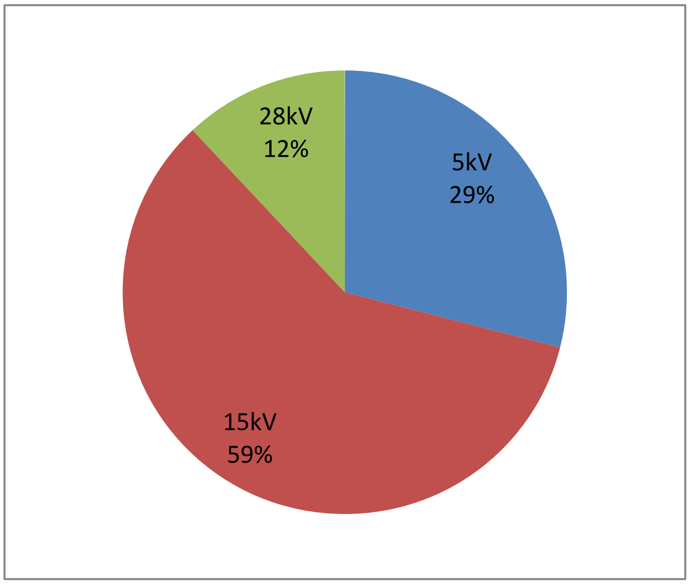



**Figure 7 - Station Switchgear Voltage Rating Distribution**

Demographic information for the station switchgear has been collected from various sources included in HOL's existing condition assessment and maintenance programs. The financial life cycle of this asset class is 40 years, while the technical end of life is anticipated to be 45 years. This variation is to ensure that the asset is fully depreciated by the time it has a high probability of failure. Roughly 58% of HOL's station switchgear breakers and reclosers are at or have passed their financial usefulness, while 43% of the equipment is at or past their end of life criteria. In addition, in the next ten years another 26% of station switchgear breakers and reclosers will be at or past their end of life criteria.

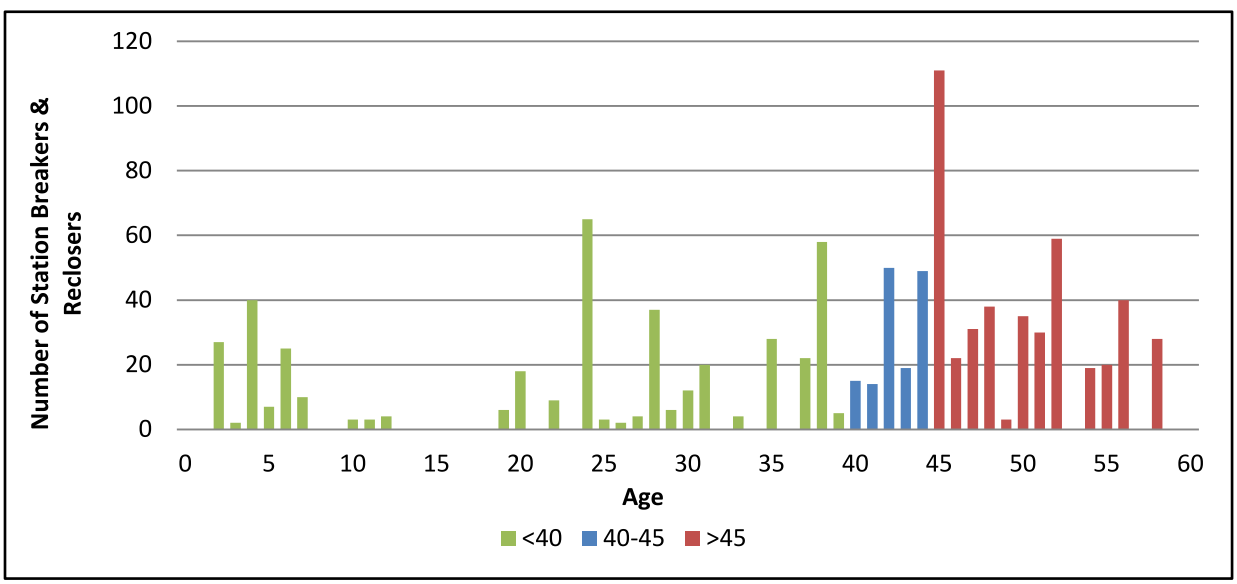



**Figure 8- Station Breaker and Recloser Demographics by Age**

HOL's health condition evaluation of station switchgear assemblies takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

On average, there has been 1.7 station breaker or recloser failures per year experienced over the last six years, seen in Figure 9. This trend is expected to stay the same and potentially increase due to the number of assets past their end of life age. Therefore a replacement plan is required to maintain the number of failures.

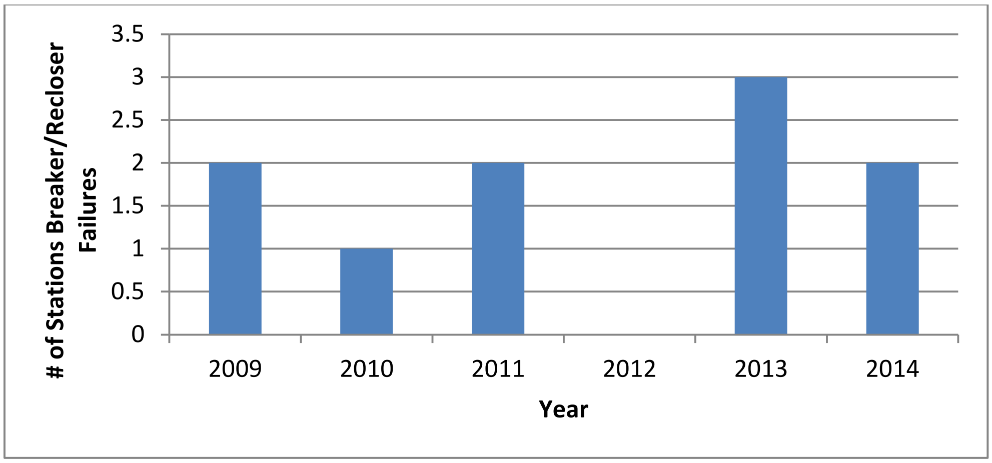



**Figure 9 - Historical Station Switchgear Failures**

### 2.2.3 Consequences of Failure

In general, switchgear failures will result in power loss to customers connected to that device. Outages as a result of a failed component of the switchgear are significant in the amount of customers affected, but also the duration of the outage. Through switching and station work, customers can be restored, however, the typical delivery time for a new breaker or recloser is roughly 6 months. In the last six years the worst outage affected 4479 customers for 6.2 hours.

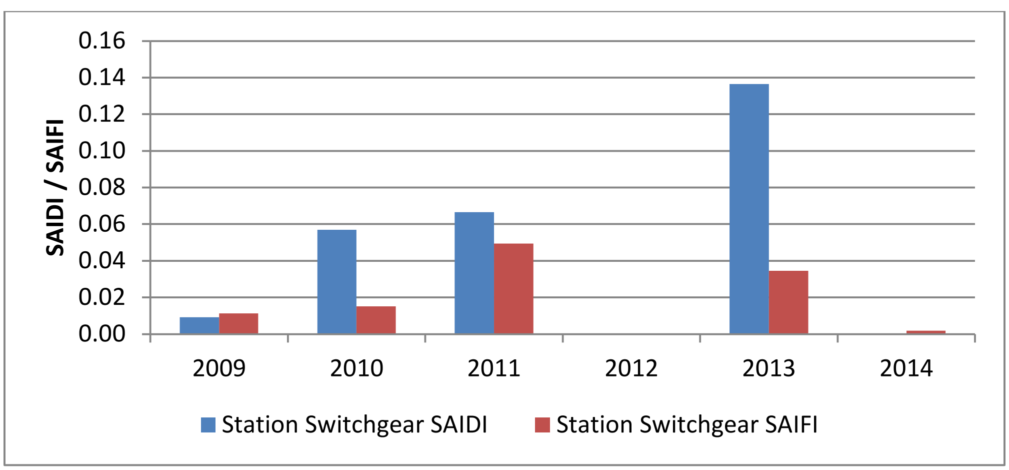



**Figure 10 - Reliability Metrics Associated with Station Switchgear Failures**

*Note: In 2014 there was a breaker failure that would have contributed considerably to the SAIFI and SAIDI. However, it had been offloaded earlier in the day.

Historically, station switchgear has contributed to about 10 percent of the Defective Equipment SAIFI over the historical period. This has remained unchanged in the past five years with minor fluctuations.

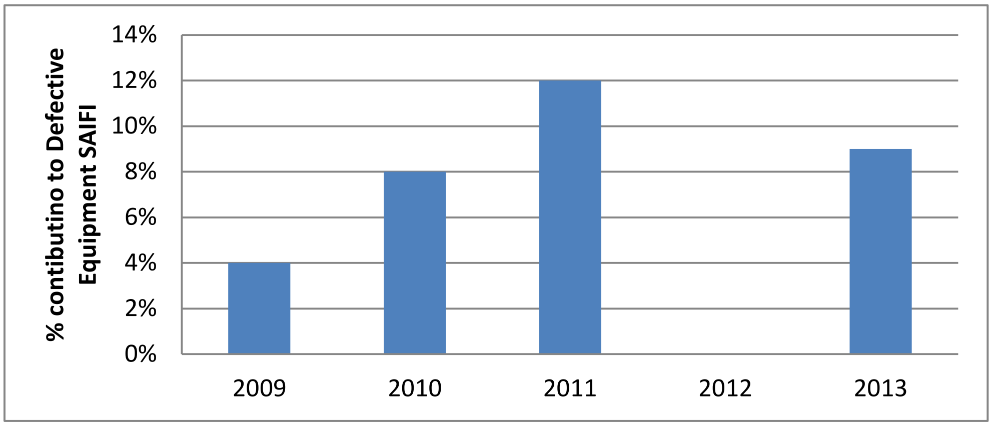



**Figure 11 - Station Switchgear Contribution to Defective Equipment SAIFI**

Failure of switchgear that contains oil as a cooling and interrupting medium can have an extensive impact on the safety of HOL employees and the public. A failure of this type of switchgear can result in burning oil and gas clouds. Older switchgear were not designed to withstand internal arc fault. High energy arcing fault inside the switchgear can lead to explosion, fire, and other catastrophic events that could result in extensive damage to buildings and properties nearby and severe injury or even death of personnel. Furthermore, it can cause oil spills that contaminate the surrounding environment.

### 2.2.4 Main and Secondary Drivers

Drivers for the station switchgear replacement program are summarized and described in Table 8 below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | 43% (436) of the breakers and reclosers in HOL`s system are at 45 years or older. This will grow by 26% (260) over the next 10 years. |
| **Secondary** | **Reliability** | Station switchgear has a direct impact on system reliability, as all customers connected will experience a power outage in the event of a switchgear failure. The amount of customers that are affected and the duration can be substantial. |
| | **Environment** | Station switchgear failures can lead to oil leaks. HOL mitigates this risk through the use of appropriate enclosure and oil containment. However, it is still possible for explosions to cause an oil leak. |
| | **Safety** | Station switchgear failure can potentially lead to injury or even death of HOL employees and the public. HOL's standard is to incorporate arc resistant switchgears to replace station switchgears without arc flash protection. This furthers the safety to employees and the public. |

**Table 8 - Station Switchgear Program Drivers**

Figure 12 - Station Switchgear Explosion

Figure 13 - Bridlewood Recloser Exploded Internally

### 2.2.5 Performance Targets and Objectives

The objective is to also decrease the number of station breakers and reclosers operating past their end of life in HOL`s system. This is expected to increase the systems reliability.

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the station switchgear replacement program, improvements are expected in the following measurement:

- Defective Equipment SAIFI
- Defective Equipment SAIDI

## 2.3 Project/Program Justification

### 2.3.1 Alternatives Evaluation

#### 2.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels.

**I. Station Switchgear Replacement Policy**

Using the rate of failure model developed for station switchgear, HOL analyzed an impact of several replacement alternatives on the performance outcome. Only the alternatives of replacing three to five switchgears a year, stabilizes the replacement amount in the rate filing period (2016-2020). The following scenarios were analyzed:

- Do Nothing, running assets to failure,
- Replace 1 switchgear / year
- Replace 3 switchgears / year
- Replace 5 switchgears / year

### 2.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resource** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 9 – Alternative Evaluation Criteria**

### 2.3.1.3 *Preferred Alternative*

The preferred alternative is to maintain the current reliability level for the station switchgears by replacing three station switchgears a year. It reflects the optimal balance between the reliability and required investment levels. It also eases the stress on the system while transferring the load and reducing the system flexibility required replacing the switchgear.

**Failure / Reliability**

HOL performed an analysis to correlate an equipment failure rate with the age of the asset. The curve used in the analysis is a calculated Weibull probability based on the total age demographic and the age at failure. This allows a curve to be built not only on failure data but incorporates the surviving population. This translates into the failure probability curve shown in Figure 14.

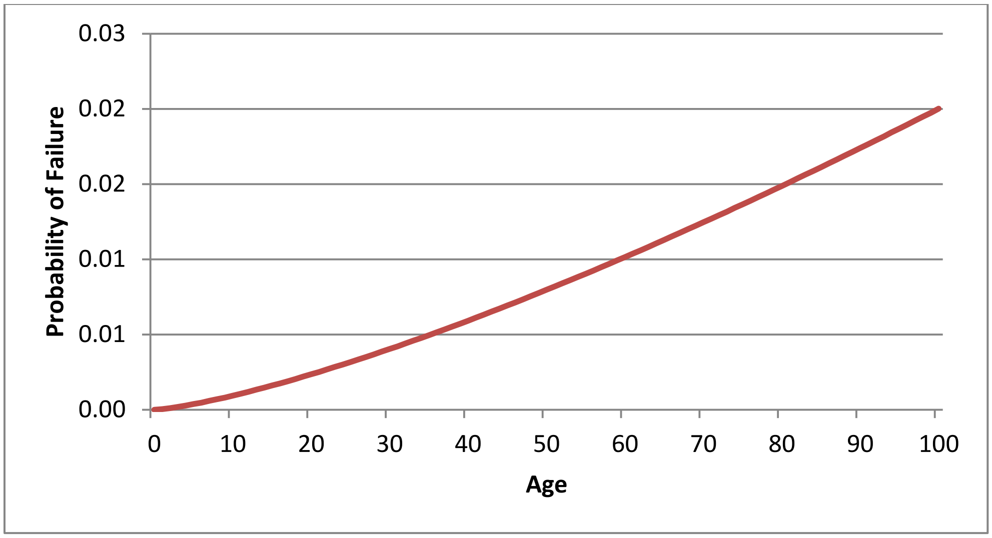



**Figure 14 - Station Switchgear Failure Probability**

Using the demographics of HOL's station switchgears, numerous rate of failures have been projected for the next 20 years under each replacement scenario, as shown in Figure 15.

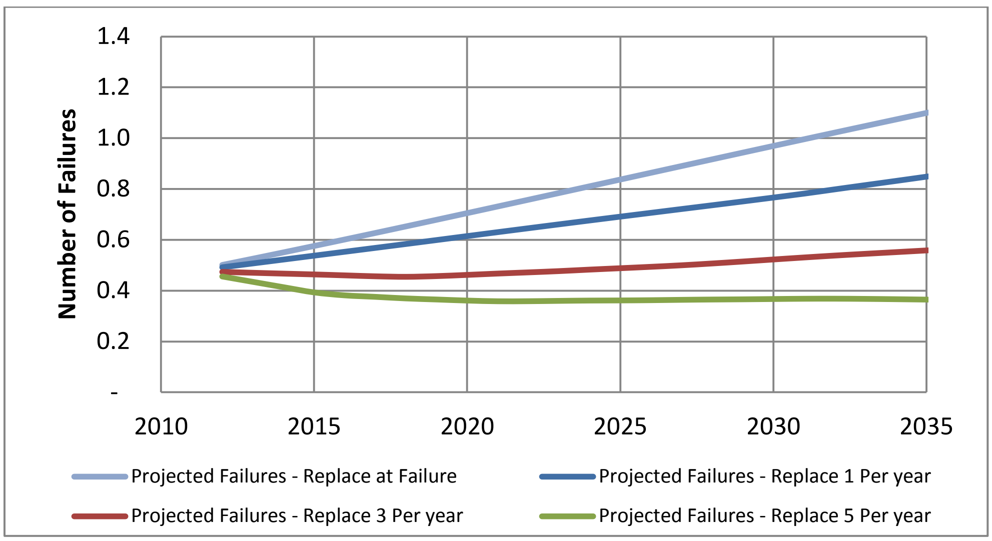



**Figure 15 - Station Switchgear Recommended Replacement Rate**

Replacing three station switchgear assemblies a year will help to maintain the current reliability levels in the near to medium term.

**Safety**

An increased station switchgear replacement policy would minimize the risk to safety of HOL employees and the public by reducing the number of switchgears that are likely to fail based on age.

**Resources**

With assets on the system continuing to age and deteriorate, inadequate planned replacements of aging station switchgears will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level.

Planned station switchgear replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

**Financial**

The cost associated with replacing station switchgears in an emergency situation has been estimated to be substantially higher than the cost of scheduled station switchgear replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent station switchgear failures resulting in a high cost impact of replacing unscheduled station switchgears. By increasing the replacement policy, the average costs to replace a switchgear, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled station switchgears also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed switchgears.

### 2.3.2 Project/Program Timing & Expenditure

Table 10 provides information on the expenditures replaced in the historical and future period. It also shows the number of projects being worked on in the respective year. These projects have the ability to carry on for more than one year due to the work involved. The projects identified in Table 10 are those that have greater than $25k spent in order to eliminate design phase work and capture years of construction and years that equipment was ordered. Costs vary year to year based on the size of switchgear required and how many projects are executing. The projects scope also vary anywhere from the reclosers to the whole metal clad switchgear.

| | Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Total Expenditure** | 1.567 | 2.521 | 5.254 | 8.349 | 6.241 | 5.424 | 7.088 | 7.408 | 6.871 | 7.965 |
| **Projects** | 3 | 5 | 5 | 8 | 6 | 5 | N/A* | N/A* | N/A* | N/A* |

**Table 10 - Expenditure History of Comparative Projects**

*The number of specific projects has yet to be determined and will depend on the number of combined switchgear/transformer projects.

Variations in annual capital spending are dependent on pacing of investments and combining works with other replacement projects.

To achieve higher cost efficiency, future station switchgear replacements will be carried out in conjunction with station transformer replacements where economic benefits exist.

Station switchgear replacement projects are usually staged such that the new switchgear is constructed while keeping the existing switchgear in-service. Once constructed, the feeders are transferred to the new switchgear with minimal interruption to the customers.

### 2.3.3 Benefits

Key benefits that will be achieved by implementing the station switchgear replacement program are summarized in Table 11 below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | New switchgears can have the added benefit of replacing switches at stations. This allows for operation from HOL's system operation control room and eliminated the need for a crew to manual operate them. This saves both time and money.<br>The proactive replacement of units at end of life, but before failure results in labour cost savings compared to unplanned replacement of a failed unit. |
| **Customer** | With the program in place the failure rate of the station switchgears will be maintained over the investment period compared with the run-to-failure approach. Maintained reliability is expected to positively impact customer satisfaction, specifically considering the lengthy nature of the restoration process as a result of the switchgear failure. |
| **Safety** | Switchgear replacements reduce the risk to employee safety by implementing new standards for arc-resistant switchgear. |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | (Not applicable) |
| **Economic Development** | HOL engages contractors to construct and install station switchgear, thereby creating job opportunities. Internal resources are used for the commissioning and acceptance testing of the equipment. |
| **Environment** | Proactive replacement of end of life station switchgears mitigates the risk of oil spilling in the event of a switchgear failure. |

**Table 11 - Station Switchgear Program Benefits**

## 2.4 Prioritization

### 2.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved, this asset group will pose an increased risk to safety and reliability, as a result of the increased potential for switchgear in-service failures. HOL is expected to experience significantly higher failure rates within the next five years without this program in place.

In the long term, deferral of station switchgear replacements will also create a backlog of bad assets that will require more capital investment in the future in order to bring the overall condition of the entire asset class to an acceptable level. This will place a high stress on HOL's internal resources at its current staffing level.

### 2.4.2 Priority

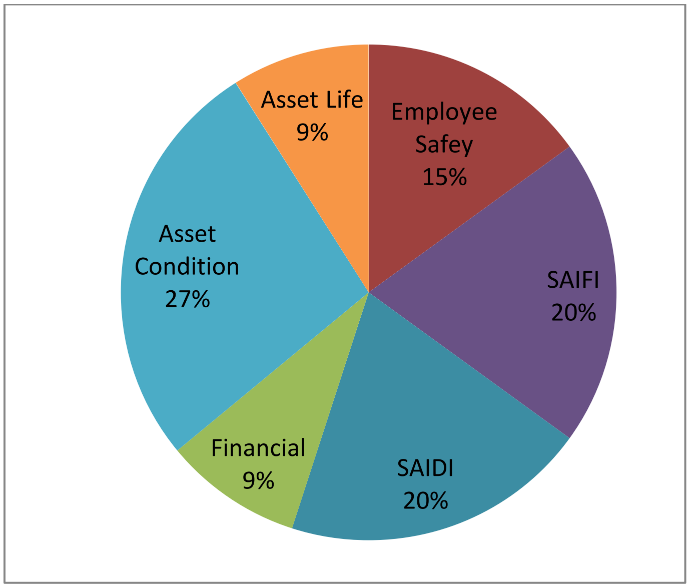



**Figure 16 - Station Switchgear Replacement Avoided Risk**

Score = 1.333

## 2.5 Execution Plan

### 2.5.1 Implementation Plan

HOL's health condition evaluation of station switchgear assemblies takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

Once the station switchgears are prioritized, they are scheduled with either internal or external work crews. Adequate planning and load switching is necessary during the switchgear replacement in order to minimize impact to customers.

### 2.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Project planning to minimize outages to customers and that coordinate with other planned work in the area;<br>• Adherence to schedules;<br>• Timely procurement of equipment;<br>• Quality of materials | HOL has dedicated project managers who oversee the project to ensure that risk is managed accordingly.<br>It is HOL practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resources and ensure continued system operability and safety in areas where crews are working. |

**Table 12 - Station Switchgear Program Risks and Mitigation Strategies**

### 2.5.3 Timing Factors

Switchgear projects are typically planned to include any civil construction outside of the winter months to avoid issues with concrete. Construction timing at the manufacture plant typically dictates the schedule of the project.

Delivery of the assets can also be a risk that is dependent on the manufacturer.

### 2.5.4 Cost Factors

The final cost of the program is affected by the number of station switchgears to be targeted for replacement. If a switchgear fails before replacement is performed, the cost of replacing the failed switchgear will be more than if the work is performed proactively. Failure of the switchgear will also incur increased costs as it will experience customer outages if the electrical assets are damaged.

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain the timelines required.
- The use of in-house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on the PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

## 2.6 Renewable Energy Generation

HOL's purchasing specification for new switchgears is designed to eliminate any short circuit restriction to connect new generation. Leave-To-Construct

(Not applicable for this program)

## 2.7 Project Details and Justification

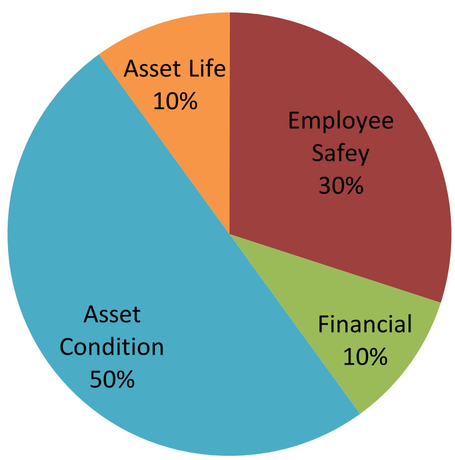
### 2.7.1 Primary Fuse to Circuit Switcher – Epworth T1

| | |
|---|---|
| **Project Name:** | Prim Fuse to C-Switcher – Epworth T1 |
| **Project Number:** | 92008497 |
| **Capital Cost:** | $1,148,693 |
| **O&M:** | N/A |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1400 customers/8400 KVA |

**Project Scope**

The project is to upgrade the protection for the 58T1 transformer at Epworth DS from a 115kV fuse to a circuit switcher. The secondary bus switch will be replaced with a bus breaker to add differential protection. The assets involved in this project are a new 115kV primary circuit switcher, a new 8.32kV bus breaker cell, new P&C panels, new protective relaying equipment and new secondary 15kV copper cable. This project takes place entirely within the boundaries of HOL Limited's Epworth distribution station at 22 Epworth Avenue. The substation capacity will not be affected by this project, nor will the feeders be altered in any way.

**Priority**




Project Score = 1.14

**Work Plan**

Once all procurement is complete, the 58T1 transformer will be taken offline and all construction work will occur during one outage. The implementation strategy for this project is to remove the existing primary fused disconnect and the old 8.32kV 58T1 bus disconnect cell. Then the new 8.32kV 58T1 bus breaker cell will be installed and the new P&C panels will be constructed. Next is the installation of new protective relaying equipment and the new primary circuit switcher. The old overhead secondary bus will be removed from the 58T1 to the switchgear, and new secondary cable from the transformer to the bus breaker cell will be installed. The final stage is commissioning and energization.

| |
|---|
| This project must be coordinated with the 92006413 Borden Farms Switchgear Replacement and 92008485 Merivale DS Rebuild projects to ensure that station outages will not affect capacity. It must be analyzed whether the area will still have adequate supply if multiple stations take outages at once. |
| **Customer Impact** |
| The main driver for this project is to enhance station reliability by replacing the manual disconnect with a motorized circuit switcher, and upgrading the transformer protection to HOL Limited's current standard. The motorized circuit switcher also provides a safer mode of operation. The new electrical protection configuration of the 58T1 transformer will be similar to that of the other transformer at the station, allowing consistency on both sides. |

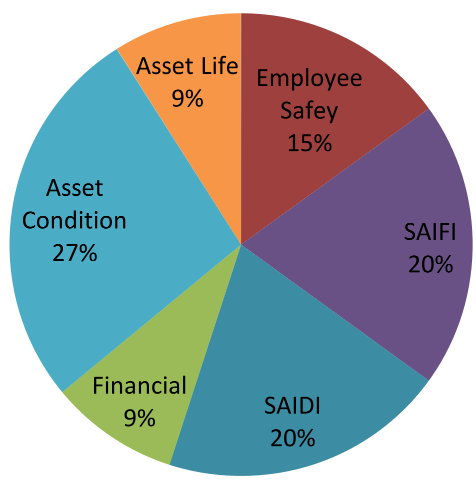
### 2.7.2 Woodroffe TW – 13.2kV Switchgear Replacement

| | |
|---|---|
| **Project Name:** | Woodroffe TW – 13.2kV SG Replacement |
| **Project Number:** | 92008657 |
| **Capital Cost:** | $7,346,447 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q2 |
| **In-Service Date:** | 2017 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 5000 customers/12.2 MVA |

**Project Scope**

- Decommissioning 4.16kV switchgear and transformers
- Replacement of 13.2kV switchgear with new equipment
- New Protection & Control building
- Potential for differential protection upgrade

**Priority**




Score = 1.333

**Work Plan**

Decommission 4.16kV equipment first once transferred to 13.2kV system under the Woodroffe Voltage Conversion project.
Build 2 new metalclad switchgear lineups and Protection & Control building. Transfer customers to new 13.2kV switchgear.
Decommission 2 of the 4 existing 13.2kV metalclad switchgear lineups.
Install 2 more 13.2kV metalclad switchgear lineups. Transfer customers to new 13.2kV switchgear.
Decommission the final 2 end of life 13.2kV metalclad switchgear lineups.

**Customer Impact**

Reliability improvements by removing end of life assets.

### 2.7.3 Borden Farms Switchgear Replacement

| | |
|---|---|
| **Project Name:** | Borden Farms Switchgear Replacement |
| **Project Number:** | 92006413 |
| **Capital Cost:** | $7,269,000 |
| **O&M:** | N/A |
| **Start Date:** | 2013 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 13MVA |

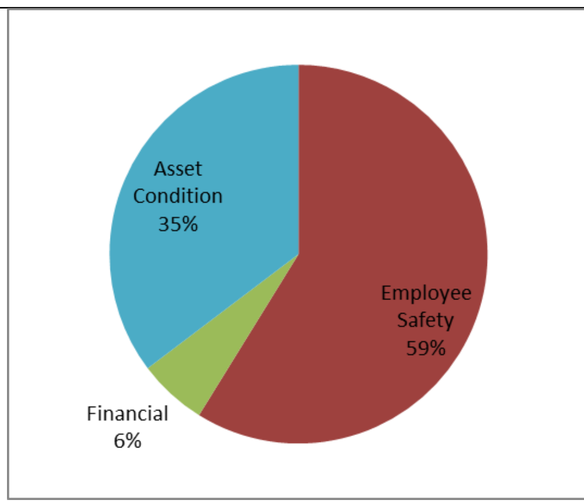
**Project Scope**

This project will replace end of life assets at Borden Farms DS and include:

- Replacement of two (2) 44kV to 8.32kV transformers,
- Installation of a 15kV metalclad SG with 6 feeders,
- Replacement of two (2) primary 44kV fuse disconnect switches with new primary 44kV circuit breakers and,
- Installation of a new protection & control building.

The station is located at 266 Viewmount Drive. The installation will include new oil containment c/w pad for each transformer, new UG duct systems, new primary and secondary riser cables, ground grid upgrade, system neutral and station services (to feed new transformer and Kelman unit) and new Kelman DGA online monitor. Upgrade of existing protection & control will allow the facilitation of differential protection for the transformers. The new transformers will be sized as a 9/12/15MVA with LTR ratings of 22.5MVA for Winter and 19.5MVA for Summer.

**Priority**




Project Score: 1.02

**Work Plan**

The project will begin with the construction of the new switchgear lineup which will house all of the new feeder breakers. Once construction is complete, the old switchgear lineups can be cut-over to the new and decommissioned. Work can then commence on replacing both transformers and primary switchgear. One transformer will be replaced at a time in order to keep the station functional during the construction.

**Customer Impact**

The customers connected to Borden Farms DS will see an increase in service availability from this project reducing the risk of asset failures.

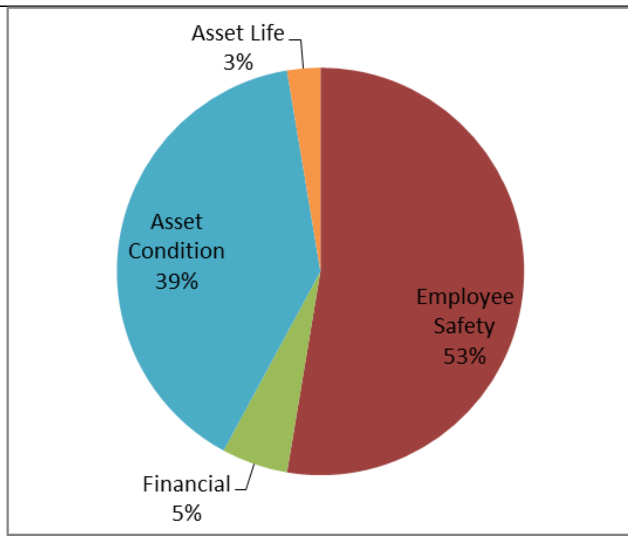
### 2.7.4 Bayshore Primary Circuit Switcher

| | |
|---|---|
| **Project Name:** | Bayshore Primary CS |
| **Project Number:** | 92006411 |
| **Capital Cost:** | $3,782,000 |
| **O&M:** | N/A |
| **Start Date:** | 2013 – Q1 |
| **In-Service Date:** | 2015 – Q2 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 12MVA |

**Project Scope**

The main driver for this project is to reduce the risk of failure due to aging assets. The existing primary disconnects switches have been in disrepair for a few years and there are concerns with the integrity of the supporting wall they are attached to.
This project will take the opportunity to update the primary protection to the current HOL practices by installing breakers which will serve to facilitate transformer differential protection.

**Priority**




Project Score: 1.14

**Work Plan**

This project is to replace the existing 44kV primary disconnect switches and tie switch with new 44kV primary air break switches and breakers. In addition, a new protection and control cabinet housing the controls for both circuit breakers, RTU, satellite clock, network switch, and power quality metering. The power quality metering will be measured by the existing CTs (in transformer and switchgear) and PTs in the existing switchgear. For differential protection from the secondary side perspective, new protection class CTs will be installed inside the existing switchgear. A new DC battery cabinet will also be installed. A feasibility study will be performed to determine how to install a primary side tie switch between both transformers. The subsequent design and construction for the tie switch & breaker will also be performed. The overhead bus inside the building will be replaced with underground cables (transformer secondary) and overhead cabling for secondary tie bus. The project design began in 2013 with the majority of the work taking place in 2014.

**Customer Impact**

Reliability improvements due to added protection of station transformers. Risk of outages and equipment damage is reduced.

### 2.7.5 Overbrook TO Switchgear Replacement

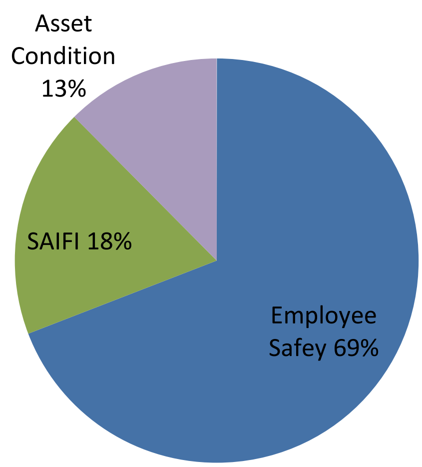
| | |
|---|---|
| **Project Name:** | Overbrook TO Switchgear Replacement |
| **Project Number:** | 92010241 |
| **Capital Cost:** | $7.13 M |
| **O&M:** | N/A |
| **Start Date:** | 2015 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 6,845 customers/ 89 MVA |

**Project Scope**

This project involves replacing and upgrading assets at Overbrook TO and will include:

- Replacement of the 13.2kV switchgear and breakers
- New P&C, new cable between switchgear terminations and splices in the basement

**Priority**




Project Score: 1.447

**Work Plan**

The work plan for this project is as follows:

- Design and major equipment procurement occurring in 2016
- Delivery of equipment, installation, and energization will occur in 4 stages -1 stage per bus of the TO
    - Stage 1 (bus 1) -2016-2017
    - Stage 2 (bus 2) -2017
    - Stage 3 (bus 3) -2017
    - Stage 4 (bus 4) – 2017-2018
- Project to be completed by Q2 2018

**Customer Impact**

The primary driver of this project is to prevent risk of failure due to aging assets. This project will replace the existing switchgear with new arcproof switchgear, limiting risk to employee safety.

### 2.7.6 Startop Protection Upgrade

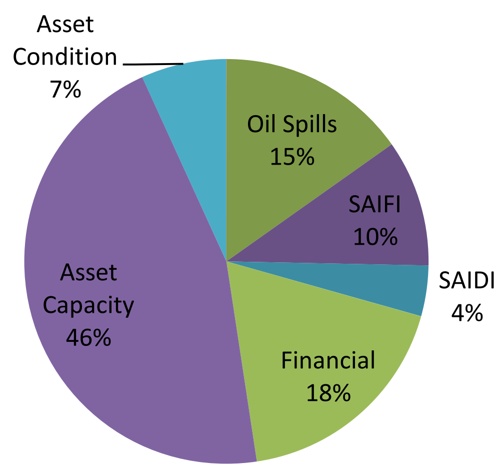
| | |
|---|---|
| **Project Name:** | Startop Protection Upgrade |
| **Project Number:** | 92007348 |
| **Capital Cost:** | $4,768,000 |
| **O&M:** | N/A |
| **Start Date:** | 2013 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 16MVA |

**Project Scope**

The project involves replacing and upgrading assets at Startop DS and will include:

- Replacement of two (2) existing transformers,
- Replacement of two(2) primary bus switches with breakers,
- Replacement of two (2) secondary bus switches with breakers,
- Installation of new tie breakers on both primary and secondary bus,
- Upgrade of existing station protection & control to include line protection, transformer differential and bus partial differential.

**Priority**




Project Score: 1.32

**Work Plan**

Project design will begin in 2013 with material procurement and construction commencing in 2014. The Startop T1 transformer will be in service by 2015 – Q1 and the remainder of the station by 2015 – Q4.

**Customer Impact**

The main driver for this project is reliability. HOL has identified that creating a loop of the 44kV sub-transmission feeder that supplies many of the City's east stations will greatly reduce the duration of unplanned system interruption. This study required Startop DS to install a primary tie breaker and upgrade the station's protection and control.

The goal is also to prevent the risk of failure due to aging assets. The scope of this project has expanded to include the replacement of the transformers and secondary bus breakers.

# 3 Pole Replacement

## 3.1 Project/Program Summary

The HOL overhead distribution system is supported both electrically and mechanically by a system of poles and fixtures. The reliability and safety of the overhead distribution is contingent on the performance of these poles and fixtures.

The pole replacement program replaces wood poles, and pole fixtures, on the overhead distribution system that are aged or in poor condition. Existing composite, concrete and metal poles, in general, are in good condition and will not require replacement.

Poles and fixtures will be replaced with an equivalent pole on a like-for-like basis. New poles are fully treated western red cedar. HOL's current practice is to replace porcelain insulators with ones made of a polymer material. The conductor will not typically be replaced at the same time as the pole as experience has shown very little failure rates resulting from conductors.

Under specific circumstances, a wood pole will be replaced with a new composite pole. Composite poles are of a fiber-reinforced material and are used in areas that have a high probability of woodpecker damage or when installed in high moisture soil conditions.

HOL recommends a replacement rate on average of 1,250 poles a year in 2016-2020, which represents 10% of the entire population of distribution poles. Increase in the amount of poles replaced during the rate filing period to 1,250 units from 600 poles in 2015 which reduces the risk of having poles in a critical or poor condition.

## 3.2 Project/Program Description

### 3.2.1 Assets in Scope

The poles targeted for replacement are either in poor or critical condition or are at high risk to degrade to poor condition in the next several years. This approach helps HOL to more effectively utilise the resources and increase customer satisfaction by avoiding multiple construction project set-ups in the same area.

The poles targeted for replacement in 2016 and 2017 are identified in the specific projects listed in Section 8 of this business case. Poles are also being replaced in voltage conversion projects which require the replacement of poor condition poles to accommodate the change in voltage. These poles have been identified based on the results on the annual inspection program performed by the utility, reports received from the construction and maintenance crews while performing their regular activities. HOL will use the same approach to identify poles for replacement in the remaining period, 2018-2020.

### 3.2.2 Asset Life Cycle and Condition

HOL owns 47,815 wood poles and 537 non-wood poles and operate on an additional 11,635 wood and 126 non-wood poles which are owned by third parties.

Currently, HOL has installation date information for approximately 25% of its poles. Those poles for which installation information is not available, install data has been estimated using manufacture date, estimated from the adjacent property legal records, or assumed to be equivalent to the average age of the known poles in that region (roughly 41% of asset group).

Typical lifecycle of wood poles is 45 years. The overall age demographics of wood poles in HOL's distribution system are shown in Figure 17. Percentage of wood poles that have passed end of life criteria is 40%. Majority of the poles, roughly 54%, were installed within the period of 1960 and 1990. Therefore, percentage of poles passed the end of useful life will grow to 52% by the end of rate filing period 2020. In addition, in the next ten year period in 2020-2030 another 16% of wood poles will reach the end of useful life.

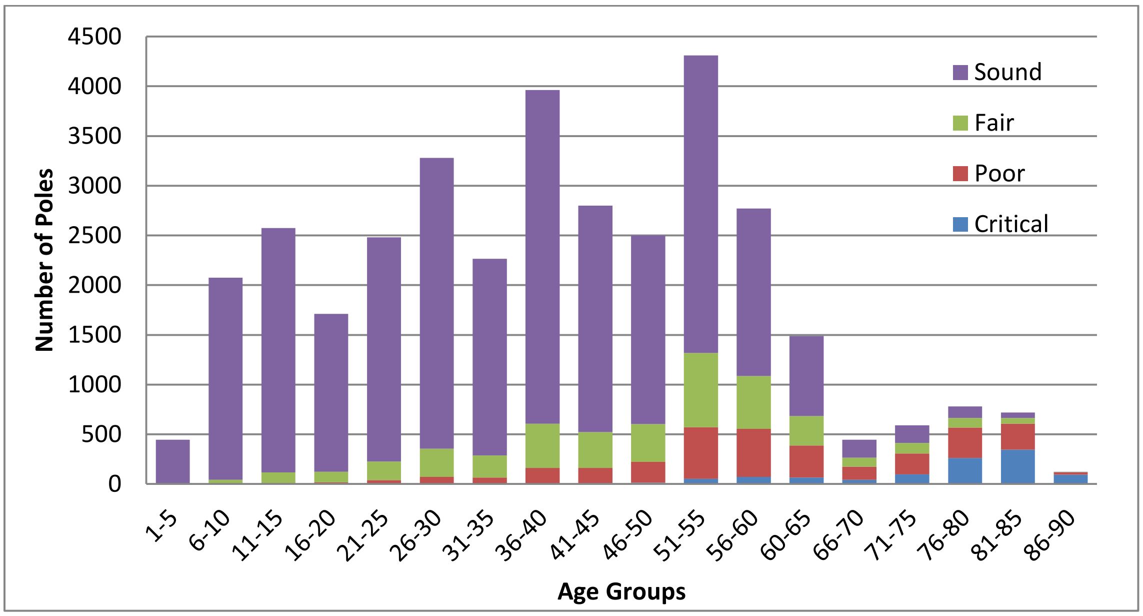



**Figure 17 – Proportion of Wood Poles by Installation date and condition (Known and Estimated)**

Wood pole health is assessed relative to the ability to perform its designed function: support overhead plant under anticipated maximum climatic stress. In general, this can be assessed as a function of a pole's remaining strength at the ground line (which is the area of maximum stress on a pole). As per Canadian Electrical Code - CSA 22.3, poles should be replaced once they fall below 60% of the required strength. HOL adopts this recommendation as key criteria for wood pole replacement decision. However, while remaining strength is a primary driver for evaluating pole condition there are other factors that are considered for replacement criteria. These factors include: shell condition, pole top condition, and woodpecker damage.

- Shell Condition – Weathering and external rot on the pole surface may not significantly impact the strength of the pole. However, it does impact the aesthetics and may present a safety hazard or impede HOL work if it is in a location where climbing the pole is required.

- Pole Top – Weathering and rot at the pole top will not significantly impact the strength of the pole. It will however increase the risk of pole hardware coming loose (due to bolts pulling through the wood). It is also unsightly and may present a perceived issue/concern to the public.
- Woodpecker Damage – Smaller holes are repairable and present predominantly aesthetic issues. Large woodpecker holes, depending on their location along the length of the pole, can significantly impact the strength of a pole. Woodpecker holes left un-repaired can potentially reduce the life of a pole, as the untreated pole heart-wood is exposed to elements which can lead to decay and insect attack.

The condition of the poles is assessed based on results obtained through an inspection program which entails a visual check and non-destructive Resistograph drilling introduced in 2010. It is utilized for the detection and measurement of internal decay and measurement of the remaining shell thickness with minimal damage to the pole. Visual inspection is conducted on all poles in a section of overhead line, and approximately 20% of the poles in each pole line are tested using the Resistograph drill, the results of which can be extrapolated to all poles within the section, or poles of similar vintage.

Required design strengths are based on the expected maximum climatic forces which the installation must endure. Even when a pole has reached end of life and/or that it has degraded to 60% or less of the required design strength, the actual failure of the pole is contingent on it being stressed by external forces approaching or equal to these maximal design conditions. Once a pole reaches end of life, it may remain standing and in service for many years before external forces result in a failure.

HOL performed earlier an analysis to correlate the pole condition to failures in order to develop a hazard curve and estimate the probability of failure at any given age. With the increased availability of inspection data for the distribution poles, current analysis has been carried out to correlate the remaining strength to pole age. The remaining strength to pole age correlation will become more accurate as more inspection data is collected every year.

Based on this analysis, poles have been grouped into 4 categories as shown in Table 13. The resulting pole distribution based on this model can be seen in Figure 18.

| Group | Remaining Strength |
|---|---|
| **Critical** | Less than 25% |
| **Poor** | 25 – 60% |
| **Fair** | 60 – 75 % |
| **Sound** | 75 – 100% |

**Table 13 - Pole Condition to Remaining Strength**

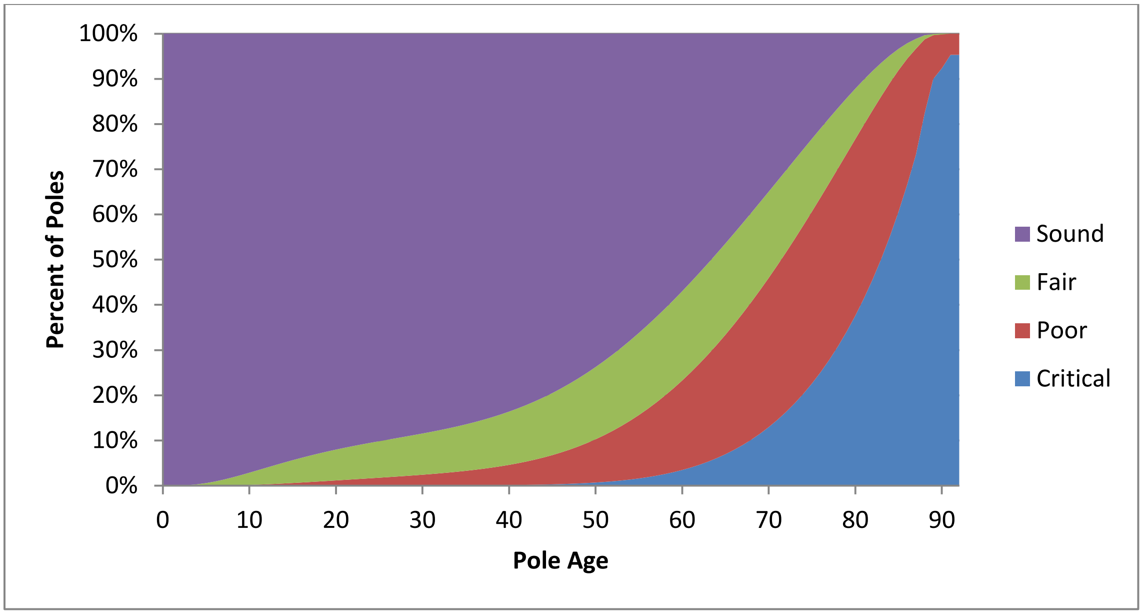



**Figure 18 - Proportion of Wood Poles by Age**

By extrapolating the results of the condition survey to the entire pole population, it is estimated that 4,901 wood poles exist in the field that are in poor or critical condition. Details of the wood pole condition are represented on Figure 19.

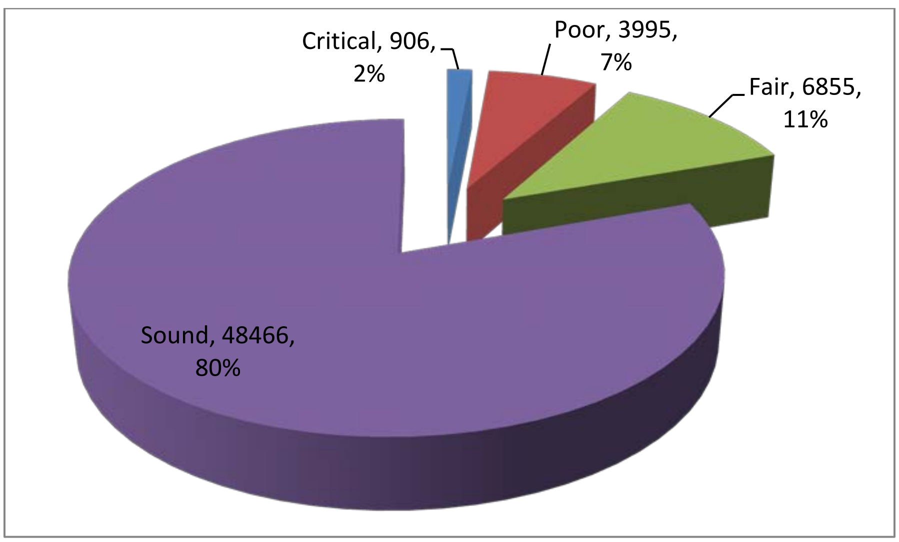



**Figure 19 - Remaining Strength of HOL's Pole Population**

Poles in poor or critical condition have technically failed as they no longer have the required strength to perform the function for which they are designed. They will not necessarily be identified and may not fail unless subjected to external forces approaching the design forces (i.e. severe wind storm). Based on average pole failures it is estimated that only 1 in 10 critical poles and 1 in 150 poor quality poles will fail annually. If this trend continues it will result in an annually increasing organizational risk due to the increasing number of poles which will not be able to weather severe storms.

The records of pole failures from 2009 to 2013, as shown in Figure 20, indicate an upward trend in the number of failures per year. Based on the data, the number of pole failures has been increased by 65% in 2013 from 2009 number.

An increasing trend with the experienced number of failures is indicative of the deterioration of the condition of poles. Therefore a more aggressive replacement plan is required to maintain system reliability.

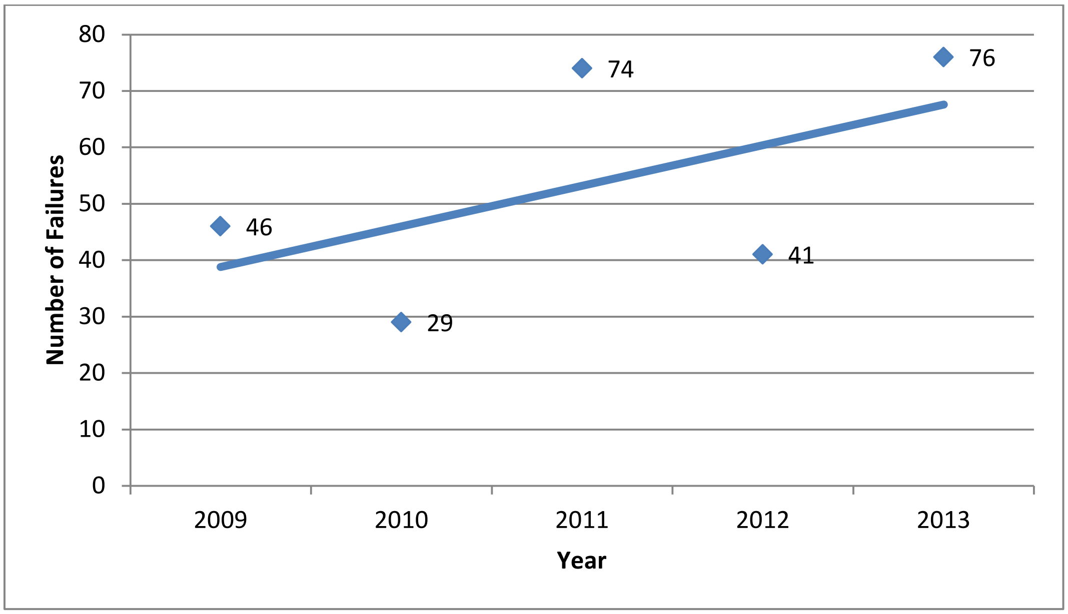



**Figure 20 – Distribution Pole Failures**

Pole fixtures are typically run-to-failure or are replaced in concert with the replacement of the pole (or other equipment) to which they are affixed. However, they do from time to time require proactive replacement in response to known design or manufacture defects. Issues have been encountered due to the failure of several styles of porcelain insulators.

### 3.2.3 Consequence of Failure

In general, pole failures will result in outages affecting customers connected to that pole. While outages as a result of pole failures are typically limited in customers impacted and duration, as the density of poor quality poles increases, the chance of cascading failures and simultaneous failures during severe weather also significantly increases. Such events can have a high impact on overall system reliability.

Figure 21 shows the Defective Equipment SAIDI & SAIFI contributed by overhead poles from 2009 to 2013.

In 2013, overhead poles contributed to 8.6 of the total SAIFI caused by defective equipment in that year.

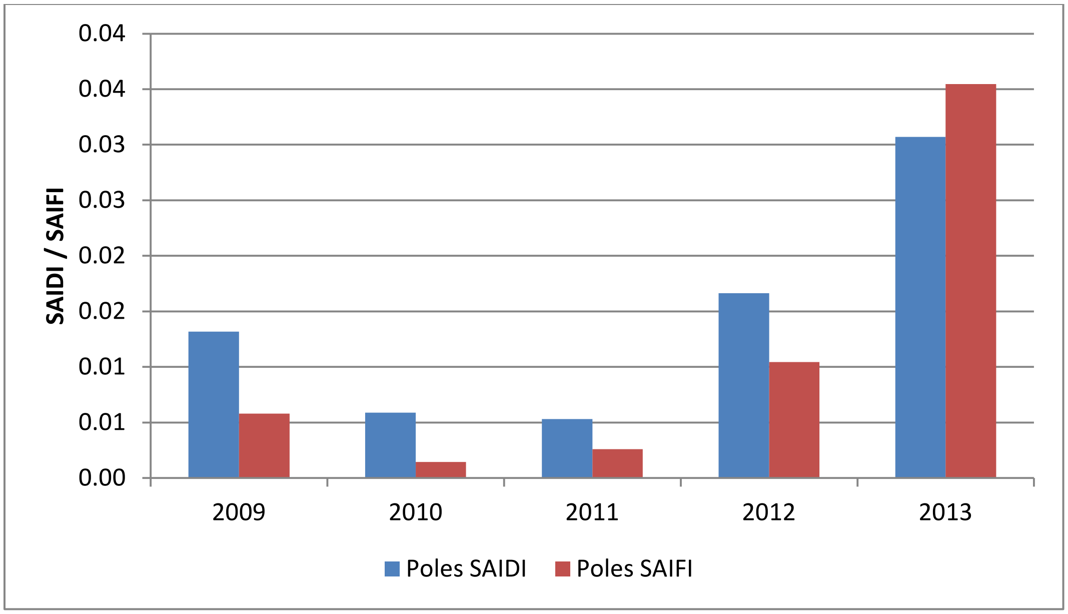



**Figure 21 – Defective Equipment Poles SAIDI & SAIFI**

When poles fail they also pose a significant safety risk to the public, employees and property as the result of downed wires and poles.

In addition, when a pole supports oil filled transformers there is the chance of environmental impact due to the release of oil.

### 3.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | Percentage of wood poles that have passed end of life criteria is 40% that will grow to 52% by the end of rate filing period 2020.<br>Approximately 9% of HOL's wood poles have been determined to be in poor or critical condition and require replacement.<br>Increasing number of pole failures and impact on SAIFI |
| **Secondary** | **Safety** | Risks of pole failures leading to injuries of HOL employees and the public. |

**Table 14 - Wood Pole Replacement Main Drivers**

### 3.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the pole replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

## 3.3 Project/Program Justification

### 3.3.1 Alternatives Evaluation

### 3.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program HOL considered two alternatives for the pole standard to be used while replacing the pole as well as four alternatives for the replacement policy levels.

I. **Pole material standard**

Wood poles can be replaced on a like-for-like basis with an equivalent wood pole or with a pole made from a composite material.

II. **Pole Replacement Policy**

Using the degradation model developed for wood poles, HOL analyzed an impact of several replacement alternatives on the performance outcome. All the alternatives stabilize the replacement amount at the same level beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of the poles,
- Status-Quo scenario (400 poles / year) by maintaining a pole annual replacement amount on the current level
- Replace 750 poles / year to maintain mid-term reliability levels
- Replace 1250 poles / year to maintain long-term reliability levels
- Replace 1500 poles / year to improve mid and long-term reliability levels

### 3.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resource** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 15 – Alternative Evaluation Criteria**

### 3.3.1.3 *Preferred Alternative*

I. **Pole material standard**

The preferred alternative is replacing the wood poles on a like-for-like basis. However, HOL considers the possibility of increasing the proportion of composite pole installations in the future.

Composite poles have been HOL's Standard for use in wood-pecker prone areas, as well as in areas where treated wood-poles cannot be used due to standing water.

**Failure / Reliability**

Composite poles are more likely to bend in severe winds compared to other materials decreasing the likelihood of a break. In addition, the composite material used cannot sustain fire.

The main drawbacks to the use of composite poles are that they cannot be climbed and are more susceptible to external damage from vehicles and snowplows.

**Safety**

Composite poles weigh significantly less than wood poles, reducing potential for strain injuries when poles are installed. They are also hydrophobic and non-conductive, reducing potential for second point of contact injuries, and help prevent arcing caused by lightning and switching.

**Resources**

Since the composite poles that HOL purchases are modular assemblies, an extra step is required to assemble composite poles before they are set in place.

**Financial**

HOL's data indicates that wood poles have a life span between 40 and in rare cases 92 years, and where external attack is prevalent shorter service life has been seen. Composite poles by contrast will not rot, splinter or decay, nor are they susceptible to insect or woodpecker damage. Composite poles will degrade due to exposure to UV light. HOL has trialed composite poles from RS Technologies. Their poles have been engineered for a minimum service life of 65 years in high UV environments such as Florida. In the less demanding climate it is anticipated that pole life could be expected to last 125 years.

Due to the composite pole material cost, the total installed cost is estimated to be roughly 1 to 11% higher than a wood pole in spite of its lower weight and modular design that reduces transportation and warehousing costs.

**Other**

Wood poles require deforestation (each pole is a tree), and requires chemical treatment in order achieve appropriate service life. By contrast, composite poles are manufactured from inert materials, preserving trees, and eliminating any leaching of preserving chemicals. They also result in lower emissions due to reduced transportation requirements.

With these benefits and potential savings and only moderate increase in direct capital costs, it is recommended that HOL considers the possibility of increasing the proportion of composite pole installations. While this will increase the capital costs in the short term, it will reduce overall program costs in the long term, while decreasing HOL's environmental footprint. With the increased minimum life of composite poles the life cycle capital costs for composite poles are expected to be on par or lower for composite poles (assumed minimum life wood-40 years, composite-70 years). Wood poles can be replaced on a like-for-like basis with an equivalent wood pole or with a pole made from a composite material.

**II. Pole Replacement Policy**

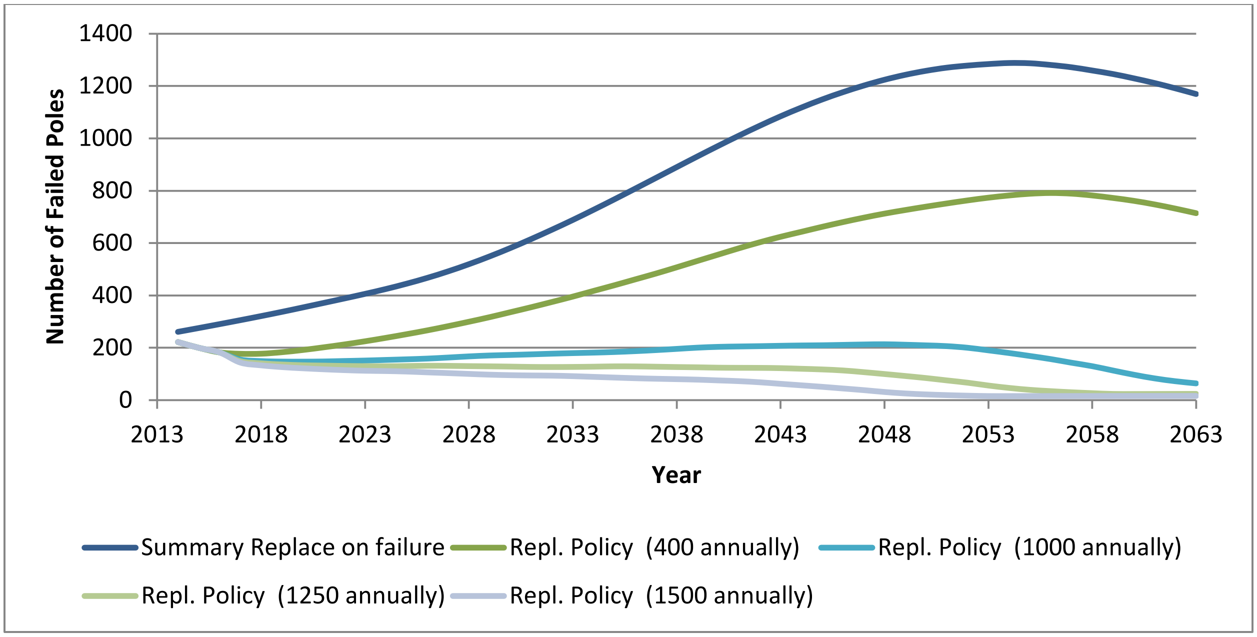
The preferred alternative is replacing the poles in poor and critical condition at 1,250 poles per year.

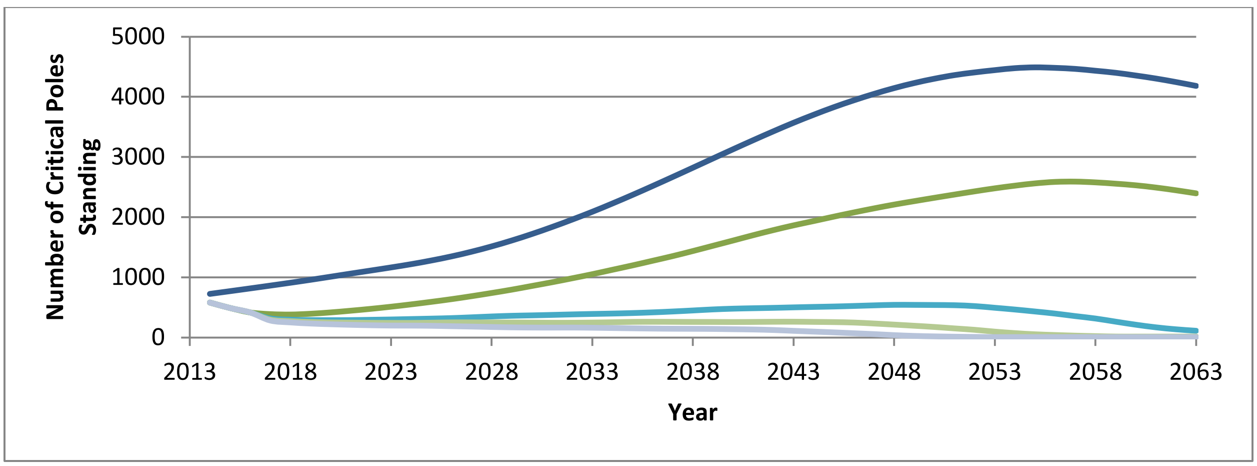
The 1,250 replacement level is based on an assumed 100% program efficiency, that is to say only the oldest and poorest condition poles are replaced first. This level of program efficiency does not occur in practice, rather as areas are targeted for replacement all poles within 5-10 years of end of life are replaced. This approach allows for financial efficiencies, and reduced customer inconvenience, over the piece-meal approach of only replacing poles currently at end of life. It is estimated that the replacement program is typically around 50% efficient, that is, 50% of the poles that are projected to fail annually are able to be replaced in a planned fashion. If the annual planned replacements exceed this value the remaining planned replacement are assumed to be the oldest poles in the system. In order to achieve the results as the 100% efficiency 1250 pole replacement program, 1300 poles annually would be required at 50% efficiency and 1558 poles at 25% efficiency. Based on this analysis it is recommended that roughly 1400 poles annually be targeted for replacement in order to achieve the desired results.

**Failure / Reliability**

HOL has analyzed the impact of several replacement policies using the degradation model developed for wood poles. Results of this analysis indicated that an increase of replacements to 1,250 poles annually would be required to manage failures while bringing the number of poles in critical and poor condition to an acceptable level.

Based on this analysis, it can be seen that an increase of replacements to 1,250 poles annually would be required to manage failures while bringing the number of poles in critical and poor condition to an acceptable level. The number of failed poles indicated in the first graph represents the number of poles that have reached end of life and/or degraded to 60% or less of the required design strength. The actual failure of the pole is contingent on it being stressed by external forces approaching or equal to these maximal design conditions.



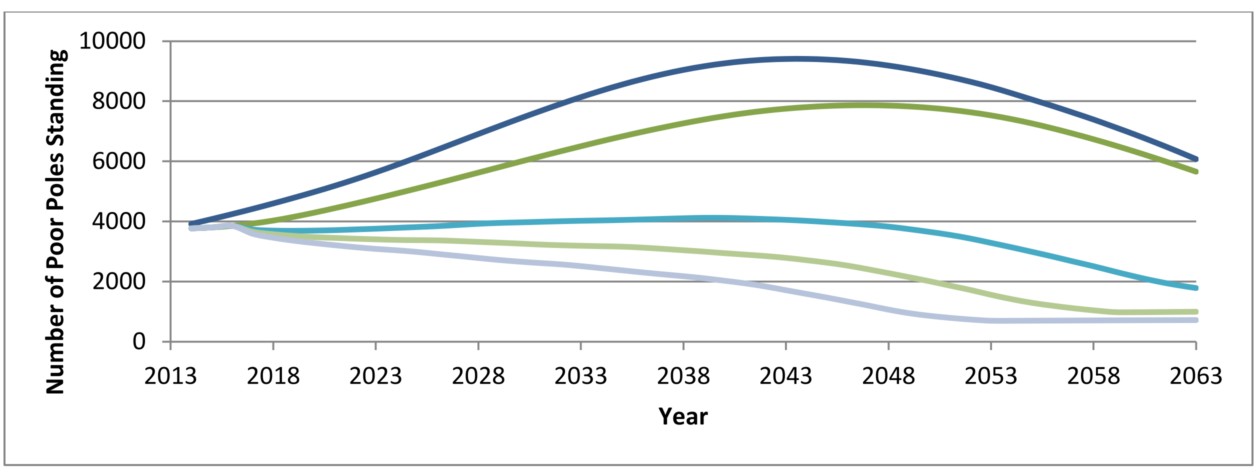




**Figure 22 - Pole Forecast Under Different Replacement Policies**

**Safety**

An increased pole replacement policy would minimize the risk to safety by reducing the number wood poles that are in critical and poor condition.

**Resources**

With assets on the system continuing to age and deteriorate, inadequate planned replacements of EOL assets will lead to accumulation of poor/critical assets and potential increase in unplanned replacements that will stress the available resources of HOL at its current staffing level.

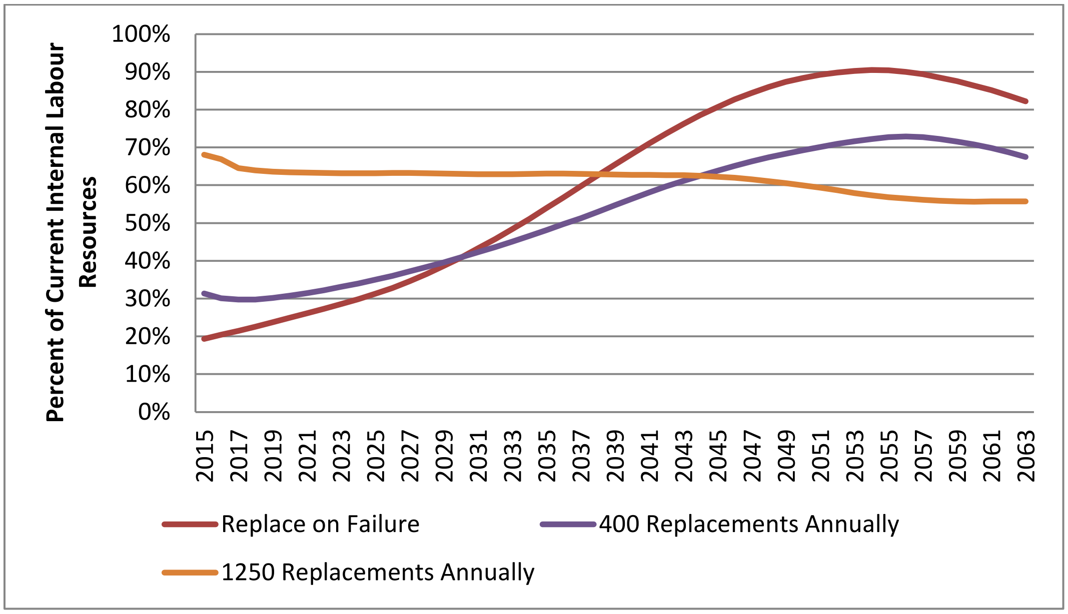



**Figure 23: Labour Requirements**

Estimated labor requirements for planned and unplanned pole replacement work are shown in Figure 23. With the proposed planned program, by 2063 unplanned pole replacements are anticipated to be reduced to approximately 2% of the available labour. Conversely, with a 400 annual replacement policy unplanned replacements account for 50% of the available labour. A planned labour approach allows for the program to be scaled from year to year and contractor resources to be brought in to assist in the replacement program. With the replace at failure approach the majority of replacements would require the use of internal resources. In addition, the unplanned work would not be divided evenly between years as shown. Plant failure trends show that while the average annual number of pole failures annually since 2005 is 42, the maximum occurred in 2013 with 76 failures – almost 200% of the average. If this trend holds true under a 400 poles annual replacement program the unplanned replacement labour requirement would be anticipated to fluctuate between 20% and 65% of current internal staffing levels.

**Financial**

The costs associated with replacing wood poles in an emergency situation has been estimated to upwards of double the cost of scheduled pole replacements. The do-nothing policy would see more frequent pole failures resulting in a high cost impact of replacing unscheduled poles. By increasing the replacement policy, the average costs to replace poles, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled poles also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed poles.

### 3.3.2 Project/Program Timing & Expenditure

Table 16 provides information on the expenditures and number of poles that were completed in the historical period. The average cost for replacing a pole in projects completed from 2010 to 2012 was $18,000, compared to the YTD cost per pole of $21,000 under this program. Poles are replaced in other programs such as voltage conversion, plant relocation, and service connections.

| | Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Total Expenditure** | $5.47 | $7.30 | $6.00 | $5.79 | 10.48 | 8.64 | 6.59 | 7.60 | 6.88 | 7.18 |
| **Units Replaced** | 372 | 374 | 257 | 210 | 500 | 411 | 313 | 362 | 328 | 342 |
| **Other Programs (New & Replaced)** | 598 | 557 | 820 | 845 | N/A | N/A | N/A | N/A | N/A | N/A |

**Table 16 - Expenditure History of Comparative Projects**

In 2013 & 2014, funds were moved from the pole replacement program to a system voltage conversion project which planned to replace poles to accommodate the change in voltage.

Specific pole replacement projects are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the pole replacement all pole fixtures are replaced and connecting transformers are reviewed and identified for replacement where required. In order to maximize system operation, phase balancing is also reviewed prior to pole replacement to see if any load connections should be relocated to a different phase during the work.

### 3.3.3 Benefits

Key benefits that will be achieved by implementing the pole replacement program are summarized in Table 17 below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | The costs associated with replacing wood poles in an emergency situation has been estimated to upwards of double the cost of scheduled pole replacements. The do-nothing policy would see more frequent pole failures resulting in a high cost impact of replacing unscheduled poles. By increasing the replacement policy, the average costs to replace poles, scheduled and unscheduled, will be reduced and provide long-term financial benefit. |
| **Customer** | Improvement to Defective Equipment related reliability statistics due to the decrease in pole and pole fixture failures. |
| **Safety** | Pole replacement reduces the risk of cascading failure of lines, thereby reducing the health and safety risk to employees and the public. Replacing |

| | |
|---|---|
| | poles that are located in areas that require climbing reduces the hazard to employees performing daily activities |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | (Not applicable) |
| **Economic Development** | HOL hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources. |
| **Environment** | Proactive replacement of end of life poles mitigates the risk of oil spilling from oil-filled transformers in the event of a pole falling down. |

**Table 17 – Pole Replacement Program Benefits**

## 3.4 Prioritization

### 3.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increased potential for cascading pole failures, and/or simultaneous pole failures during severe weather.

Deferral of pole replacements will also create a backlog of bad poles that will require more investment in the future. As evident in Figure 24, if increase in pole replacements is deferred until 2020 the annual pole replacements required to achieve the same results as increasing the number of pole replacements to 1,250 in 2016, would be 1,317.

A summary of the impact of different deferrals on forecasted pole failures is provided in Figure 24.

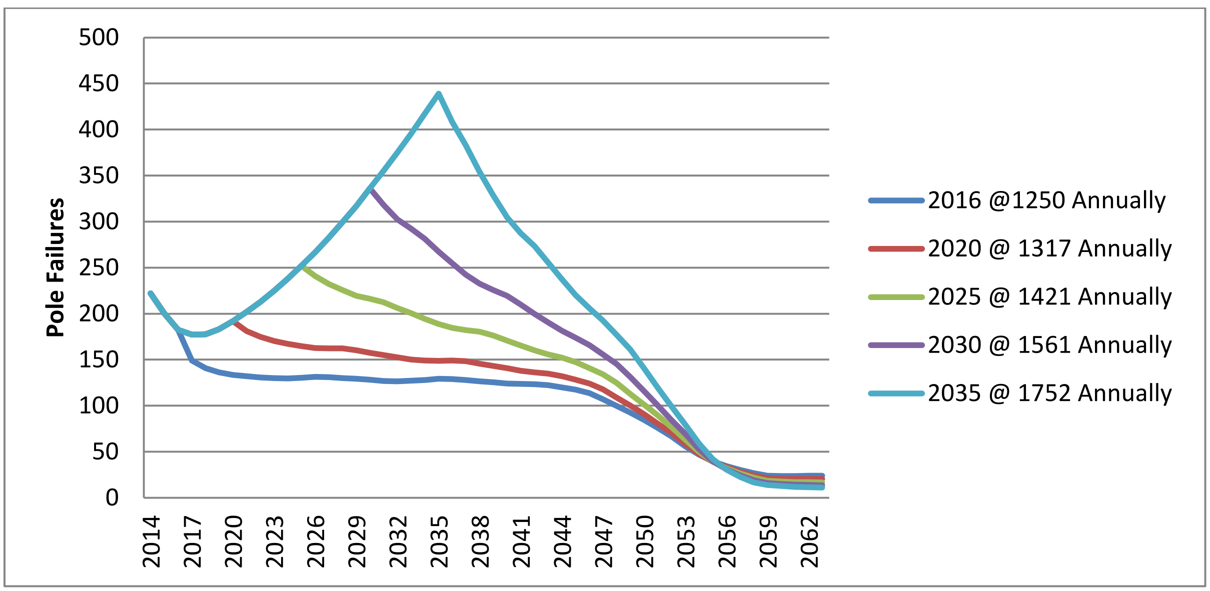



**Figure 24: Impact of Deferral**

### 3.4.2 Priority

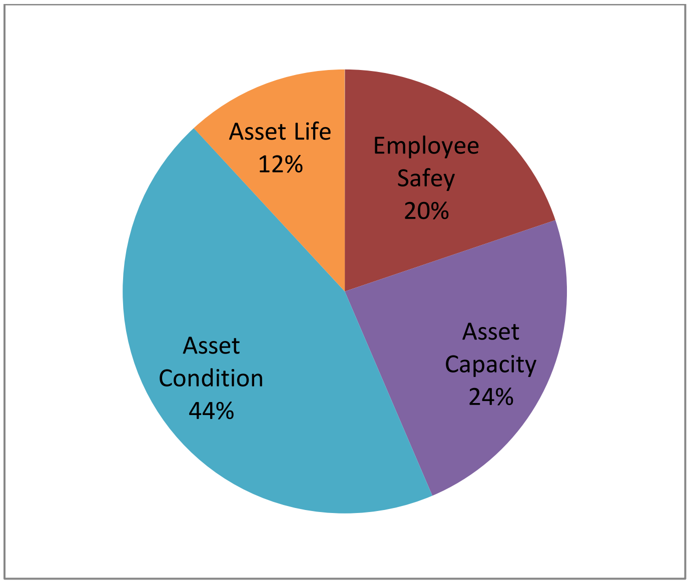



**Figure 25 - Typical scoring for Pole replacement projects.**

Typical Pole replacement project score: 1.01

## 3.5 Execution Path

### 3.5.1 Implementation Plan

HOL has prioritized pole inspections based on information about age of the distribution system and when it was built, and information from area construction crews.

The planned pole replacement projects will be prioritized based on the condition information retrieved from the inspections.

### 3.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Obtaining road cut permits from the City of Ottawa;<br>• Coordinating activities in areas where multiple parties are working;<br>• Getting approval for traffic plans where required | It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources. |

**Table 18 - Pole Replacement Risks and Mitigations**

### 3.5.3 Timing Factors

Typical factors that affect timing of projects:

- Acquiring road-cut permits
- Availability of contractors
- Disconnecting customers for periods of time

### 3.5.4 Cost Factors

Typical factors that affect cost of replacement:

- Rock below grade
- Tree trimming
- Cable risers on poles

### 3.5.5 Other Factors

N/A

## 3.6 Renewable Energy Generation

(Not applicable for this program)

## 3.7 Leave-To-Construct

(Not applicable for this program)

## 3.8 Project Details and Justification

### 3.8.1 Centretown East Pole Replacement

| | |
|---|---|
| **Project Name:** | Centretown East Pole Replacement |
| **Project Number:** | 92008625 |
| **Capital Cost:** | $7,416,239 |
| **O&M:** | N/A |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 135 customers/ 3000 kVA |

**Project Scope**

This is a pole replacement project for EOL poles in the Centretown East area determined by pole testing and inspections programs. This project is scheduled to take place in several phases separated by area. To date a total of 12 phases of this project have been completed with 130 poles replaced with an estimated budget of $3,246,000. For 2015 a total of 5 phases are scheduled to be completed with 85 poles to be replaced with an estimated budget of $2,357,000. For 2016, 3 more phases are scheduled to be completed with 50 poles to be replaced with an estimated budget of 2,600,000. The variation in expenditure is due to the expected man hours, equipment needed, and plant that is being transferred or replaced. This is dependent on the physical location of the poles.

**Priority**

Score: 0.95

**Work Plan**

During pole replacement projects other assets are replaced such as transformers, switches and cables where necessary. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

Work completed to date includes 12 phases in the following phases:

- Cartier Street: 20 Poles
- Gloucester Street: 4 Poles
- Cooper Street: 14 Poles
- Gilmour Street: 12 Poles
- Gladstone Avenue: 3 Poles
- McLeod Street: 12 Poles
- Park Avenue: 6 Poles
- Argyle Avenue: 14 Poles
- The Driveway: 6 Poles
- Robert Street: 4 Poles
- Waverly Street: 21 Poles
- Frank Street: 14 Poles

Work scheduled in 2015 includes 6 phases:

- Nepean Street: 13 Poles
- Lisgar Street: 13 Poles

| | |
|---|---|
| • MacLaren Street: 24 Poles<br>• Somerset Street West: 17 Poles<br>• Bank and Catherine: 2 Poles<br>• Metcalfe Street: 16 Poles (Started in 2014)<br><br>Work scheduled in 2016 includes 2 phases:<br>• Elgin Street: 24 Poles<br>• O'Connor Street: 26 Poles |
| **Customer Impact** |
| This project will improve distribution system reliability and decrease the risk of asset failure in the planned areas. |

### 3.8.2 64A3A – South East Kilborn Area Pole Replacement

| | |
|---|---|
| **Project Name:** | 64A3A – South East Kilborn Area |
| **Project Number:** | 92008551 |
| **Capital Cost:** | $1,054,000 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2016 – Q2 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 278 customers / 1290 kVA |

**Project Scope**

This is a pole replacement project consisting of 85 wood poles and secondary buss replacement including transformers. This project was identified by pole testing to the north side of Walkley road which showed poles in this area to have internal or external decay and rot. This option was decided given the dense area and the number of EOL poles, and the alternatives to replacement such as stubbing or remediation are not practicable at this time. During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

**Priority**

Score: 1.01

**Work Plan**

The work plan is to install and replace 85 wood poles, transfer existing primary conductors & street lights, frame poles according to standards provided, install new dual voltage transformers, install 266 MCM pre spun bus secondary cable, remove existing poles and transformers. Work is scheduled to begin in Q1 – 2015 and will continue throughout the year.

This project will take place in 8 parts with the areas and the number of poles to be replaced in each area below.

- Part 1: Installation of 12 Poles on Lorraine Avenue
- Part 2: Installation of 13 Poles on Arizona Avenue
- Part 3: Installation of 6 Poles on Florida Avenue
- Part 4: Installation of 6 Poles on Palm Street
- Part 5: Installation of 8 Poles on Michigan Avenue
- Part 6: Installation of 11 Poles on Connecticut Avenue
- Part 7: Installation of 16 Poles on Featherston Drive
- Part 8: Installation of 13 Poles on Ryder Street

**Customer Impact**

This project will upgrade aging infrastructure which will increase the reliability in this area in the future. The ability of the system to operate through adverse weather without interruption will also be improved.

### 3.8.3 54B4A – Riverside Park South Pole Replacement

| | |
|---|---|
| **Project Name:** | 54B4A - Riverside Park South Pole Replacement |
| **Project Number:** | 92008591 |
| **Capital Cost:** | $4,565,301 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 100 customers/ 500 kVA |

**Project Scope**

This is a pole replacement project taking place in an area south of Walkey Road, between the Airport Parkway and McCarthy Drive. Prior to commencing this project extensive pole testing done in this area shows lots of rotten poles. There are a total of 379 poles in this plot boundary. A total of 201 poles were identified to be replaced as part of this project. During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards.

**Priority**

Score: 0.95

**Work Plan**

This project has been divided into two areas, East and West of McCarthy. Work is scheduled to begin in Q1- 2015 and will take place throughout the year.
For West of McCarthy, 103 poles will be replaced, 15 transformers as well as the transfer of all existing conductors, guys/anchors, street lights, pole dips as well as installing 266 MCM pre spun bus secondary cable. This area has been divided into 6 groups listed below.

- Group 1 Cowan: 21 Poles
- Group 2 Southmore: 20 Poles
- Group 3 Buxton: 20 Poles
- Group 4 Farmington: 13 Poles
- Group 5 Hartman: 20 Poles
- Group 6 Otterson: 9 Poles

For East of McCarthy, 98 poles will be replaced as well as the transfer of all existing conductors, guys/anchors, street lights, pole dips as well as installing 266 MCM pre spun bus secondary cable. This area has been divided into 7 groups listed below.

- Group 1 Marcel – Hyde – McCarthy: 22 Poles
- Group 2 McCarthy @ Southmore: 3 Poles
- Group 3 Southmore – Stanstead: 17 Poles
- Group 4 Southmore South Side: 13 Poles
- Group 5 Southmore South Side: 13 Poles
- Group 6 Garwood – Rand – Throndale: 26 Poles
- Group 7 Garwood @ Southmore: 4 Poles

**Customer Impact**

This project will increase the reliability and decrease the risk of asset failure in the area; also the ability of the system to operate through adverse weather without interruption is improved.

### 3.8.4 45B4 – Grandview Road Pole Replacement

| | |
|---|---|
| **Project Name:** | 45B4 – Grandview Road Pole Replacement |
| **Project Number:** | 92006285 |
| **Capital Cost:** | $1,085,809 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q3 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Asset Condition, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 158 customers/ 2190 kVA |

**Project Scope**

There are 80 poles to be replaced, pole testing results show that these poles are in bad condition and are approaching end of life. Includes both utility and service poles. Very few poles owned by Bell. Secondary is also being upgraded. Primary is not being replaced, except for ~250m along Hastings Street due to current poor condition.

Grandview Road north of Carling is a long, dead end street by the Ottawa River. HOL Limited is addressing all issues along this street so as not to require another project here.
Location: Grandview Road (North of Carling)

**Priority**

Score: 1.01

**Work Plan**

HOL Limited's West region crew will begin construction in March 2015. The West crew has been assigned this project in the South for scheduling purposes. Poles will be replaced along with secondary services, and old primary will be transferred to new poles. Along Hastings Street, new conductor will be installed.

**Customer Impact**

Reliability improvements due to new equipment and removal of end of life assets.

### 3.8.5 54A4C4 Pole Replacement

| | |
|---|---|
| **Project Name:** | 54A4C4 Pole Replacement |
| **Project Number:** | 92008541 |
| **Capital Cost:** | $694,764 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q2 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Asset Condition, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 725 KVA |

**Project Scope**

27 poles in this area have reached end of life and are in need of replacement.

Locaton: Cleopatra Drive, Caesar Avenue, Camelot Drive, Enterprise Avenue

**Priority**

Score: 0.95

**Work Plan**

- Replace 27 poles
- Install 7 new overhead transformers
- Install new fuses and replace secondary services at select locations

**Customer Impact**

Reliability improvements due to replacement of aged assets with new equipment.

### 3.8.6 Centretown West Pole Replacement

| | |
|---|---|
| **Project Name:** | Centretown West Pole Replacement |
| **Project Number:** | 92010273 |
| **Capital Cost:** | $6,680,865 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2017 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 650 customers/ 1600 kVA |

**Project Scope**

This is a pole replacement project for EOL poles in the Centretown West area determined by pole testing and inspections. This project is scheduled to take place in several phases separated by area. For 2016, one phase (Gilmour Street) is scheduled to be completed with the replacement of 22 poles with a planned budget of $440,000. For 2017, ten phases are scheduled to be completed with the replacement of 105 poles with a planned budget of $2,237,000.

**Priority**

Score: 0.78

**Work Plan**

During pole replacement projects other assets are replaced such as transformers, switches and cables where necessary. Also, circuitry is upgraded where deemed necessary to bring older designs to current standards.

Work scheduled for 2016 includes 1 phase:

- Gilmour Street: 22 Poles

Work scheduled for 2017 includes 10 phases:

- Lisgar Street: 7 Poles
- Albert and Bay: 8 Poles
- Nepean Street: 14 Poles
- Laurier and Bay: 3 Poles
- Cooper Street: 11 Poles
- Gloucester Street: 11 Poles
- Slater Street: 8 Poles
- Kent Street: 29 Poles
- Somerset (west of Bank): 4 Poles
- Maclaren Street: 10 Poles

**Customer Impact**

This project will improve distribution system reliability and decrease the risk of asset failure in the planned areas.

### 3.8.7 Alphabet Avenue Pole Replacement

| | |
|---|---|
| **Project Name:** | Alphabet Ave Phase 1 Pole Replacement |
| **Project Number:** | 92010253 |
| **Capital Cost:** | $1,223,795 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 287 customers/ 901 kVA |

**Project Scope**

This is a pole replacement project that will target EOL 4.16kV poles along an area surrounding Avenue N to Avenue U including Tremblay Road both rear lot and front lot construction. The conditions of poles are tested on an ongoing basis. Areas with poles which are determined to be in the poorest condition are identified for replacement. The project is still in the preliminary stages, but at this point it is estimated that approximately 65 poles will need to be replaced as part of this project.

During pole replacement projects other assets are replaced such as transformers, switches and cables. Also, circuitry is updated where deemed necessary to bring older designs to current standards and protection on all distribution laterals will be added.

**Priority**

Score: 0.92

**Work Plan**

Work for this project is scheduled to begin in Q1 – 2016. Pole replacement projects continue throughout the year. In certain cases considerations of the customers must take place which adjusts the dates of the work plan.

**Customer Impact**

This project will increase the reliability and decrease the risk of asset failure in the area. The ability of the system to operate through adverse weather without interruption will also be improved.

### 3.8.8 Prince of Wales & Greenbank South of Barnsdale Pole Replacement

| | |
|---|---|
| **Project Name:** | Prince of Wales & Greenbank South of Barnsdale |
| **Project Number:** | 92006287 |
| **Capital Cost:** | $2,456,004 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q3 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Voltage Conversion |
| **Customer/Load Attachment** | 1.73MVA |

**Project Scope**

Poles are approaching end of life and require replacement. The South Nepean area will be converted to 27.6kV within the next few years, so preparation for voltage conversion will be done in conjunction with pole replacement. 2 circuits will be held on new pole line.
Poles along Greenbank Road are owned by Bell Canada, and will require Joint Use agreement to replace. Approximately 23 Bell Poles and 43 HOL Poles.

Out of Scope: Replacement of poles on Barnsdale Road and Viewbank Road, extending line to Bankfield (Stopping 2-3 spans after Greenbank/Prince of Wales intersection) as location of proposed station is not yet decided.

**Priority**

Score: 1.01

**Work Plan**

Installation of 60 foot poles to accommodate 2 ccts of 556mcm, 336mcm tensioned neutral, 46kv rated insulators, dual high voltage transformers, poles re-spanned to eliminate the existing long spans which are non-standard. Anchor easements will be attained.

**Customer Impact**

Reliability improvements due to new equipment and looped circuit supply.
Additional capacity to support new development once voltage conversion takes place.

### 3.8.9 Trans-Canada Trail Pole Line (Eagleson to Terry Fox)

| | |
|---|---|
| **Project Name:** | Trans-Canada Trail Pole Line (Eagleson to Terry Fox) |
| **Project Number:** | 92010158 |
| **Capital Cost:** | \$670,228 |
| **O&M:** | \$0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 6294 customers/ 13856 kVA |

**Project Scope**

The main driver of this project is to convert an overhead distribution to underground. The scope of this project has recently changed due to the City of Ottawa considering the use of the Trans-Canada trial line as an option for LRT in the future. The pole line along the Trans Canada Trail has reached EOL and begun failing.

The current 27.6kV line along the Trans-Canada Trail will be moved to Michael Cowpland Drive and run parallel to an existing 27.6kV line up to Eagleson Road coming out of Terry Fox MTS. The 27.6kV feeder will make use of existing concrete encased duct structure existing on Michael Cowpland Drive.

The 8.32kV overhead line along the Trans-Canada Trail will eventually be converted to an underground 27.6kV circuit.

**Priority**

Score: 0.95

**Work Plan**

- Pull cables through underground duct
- Install new risers and make all connections
- Remove overhead distribution equipment
- Conversion of distribution equipment from 8.32kV to 27.6kV

**Customer Impact**

This project will increase the reliability of service in the area, and decrease the risk of asset failure.

# 4 Distribution Transformer Replacement – Polemounted

## 4.1 Project/Program Summary

The polemounted transformer asset class includes roughly 16,000 service transformers which convert electrical power from its primary distribution voltage to service level voltage, nineteen (19) step transformers which convert from one primary distribution voltage to another and three (3) voltage regulators. The polemounted distribution transformer replacement program focuses on the optimal the time to replace an asset just before it fails. Inspections help identify the condition of the transformers so that they can be prioritized and replaced.

## 4.2 Project/Program Description

### 4.2.1 Assets in Scope

The HOL overhead distribution system uses three types of pole mounted transformers to convert electricity from medium distribution voltage to a lower distribution voltage or to a service level voltage as well as for voltage regulating. Step transformers are used to convert medium distribution voltage to a lower distribution voltage which are used for reliability back-up and avoid extensive costs by completing a voltage conversion. Service level voltages are used to supply residential, commercial, and industrial customers. Voltage regulators are used to regulate the medium distribution voltage on long lines experiencing voltage drops below the minimum allowable ±6% of system voltage.

The reliability of the overhead distribution system is dependent on the performance of step transformers and voltage regulators due to their integration into the trunk of the system. Failures of service transformers are less impactful to the overhead system because they have means of disconnection through a fuse in the event of the failure.

Polemounted transformers are replaced for numerous reasons including: asset failure, leaking oil, voltage conversion, insulator degradation identified by IR scans, and in conjunction with pole replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

In addition, it is HOL's standard to replace polemounted transformers with like-for-like, but includes installation of animal guards on the bushings of the transformer. This is due to the high number of failures experienced on the overhead system due to animals making contact between the primary wire and the grounded transformer case.

Federal Regulation SOR 2008-273 dictates that all polemounted equipment with oil containing PCBs in concentrations of 50 mg/kg or greater must be removed from service by 2025. There are 150 known PCB containing HOL polemounted transformers remaining in service, and 2 voltage regulators. As a result of the regulatory obligations, HOL has elected to take an accelerated approach to remove these remaining transformers from service. Aging infrastructure work will be superseded by the removal of the remaining PCB containing transformers, expected to be complete in 2016. Two of the six voltage regulators contained concentrations of PCBs in excess of 50mg/kg and all six were replaced with three (3) new units in 2014.

HOL recommends an annual replacement rate of 250 polemounted transformers per year which represents 1.6% of the entire population of polemounted transformers. Under these scenarios transformers are still expected to fail, but the level of failures will be kept constant, if not reduced due to the proactive replacement.

### 4.2.2 Asset Life Cycle and Condition

HOL owns 16,000 service transformers, nineteen (19) step transformers and three (3) voltage regulators.

Currently, HOL has installation or manufactured date information for approximately 97% of its polemounted service transformers, 89% of the step transformers and 100% of the voltage regulators. The voltage regulators contain concentrations of PCBs in excess of 50mg/kg and are to be replaced in 2014.

Typical lifecycle of polemounted transformers is in the average of 90 years. The percentage of polemounted transformers that have passed end of life criteria is 1% and is expected to reach 2% by 2020.

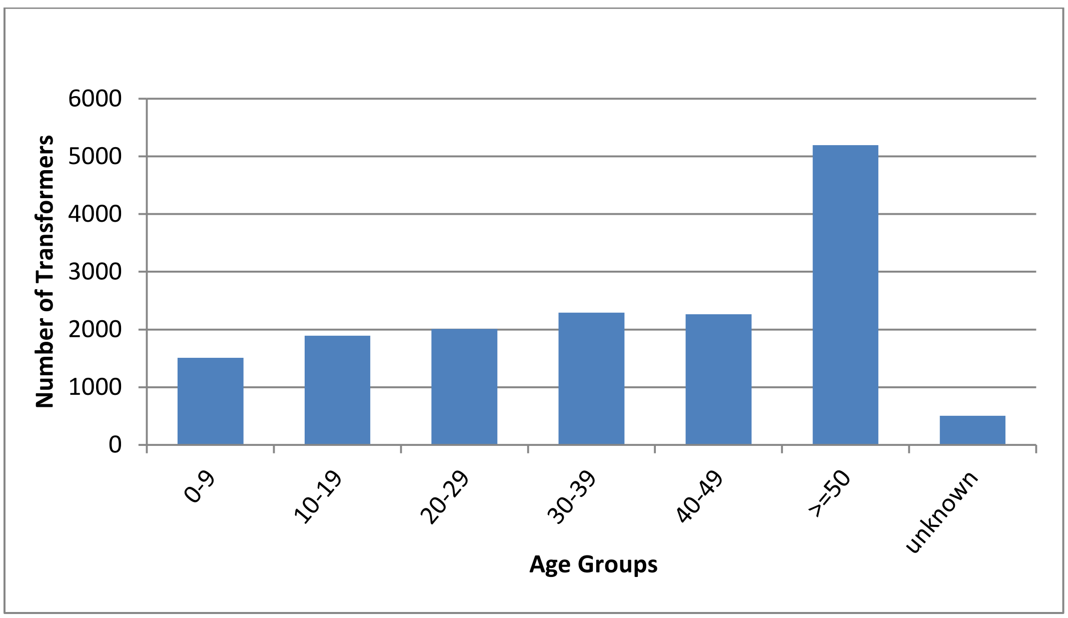



**Figure 26 - Age of Service Transformers**

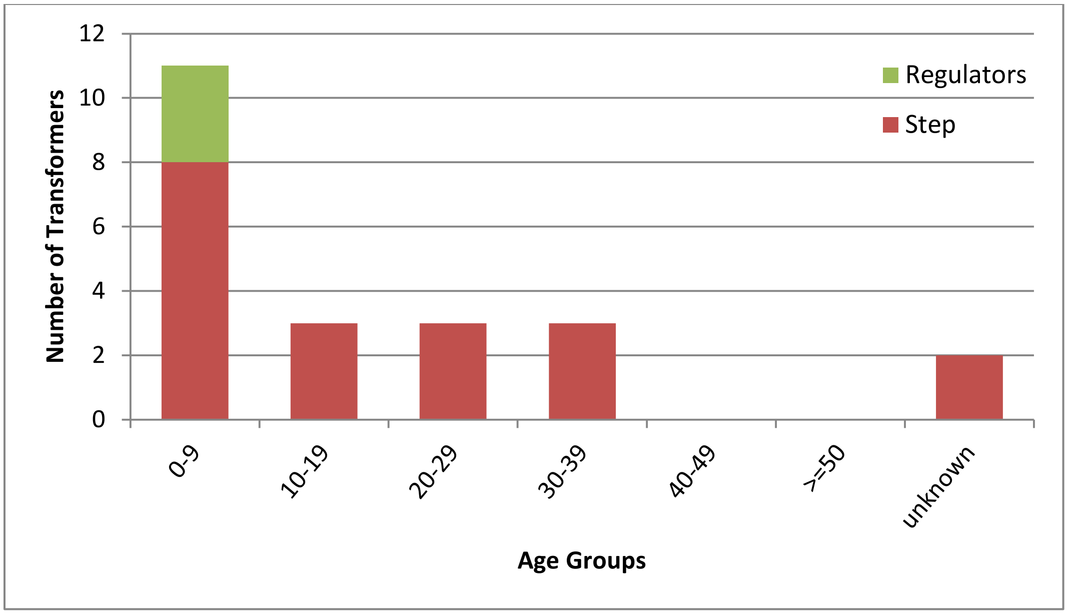



Figure 27 - Age of Step Transformers & Voltage Regulators

Infrared (IR) and inspections are also carried out on polemounted transformers. HOL attempts to inspect these transformers on a three year cycle. Most of the problems identified can be mitigated by cleaning connections, replacing minor components, or tightening connects, thus avoiding the need to replace the entire asset.

In order to effectively use the IR scanning information, an equipment health index was created for all IR scanned equipment. This can be seen below. The condition rating is based on the temperature difference between the reference temperature and the equipment's actual measured temperature.

| |
|---|
| Critical - (>75°C), immediate repair |
| Major Problem - (>36°C-75°C), repair as soon as possible |
| Intermediate - (>10°C- 36°C) |
| Minor - 10°C or less |

Table 19 - Infrared Condition Rating

The records of polemounted transformer failures from 2009 to 2013 indicate an upward trend in the number of failures per year. Based on the data, the number of polemounted transformer failures has increased by 24% in 2013 from 2009. Increasing number of failures indicate an increasing condition deterioration of polemounted transformers due to aging transformers. Therefore an aggressive replacement plan is required to maintain the number of failing transformers.

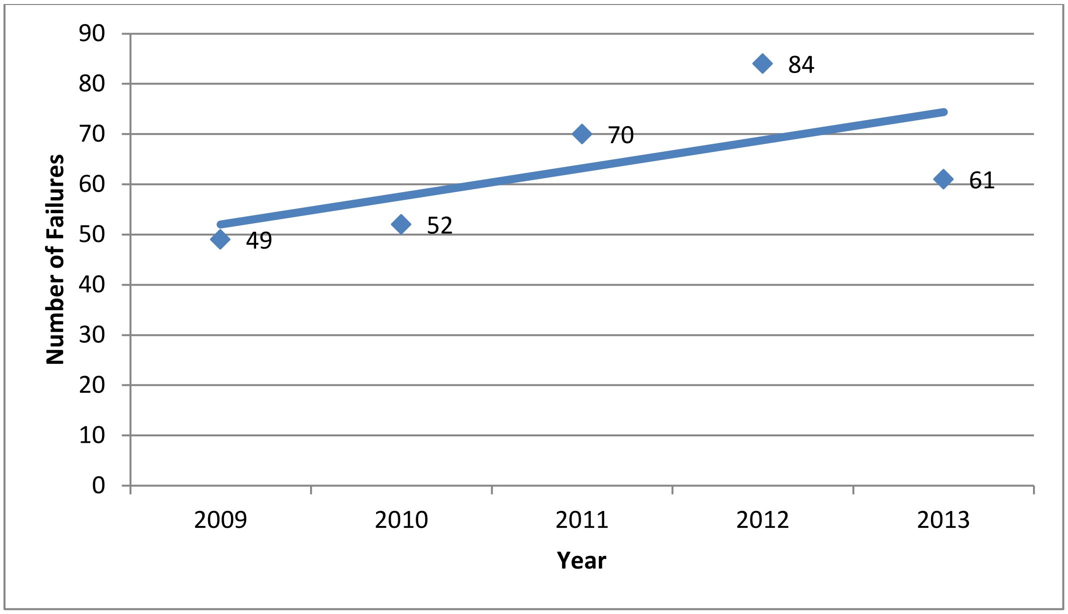



**Figure 28 - Polemounted Transformer Failures**

The majority of failures experienced on polemounted transformers are a result of animals making contact between the primary wire and the grounded transformer case. It is HOL's standard to replace polemounted transformers with like-for-like, but includes installation of animal guards on the bushings of the transformer. This is expected to reduce the number of failures of polemounted transformers.

Polemounted transformers are typically run-to-failure or are replaced in conjunction with projects such as pole replacement or voltage conversion. However, they do from time to time require proactive replacement in response to known defects identified through IR and visual inspection. Issues have been encountered due to loose connections, equipment overload, cracked bushings, exposed electrical hazards, etc.

### 4.2.3 Consequence of Failure

Polemounted transformers have a low probability of failure due to the number of transformers exceeding the average life of a polemounted transformer and are more susceptible to failure due to animal contact. The three-year rotational visual inspection and IR scanning identifies transformers before failure so that proactive replacement can be completed. The consequence failure includes some or all of the following:

- Customer outage effects. This will include "event" effects due to the outage (SAIFI), "duration" effects (SAIDI), and effects on critical customers;
- Health and safety consequences; and
- Environmental consequences.

Polemounted transformers have been forecasted under different replacement policies. Based on this analysis, replacement of roughly 250 units annually is required to reduce annual failures from the 61 seen in 2013 to a more averaged number of failures around 40. Given the low correlation between risk of failure and age, and the renewal impact of polemounted PCB replacements at this time, proactive replacement of this asset is not recommended.

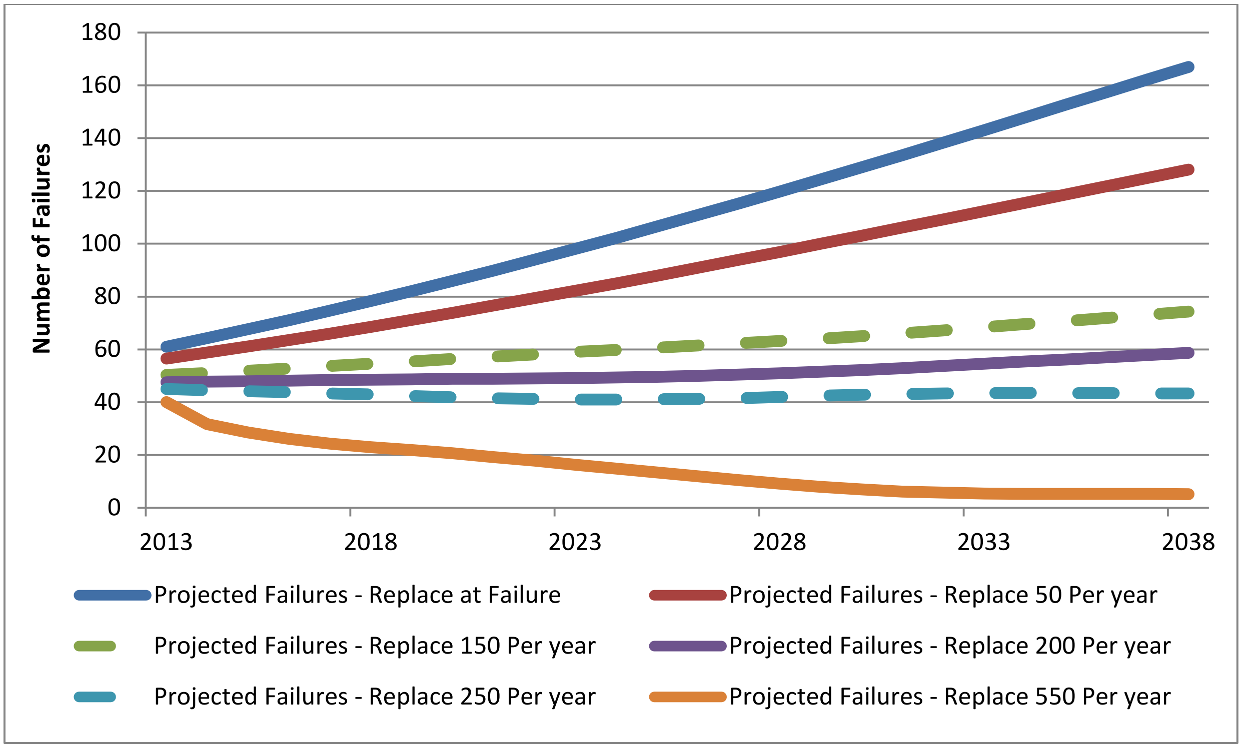



**Figure 29 - Polemounted Transformer Recommended Replacement Rates**

### 4.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | 1% of the polemounted transformers have exceeded their life expectancy, totalling 186. It is estimated that the number will grow to 246 by the end of 2020. |
| **Secondary** | **Safety** | Risks of the polemounted transformer failure could lead to potential injuries to the public as a result of being located on poles above the ground and have the potential to fall. |
| **Tertiary** | **Environment** | Risks of the polemounted transformer failure could lead to potential release of oil into the environment. |

**Table 20 - Polemounted Transformers Replacement Program Main Drivers**

### 4.2.5 Performance Targets and Objectives

Targets of the distribution polemounted transformer replacement program are to continue on the current path of replacing polemounted transformers containing PCBs in accordance with regulation SOR 2008-273 and in conjunction with other projects, while maintaining current failure rates.

## 4.3 Project/Program Justification

### 4.3.1 Alternatives Evaluation

#### 4.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels. Using the degradation model developed for polemounted transformers, HOL analyzed an impact of several replacement alternatives on the performance outcome. All of the alternatives, other than run-to-failure, stabilize the replacement amount beyond 2016-2020 rate filing period. The following scenarios were analyzed:

1. Run-to-Failure scenario with only reactive replacement of the transformers
2. Replace 200 polemounted transformers per year to maintain a mid-term reliability level
3. Replace 250 polemounted transformers per year to maintain a mid-term reliability level
4. Replace 550 polemounted transformers per year to maintain a mid-term reliability level

#### 4.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resource** | Unplanned and planned replacements utilize internal resources. Alternatives that incur more on-failure replacements are less favorable as it will be more challenging to gather resources on as needed basis. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 21 – Alternative Evaluation Criteria**

#### 4.3.1.3 *Preferred Alternative*

The preferred alternative is to target replacement of the worst conditioned polemounted transformers at a rate of 250 transformers annually. Since specific projects are not identified within the distribution polemounted transformer replacement program, except for the PCB removal projects, the 250 transformer annual replacement is the optimal replacement level that is completed in conjunction with other projects like pole replacement and voltage conversion projects.

Alternatives and their associated benefits with regards to reliability, safety, resources and finances, are discussed for each alternative below:

**Failure / Reliability**

HOL has analyzed the impact of several replacement policies using the failure rate model developed for polemounted transformers. Results of this analysis indicated that an optimal replacement rate of 250 transformers annually would be required to manage failures and keep them from increasing yearly.

Increasing the number of polemounted transformers replaced annually would minimize the number of transformers that are likely to fail. Installation of animal guards on all replaced transformers will also reduce the number of failures and impact on reliability.

**Safety**

Increasing the number of polemounted transformers replaced annually would minimize the risk to safety by reducing the number of transformers that are likely to fail based on age.

**Resources**

With assets in the system continuing to age and deteriorate, inadequate planned replacements of aging transformers will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned polemounted transformer replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

**Financial**

The cost associated with replacing polemounted transformers in an emergency situation has been estimated to be substantially higher than the cost of scheduled transformer replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact of replacing unscheduled polemounted transformers. By increasing the replacement policy, the average costs to replace a transformer, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled polemounted transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

### 4.3.2 Project/Program Timing & Expenditure

Historically there have been no expenditures for proactive polemounted transformer replacement due to the assets being run-to-failure. However, from inspection information, transformers have been deemed end of life and scheduled for replacement when resources were available. As described in section 2.1, a project to replace the voltage regulators was completed in 2014 due to their condition. HOL has also complied with the federal regulation SOR 2008-273 of replacing equipment that contains greater than 50mg/kg of PCBs. The costs associated with the replacement of polemounted transformers are shown in below.

| | Historical ($M) | | | | Future ($M) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **End of life** | $0.005 | $0.001 | $0.050 | $0.024 | - | - | - | - | - | - |
| **PCBs** | $0.124 | $0.011 | $0.002 | $0.421 | $0.615 | $0.365 | - | - | - | - |

**Table 22 – Polemounted Transformer Replacement Program Historical and Future Spending**

Specific polemounted transformer replacements are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the pole replacement all pole fixtures are replaced and connecting transformers are reviewed and identified for replacement where required. In order to maximize system operation, phase balancing is also reviewed prior to pole replacement to see if any load connections should be relocated to a different phase during the work.

### 4.3.3 Benefits

Key benefits that will be achieved by implementing the distribution polemounted transformer replacement program are summarized in Table 23 below.

| Benefits | Description |
| --- | --- |
| **System Operation Efficiency and Cost-effectiveness** | Costs associated with a failed transformer are significantly higher than planned replacement. Aging and deteriorating transformers increase the risk of failure and safety concerns. This alternative is the most effective means to minimize the potential safety and reliability risks associated with failed polemounted transformers. |
| **Customer** | System reliability will be preserved as the number of failed transformers will remain constant which will cause outages to very few customers annually. |
| **Safety** | Public safety is maintained as polemounted transformers are located above ground on poles; a falling transformer has the possibility of incurring serious injury to the public. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | N/A |
| **Environment** | Transformers encase oil as a cooling medium and have the potential for oil leaks. These transformer cases are unable to contain oil if they have cracks or holes and oil will be spilt into the environment. |

**Table 23 - Polemounted Transformers Program Benefits**

## 4.4 Prioritization

### 4.4.1 Consequences of Deferral

The run-to-failure replacement strategy is the ongoing directive of the program year after year. It cannot be deferred and therefore has no consequence of deferral. The preferred alternative of proactive replacement of 250 polemounted transformers annually would see an impact from deferral. The positive impacts discussed in section 3.3 would be neglected to the date at which the alternative began. This would also see a buildup of polemounted transformers at end of life condition.

### 4.4.2 Priority

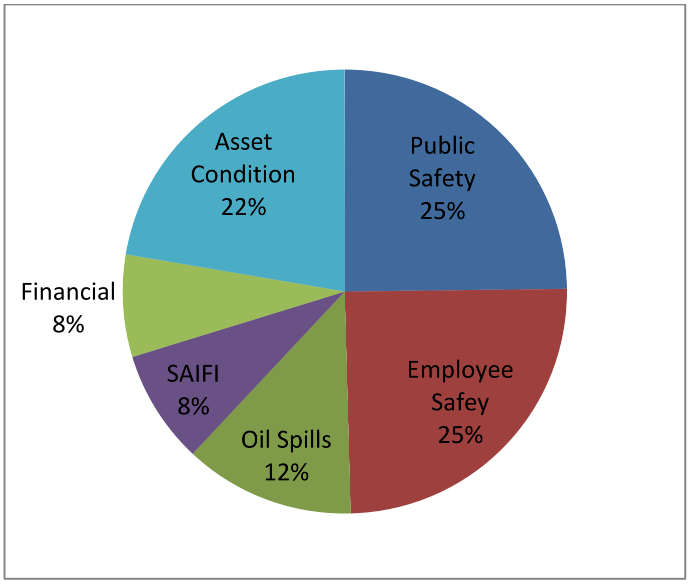



**Figure 30 - Polemounted Transformer Replacement Avoided Risk**

Project Score = 0.807

## 4.5 Execution Path

### 4.5.1 Implementation Plan

Polemounted transformers with issues that pose a risk to the safety of the public and the employees working in the vicinity are given a high priority. Transformers with a low health index score are being addressed next. The priority of the replacement of the deteriorating transformer also depends on whether or not the City of Ottawa or HOL has planned work in the area.

### 4.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Coordinating activities in areas where multiple parties are working;<br>• Getting approval for traffic plans where required<br>• Priority changes as additional inspection results become available | HOL's mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities of resource use efficiency. |

**Figure 31 - Polemounted Transformer Program Risks and Mitigations**

### 4.5.3 Timing Factors

Three year rotational visual and IR scan inspections identify polemounted transformers with poor conditions and expected to fail. Additional higher priority transformers might be identified prompting a reprioritization of the target transformers and will be scheduled as priorities are set.

### 4.5.4 Cost Factors

The final cost of the program is affected by the number of polemounted transformers that are identified as requiring replacement. Accessibility of the transformers can add significant costs to each replacement. In addition cost savings are available through planned scheduling with the City of Ottawa roadwork projects which require pole relocation. If a polemounted transformer fails before replacement is performed, the cost of replacing the failed transformer will be more than if the work is performed proactively.

### 4.5.5 Other Factors

Other factors to consider include possibility of project overlap with another planned program. Polemounted transformer may be replaced as part of pole replacement, line extension, or voltage conversion projects.

## 4.6 Renewable Energy Generation (if applicable)

Not Applicable.

## 4.7 Leave-To-Construct (if applicable)

Not Applicable.

## 4.8 Project Details and Justification

### 4.8.1 Overhead Transformer – PCB Regulatory Compliance

| | |
|---|---|
| **Project Name:** | OH TXF- PCB Regulatory Compliance – Phase 3 |
| **Project Number:** | 92008627 |
| **Capital Cost:** | $1,473,298 |
| **O&M:** | N/A |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2016 – Q1 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1038 customers/ 6210 kVA |

**Project Scope**

This project entails HOL's PCB Regulatory Compliance Overhead Transformer Replacements. It involves the targeted removal of overhead transformers containing PCB's, replacement of brackets, switches and arrestors across the City of Ottawa. This project has been divided into 4 areas across the city with the amounts of transformers to be replace listed below

- 2014 - East – 45 Transformers
- 2015 - Core – 66 Transformers
- 2016 - South – 30 Transformers
- 2016 - West – 9 Transformers

**Priority**

Score: 0.03

**Work Plan**

Crews will be dispatched to the identified transformers throughout the city year round. Transformers to be replaced are de-energized, then replaced and re-energized. This project will continue through to Q1-2016

**Customer Impact**

Customers in the areas affected by this project may experience a sustained planned outage during replacement. This project will lead to an increase in reliability and decreased risk of asset failure and environmental risk.

# 5 Distribution Transformer Replacement - Padmounted

## 5.1 Project/Program Summary

HOL's underground transformer asset class includes a variety of transformers which are used in the delivery of power to customers. These transformers include submersible, padmounted, kiosk and vault transformers. While primarily oil filled, there is also a subset of solid dielectric transformers owned and operated by HOL. The underground distribution transformer replacement program focuses on the optimal time to replace an asset just before it fails. Inspections help identify the condition of the transformers so that they can be prioritized and replaced.

## 5.2 Project/Program Description

### 5.2.1 Assets in Scope

The HOL underground distribution system uses various types of underground transformers to convert electricity from medium voltage to low voltage. The low voltage power is used to supply residential, commercial, and industrial customers. The reliability of the underground distribution system is dependent on the performance of these underground transformers.

The underground transformer replacement program replaces submersible, padmounted, kiosk, and vault transformers connected to the underground cable network. These transformers are assessed based on their age which has a correlation to their condition. The exception is submersible transformers which are inspected for corrosion leading to leaking of oil due to their small population.

Underground transformers are replaced for numerous reasons including: asset failure, leaking oil, voltage conversion, insulator degradation identified by infrared scans, and in conjunction with cable replacement. The transformers that experience failure are replaced with a like-for-like transformer in order to provide electricity to the customer in a timely manner. Replacement completed during other projects will generally be like-for-like as well, however, the loading is assessed and there is the possibility for a smaller or larger capacity transformer to be used for economic or environmental benefits.

In addition, it is HOL's standard to replace live front transformers with dead front transformers. This is due to the safety benefits associated with having the cables insulated through the use of elbows. Padmounted and kiosk transformers and their concrete base have the potential to sink below grade. This poses a risk of flooding. This is flagged and remediated immediately to proactively avoid a failure.

Finally, federal regulation SOR 2008-273 dictates that all underground equipment with oil containing polychlorinated biphenyls (PCBs) in concentration of 50mg/kg or greater must be removed from service by 2025. The purpose of this is to improve protection of Canada's environment and the health of Canadians by minimizing the risks posed by the use, storage, and release of PCBs and by accelerating their elimination. HOL has been proactive with this replacement and all equipment that does not comply with this regulation will be removed by the end of 2016.

There have been field reports indicating that a high portion of submersible transformers are beginning to corrode. As a result, active replacement of all remaining submersible transformers has been scheduled for 2016.

HOL recommends a replacement rate on average of 300 to 400 padmounted and kiosk transformers per year and 60 to 80 vault transformers which represents 2.5% of the entire population of underground transformers. Under these scenarios transformers are still expected to fail, but the level of failures will be kept constant, if not reduced due to the proactive replacement.

### 5.2.2 Asset Life Cycle and Condition

HOL owns 19,189 underground transformers. These include roughly 29 submersible, 14,000 padmounted, 1,800 kiosk, and 3,500 vault transformers.

Currently, HOL has the installation or manufactured date information for approximately 98% of its kiosk and padmounted transformers. There is also data for 86% of the submersible transformers and 91% of the vault transformers on when they were installed or manufactured.

A typical lifecycle of an underground transformer is 30 years, with the exception of vault transformers which have a 35 year lifecycle. The overall age demographics of underground transformers in HOL's distribution system are shown in Figure 32. The percentage of underground transformers that have passed end of life criteria is 34%. In addition, in the next ten year period another 26% of underground transformers will reach the end of their useful life.

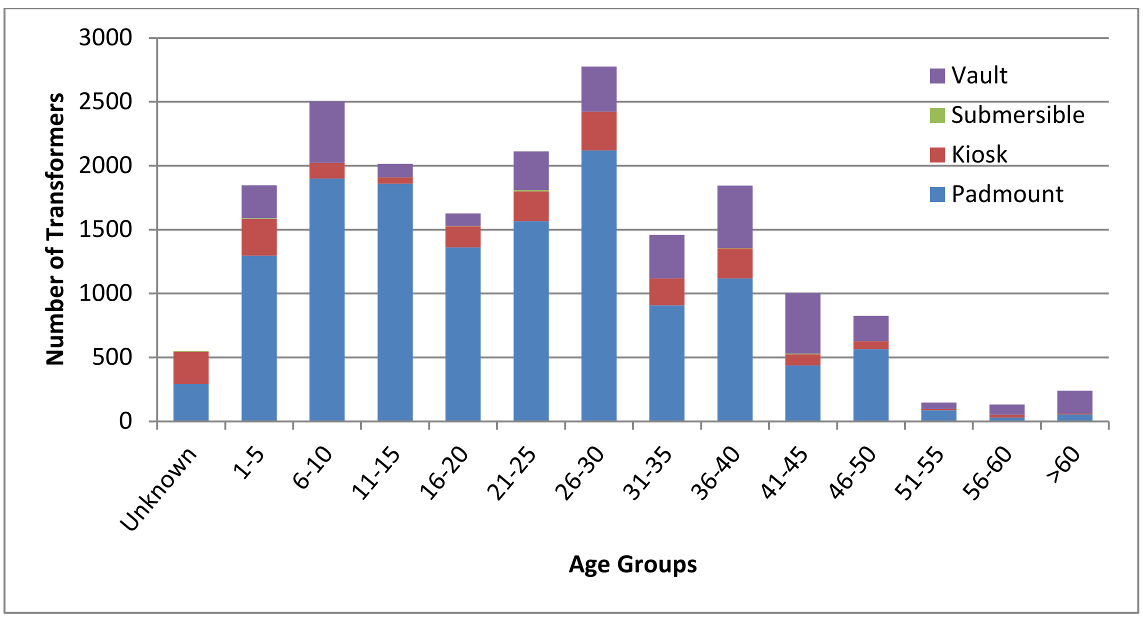



**Figure 32 - Age Demographics of Underground Transformers**

The current evaluation of underground transformers is based on the age of the asset. Underground transformers that have failed between 2011 and 2014 that had an associated year of installation or manufactured date can be seen below. There is a noticeable correlation between the age of the asset and the frequency of failure. The only exception to this is submersible transformers which are based on inspection due to the low number in the field and their primary mode of failure is corrosion leading to leaking of oil.

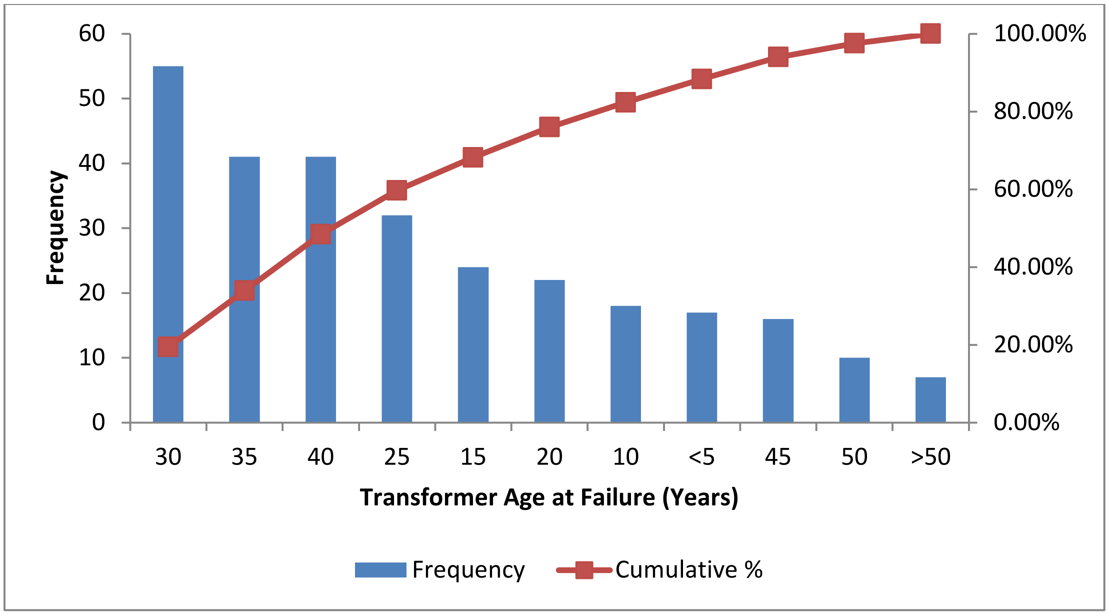



**Figure 33 - Underground Transformer Age at Failure**

Infrared (IR) tests and inspections are also carried out on padmounted and kiosk transformers. HOL attempts to inspect these transformers on a three year cycle. Most of the problems identified can be mitigated by cleaning connections, replacing minor components, or tightening connects, thus avoiding the need to replace the entire asset.

In order to effectively use the IR scanning information, an equipment health index was created for all IR scanned equipment. This can be seen below. The condition rating is based on the temperature difference between the reference temperature and the equipment's actual measured temperature.

| |
|---|
| **Critical - (>75°C), immediate repair** |
| **Major Problem - (>36°C-75°C), repair as soon as possible** |
| **Intermediate - (>10°C- 36°C)** |
| **Minor - 10°C or less** |

**Table 24 - Infrared Condition Rating**

The records of underground transformer failures from 2009 to 2013, as shown below, indicate an upward trend in the number of failures per year. Based on the data, the number of underground transformer failures has increased by 52% in 2013 from 2009.

Increasing numbers of failures indicate an increasing condition deterioration of underground transformers. This trend is expected to continue due to the increasing number of transformers past their end of life. Therefore an aggressive replacement plan is required to maintain the number of failing transformers.

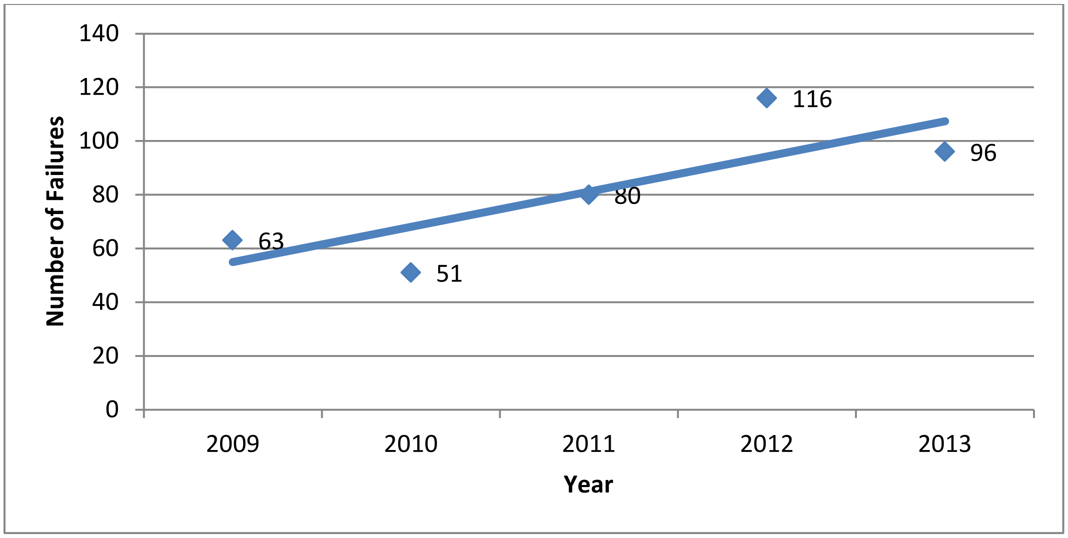



Figure 34 - Underground Transformer Failures

Underground transformers are typically run-to-failure or are replaced in concert with projects such as cable replacement or voltage conversion. However, they do from time to time require proactive replacement in response to known defects identified through IR and visual inspection. Issues have been encountered due to loose connections, equipment overload, swollen elbows, exposed electrical hazards, etc.

### 5.2.3 Consequence of Failure

In general, underground transformer failures will result in an outage affecting customers connected to that transformer. Outages as a result of underground transformer failures are typically limited in duration and customers impacted. However, as the amount of underground transformers progress past their end of life it is anticipated that annual failures will increase in the future. These events have a negative impact on overall system reliability. Figure 35 shows the contribution to the SAIFI and SAIDI metrics from failed underground transformers between 2009 and 2013.

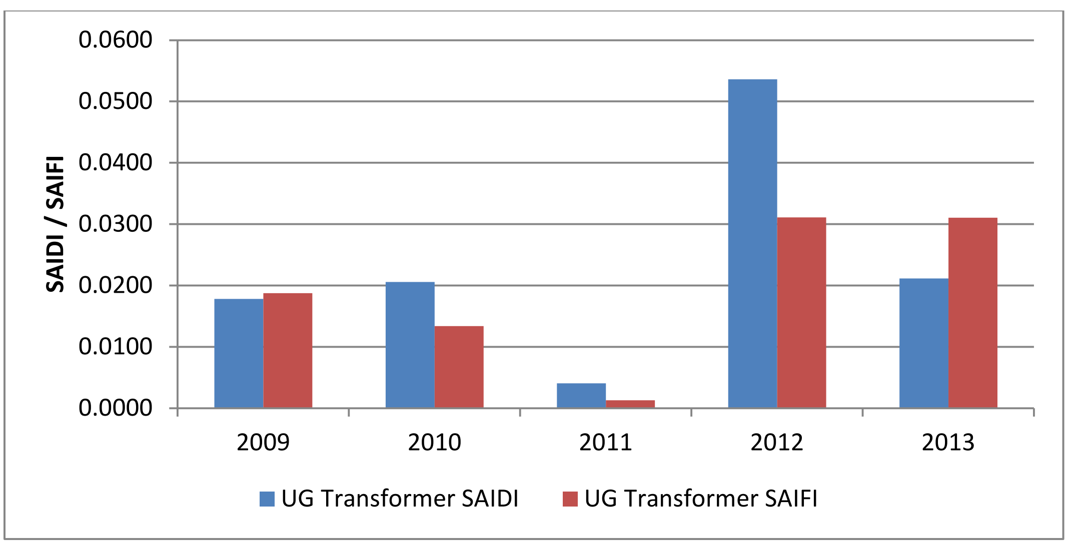



Figure 35 - Underground Transformer Failure Impact on System Reliability

When underground transformers fail, potentially pose a significant safety risk to the public, employees, and property. HOL mitigates the safety risks through the use of protection equipment such as fuses and appropriately rated enclosures.

In addition, when an underground transformer fails there is the chance of environmental impact due to the release of oil. HOL mitigates this risk through the use of appropriate enclosure and oil containment. HOL also historically replaced submersible transformers with solid dielectric models as opposed to oil filled models. As of 2010 HOL began replacing the transformers with stainless steel to protect from corrosion.

### 5.2.4 Main and Secondary Drivers

The drivers are represented in the Table 25 below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | Percentage of underground transformers that have passed end of life criteria is 34%. An additional 26% of transformers will reach their end of life criteria by 2024.<br>Increasing number of underground transformer failures has an impact on SAIFI and SAIDI. |
| **Secondary** | **Safety** | Risks of underground transformers can lead to injuries of HOL employees and the public. The risks are mitigated through the use of protection equipment such as fuses and appropriately rated enclosures. |
| **Secondary** | **Environment** | Underground transformer failures can lead to oil leaks. HOL mitigates this risk through the use of appropriate enclosure and oil containment. In addition, submersible transformers are being replaced with solid dielectric models as opposed to oil filled models. As of 2010 HOL began replacing the transformers with stainless steel to protect from corrosion. Federal regulation also demanded the replacement of transformers containing PCBs of 50mg/kg or greater by 2025. |

**Table 25 - Underground Transformer Program Main Drivers**

### 5.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the underground transformer replacement program, improvements are expected in the following measurement:

- Defective Equipment SAIFI

HOL also expects to complete the replacement of all equipment that contains PCBs greater than 50mg/kg in accordance with federal regulation SOR 2008-273. This is anticipated to be met by the end of 2016.

## 5.3 Project/Program Justification

### 5.3.1 Alternatives Evaluation

#### 5.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the replacement program, HOL considered four alternatives for the replacement policy levels.

**I. Underground Transformer Replacement Policy**

Using the rate of failure model developed for underground transformers, HOL analyzed an impact of several replacement alternatives on the performance outcome. All of the alternatives, other than run-to-failure, stabilize the replacement amount beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of the transformers
- Replace 300 padmounted/kiosk transformers and 60 vault transformers / year to maintain an mid-term reliability levels
- Replace 350 padmounted/kiosk transformers and 80 vault transformers / year to maintain long-term reliability levels
- Replace 520 padmounted/kiosk transformers and 120 vault transformers / year to improve mid and long-term reliability levels

#### 5.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the criteria below.

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resources** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 26 – Alternative Evaluation Criteria**

#### 5.3.1.3 *Preferred Alternative*

**I. Underground Transformer Replacement Policy**

The preferred alternative is replacing the oldest underground transformers at a rate of 350 padmounted/kiosk transformers and 80 vault transformers per year.

The 350 padmounted/kiosk transformers and 80 vault transformers replacement level is based on an assumed 100% program efficiency, that is to say only the oldest transformers are replaced first. This level of program efficiency does not always occur in practice. If a subset of transformers is known to be failing, then replacement of transformers with like qualities such as age and manufacturer will be replaced. These transformers may not always be the oldest transformers in the system.

**Failure / Reliability**

HOL has analyzed the impact of several replacement policies using the failure rate model developed for padmounted and kiosk transformers. A failure rate model was also developed for vault transformers. Results of this analysis indicated that an increase of replacements of kiosk and padmounted transformers to 350 and vault transformers to 80 annually would be required to manage failures and keep them from increasing yearly.

The impact of different replacement policies is shown below. The number of failed underground transformers indicated in the two graphs represents the number of transformers that have reached end of life based on their age. The actual failure of the transformer can occur prior or post to the 30 or 35 year age used for kiosk and padmounted transformers and vault transformers, respectively.

Actively replacing underground transformers also allows HOL to warn the customers of an outage. In addition, these outages can be planned during times that customers are not likely to be impacted. By not actively replacing these assets, increasing transformer outages will occur at unexpected and inconvenient times.

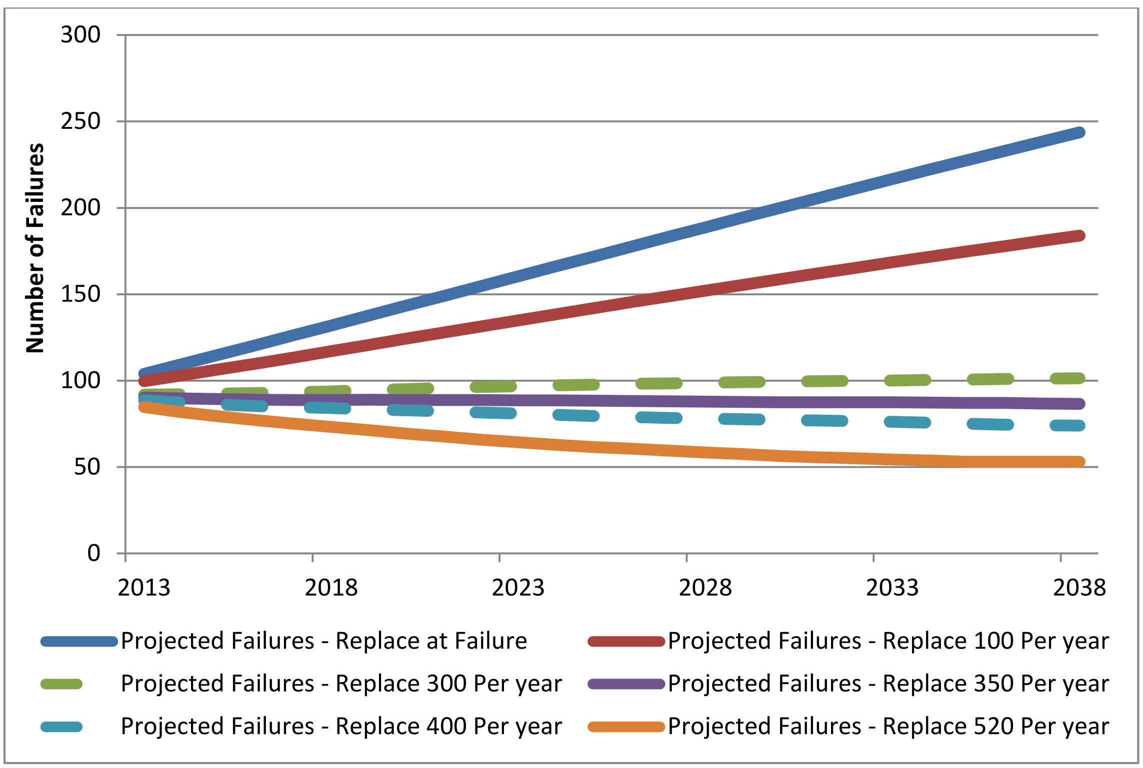



**Figure 36 - Padmounted and Kiosk Transformers Recommended Replacement Rates**

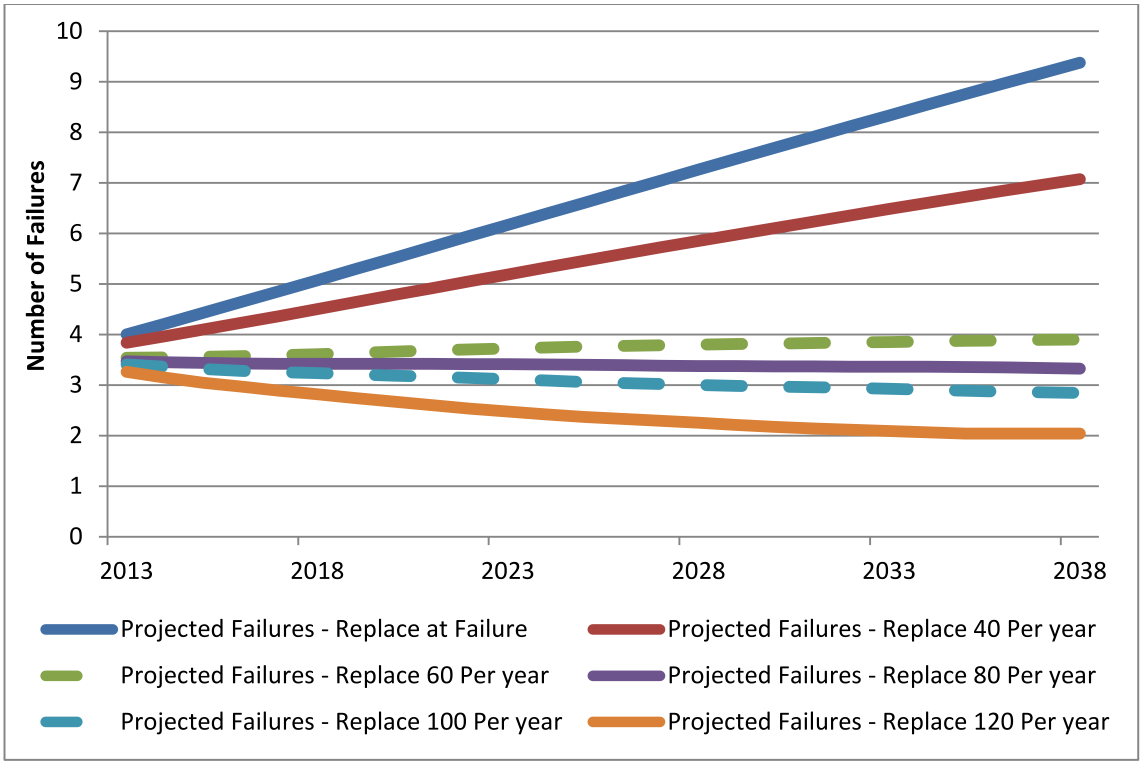



**Figure 37 - Vault Transformer Projected Replacement Rates**

**Safety**

An increased underground transformer replacement policy would minimize the risk to safety by reducing the number of transformers that are likely to fail based on age.

**Resources**

With assets on the system continuing to age and deteriorate, inadequate planned replacements of aging transformers will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned underground transformer replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

**Financial**

The cost associated with replacing underground transformers in an emergency situation has been estimated to be substantially higher than the cost of scheduled transformer replacements. This can be due to many factors including over time labour and express ordering equipment that was used as an emergency replacement. The do-nothing policy would see more frequent transformer failures resulting in a high cost impact of replacing unscheduled underground transformers. By increasing the replacement policy, the average costs to replace a transformer, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled underground transformers also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed transformers.

### 5.3.2 Project/Program Timing & Expenditure

Historically there have been no expenditures for proactive underground transformer replacement due to the assets being run-to-failure. However, from inspection information, transformers have been deemed end of life and scheduled for replacement when resources were available opposed to right away. As described in section 2.1, a project to replace submersible transformers is anticipated for 2016 due to their condition. HOL has also complied with the federal regulation SOR 2008-273 of replacing equipment that contains greater than 50mg/kg of PCBs.

| | Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| End of life | 0.064 | 0.417 | 0.038 | 1.121 | - | - | - | - | - | - |
| Submersible | 0.07 | - | - | - | - | 0.439 | - | - | - | - |
| PCBs | 0.691 | 0.533 | 0.465 | - | - | - | - | - | - | - |

**Table 27 - Historical and Future Spend on Transformer Replacement**

### 5.3.3 Benefits

Key benefits that will be achieved by implementing the underground transformer replacement program are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | Costs associated with a failed transformer are significantly higher than planned replacement. Also, planned outages as opposed to unplanned are easier for HOL's system operators to handle and manage. Aging and deteriorating transformers increase the risk of failure and safety concerns. The alternative of replacing underground transformers at a rate of 350 padmounted/kiosk transformers and 80 vault transformers per year is the most effective means to minimize the potential safety and reliability risks associated with failed underground transformers. |
| **Customer** | System reliability will be preserved as the number of failed transformers will remain constant which will cause outages to fewer customers annually. Planned outages are resolved more quickly than unplanned. They can also be scheduled at times that would minimize the impact to our customers. |
| **Safety** | A failed transformer has the possibility of incurring serious injury to the public. HOL mitigates this possibility through the use of protection equipment and adequately rated enclosures. The preferred alternative will improve public safety by reducing the probability of a failed transformer. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | N/A |
| **Environment** | Transformers utilize oil as a cooling medium and have the potential for oil leaks. Underground transformers are built with oil containment, but a failed transformer could lower the containments integrity. This could lead to an oil spill. |

**Table 28 - Underground Transformer Replacement Program Benefits**

## 5.4 Prioritization

### 5.4.1 Consequences of Deferral

The run-to-failure replacement strategy is an ongoing program year after year. It cannot be deferred and therefore has no consequence of deferral. On the other hand, the preferred alternative of proactive replacement would see an impact from deferral. The positive impacts discussed in section 3.3 would be neglected to the date at which the alternative began. This would also see a buildup of underground transformers past their end of life.

### 5.4.2 Priority

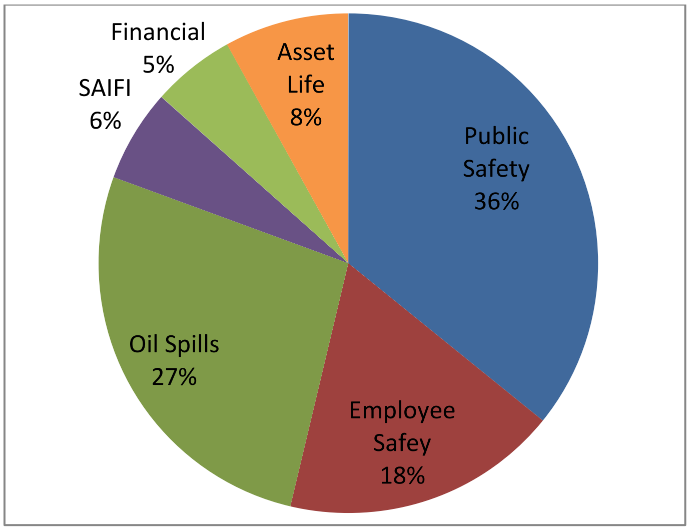



**Figure 38 - Underground Transformer Replacement Avoided Risk**

Score = 1.117

## 5.5 Execution Path

### 5.5.1 Implementation Plan

HOL currently evaluates its underground transformers based on their age demographics alone. This is likely to continue as a method of prioritization until a health index and supporting condition information is captured. Prioritization would then be based on both the transformers age and condition data.

### 5.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
| --- | --- |
| Typical risks to completion include:<br>• Coordinating activities in areas where multiple parties are working;<br>• Getting approval for traffic plans where required<br>• Priority changes as additional inspection results become available | HOL’s mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities of resource use efficiency. |

**Table 29 - Underground Transformer Risks and Mitigation**

### 5.5.3 Timing Factors

Three year rotational visual and IR scan inspections identify underground transformers with poor conditions and expected to fail. Additional higher priority transformers might be identified prompting a reprioritization of the target transformers and will be scheduled as priorities are set.

### 5.5.4 Cost Factors

The final cost of the program is affected by the number of underground transformers to be targeted for replacement. If a transformer fails before replacement is performed, the cost of replacing the failed transformer will be more than if the work is performed proactively. Failure of the transformer will also incur increased costs as it will experience customer outages if the electrical assets are damaged.

### 5.5.5 Other Factors

Other factors to consider include the possibility of project overlap with another planned program. Underground transformers may be replaced as part of cable replacement or voltage conversion projects.

## 5.6 Renewable Energy Generation

(Not applicable for this program)

## 5.7 Leave-To-Construct

(Not applicable for this program)

# 5.8 Project Details and Justification

## 5.8.1 Submersible Transformer Replacement

| | |
|---|---|
| **Project Name:** | Submersible Transformer Replacement |
| **Project Number:** | 92010279 |
| **Capital Cost:** | $442,456 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 58 customers/ 167 kVA |

**Project Scope**

This project involves the replacement of 14 solid-dielectric submersible transformers (Turtles) across the city. Typically submersible transformers are subject to salt contamination which can lead to corrosion and a diminished structural integrity. This can result in oil leaks. For this project, the solid-dielectric transformers will be replaced with either padmounted transformers or stainless steel submersible transformers to reduce the risk of damage due to corrosion and mitigate the risk of environmental hazards.

**Priority**

Score: 0.743

**Work Plan**

The following transformers identified below, will be replaced as part of this project and will be completed throughout 2016. Crews will be dispatched with appropriate equipment to perform the replacement. Where there is real estate, HOL will replace the submersible transformer with a padmounted transformer. If there is no available space the submersible will be replaced with a stainless steel type.

- TV113 @ 180 Beausoleil – Replace with Padmounted
- TV90 @ 115 Beausoleil – No real estate
- TV146 @ 75 Henry – Replace with Padmounted across the road
- TV144 @ 1 Rockwood – Replace with Padmounted on Laframboise
- TV179 @ 462 St. Patrick – Replace with Padmounted beside
- TV143 @ 106 Wurtemburg – Future Replacement by shared vault at 101 Wurtemburg
- TV114 @ 294 York – Replacement with Padmounted
- TV187 @ 260 Clarence – Replaced by shared vault at 333 King Edward
- TV139 @ 468 Clarence – No real estate
- TV91 @ 331 Clarence – No real estate
- TV141 @ 30 Desjardins – No real estate
- TV195 @ 292 St. Andrew – No real estate
- TV194 @ 260 St. Andrew – No real estate
- TV181 @ Murray Street – Repalce with Padmounted across the road

**Customer Impact**

During transformer replacement the customer may experience a planned sustained outage if not supplied by a backup circuit while crews are working. This project increases the distribution reliability and decreases the risk of asset failure in the areas affected.

# 6 Civil Structure Rehabilitation

## 6.1 Project/Program Summary

HOL's Underground Civil Structure asset class consists of underground duct banks, hand holes and various types of underground chambers forming a network through which cables may be installed. Distribution underground civil structures are used in areas where underground wiring is required for:

- aesthetics or clearances;
- to improve reliability;
- to reduce the time to access and correct faulty wiring;
- to permit access in congested areas; and
- to allow re-entry or expansion in areas where further excavation would be costly.

While duct structures are run to the unlikely event that they fail, underground chambers are maintained through a replacement and rehabilitation program based on regular condition assessment. Based on the currently available inspection data it is recommended that the program target a minimum of ten (10) underground chambers per year.

## 6.2 Project/Program Description

### 6.2.1 Assets in Scope

HOL's underground distribution system is supported by a vast network of underground civil structures ranging from cable chambers to duct banks. Generally, underground civil structures are divided into two groups: Duct structures and Underground Chambers.

The scope of this project is to rehabilitate or replace damaged underground cable chambers that are known to be in poor or critical condition which pose a safety risk to the public. As duct structures are run-to-failure, replacement is done reactively as asset condition cannot be assessed without excavation.

Manholes are proactively maintained through the current inspection program and work is coordinated with the City of Ottawa if possible to optimize resource usage. Based on the available inspection data, the program is to target a minimum of ten (10) underground chambers per year with a total of sixty (60) cable chambers to be replaced by 2020. These sixty (60) chamber rehabilitations will vary in complexity from roof replacements to complete chamber replacements. This number represents only 1.9% of a total population of the cable chambers in HOL's distribution system. Additional chamber rehabilitations may be completed over this time through the inclusion of other projects.

The cable chambers targeted for replacement are identified at the beginning of the specific budget year. The targeted chambers are based on the most up to date inspection results and are prioritized based on a condition assessment to identify the rehabilitation projects for the year. The projects are chosen to fit within the constraints of the annual budget, but are re-prioritized if during the annual inspection a chamber is identified to be in a worse condition than a scheduled project.

Chambers are typically repaired like-for-like, expect in cases where the chambers do not meet current HOL standards in which case these chambers will be repaired to meet these standards. In cases where an upcoming project has been identified, the chamber will be repaired to suit the needs of the upcoming project.

Each underground chamber costs an estimated $20,000 to repair or replace the structure roof, and $60,000 for a complete rebuild. Installation of new pads and vaults are also included in the scope of this project.

### 6.2.2 Asset Life Cycle and Condition

Underground civil structures include: Cable Chambers (Manholes), Ducts, Handholes, Sidewalk Vaults, and Equipment Pads. There are a total of 24,349 assets categorized as underground civil structures, including 3,174 manholes, 328 handholes, 34 sidewalk vaults, and 20,813 equipment pads. Before 1970, manholes were installed using cast-in-place construction. As standards became more stringent after 1970, precast manholes became favored as the structures can be made to exact specifications.

| Civil Structure Type | Pre 1970 | Post 1970 | Unknown | Total |
|---|---|---|---|---|
| **Cable Chambers** | 343 | 2,097 | 734 | 3,174 |
| **Handholes** | 8 | 238 | 82 | 328 |
| **Sidewalk Vaults** | - | 34 | - | 34 |
| **Equipment Pad** | - | 3,698 | 17,115 | 20,813 |

**Table 30 - Civil Structures by Type**

The typical lifecycle of civil structures is 40 years. The overall age demographics of civil structures are approximated based upon the age of the equipment utilizing the civil structure, but are not a reliable source of information. As a result the civil rehabilitation program is strictly based upon inspection and condition assessments.

The manhole inspection program targets 300 manholes annually as part of a 10 year inspection cycle. Underground chambers are also inspected through regular work activities when crews perform scheduled work in manholes and handholes. All of the manholes will have undergone inspection by 2017.

During manhole inspections the roof, collar, walls, and floor are examined to determine if there are cracks, concrete spalling, exposure and corrosion of the reinforcing steel rebar, and water entering cracks in the masonry. The table below summarizes the grade scale given to each part of the structure during the manhole inspection.

| Condition | 0 | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|
| **Description** | **Very Good** | **Good** | **Fair** | **Poor** | **Very Poor** | **Critical** |
| **Criteria** | No significant deterioration | Minor hairline cracks or minor spalling | Large cracks and some spalling | Very large cracks and significant spalling | Major spalling and cracks reaching the steel rebar, concrete falling, some rusting | Concrete has deteriorated, large amounts of steel showing and strengths of rebar is questionable |

**Table 31 - Ratings for Underground Civil Structures**

The manhole health index is formulated using the condition scoring above, which is then used to determine the remaining life of the structure. The table below summarizes the grade scale used to assess the asset health.

| Overall Condition | Health Index |
|---|---|
| **Very Good** | 90-100 |
| **Good** | 80-90 |
| **Fair** | 65-80 |
| **Poor** | 35-65 |
| **Very Poor** | 0-35 |

**Table 32 - Asset Health Index condition rating**

Of the inspected 1178 manholes for last three years, 1118 are in a fair and above condition and 60 are in a poor to very poor condition. The latter condition group will be targeted for rehabilitation or replacement during the length of the program in 2016-2020. The table below summarizes the condition of the manholes with inspection data organized by year inspected.

| Health Index | Total Manholes Inspected | | | |
|---|---|---|---|---|
| | 2012 | 2013 | 2014* | Total |
| **>90%** | 348 | 404 | 61 | 813 |
| **80%-90%** | 95 | 110 | 25 | 230 |
| **65% - 80%** | 42 | 47 | 6 | 95 |
| **35% - 65%** | 29 | 24 | 3 | 56 |
| **<35%** | 3 | 3 | 0 | 6 |

**Table 33 - Manhole health index by inspection year**

***Note 2014 data only includes up to July 17, 2014**

Of the 3,174 in-service manholes, approximately 1,178 manholes have been inspected in the past three years and an approximately 538 additional manholes have been installed within the last 15 years. This leaves 46% of the 3,174 that have yet to be inspected; however, HOL aims to inspect 100% of the manhole population by the end of 2020 to better support the rehabilitation program. Extrapolating this data over the entire population would suggest that approximately 135 manholes have a poor to very poor condition. Annual prioritization of manhole inspection results will continue to address the most critical manholes and the program allocated budget will continue to be monitored to determine if it is sufficient based upon completing 100% of inspections.

### 6.2.3 Consequence of Failure

Underground civil structures have a low probability of failure, as issues leading to failure are addressed proactively. Proactive maintenance is the direct result of high consequence cost that could result from the collapse of underground civil structures. As the majority of underground civil structures are located in roadways and sidewalks, the health of the underground civil structure must be maintained to minimize the risk of injury to the public and employees, while preserving the corporate image of HOL.

Failure of underground civil structures are the result of deteriorating structural integrity from concrete breaks and corrosion of the metal rebar which will eventually lead to the collapse of the structure. Repair and replacement of structural components such as the walls, roof, and collar are vital to the mitigation of injury to the public and employees. In addition, a collapse of the underground civil structure can result in damage to electrical distribution assets located in the structure, and as a result customer interruptions can occur. The number of customers impacted by structure failures varies greatly depending on the asset that is housed in the structure; the number can vary from 1 customer to hundreds. Effected customers could expect to be without power for a minimum of four hours and up to twenty-four hours if it is not a redundant system.

There have been no failures of the cable chambers in HOL's distribution system that resulted in customer outages.

### 6.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | 1.9% of the inspected cable chambers are in Poor or Very Poor condition, totalling 60 chambers. It is estimated that the number will grow to 135 by the end of 2020 or completion of all inspections. |
| **Secondary** | **Safety** | Risks of the cable chamber collapse leading to potential injuries to the public as a result of being located on the roadways and sidewalks. |

**Table 34 - Civil Structure Rehabilitation Program Main Drivers**

### 6.2.5 Performance Targets and Objectives

The target of the civil rehabilitation program is to continue on the current path of rehabilitating or replacing a minimum of 10 civil structures annually and maintaining the historical reliability trend of zero outages caused by a failed civil structure. Another target would be to have no injuries to the public or to employees as a result of a failed civil structure.

## 6.3 Project/Program Justification

### 6.3.1 Alternatives Evaluation

#### 6.3.1.1 *Alternatives Considered*

The following alternatives have been analyzed:

1. Do nothing (Status-quo, Run-to-failure)
2. Increased Maintenance and Inspection with Run-to-failure
3. Replace all cable chambers that are currently in poor and very poor condition by the end of 2020 (60 units)
4. Replace all cable chambers that are estimated to be in poor and very poor condition by 2020 (135 units)

#### 6.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resources** | Unplanned and planned replacements utilize both internal and external resources. Alternatives that incur more on-failure replacements are less favorable as it will be more challenging to gather resources on as needed basis. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 35 – Alternative Evaluation Criteria**

#### 6.3.1.3 *Preferred Alternative*

The preferred alternative is to target a minimum of 10 civil structures per year in order to meet the target of 60 by the end of 2020. A run-to-failure approach would increase the safety risks to the public and employees as well as contribute to deteriorating condition which would lead to increased failures and unexpected costs. Rehabilitation versus replacement (Like for like or not-in-kind) is to be evaluated on a case by case basis.

Alternatives and their associated benefits with regards to reliability, safety, resources and Financial, are discussed for each criteria below:

**Reliability**

Alternative #1: increased levels of failing civil structures that would collapse on electrical equipment could cause outages that would increase SAIFI and have long duration outages increasing SAIDI.

Alternative #2: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

Alternative #3: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

Alternative #4: Reliability would be expected to remain consistent with the current situation – no outages caused by failing civil structures.

**Safety**

Increasing the number of civil structures rehabilitated or replaced annually would minimize the risk to safety by reducing the number that is likely to fail based on deterioration.

**Resources**

With assets in the system continuing to age and deteriorate, inadequate planned rehabilitation or replacements of aging civil structures will lead to accumulation of end of life assets. This has the potential to increase unplanned replacements that will stress the available resources of HOL at its current staffing level. Planned civil structure replacements are much more easily handled due to the ability to schedule work rather than replacing upon failure which is done as soon as possible.

**Financial**

The cost associated with replacing civil structures in an emergency situation has been estimated to be substantially higher than the cost of scheduled replacement. This can be due to many factors including over time labour and organizing civil contractors that are used for emergency replacement. The do-nothing policy would see more frequent failures resulting in a high cost impact of replacing unscheduled civil structures. By increasing the replacement policy, the average costs to replace a civil structure, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled civil structures also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed civil structures.

### 6.3.2 Project/Program Timing & Expenditure

The average cost to rehabilitate a manhole from 2010 to 2012 was $60,000. Budgets in 2011-2013 varied to be capable of completing other system improvement activities; however the budgeted amount was met each year. HOL plans to spend approximately $0.5M each year starting from 2014 and ending in 2020.

| | Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| **Total Expenditure** | $0.4 | $0.2 | $0.3 | $0.5 | $0.5 | $0.5 | $0.5 | $0.5 | $0.5 | $0.5 |

**Table 36 - Civil Rehabilitation Program Expenditure**

Spending for refurbishment and replacement of manholes is optimized by pre-planning the construction schedule and ensuring vehicles, staff, contractors and material are all available for start of construction. Where practical, manhole refurbishments and replacements are scheduled in conjunction with City of Ottawa roadwork.

### 6.3.3 Benefits

Key benefits that will be achieved by implementing the civil rehabilitation program are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | Costs associated with a collapsed chamber are significantly higher than planned rehabilitation or repair. Aging and deteriorating civil structures increase the risk of failure and safety concerns. This alternative is the most effective means to minimize the potential safety and reliability risks associated with collapsed |

| | |
|---|---|
| | structures. |
| **Customer** | Lower likelihood of a manhole collapsing and damaging cables if the structures are in good health. System reliability will be preserved as vital electrical assets are usually housed in underground civil structures. Failure of the structure results in damage to electrical assets, which will then impose customer outages. |
| **Safety** | Public safety is maintained as most manholes are located either on sidewalks or public roadways; a collapsing manhole has the possibility of incurring serious injury to the public. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | HOL hires external third party contractors to complete the work in the Civil Rehabilitation program. |
| **Environment** | Transformer bases and switchgear manholes are intended to contain potential oil leaks. These structures are unable to contain oil if they have cracks or holes and oil will be spilt into the environment. |

**Table 37 - Civil Rehabilitation Benefits**

## 6.4 Prioritization

### 6.4.1 Consequences of Deferral

Deferring the project will result in failure of rapidly deteriorating manholes. Public and worker safety will be compromised if a manhole collapses due to poor health. Operating and Maintenance costs will increase as it costs more to repair/replace a civil structure once it has failed, since the optimal intervention time is exceeded. Annual spending will also increase if the project is not performed in conjunction with City of Ottawa roadwork.

### 6.4.2 Priority

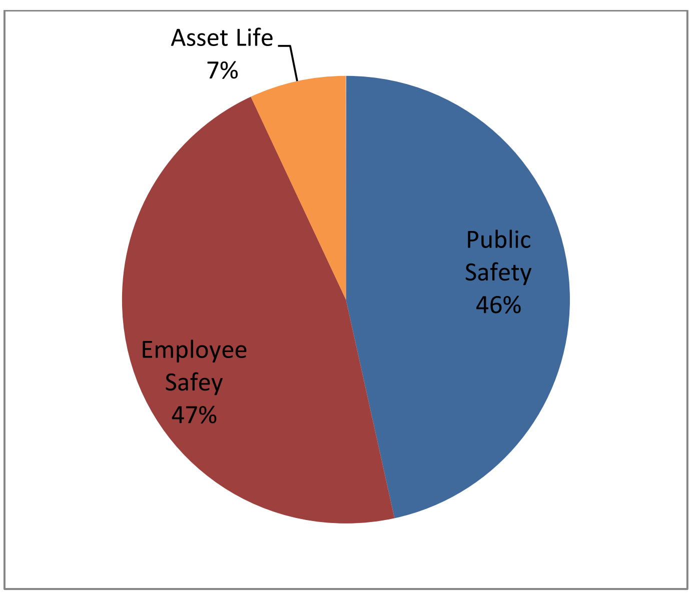



**Figure 39 - Civil Rehabilitation Avoided Risk**

Project Score = 0.92

## 6.5 Execution Path

### 6.5.1 Implementation Plan

Structures with issues that pose a risk to the safety of the public and the employees working in the vicinity are given a high priority. Manholes with a low health index score are being addressed next. The priority of the rehabilitation or replacement of the deteriorating manholes also depends on whether or not the City of Ottawa has planned work in the area.

### 6.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Obtaining road cut permits from the City of Ottawa;<br>• Coordinating activities in areas where multiple parties are working;<br>• Getting approval for traffic plans where required<br>• Priority changes as additional inspection results become available | HOL's mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities for efficient resource use<br><br>Projects are chosen based on condition assessment and as new priorities arise, coordination can be adjusted with minimal impact to the program. |

**Table 38 - Civil Rehabilitation Risks and Mitigation**

### 6.5.3 Timing Factors

As inspections are currently ongoing for manholes, additional higher priority structures might be identified prompting a reprioritization of the target manholes. If additional manholes are identified to be in poor or worse health, investment will have to be increased to allow for inclusion into the rehabilitation program.

### 6.5.4 Cost Factors

The final cost of the project is affected by the number of manholes to be targeted, and the type of rehabilitation or replacement work to be performed. In addition, cost savings are available through planned scheduling with the City of Ottawa roadwork projects. If a manhole fails before rehabilitation or replacement is performed, the cost of replacing the failed manhole will be more than if the work is performed proactively. Failure of the manhole will also increase costs as it will incur customer outages if the electrical assets are damaged. In addition, not-in-kind replacements will change the final cost of the project as it usually costs more to install a manhole with different specifications as it may require a redesign of the feeder section.

### 6.5.5 Other Factors

Other factors to consider include possibility of project overlap with another planned program. Civil structures may be rehabilitated or replaced as part of cable replacement, line extension, switchgear replacement or voltage conversion projects (transformer replacements).

## 6.6 Renewable Energy Generation (if applicable)

Not Applicable.

## 6.7 Leave-To-Construct (if applicable)

Not Applicable.

## 6.8 Project Details and Justification

### 6.8.1 2015 Manhole Rehabilitation

| | |
|---|---|
| **Project Name:** | 2015 Manhole Rehab |
| **Project Number:** | 92008643 |
| **Capital Cost:** | $540,897 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 13500 customers/ 27000 kVA |

**Project Scope**

This manhole replacement/repair project occurs throughout the city through an inspection program that identifies deteriorating or damaged civil structures. When the manholes are inspected features such as the collars, roofs, walls, floors, and racks are ranked on a 0-5 scale and kept in a database. Manholes are then identified on a priority basis for rehabilitation and replacement.

**Priority**

Score: 0.53

**Work Plan**

- MH4422 – Rebuild
- MH299 – Roof
- MH507 – Rebuild
- MH1551 – Roof
- MH389 – Roof
- MH298 – Roof
- MH490 – Roof
- MH566 – Roof
- MH664 – Roof
- MH388 – Roof
- MH629 – Collar
- MH742 – Collar
- MH2766 – Collar
- MH795 – Collar
- MH2677 – Collar

**Customer Impact**

The project increases distribution reliability and decreases the risk of asset failure.

### 6.8.2 2016 Manhole Rehabilitation

| | |
|---|---|
| **Project Name:** | 2016 Manhole Rehab |
| **Project Number:** | 92010285 |
| **Capital Cost:** | $500,000 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 13500 customers/ 27000 kVA |
| **Project Scope** | |
| This manhole replacement/repair project occurs throughout the city through an inspection program that identifies deteriorating or damaged civil structures. When the manholes are inspected features such as the collars, roofs, walls, floors and racks are ranked on a 0-5 scale and kept in a database. Manholes are then identified on a priority basis for rehabilitation and replacement. | |
| **Priority** | |
| Score: 0.53 | |
| **Work Plan** | |
| The manhole rehabilitation and repair program for 2016 will become clearer as information is compiled during the 2015 inspection program and is used to identify manholes to be replaced and repaired. Typically manhole repairs will begin in Q2 when the weather becomes more favourable for working. | |
| **Customer Impact** | |
| This project increases the distribution reliability and decreases the risk of asset failure in the areas affected. | |

### 6.8.3 Civil Rehabilitation on Carling (Bronson to Sherwood)

| | |
|---|---|
| **Project Name:** | Civil on Carling from Bronson to Sherwood |
| **Project Number:** | 92010283 |
| **Capital Cost:** | $2,602,393 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 27 customers/ 5700 kVA |

**Project Scope**

The current unground duct banks along Carling Avenue are approaching their end of life. It is necessary to replace these civil structures to decrease the probability of failure. Also, new underground circuits from Bronson SB Substation to Sherwood Drive along Carling Avenue are required for future planned growth along the Preston Street area. Increased civil capacity is also required for the same reason. To date, LRT and planned bus lanes are changing the scope of this project and further meetings are required with the City of Ottawa to better align the project which was planned to occur simultaneously during road construction with the city in 2016.

**Priority**

Score: 1.17

**Work Plan**

At this point further meetings are required to take place with the City of Ottawa to better align the work plan for this project.

This project will involve civil duct work and electrical work.

**Customer Impact**

This project will increase the capacity and reliability in the Preston Street area and decrease the risk of asset failure.

# 7 Cable Replacement

## 7.1 Project/Program Summary

HOL's underground distribution system is fed using underground circuits running from distribution stations to overhead lines and from overhead lines to transformers and switches. This system is configured and connected through the use of underground cable. Distribution underground cables are used mainly in urban and newer residential areas where it is not feasible to build overhead lines due to aesthetic, legal, environmental or safety issues. The reliability of the overhead and underground distribution systems is contingent on the performance of this underground cable.

The cable replacement program manages HOL's underground replacement of polymer cable. All other cable types are run-to-failure. Underground cable is replaced on a like-for-like basis. In instances where cable is directly buried in a trench, the current standard is to bury the cable encased in a Poly Vinyl Chloride (PVC) duct in non-roadway applications. For roadway applications concrete encased PVC duct is used to reduce risk of physical factors such as dig-ins and vehicle weight.

Historically, HOL has replaced an average of 12km of cable per year. This cable replacement analysis is based on inspection information taken from known aged and problem areas in the system which may have biased the results. HOL will continue to do distributed inspections throughout the system to get a complete picture of the underground cable condition demographics. HOL's analysis recommends a replacement rate of 99km of underground cable per year over the 2016-2020 period to maintain the current fault levels. The equivalent estimated yearly cost of the proposed cable replacement program is $30 million dollars per year. Until confidence levels are more in-line, an average annual budget of $5.6 million will be spent replacing underground cable. This budget amount aligns with the available internal resources that have the qualification to complete this program.

## 7.2 Project/Program Description

### 7.2.1 Assets in Scope

Historically, cable replacements have been prioritized based on the number of faults, or the number of customer interruptions due to cable faults. Cables prioritized in the 2016-2020 period have been assessed using cable testing results in combination with cable age and inspection data. As such, poor and critical condition cable is scheduled for replacement first, while cable testing and condition assessments continue to identify high priority cables for future replacement.

HOL is also reviewing cable injection as a means of life extension in order to defer investments due to the large amount of assets approaching end of life. Targeted cable that meets a specific requirement will be identified for life extension. HOL is currently developing these criteria for identifying cables to be injected.

### 7.2.2 Asset Life Cycle and Condition

HOL owns and manages approximately 4,484 km of underground cable installed in its service territory. The breakdown between various types of cable is 92% cross-linked polyethylene (XLPE), 8% paper insulated lead covered (PILC), and <1% Butyl rubber (14 km installed in the Nepean area).

Demographic information for underground cables has been collected from HOL's Geographic Information System (GIS). When the installation date was not available, an estimated installation date has been used. The estimated installation date for the cable is based on the adjacent property legal records – i.e. date a subdivision was built. Proportional age demographics are illustrated by cable type in the figures below.

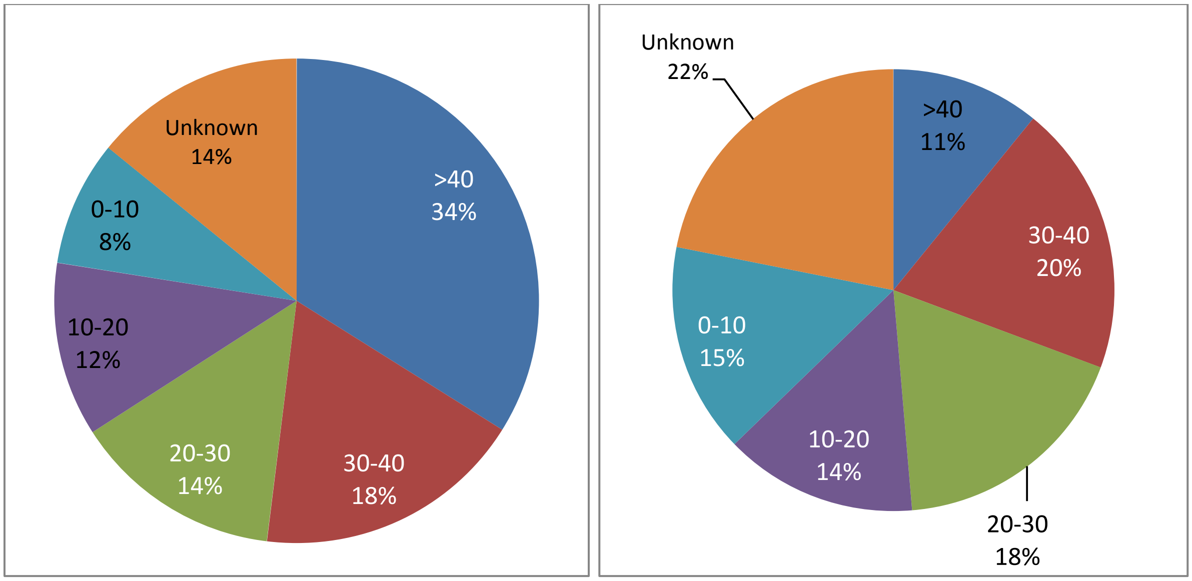



**Figure 40 - Proportion of PILC (left) and XLPE (right) by age**

The following table provides a breakdown of underground cables by voltage class and cable type (polymer or PILC).

| Voltage Class | Polymer (km) (XLPE, EPR, Butyl Rubber) | PILC (km) |
|---|---|---|
| **44kV** | 19 | - |
| **27.6kV** | 1,770 | - |
| **13.2kV** | 1,104 | 308 |
| **12.43kV** | 73 | - |
| **8.32kV** | 756 | - |
| **4.16kV** | 406 | 48 |
| **Total** | 4,128 | 356 |

**Table 39 - Cable length by voltage class**

Typical lifecycles of the various types of polymer and PILC cable is provided in the table below, based on the International Financial Reporting Standards (IFRS) Life.

| Cable Type | IFRS Life |
|---|---|
| **U/G Polymer Insulated cable** | 35 |
| **U/G PILC cable** | 60 |

**Table 40 - IFRS Life for Underground Cable**

Cable age is not the overarching factor in determining the insulation condition of in-service cable. Other factors such as soil condition, ground moisture, presence of a cable jacket, and operating condition play an important role in determining the rate of decay. Historically, cable replacements have been prioritized based on the number of faults, or the number of customer interruptions due to cable faults. While these reliability figures provide indication of cable health, they are lagging indicators. Replacement based on fault data may result in a cable in good health being replaced prematurely when the cable faults were the result of localized defects or damage.

An underground cable testing program was initiated in 2011 with The National Research Council of Canada (NRC). The testing method used by NRC determines the general condition of a polymer cable segment. Cable sites targeted for testing include ones scheduled for replacement in the next 2 to 5 years, high fault areas, and areas with known aged cable. In the 3 years of testing, 1.7% of the total polymer distribution cable has been tested. The following figure summarizes the results of the cable testing program.

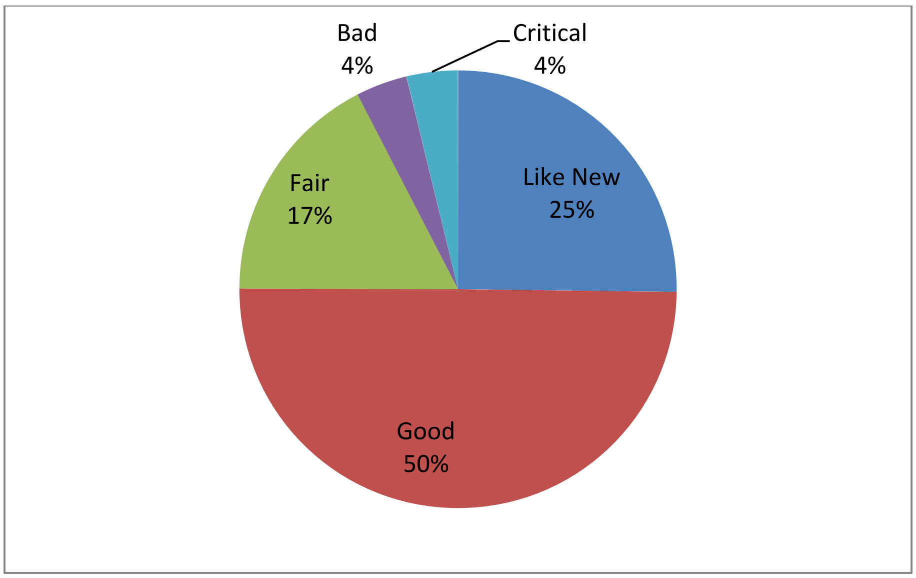



**Figure 41 - Proportion of tested cable by condition**

The NRC testing method assesses the progression of water-treeing in polymer cable to determine the relative condition of the entire segment. Water trees develop in the polymeric insulation due to the ingress of moisture and impurities from the soil which are driven into the dielectric by the electric field. Water trees cause the reduction of the insulation strength making the cable more prone to failure. While the testing procedure captures the general condition of the cable insulation, it does not capture issues such as neutral corrosion, accessory issues or local defects that also impact cable life. These other issues must be qualitatively assessed when reviewing and prioritizing potential cable replacement projects.

Although cable age is not the main factor in determining cable condition, it is currently the most reliable data source captured for the entire asset class. The cable tested was grouped into age ranges and fitted to normal distribution. The estimated distribution of cable age ranges, cable quality and percentage of the systems cable can be seen in Figure 42. These results were created by sorting the tested cable into age ranges and using their testing results, extrapolating it city wide based on the system’s cable age.

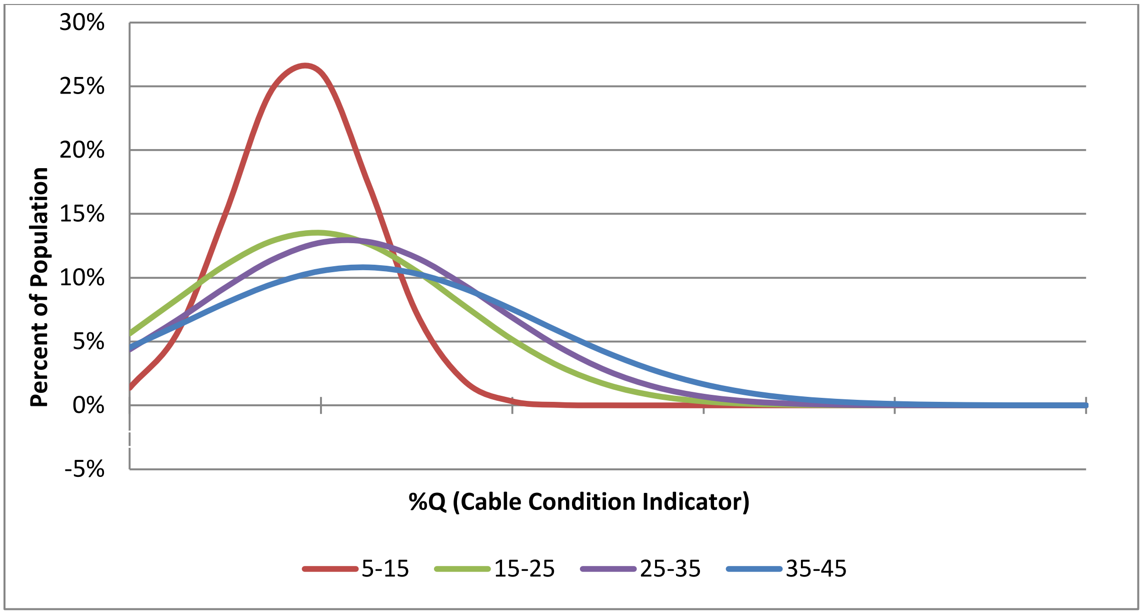



**Figure 42 - Cable degradation model**

Using the cable inspections and in service cable demographics, an overall HOL cable condition representation was created (see Figure 43). Further cable inspection will improve the accuracy of the estimated cable conditions. The graph indicates that 3% of the cable is in critical condition and 14% in poor condition. Areas with high percentages of this cable condition are the focus for cable injection and cable replacement projects.

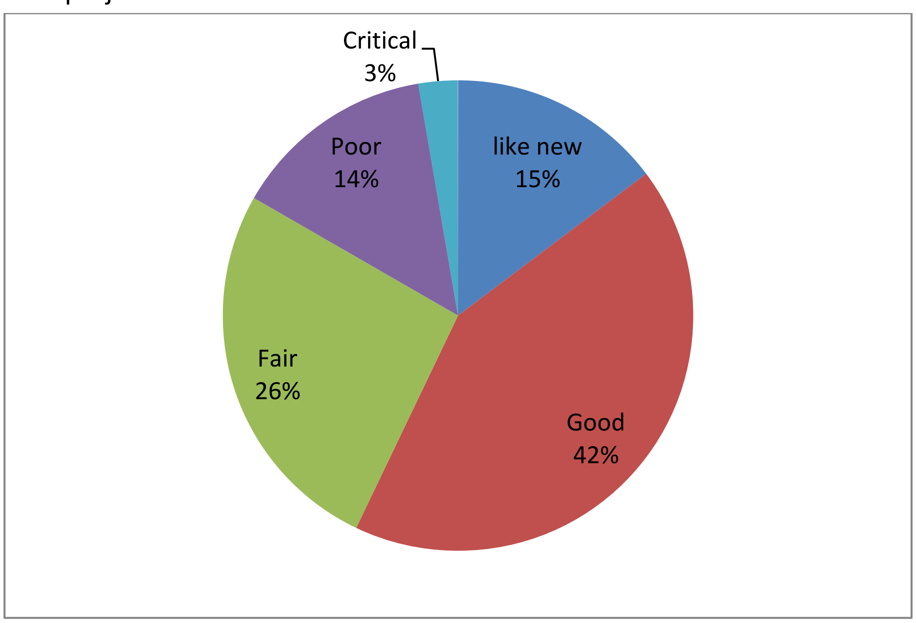



**Figure 43 - Estimated condition of in service polymer cable**

### 7.2.3 Consequence of Failure

The main impact of cable failures is on system reliability. Each cable fault will result in an outage to the customers fed by that circuit. Cable outages can have significant duration due to the time required to locate, isolate and repair the failed section. Failures will have increased impacts if they occur on the trunk of a circuit.

Much of HOL's underground distribution system is designed with a redundant loop to back-up the section of the feeder. A typical cable fault will result in an interruption for 2 to 4 hours depending on the availability of dispatch-able crews. Locating and isolating the faulted cable section is the most time consuming part of the interruption. The faulted section may remain in an isolated state for several days until a crew is available to repair the section. For direct buried cable, trenching is required to install the new section or splice the cable. For this time period, the looped segment has effectively lost its redundancy and could result in an outage of up to 8 hours or more if there are multiple failed sections.

Historical reliability for defective equipment XLPE cable is provided in the graph below.

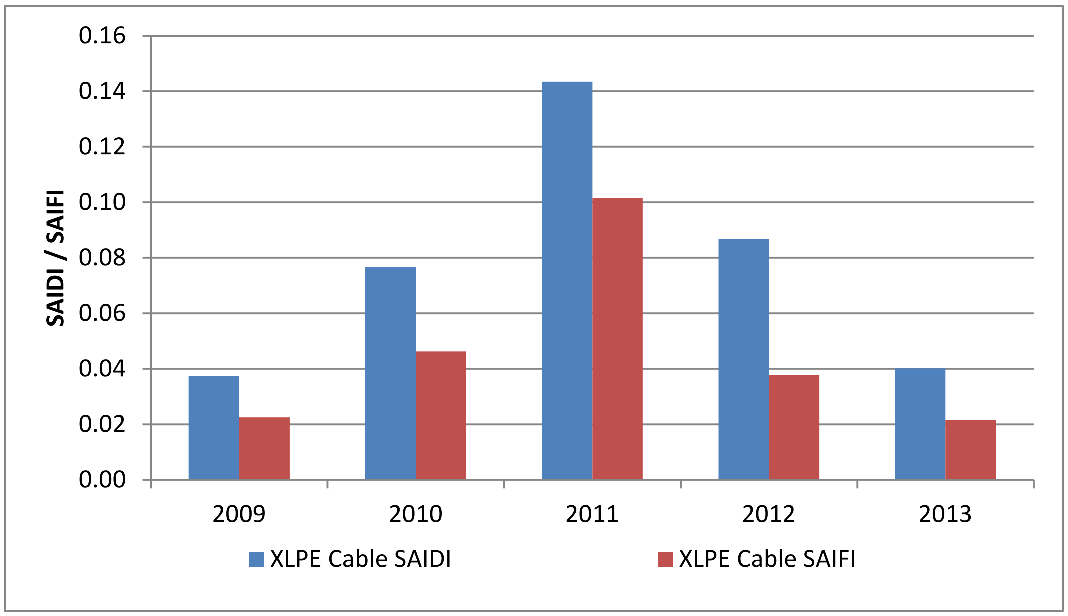



**Figure 44 - Historical Impact on System SAIDI & SAIFI**

### 7.2.4 Main and Secondary Drivers

The drivers are represented in the table below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | The percentage of cable that has passed end of life criteria is 22%. That will grow to 30% by the end of the rate filing period 2020.<br>The number of cable faults is forecasted to increase at approximately 0.2% annually if the current level of investment is maintained. |
| **Secondary** | **Reliability** | Increasing number of cable failures have a negative impact on SAIFI and SAIDI |

**Table 41 – Cable Replacement Program Main Drivers**

### 7.2.5 Performance Targets and Objectives

HOL employs key performance indicators for measuring and monitoring its performance. With the implementation of the cable replacement program, improvements are expected in the following measurements:

- Defective Equipment SAIDI
- Defective Equipment SAIFI

## 7.3 Project/Program Justification

### 7.3.1 Alternatives Evaluation

#### 7.3.1.1 *Alternatives Considered*

In order to address the drivers and achieve the performance objectives of the program, HOL considered 3 alternatives for the replacement cable type to be used when replacing the underground cable as well as five alternatives for the replacement policy levels.

**I. Cable Replacement Standard**

1. Existing cable is replaced with tree-retardant crosslinked polyethylene (TR XLPE) cable which has proven to perform better than regular XLPE and butyl rubber cable which was installed in older areas of HOL service territory.
2. Where practical, cable will be installed in a direct buried duct for ease of installation and removal. Cable located in roadways or driveway will be installed in concrete encased ducts.
3. HOL is developing criteria for cable injection which is to extend the existing life of the cable section as an alternative to replacement.

**II. Cable Replacement Policy**

Using the condition model developed for underground cable, HOL analyzed an impact of several replacement alternatives on the performance outcomes. All the alternatives look to stabilize reliability levels beyond 2016-2020 rate filing period. The following scenarios were analyzed:

- Run-to-Failure scenario with only reactive replacement of cables
- Faults to increase at rate of 0.2 annually
- Status Quo: Maintain current fault level
- Faults to be reduced at rate of 0.2 annually
- Faults to be reduced at rate of 0.5 annually

#### 7.3.1.2 *Alternatives Evaluation*

HOL evaluates all alternatives with consideration of the following criteria:

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the |

| | |
|---|---|
| | safety of HOL's employees and the public. |
| **Resources** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favourable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 42 – Alternative Evaluation Criteria**

#### 7.3.1.3 *Preferred Alternative*

**I. Underground cable standard**

**Failure / Reliability**

TR XLPE performs better than normal XLPE and butyl Rubber. Replacing existing cable with this type of cable will result in a longer service life for cable.

Cable injection effectively rejuvenates the cable to like-new, improving the condition and deferring the need for replacement to another date. Injecting the cables can only be performed once and will require replacement once the cable section had degraded.

**Safety**

Installing cables in direct buried or concrete encased ducts will help reduce accidental dig-ins with the possibility of electrification.

**Resources**

Installing ducts for cable requires greater upfront costs and labour time but will reduce future efforts when replacing cable.

Cable injection requires additional time isolating the section of cable so that it can be work on in a de-energized state.

**Financial**

Cable injection is much less costly than cable replacement however; cable injection is only deferring the replacement of the cable to a later date. Cable injections should be used strategically to levelize replacement costs.

**II. Cable Replacement Policy**

The preferred alternative is replacing cable to reduce faults at rate of 0.2 annually. This will be achieved through the replacement of, approximately 138,000m of cable per year.

The historical replacement level of 60,000m per year is not a feasible approach to replacement due to an increase in poor condition assets. This level of investment would see the annual fault rate increase at a rate of 0.2 annually. In order to maintain the current annual fault rate HOL forecasts that a level of replacement of approximately 98,000m of cable would have to be replaced annually. The investment policy alternatives are summarized in the table below.

| Scenario | | 2013 | 2023 | 2033 |
|---|---|---|---|---|
| Allow Faults to increase at a rate of 0.2 Annually | Annual Cost | $17,783,700 | $17,667,300 | $17,653,500 |
| | Cable lengths replaced (m) | 59,279 | 58,891 | 58,845 |
| Maintain Current Fault Level | Annual Cost | $29,672,400 | $29,555,700 | $29,542,200 |
| | Cable lengths replaced (m) | 98,908 | 98,519 | 98,474 |
| Reduce faults at a rate of 0.2 Annually | Annual Cost | $41,561,100 | $41,444,400 | $41,430,900 |
| | Cable lengths replaced (m) | 138,537 | 138,148 | 138,103 |
| Reduce faults at a rate of 0.5 Annually | Annual Cost | $95,566,200 | $75,388,200 | $68,671,800 |
| | Cable lengths replaced (m) | 318,554 | 251,294 | 228,906 |
| Reduce faults at a rate of 1 Annually | Annual Cost | $166,806,600 | $146,628,600 | $139,911,900 |
| | Cable lengths replaced (m) | 556,022 | 488,762 | 466,373 |

**Table 43 - Cable Replacement Investment Scenarios**

**Failure / Reliability**

HOL has analyzed the impact of several replacement policies using the degradation model developed for underground cables.

The average annual number of faults was calculated for the circuits which have had cable segments tested used by NRC (see Table below).

| | Fault Rate (faults/100km/year) |
|---|---|
| **Condition** | Average |
| **Like New** | 0.004 |
| **Good** | 0.012 |
| **Fair** | 0.018 |
| **Poor** | 0.021 |
| **Critical** | 0.039 |

**Table 44 - Cable Failure Rates**

As there have been several segments of cable tested on circuits, the result of the worst section was utilized to forecast overall condition of the segment. As cable segments selected for testing was based on the number of historic faults there was a bias towards cables representing poorer reliability than the system as a whole, which may have resulted in a higher fault rate than actual being forecasted.

Using the current age demographics for the cable, the cable condition distribution has been forecasted forward (neglecting the impact of new installations).

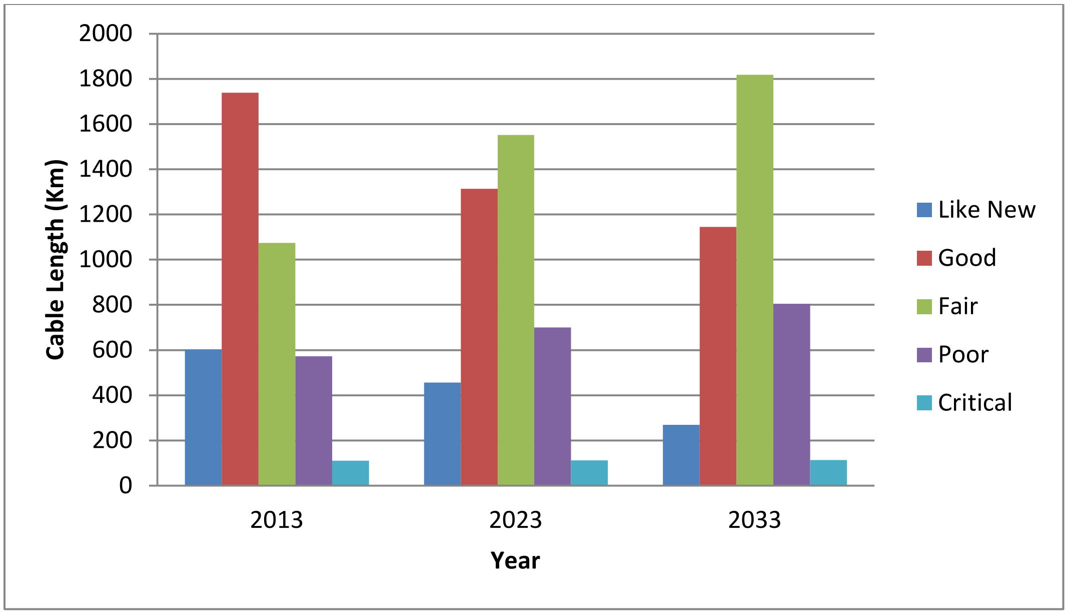



**Figure 45 - Forecasted polymer cable condition**

HOL has analyzed the impact of several replacement policies using the degradation model developed for underground cable. As previously outlined, in order to maintain a current fault rate for underground cable within the system a more aggressive replacement policy is required.

**Safety**

With a more aggressive approach to cable replacement direct buried installations will be reduced at an accelerated pace. In instances where risk to public is the exposure to trench cave-in exist this risk is reduced.

**Resources**

With assets on the system continuing to age and deteriorate, inadequate planned replacements of EOL assets will lead to the accumulation of poor/critical assets and potentially increase unplanned replacements that will stress the available resources of HOL at its current staffing level.

**Financial**

The costs associated with replacing cable in an emergency situation have been estimated to be upwards of double the cost of scheduled cable replacements. The do-nothing policy would see more frequent cable failures resulting in a high cost impact. By increasing the replacement policy, the average costs to replace cable, scheduled and unscheduled, will be reduced and provide long-term financial benefit.

Replacing unscheduled cable failures also affects HOL's ability to complete other planned projects throughout the year. With a do-nothing approach, both labour time and budget resources will be taken away from scheduled work throughout the year by focusing on replacing unscheduled failed cable.

### 7.3.2 Project/Program Timing & Expenditure

Information on the expenditures and length of cable replaced that was completed over the historical period is shown below. The average cost per meter of cable replaced in projects, historically, has been $350 per metre.

| | Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| Total Expenditure | $2.26 | $3.4 | $5.12 | $5.3 | $5.4 | $5.97 | $5.26 | $6.07 | $5.5 | $5.74 |
| Km Replaced | 6.15 | 15.64 | 14.57 | 12.9 | 15.4* | 17.1* | 15* | 17.3* | 15.7* | 16.4* |

**Table 45 - Expenditure History of Comparative Projects**

*Future kilometres replaced are approximate values

Specific Cable Replacement projects are coordinated to allow for optimal efficiency of crew resources by sub-dividing the work into suitable packages by geographic region or operational zones. To ensure cost-effectiveness, in conjunction with the cable replacement, all cable attachments are replaced and connecting transformers are reviewed and identified for replacement where required.

### 7.3.3 Benefits

Key benefits that will be achieved by implementing the cable replacement program are summarized in Table 46 below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | The costs associated with replacing cable in an emergency situation have been estimated to be upwards of double the cost of scheduled cable replacements. The do-nothing policy would see more frequent cable failures resulting in a high cost impact. By increasing the replacement policy, the average costs to replace cable, scheduled and unscheduled, will be reduced and provide long-term financial benefit. |
| **Customer** | Improvement to Defective Equipment related reliability statistics due to the decrease in underground cable failures: reduced failure rate. |
| **Safety** | Cable replacement reduces the risk of cave-ins where cables are not fed in a concrete encased duct, thereby reducing the health and safety risk to employees and the public. |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | (Not applicable) |
| **Economic Development** | HOL hires third party contractors to complete certain projects when the projects cannot be completed with our own internal resources. |
| **Environment** | (Not applicable) |

**Table 46 – Cable Replacement Program benefits**

## 7.4 Prioritization

### 7.4.1 Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved this asset group will pose an increased risk to safety and reliability, as a result of the increase in cable failures per year.

Deferral of cable replacements will also create a backlog of poor condition cable that will require an increased level of investment in the future. As evident in the figure below, if increase in cable replacements is deferred until 2020 the cable demographics show a higher level of assets in poor condition.

### 7.4.2 Priority

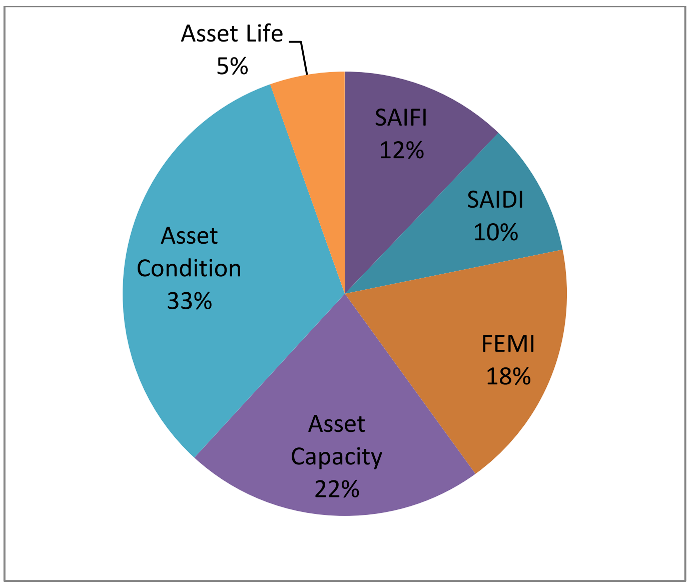



**Figure 46 - Typical Cable Replacement Project Scoring Breakdown**

Typical project score: 1.1

## 7.5 Execution Path

### 7.5.1 Implementation Plan

In 2014, HOL started proactively replacing the butyl rubber cable in Ottawa’s Nepean community. The projects will span 2015 and 2016, effectively removing the majority of butyl rubber cable in the system.

In 2014, a project was initiated to replace and upgrade the underground cable along Stittsville Main Street which has seen poor reliability over the last few years.  The cables will also be increased in size to accommodate increased capacity requirements. The project will continue until 2016.

The underground cable in the Blackburn community has had degrading reliability over the past years and will be replaced in a multi-phase project starting in 2015-2017.

The underground cable in the Beaconhill community has had degrading reliability over the past years and will be replaced in a project starting in 2016.

### 7.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>• Obtaining road cut permits from the City of Ottawa;<br>• Coordinating activities in areas where multiple parties are working;<br>• Getting approval for traffic plans where required<br>• Access to residential backyards and removal of customer installed structures | It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources. |

Table 47 - Cable Replacement Risks and Mitigation

### 7.5.3 Timing Factors

Cable replacements typically take place in the spring, summer, and fall months to avoid winter construction costs from contractors and the forming of concrete structures in cold temperatures.

### 7.5.4 Cost Factors

Cost factors that typically affect projects are:

- Requirement for direct buried ducts and concrete encased ducts
- Backyard cable installation
- Replacement of transformers and switchgear that have been deemed cost-effective to replace in conjunction with the cable.

### 7.5.5 Other Factors

N/A

## 7.6 Renewable Energy Generation

(Not applicable for this program)

## 7.7 Leave-To-Construct

(Not applicable for this program)

## 7.8 Project Details and Justification

### 7.8.1 2015 Cable Injection

| | |
|---|---|
| **Project Name:** | Cable Injection 2015 |
| **Project Number:** | 92008682 |
| **Capital Cost:** | $500,000 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | N/A |
| **Project Scope** | |
| This is a cable injection project that is used to extend the life of direct buried cables that have been identified as successful candidates for this project. Cable Injection locations are identified through the results of a cable testing program carried out across the city in areas based on fault history and age. The life of a direct buried cable that has been injected can be extended by 40 years. | |
| **Priority** | |
| Score: 0.53 | |
| **Work Plan** | |
| The project will begin in 2015, most likely in Q2/Q3 due to the weather. This project also identifies transformers, elbows and joints that are damaged and need to be replaced. | |
| **Customer Impact** | |
| This project increases the reliability to the customers in the areas identified, and also eliminates the need for cable replacement due to the extension of life of the buried cables. | |

### 7.8.2 Beaconhill Cable Replacement – Tisdale Crescent

| | |
|---|---|
| **Project Name:** | Beaconhill Cable – Tisdale Crescent |
| **Project Number:** | 92010259 |
| **Capital Cost:** | $212,000 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 100 customers/ 500 kVA |
| **Project Scope** | |
| This is the final phase of a cable replacement project in the Beaconhill Area. This is an area that was identified for a cable replacement as the cables were shown to test in poor condition and were also an older vintage.<br><br>Location: Beaconhill Area, Tisdale Crescent | |
| **Priority** | |
| Score: 1.093 | |
| **Work Plan** | |
| For cable replacement projects the civil work will typically begin between April and July when the weather become more ideal for outdoor construction. The electrical work generally begins sometime after between August and October. In certain cases considerations of the customers must take place which adjusts the dates of the work plan. | |
| **Customer Impact** | |
| The customers in this area will experience increased reliability and decreased risk of interruptions due to asset failure. | |

### 7.8.3 48M4 & 48M5 Cable Replacement

| | |
|---|---|
| **Project Name:** | 48M4 & 48M5 Cable Replacement |
| **Project Number:** | 92008700 |
| **Capital Cost:** | $841,262 |
| **O&M:** | N/A |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2015 - Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 10 MVA |

**Project Scope**

This is a cable replacement project which will replace the existing direct buried underground cables (3 circuits are left to transfer), which are currently located within a HOL easement. The duct structure is already in place, this will be used to pull in new cable.

Also this project includes the installation of 6 new 60' poles and finish construction on the concrete duct structure to each new pole (duct structure was installed during the summer/fall 2008 parallel to the existing cables) within our 20-meter easement. Upon completion of the concrete duct structure with the 6 new poles, new primary high voltage cables will be pulled into the duct structure.

Location: 48M5 crossing the 417 south of Cyrville Substation

**Priority**

Score: 0.69

**Work Plan**

Pending all permits and land access issues are resolved HOL would like to start civil construction after August 15, 2015
The electrical work will begin after civil work has been completed
Ground water testing will be required around the poles that are located on NCC property (4 poles west of Hwy 174, 2 poles east of Hwy 174)

**Customer Impact**

This project will increase the reliability and decrease the risk of asset failure in the area, also the ability of the system to operate through adverse weather without interruption is improved.

### 7.8.4 Butyl Rubber Cable Replacement – Craig Henry Drive

| | |
|---|---|
| **Project Name:** | Butyl Rubber Rep. Craig Henry Drive |
| **Project Number:** | 92008533 |
| **Capital Cost:** | $1,604,722 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q2 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Asset Condition, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 106 customers |

**Project Scope**

The project involves replacement of approximately 3km of existing underground Butyl Rubber primary cable (direct buried cable) and 10 pad mounted transformers which are end of life.
This project will eliminate some of the last remaining butyl rubber cable in the South. Direct buried cable will be replaced with ducts, thus increasing reliability and decreasing restoration time. New transformer bases will be installed.

**Priority**

Score: 1.0133

**Work Plan**

Install new direct buried ducts and new cable.
Replace underground pad mounted transformers.
Routing options still being assessed.

**Customer Impact**

Reliability improvements due to new equipment and elimination of end of life assets.
Faster restoration time due to installation of direct buried ducts.
Multiple faults have occurred in this area already.
Possible routing alternatives to avoid disruption of customer backyards.

### 7.8.5 QCH Egress Cable Replacement

| | |
|---|---|
| **Project Name:** | QCH Egress Cable Replacement |
| **Project Number:** | 92010208 |
| **Capital Cost:** | $333,578 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q2 |
| **In-Service Date:** | 2015 - Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Asset Condition, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1160 customers/ 2363 kVA |

**Project Scope**

This project involves the replacement of the 160F1, 160F2, 160F3 and 160F4 350MCM XLPE direct buried egress cable. These cables have reached end of life and in 2014 there was a cable fault on the 160F1. The 160F1 and 160F3 are the only back-ups to the Bayshore Mall.

**Priority**

Moved ahead from 2016 into 2015 due to concerns about cable condition.

**Work Plan**

New riser poles were installed within the past two years. New egress cable will be installed and placed into concrete encased duct. A small segment of direct buried duct (no concrete) will be installed at connection point from egress to station foundations, to allow for emergency access.

**Customer Impact**

Reliability improvements due to new equipment, reliable backup supply.
Mitigate risk of full feeder outages.

### 7.8.6 Stittsville Main Cable Replacement & Switchgear Upgrade

| | |
|---|---|
| **Project Name:** | Stittsville Main Cable Replacement & SG Upgrade |
| **Project Number:** | 92008567 |
| **Capital Cost:** | $2,868,447 |
| **O&M:** | $0 |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2016 – Q3 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Risk of Failure |
| **Customer/Load Attachment** | 4903 customers/ 11000 kVA |

**Project Scope**

The driver of this project is to get a switchable trunk down Stittsville Main Street. Included is upgrading the 27.6kV cable to 1000MCM from S20 to S18 and will require 4 new Vista Switchgears. A separate distribution loop will be created to pick up all existing customers.

Also some reconfiguration of the customers around S20 will be required with some cost sharing from the commercial customers in the area. All 8.32kV supplied customers between S20 and S18 will be converted to be supplied by 27.6kV - allowing S17 primary pedestal to be removed.

The 8.32kV line is currently a mix of overhead and underground, which will all be switched to underground in the future.

**Priority**

Score: 1.2833 (2015), 1.76 (2016)

**Work Plan**

The work plan for this project is as follows:

- Design civil infrastructure for Stittsville Main (Ravenscroft Court to Abbott Street) to be completed with Poole Creek being the divider of 2014 and 2015 work.
- Limited electrical isolation by crews to occur throughout civil construction.
- Civil work is to prepare for complete cable replacement in Phase 3 - 2016
- Phase 3 – complete electrical primary cable replacement to be completed by HOL in 2016

**Customer Impact**

This project will increase capacity, reliability and switching capability in Stittsville as well as will set up the community for future voltage conversion to be solely supplied by 27.6kV.

### 7.8.7 2016 Cable Injection

| | |
|---|---|
| **Project Name:** | Cable Injection 2016 |
| **Project Number:** | 92010229 |
| **Capital Cost:** | $500,000 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | N/A |

**Project Scope**

This is a cable injection project that is used to extend the life of direct buried cables that have been identified as successful candidates for this project. Cable Injection locations are identified through the results of a cable testing program carried out across the city in areas based on fault history and age. The life of a direct buried cable that has been injected can be extended by 40 years.

**Priority**

Score: 0.577

**Work Plan**

The project will begin in 2016, most likely in Q2/Q3 due to the weather. This project also identifies transformers, elbows and joints that are damaged and need to be replaced.

**Customer Impact**

This project increases the reliability to the customers in the areas identified, and also eliminates the need for cable replacement due to the extension of life of the buried cables.

### 7.8.8 Pothead Replacement – 470 Cambridge

| | |
|---|---|
| **Project Name:** | Pothead Replacement at 470 Cambridge |
| **Project Number:** | 92010289 |
| **Capital Cost:** | $25,127 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 27 customers/ 550 kVA |

**Project Scope**

This project will see the replacement of a pothead, leaning pole, broken pole lateral, and cables to the customer's vault. There is a broken concrete lateral at the base of the pole X25770 and it is putting strain on the lead primary cable going into vault V220 from the pole's pothead. The pole is beginning to slant which can add to the stress on the cables.

**Priority**

Score: 0.867

**Work Plan**

For this project a fleet will be dispatched to 470 Cambridge with appropriate equipment. They will install a new pole while replacing the pole top equipment. New cable will be installed into the customer's vault and a new concrete pole lateral will be installed.

**Customer Impact**

The customers at 470 Cambridge will experience a scheduled sustained outage while crews are undertaking the work. This outage will be coordinated with the customer. This is a benefit to the alternative which would be an unplanned sustained outage due to pole/lateral failure.

### 7.8.9 Blackburn 4F8 Cable Replacement – Phase 4

| | |
|---|---|
| **Project Name:** | Blackburn 4F8 – Phase 4 |
| **Project Number:** | 92008609 |
| **Capital Cost:** | $1,610,836 |
| **O&M:** | N/A |
| **Start Date:** | 2017 – Q1 |
| **In-Service Date:** | 2017 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 50 customers/ 300 kVA |

**Project Scope**

This reliability driven project replaces direct buried residential cable on the 4F8 circuit in Blackburn. This circuit has been prioritized due its significant fault history and poor results from cable testing. This is one of the three final phases in the Blackburn Cable Replacement Project.

**Priority**

Score: 0.62

**Work Plan**

For cable replacement projects the civil work will typically begin between April and July when the weather become more ideal for outdoor construction. The electrical work generally begins sometime after between August and October. In certain cases considerations of the customers must take place which adjusts the dates of the work plan.

**Customer Impact**

This project will increase the reliability and decrease the risk of failure in this neighbourhood.

### 7.8.10 Butyl Rubber Cable Replacement – Tanglewood Subdivision

| | |
|---|---|
| **Project Name:** | Butyl Rubber Replacement – Tanglewood Subdivision |
| **Project Number:** | 92010206 |
| **Capital Cost:** | $2,540,156 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Asset Condition, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 386 customers/ 2421 kVA |

| **Project Scope** |
|---|
| This project involves the replacement of 2.7km of butyl rubber cable and the replacement of 16 end of life transformers.<br>This project will eliminate some of the last remaining butyl rubber cable in the South. Direct buried cable will be replaced with ducts, thus increasing reliability and decreasing restoration time. New transformer bases will be installed.<br><br>Location: Woodfield Drive, Downsview Crescent, Benlea Drive; Bordered by Hydro One Corridor and City of Ottawa Land. |
| **Priority** |
| Score: 1.0133 |
| **Work Plan** |
| Install new direct buried ducts and new cable.<br>Replace underground pad mounted transformers. |
| **Customer Impact** |
| Reliability improvements due to new equipment and elimination of end of life assets.<br>Faster restoration time due to installation of direct buried ducts.<br>Multiple faults have occurred in this area already. |

# 8 Underground Switchgear Replacement

## 8.1 Project/Program Summary

Underground distribution switchgear at HOL is used to provide switching and isolation points as well as overcurrent protection for loads on the underground distribution system. The underground switchgear replacement program targets the planned replacement of air-insulated padmounted switchgear and pedestal switches to maintain system reliability and safety in the most cost-effective manner.

## 8.2 Project/Program Description

### 8.2.1 Assets in Scope

The Underground Switchgear Replacement program scope encompasses the planned replacement of approaching end of life underground distribution air-insulated padmounted switchgear and pedestal switches due to functional and safety concerns. The switchgears identified for replacement present the highest failure rate and pose reliability issues due to environmental and operational factors.

Gas and oil operated padmounted switchgears and all vault switchgears including wall-mounted switches will not require proactive replacement in 2016-2020 as they are not approaching end of life and are, in general, in good condition.

Underground padmounted air-insulated switchgears will be replaced on a like-for-like basis in accordance with the current HOL practice using SF6 underground switchgear. New SF6 switches have sealed enclosures which are better protected against dirt or moisture, therefore are expected to provide longer life. The sealed enclosure also enables elbow operated operation of the switchgear which provides more operator safety when compared with air-insulated switchgear which has some live components exposed. In addition, this switchgear requires less maintenance costs over the life-cycle. Figure 47 and Figure 48 show the inside of air-insulated switchgear and SF6 switchgear, respectively.

**Figure 47 – Inside of air-insulated switchgear**

**Figure 48 - Inside of SF6 underground switchgear**

HOL plans to replace 20 primary pedestals in both the South and West ends of the city and on average 3 to 5 pieces of live front switchgear across the system to minimize reliability risks associated with these switchgears.

Section 8 of this business case lists specific projects for switchgears at their end of life targeted for replacement in 2016 and 2017.

### 8.2.2 Asset Life Cycle and Condition

Underground switchgears in HOL's distribution system include padmounted, vault, and submersible units. Based on the existing records, HOL owns 439 padmounted switchgears, 191 vault switchgears, and 2 submersible switchgears. Wall-mounted, stick-operated switches in the system have been included in the analysis with vault switchgear, although these are not strictly considered to be "switchgears".

Detailed records do not exist for the underground switchgear class and therefore the demographics have been estimated using available records. While these estimates provide an initial baseline for analysis, collection and consistent representation of switchgear information in a centralized repository is essential to enable accurate asset assessment in the future.

There are many sub-types of the switchgears with different insulating media and various interrupting styles. The distribution of sub-types is shown in Figure 49, which depicts the padmounted switchgear and Figure 50, which depicts the vault switchgear population by type.

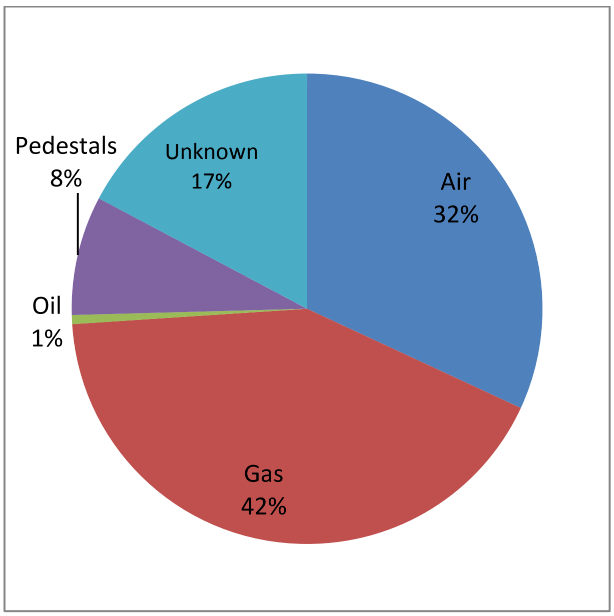



Figure 49 - Padmounted switchgear population by type

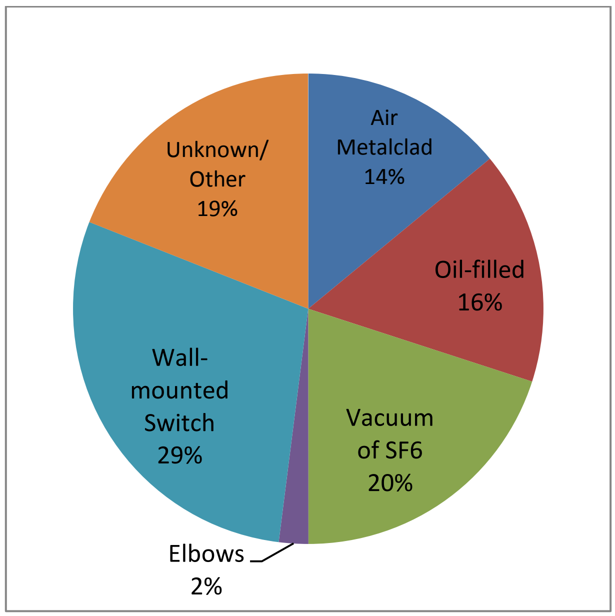



Figure 50 - Vault switchgear population by type

The life expectancy of padmounted switchgears is 25 years and is impacted by a number of factors including the frequency of switching operations, load dropped, the presence of a corrosive environment, and dampness at the installation site.

The life expectancy of vault switchgears is 30 years and may be affected by environmental factors; including salt water, pollutants, UV light, and frequent wet/dry cycles. The life expectancy may also be affected by electrical and mechanical stresses due to a high number of operations.

HOL follows industry standard practices of running switchgears to end of life, just short of failure. To extend the life of these assets, a number of intervention strategies are employed on a regular basis such as inspections with thermographic cameras and cleaning with CO2 for air-insulated padmounted switchgears and inspection and cleaning for vault switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Switchgear failures may not directly be linked to the age of the asset. Padmounted switchgears may fail due to dirt/contamination, vehicle accidents, rusting of the casing, and broken insulators caused by misalignment during switching. As such, HOL's padmounted switchgear inspection program seeks to identify and remediate certain degradation modes. Dirt and contaminant accumulation can often be removed by cleaning. Re-painting and touch-ups of the casing can delay the rusting process, but eventually a planned replacement of the unit is still required.

Moisture ingress into the insulation tank of a vault switchgear can lead to equipment failure by decreasing the insulation properties in an oil-immersed switchgear or form corrosive acids in an SF6 switchgear. Breakdown of the switchgear's insulation due to electrical stress may also lead to asset failure on subsequent operations. The switchgear's operating mechanism and bearings and linkages wear out over time. Furthermore, the electrical contacts of the switchgear may degrade to the point that the units fails. HOL's maintenance program seeks to extend the life of its vault switchgears by cleaning dirt and contamination, maintaining bearings and linkages, and repairing defects.

Switchgears are identified and prioritized for replacement based on condition and consequence. Condition information is gathered through the three year cycle Padmounted Switchgear Infrared (IR) and Visual Inspection program. Consequence scoring is based on the number of customers that will be affected by the interruption, the duration of the interruption, the environmental risk and the health and safety risk.

The age demographics of the padmounted switchgears are presented in Figure 51.

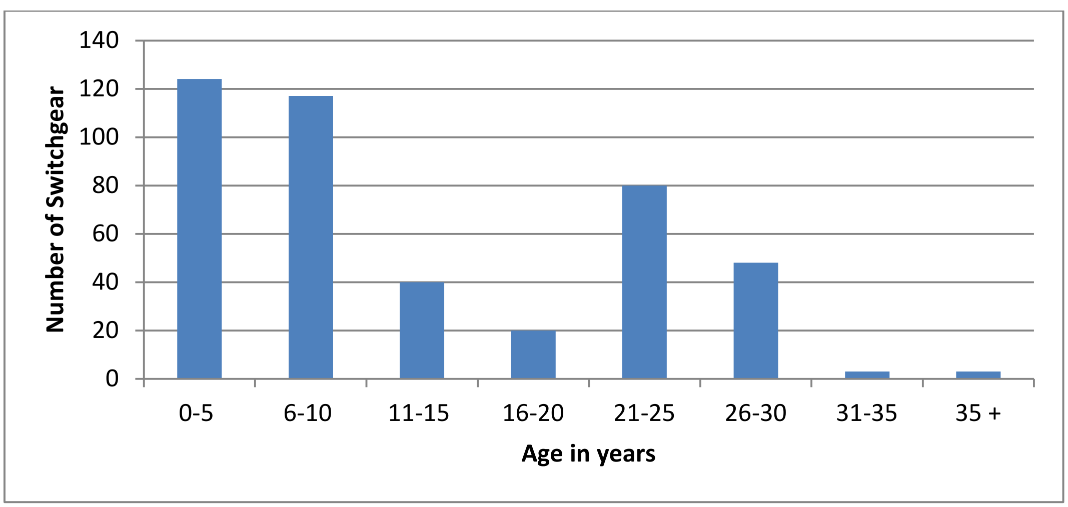



**Figure 51 - Padmounted switchgear population by age group (in years)**

### 8.2.3 Consequence of Failure

Although the effects are not as severe as station switchgear failures, underground switchgear failures diminish HOL's ability to provide reliable electricity service to its customers. A switchgear failure causes an outage, the severity of which depends on the number of affected customers and the duration of the outage.

Oil-immersed switchgears may leak oil into the environment upon failure. SF6 is a greenhouse gas, thus a gas leak due to failed SF6 switchgear is detrimental to the environment. Furthermore, SF6 may form corrosive acids when it reacts with water. SF6 is heavier than air and therefore may pose a suffocation danger if leaked into a contained area by displacing breathable oxygen from the air. Rusting on the casing of a padmounted switchgear can lead to perforation and is a public safety hazard.

HOL measures the defective equipment contribution to SAIFI in customer interruptions per 100 customers served. Figure 52 depicts the SAIFI contribution by defective underground switchgears for the years 2009 to 2013. The five-year average over this time period is 1.82 customer interruptions per 100 customers. Due to the small sample size in the number of underground switchgear, the effect on SAIFI varies between years and is not indicative of trends or patterns.

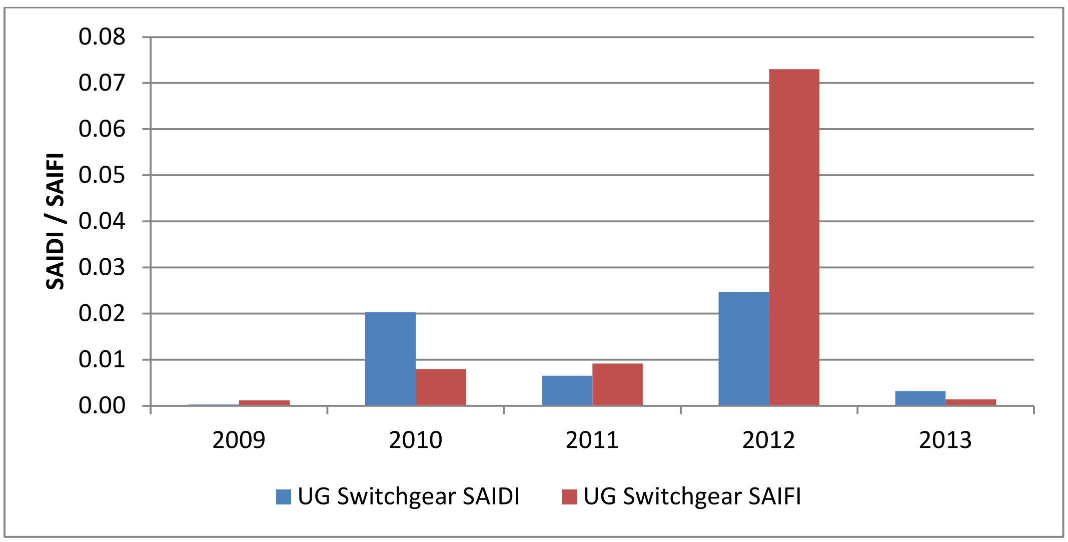



**Figure 52: Defective underground switchgear on overall SAIDI/SAIFI**

### 8.2.4 Main and Secondary Drivers

The drivers are represented below.

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Failure Risk** | Air-insulated switchgears are reaching the end of life and are a critical part of the distribution system. |
| **Secondary** | **System Efficiency** | Newly installed styles of switchgears (SF6) require minimal maintenance in comparison with air-insulated switchgears. |

**Table 48 - Switchgear Replacement Program Drivers**

### 8.2.5 Performance Targets and Objectives

HOL will minimize the number of underground switchgear failures through replacement of the worst condition end of life units. Another objective is to maximize operational efficiency by minimizing maintenance costs through replacement of switchgears with units that require less maintenance.

## 8.3 Project/Program Justification

### 8.3.1 Alternatives Evaluation

#### 8.3.1.1 *Alternatives Considered*

The following alternatives have been considered:

- Run-to-Failure with only reactive replacement of the switchgears (Do-Nothing),
- Proactive replacement of all switchgear older than their 25 year life expectancy
- Proactive replacement of approximately three (3) to four (4) worst condition end of life switchgear annually while continuing maintenance and inspection program

#### 8.3.1.2 *Evaluation Criteria*

HOL evaluates all alternatives with consideration of the criteria summarized below.

| Criteria | Description |
|---|---|
| **Failure / Reliability** | The increased potential of failure posed by these aging assets will impact the organization's ability to guard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system. |
| **Safety** | HOL puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of HOL's employees and the public. |
| **Resource** | Unplanned replacements are usually carried out by HOL's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favorable as it will be more challenging from a resource perspective. |
| **Financial** | Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers. |

**Table 49 - Criteria used to evaluate alternatives**

#### 8.3.1.3 *Preferred Alternative*

The preferred alternative is the proactive replacement of approximately three (3) to four (4) worst condition, end of life switchgears annually while continuing maintenance and inspection programs.

| | Do-Nothing | Replace All Switchgear older than 25 years | Proactively replace 3-5 switchgear and inspect and maintain |
|---|---|---|---|
| **Failure / Reliability** | Increased annual failures and worse reliability through unplanned failures | All older switchgear are replaced increasing reliability | Worst condition switchgear replaced – reliability maintained |
| **Safety** | Least safe option as switchgear is run-to-failure | All older switchgear are replaced increasing safety | Worst condition switchgear replaced increasing safety |
| **Resource** | Unplanned replacements are less efficient from a resource perspective | Large amount of resources required | Resourcing is levelized annually |
| **Financial** | Least expensive option at first, however unplanned replacement is more expensive than planned replacement | Most expensive solution | Most cost-effective solution as replacement is optimized |

**Table 50 - Switchgear Replacement Alternatives**

**Run-to-Failure with only reactive replacement of the switchgears (Do-Nothing)**

This alternative involves ceasing the planned replacement of underground switchgear and allowing the assets to run-to-failure. This alternative is least costly at first. However, the cost associated with replacing switchgear in an unplanned emergency is substantially higher than the cost of planned replacement. This is due to many factors including over time labour and organizing civil contractors that are used for emergency replacement. Therefore, in the long term this alternative will be more expensive than a planned program. This alternative also inherently results in worse reliability and safety.

**Proactive replacement of all switchgear older than their 25 year life expectancy**

This alternative replaces all switchgears which have exceeded 25 years of age. This alternative should result in improved switchgear reliability and maintenance. However, large amounts of resources will be required at first to achieve this alternative. Additionally, this is the most expensive alternative and may result in unnecessary replacement of some switchgears which are still in good condition

**Proactive replacement of approximately three (3) to four (4) worst condition end of life switchgear annually while continuing maintenance and inspection program**

This alternative utilizes data collected from the annual 3 year rotational inspection program to identify the worst condition switchgear to be scheduled for replacement. This alternative maintains reliability and maintenance through inspection and targeted replacement. This is the most cost-effective of the three since it relies on planned replacement and levelized annual resourcing.

### 8.3.2 Project/Program Timing & Expenditure

The following table shows the historical and future capital expenditure in the underground switchgear replacement program and the number of units replaced each year.

| | Historical | | | | | | Future | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Expenditure ($M)** | $1.14 | $1.73 | $1.09 | $0.67 | $0.16 | $1.22 | $0.38 | $0.43 | $0.39 | $0.41 |
| **Units Replaced** | 5 | 10 | 7 | 5 | 2 | 8 | 4 | 4 | 4 | 4 |

**Table 51 - Historical and forecast investments in underground switchgear replacements**

### 8.3.3 Benefits

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | SF6-insulated switchgears require less maintenance than oil-immersed or air-insulated units, thus reducing O&M costs over the lifecycle of the asset. The proactive replacement of units at end of life but before failure results in labour cost savings compared to unplanned replacement of a failed unit. |
| **Customer** | The new SF6 switchgear units are relatively compact and provide an intangible benefit to customers since they are less intrusive than older, bulky units. The proactive replacement of an underground switchgear before failure prevents unplanned outages from occurring, improving system reliability for customers. |
| **Safety** | Underground switchgear replacements mitigate potential safety hazards due to leaking SF6 gas and live components exposed by rusting enclosures. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | Improved system reliability has a subtle, yet direct impact on economic development, as local businesses and self-employed residents benefit. |
| **Environment** | Underground switchgear replacements mitigate potential environmental damage due to leaking oil or SF6 gas from units at their end of life. |

**Table 52 - Switchgear Replacement Benefits**

## 8.4 Prioritization

### 8.4.1 Consequences of Deferral

The probability of failure of a distribution switchgear increases every year. The assets targeted in the replacement program are at end of life and will fail if not replaced, causing an outage and requiring the failed unit to be replaced at a higher cost than a planned replacement.

### 8.4.2 Priority

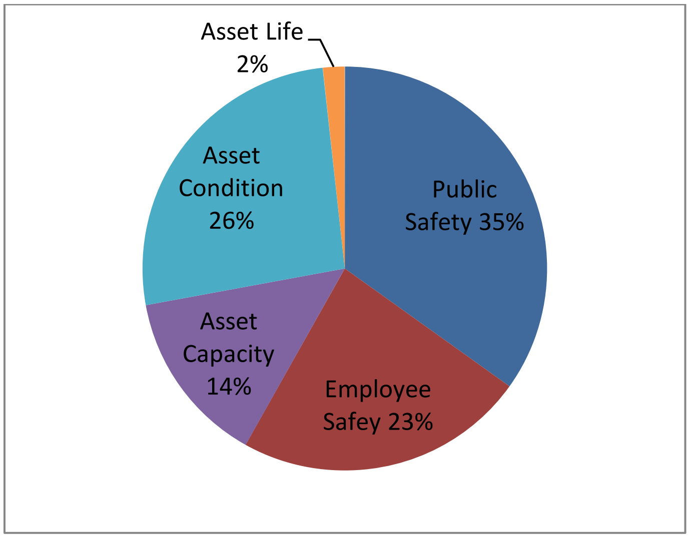



**Figure 53 - Switchgear Replacement Avoided Risk**

Project Score: 1.72

## 8.5 Execution Path

### 8.5.1 Implementation Plan

Replacement of distribution switchgear may occur year round. Old switchgear will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new switchgear will be installed on the new manhole and be commissioned.

### 8.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation |
|---|---|
| Typical risks to completion include:<br>Project planning to minimize outages to customers and that coordinate with other planned work in the area. | It is HOL practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resourcing and ensure continued system operability and safety in areas where crews are working. |

**Table 53 - Switchgear Replacement Program Risks and Mitigation**

### 8.5.3 Timing Factors

Work scheduling of resources in coordination with other HOL underground work is a timing risk.

### 8.5.4 Cost Factors

None identified.

### 8.5.5 Other Factors

None identified.

## 8.6 Renewable Energy Generation (if applicable)

N/A

## 8.7 Leave-To-Construct (if applicable)

N/A

## 8.8 Project Details and Justification

### 8.8.1 S124 Pedestal to Switch Replacement

| | |
|---|---|
| **Project Name:** | S124 Pedestal to Switch |
| **Project Number:** | 92008601 |
| **Capital Cost:** | $166,395 |
| **O&M:** | $0 |
| **Start Date:** | 2015 – Q2 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1953 customers/ 9131 kVA |

**Project Scope**

This project involves the replacement of a primary pedestal S124 (MWDF2) due to EOL, with the installation of a new padmounted switchgear SC6881. The switch will be incorporated with future cable upgrades and will enable Katimavik voltage conversion from 12.43kV to 27.6kV.

**Priority**

Score: 0.15

**Work Plan**

A HOL Contractor will be responsible for supplying and installations of switching manhole and ducts. HOL will supply all material (primary cables, switchgear and splice kits) and will be responsible for primary cables installations, splicing and terminations/connections.

Civil and electrical work should be ready before the isolation of the single customer supplied by the pedestal - vault 4592.

HOL will replace existing SMD-20 switches with a new one inside vault 4592

**Customer Impact**

This project will help improve the reliability and power quality of the electrical system at 150 Katimavik Road.

### 8.8.2 SE20 Replacement & Relocation

| | |
|---|---|
| **Project Name:** | SE20 Replacement & Relocation |
| **Project Number:** | 92010212 |
| **Capital Cost:** | $107,818 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure, Flooding Issues |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 746 customers/ 2219 kVA |

**Project Scope**

This project includes the replacement and relocation of the SE20 switchgear based on inspection results and a history of flooding issues at this switchgear location. The switchgear will be relocated to higher ground, closer to the road and protected with bollards. Application to the MTO will be required. The attached transformer was recently replaced and will not be moved. The old switchgear location will become a splice pit.

Location: West Hunt Club Road and Cedarview Road

**Priority**

Score: 1.20

**Work Plan**

MTO permit will be obtained before construction begins. SE20 will be replaced with a new SF6 switchgear including a new base and relocated to higher ground near the road. Old switchgear location will be used as splice pit. Bollards will be installed.

**Customer Impact**

Reliability improvement due to new equipment.
No more flooding issues causing outages.

### 8.8.3 SW89 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | SW89 S/G Replacement |
| **Project Number:** | 92010261 |
| **Capital Cost:** | $122,360 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q2 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 300 customers / 1000 kVA |
| **Project Scope** | |
| This project involves the replacement of an existing switchgear, SW89 near Thurston and Conroy, with a new S&C Vista switchgear.<br><br>This project was identified through Siemens S/G inspection and IR scan. The age of the switchgear is 1986 vintage. | |
| **Priority** | |
| Score: 1.48 | |
| **Work Plan** | |
| This civil and electrical work for this project is scheduled to being in Q2- 2016 and will be complete before then end of the year. In certain cases considerations of the customers must take place which may adjust the dates of the work plan. | |
| **Customer Impact** | |
| Customers in this area will experience increased reliability and power quality and decreased risk of asset failure | |

### 8.8.4 SW190 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | SW190 S/G Replacement |
| **Project Number:** | 92010263 |
| **Capital Cost:** | $125,159 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q2 |
| **In-Service Date:** | 2016 – Q2 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 300 customers/ 1000 kVA |

**Project Scope**

This project involves the replacement of an existing switchgear, SW190 located at 1051 Ages Drive, with a new S&C Vista switchgear.

This project was identified through Siemens S/G inspection and IR scan. The age of the switchgear is 1989 vintage.

**Priority**

Score: 1.39

**Work Plan**

This civil and electrical work for this project is scheduled to being in Q2- 2016 and will be complete before then end of the year. In certain cases considerations of the customers must take place which may adjust the dates of the work plan.

**Customer Impact**

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure

### 8.8.5 S62 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | S62 Replacement |
| **Project Number:** | 92010168 |
| **Capital Cost:** | $170,666 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 3765 customers/ 24524 kVA |

**Project Scope**

This project involves the replacement of switchgear S62, due to aging infrastructure, with an SEL automated Vista seitchgear. S62 is located at the corner of Kukulu Road and Pickford Drive.

**Priority**

Score: 1.72

**Work Plan**

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

**Customer Impact**

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

### 8.8.6 S98 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | S98 Replacement |
| **Project Number:** | 92010160 |
| **Capital Cost:** | $170,666 |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 857 customers/ 13481 kVA |
| **Project Scope** | |
| This project involves the replacement of switchgear S98, due to aging infrastructure, with an SEL automated Vista switchgear. The switchgear is located at Terry Fox and Mckinley. | |
| **Priority** | |
| Score: 1.72 | |
| **Work Plan** | |
| This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned. | |
| **Customer Impact** | |
| Customers in this area will experience increased reliability and power quality and decreased risk of asset failure. | |

### 8.8.7 S45 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | S45 Replacement |
| **Project Number:** | 92010164 |
| **Capital Cost:** | $170,666 |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 4097 customers/ 20508 kVA |
| **Project Scope** | |
| This project involves the replacement of switchgear S45, due to aging infrastructure, with an SEL automated Vista switchgear. S45 is located at the intersection of Westlock Way and Knudson Drive. | |
| **Priority** | |
| Score: 1.72 | |
| **Work Plan** | |
| This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned. | |
| **Customer Impact** | |
| Customers in this area will experience increased reliability and power quality and decreased risk of asset failure. | |

### 8.8.8 S54 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | S54 Replacement |
| **Project Number:** | 92010162 |
| **Capital Cost:** | $170,666 |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1400 customers/ 800 kVA |

**Project Scope**

The project involves the replacement of switchgear S54, due to aging infrastructure, with an SEL automated Vista switchgear. S54 is located along Teron road, between Beaverbrook and The Parkway.

**Priority**

Score 1.72

**Work Plan**

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

**Customer Impact**

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

### 8.8.9 S584 Switchgear Replacement

| | |
|---|---|
| **Project Name:** | S584 Replacement |
| **Project Number:** | 92010166 |
| **Capital Cost:** | $170,666 |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 156 customers/ 17544 kVA |

**Project Scope**

This project involves the replacement of switchgear S584, due to aging infrastructure, with an SEL automated Vista switchgear. S582 is located along Terry Fox Drive, close to the intersection with Helmsdale Drive.

**Priority**

Score: 1.72

**Work Plan**

This project is scheduled to start and be completed in 2016. To replace this switchgear it will be de-energized while crews remove the old switchgear and base. Civil contractors will then install a new switching manhole and the new automated switchgear will be installed on the new manhole and commissioned.

**Customer Impact**

Customers in this area will experience increased reliability and power quality and decreased risk of asset failure.

# 9 Overhead Distribution Switches & Reclosers

## 9.1 Project/Program Summary

Overhead distribution switches are used to isolate sections of the system for planned work or restoring customers from an interruption. They provide a means of protecting major system equipment as well as allowing circuits to be available for backup supply. The number of failures per year within this asset class is very minimal and as such, HOL employs a run-to-failure strategy for overhead switches. As an exception, there are three types of switches which have been identified as reaching end-of-life or defective presenting a safety concern.

## 9.2 Project/Program Description

### 9.2.1 Assets in Scope

HOL's overhead distribution switch and recloser asset class consists of all pole mounted load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating as high as 44kV. Equipment belonging to this asset class serves the main purpose of providing a means to isolate or re-route a section of overhead line due to a fault condition or planned work. Overhead switches and reclosers of varying size and type are located within all geographic areas covered by HOL's service territory and are found on all distribution feeders. The overhead switch and recloser program is typically a run-to-failure strategy, unless a technical or health and safety issue has been identified.

### 9.2.2 Asset Life Cycle and Condition

For the majority of this asset class, accurate demographic data exists within HOL's database. This includes known populations of reclosers, load break switches and inline switches. The number of fused cut-out switches in the system was estimated from the number of pole mounted transformer connections and fused switches in the database. Within these four switch types, there is a variety of switch sub-types that make up each category. The population distribution as of spring 2014 is shown in the following table, based on switch type and voltage class.

| Switch Type | 4.16kV | 8.32kV | 12.43kV | 13.2kV | 27.6kV | 44kV | Total |
|---|---|---|---|---|---|---|---|
| **Non-Load Break** | 1,610 | 2,293 | 39 | 1,342 | 1,467 | 483 | 7,234 |
| **Load Break** | 51 | 137 | 0 | 159 | 446 | 309 | 1,102 |
| **Cut-Outs** | 8,333 | 6,139 | 41 | 2,770 | 3,977 | 9 | 21,323 |
| **Reclosers** | 0 | 19 | 2 | 1 | 35 | 0 | 57 |

**Table 54 - Overhead Switchgear Demographics**

The typical useful life of the switches in the distribution system is 35 years.

There are two types of switches that have been identified as health and safety concerns. They are the 4.16kV rated porcelain box switches and the S&C Electric Company (S&C) 27.6kV SMD-20 porcelain and polymer fused cut-outs. Porcelain box switches have been identified as posing a safety and reliability risk due to issues of mechanical fracturing. There are four substations with a total of 28 sets of switches remaining that require porcelain box switch replacements. SMD-20 switches manufactured between 2004 and 2011 are reportedly experiencing failures when the switches are operated using a load break tool. There were approximately 2,800 S&C 27.6kV polymer and porcelain SMD-20 switches deployed in the system in 2013. HOL has initiated a replacement program for these switches. It is expected that the replacement of all porcelain box switches and SMD-20 switches will be completed in 2016.

HOL has started to experience failures on 13kV porcelain cut-out switches installed in areas that were converted from 4kV which have reduced spacing. Replacement of these switches has started in areas of concern and will increase into a larger program once the urgent safety concern switches are replaced. This program is expected to continue beyond the 2020 expenditure plan.

HOL employs a run-to-failure strategy for this asset class. Information regarding overhead switch and recloser failures has been collected to allow for predictive spending levels. Other than the three switches mentioned previously, failure rates for this asset group have been minimal in the past and do not require predictive analysis or active replacement programs. Recent performance does not suggest an accelerated deterioration of overhead switches and reclosers.

### 9.2.3 Consequence of Failure

It is important to distinguish between the failure of an overhead switch and the failure of other equipment that may lead to a blown fuse or open switch. In the case of a fault that causes a recloser to operate, this would not be considered a recloser failure. This is also applicable to fused switches in the sense that they are incorporated into the distribution system with the intention of breaking the circuit, should there be an electrical short circuit. Since switches and reclosers are installed as protective devices or for operational efficiency, the consequence of operation will not be heavily discussed.

HOL would be more concerned with the failure of a switch, fuse or recloser, to operate under a fault condition. Although unlikely, this would result in damage to other equipment and a larger outage. Any customers or assets upstream or downstream of the failed switch would be affected by the fault current. In other words, the fault would travel beyond the broken switch until it hit another switch. In some cases, this could mean that the fault current would travel back to the station, potentially causing a very large outage.

The scenario described above would present multiple consequences to HOL and its customers. Defective overhead switches in the system would have a negative impact on system reliability. Larger outages than necessary would occur and adversely affect SAIDI and SAIFI metrics. This effectively reduces the level of customer service that HOL strives to uphold. Defective protection could also lead to more equipment damage, which would increase the cost of repairs and require more time and labour efforts.

Certain switch types that exist in the current system have been identified for replacement due to manufacturer defects. These switches present a safety hazard to line crews when operated. A replacement program was initiated based on the large risk they posed compared to other proposed projects.

### 9.2.4 Main and Secondary Drivers

HOL's overhead switch and recloser program is a run-to-failure maintenance strategy for most switches. The main driver for this strategy is system reliability. Overhead switches have performed steadily in the past and there have been very few failures. For this reason, HOL sees more value in allocating resources towards the replacement of other assets which experience more failures. A secondary driver is operability. Time and labour is saved if a manual switch is replaced with an automated switch, for instance. An automated system will experience shorter restoration times.

In the case of switches that have been identified as defective and that pose a safety risk, the main driver for replacement is worker safety. Porcelain box switches and SMD-20 switches represented a large risk based on HOL's value scoring and a replacement program was immediately initiated. A secondary driver for the replacement of known defective equipment is system reliability. Defective equipment will likely cause outages and it is desired to remove any defective equipment from the system as soon as possible.

### 9.2.5 Performance Targets and Objectives

The objective of this program is to replace any failed or defective overhead switches effectively and efficiently. Where replacement is needed, HOL considers type, location and rating with the goal of optimizing the design of the system. Not every replacement is a like-for-like scenario. The main objective regarding defective switch types is to eliminate the safety risk they present by removing them completely from the system by the end of 2015.

## 9.3 Project/Program Justification

### 9.3.1 Alternatives Evaluation

#### 9.3.1.1 *Alternatives Considered*

In general, there is only one alternative in the event of an overhead switch failure – replacement. The failure of a switch will likely cause an outage and customers will not be restored until the circuit is corrected and the switch replaced. Within the scope of replacing a failed switch, HOL considers various replacement options. In some cases, a different type of switch would be better suited to the location. In other cases, the rating or fuse size of the switch is upgraded to meet current standard or to prepare for upcoming development. For every replacement, the entire circuit is analyzed to increase system efficiency and to take full advantage of the replacement opportunity.

As for the switch types that have been identified for replacement, leaving them in the system to run-to-failure is not an option. They have been labeled as defective equipment and they present a safety hazard to crews. As such, they must be eliminated from the system as soon as possible.

#### 9.3.1.2 *Evaluation Criteria*

Switches in the system that have failed must be replaced immediately to restore load. Porcelain box switches and S&C 27.6kV porcelain and polymer fused cut-outs are a known safety risk and must be replaced as soon as possible. Within the study for various replacement options, system planners and designers account for design standards, system protection, feeder expansion or development, past feeder performance, operability, and connectivity. The objective in any asset replacement scenario is to choose a replacement option that will optimize effective performance with cost efficiency.

#### 9.3.1.3 *Preferred Alternative*

It is generally preferred to deploy a run-to-failure maintenance strategy for overhead switches and reclosers. Failure rates for this asset group have been minimal and do not require predictive analysis or active replacement programs, except in the case of identified defective switch types. Creating a program targeting overhead switch maintenance or replacement would not be cost or labour effective, due to their reliability and low failure rates. If the failure trend should increase, maintenance or replacement programs will be re-evaluated for effectiveness.

For the few failures that do occur, the replacement opportunity is used to optimize system design in that region. It is cost and labour efficient to account for system enhancements within a required asset replacement job. This also minimizes public disruption, as a second outage and crew along with potentially large vehicles would be required if an upgrade was planned for the same switch in the future. Blocking roads or entering private property reduces customer satisfaction. HOL attempts to address all issues within the scope of one construction period.

In response to the design flaw identified within the S&C 27.6kV polymer switches, a refurbishment program was initiated in which S&C will refurbish any affected switches at no cost. However, they will not cover any of the labour costs associated with the replacement or removal of these switches. HOL's multi-year replacement program began in 2013 targeting the defective polymer switches first, followed by the porcelain switches.

### 9.3.2 Project/Program Timing & Expenditure

HOL minimizes the controllable costs of its overhead switch replacement program by using a run-to-failure maintenance strategy. This asset class does not experience many failures so detailed predictive analysis and active replacement is not required. In the case of the defective S&C SMD-20 switches, S&C Electric Company will refurbish any affected switches at no cost. However, the labour costs associated with removing these switches is not covered, so HOL has divided the program across their planning regions. There are four different teams composed of planners, designers and field technicians who are responsible for SMD-20 removals in their areas – Central, East, South and West. This effectively saves the time and costs of individual field crews travelling all over the city. This also allows the program to proceed more rapidly, eliminating the inevitable future cost of equipment failures.

The costs associated with the replacement of a failed overhead switch are minimized by using the replacement opportunity to optimize system design in that region. It is cost and labour efficient to account for system enhancements within a required asset replacement job. HOL attempts to address all issues related to the switches within the scope of one construction period, rather than sending crews out for a second time in the future.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| 0.314 | 0.199 | 0.422 | 1.54 | 1.02 | 0.785 | 0.902 | 1.04 | 0.942 | 0.983 |

**Table 55 - Overhead Switchgear Expenditures**

### 9.3.3 Benefits

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | System operation efficiency is achieved by accounting for system design when replacing a failed switch. Any upgrades to account for current standards or system expansion are considered. The run-to-failure strategy is cost-effective in that the minimal number of overhead switch failures every year does not justify an active replacement program. Eliminating known defective switches will save future failure costs and will contribute to a stronger electrical system. Reliability metrics such as SAIDI and SAIFI will improve. |
| **Customer** | Customers are benefitted by improved reliability associated with eliminating defective equipment from the system. Any safety risk is also mitigated. System enhancement is considered when replacement is required, which benefits both system reliability and customer disruption. HOL accounts for all known factors influencing replacement decisions to avoid any future work on the same piece of equipment. |
| **Safety** | Removing and replacing all overhead switch types that carry a health and safety hazard will eliminate this risk. |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | S&C Electric Company will refurbish all of their defective switches at no cost. |
| **Economic Development** | This program adds to the scope of work of HOL's field crews. |
| **Environment** | (Not applicable) |

**Table 56 - Overhead Switchgear Benefits**

## 9.4 Prioritization

### 9.4.1 Consequences of Deferral

The run-to-failure maintenance strategy is an ongoing program year after year. It cannot be deferred and therefore has no consequence of deferral. On the other hand, the urgent replacement of defective switch types would carry potentially heavy consequences, were it to be deferred. These defective switches located throughout the system present a safety risk and do not function properly. In terms of safety, deferring their replacement could result in severe worker injury. In terms of system reliability, a defective switch could lead to the damage of equipment upstream or downstream of the switch, prolonging outages and increasing replacement costs.

### 9.4.2 Priority

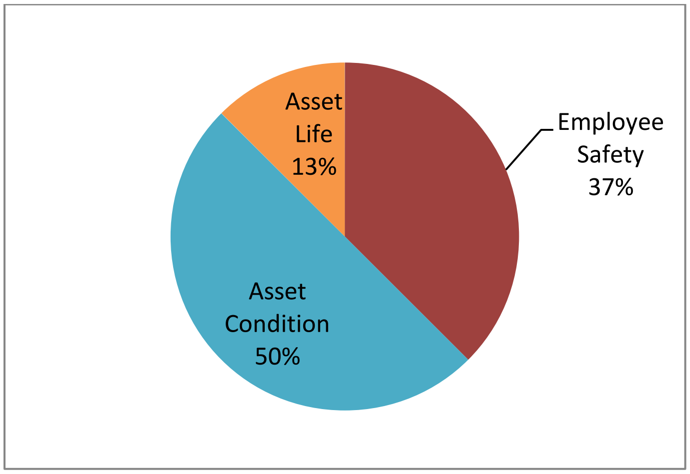



**Figure 54 - Porcelain Box Switch Replacement Avoided Risk**

Typical Project Score = 0.99

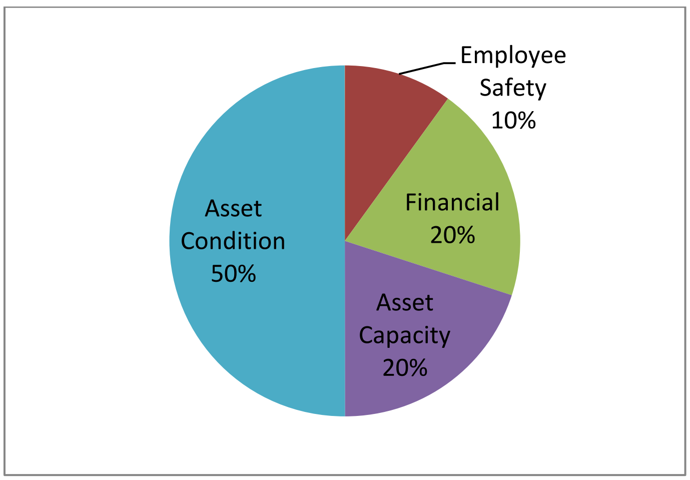



**Figure 55 - SMD-20 Replacement Avoided Risk**

Total 3-Year Program Project Score = 1.01

## 9.5 Execution Path

### 9.5.1 Implementation Plan

For most overhead switches and reclosers, HOL does reactive replacement on the few occasions that these assets experience failures every year. Overhead switches are generally in good condition and do not require an active replacement program.

For porcelain box switches, HOL has identified 28 remaining sets of switches located at 4 different substations that require porcelain box switch replacement. Individual projects for each of these switches have been created and budgeted for 2014 and 2015. By the end of 2015, it is expected that all porcelain box switches will be eliminated from the system.

For S&C 27.6kV SMD-20 switches, HOL has identified a total of 2,800 of these switches in the system. In 2013, a multiple-year replacement program was put into place which targeted the defective polymer switches first, followed by the porcelain switches. S&C will refurbish all of these switches at no cost. HOL's own crews have been actively replacing these switches with each crew focused on their respective planning region. The service territory is divided into four distinct planning regions – central, east, south and west. Crews incorporate this work into their schedules throughout the year.

Replacement of the 13kV porcelain cut-outs commenced in 2014 with the replacement of approximately 100 switches. This program will continue at this rate until the SMD-20 switches are all replaced after which the program replacement rate will be increased.

### 9.5.2 Risks to Completion and Risk Mitigation Strategies

It is possible that there are remaining S&C 27.6kV SMD-20 switches that are still unaccounted for, as some crews have found more in the system. It is possible that if any more of these switches are found past 2015, they will not be eliminated by the target date of 2016. However, the safety concern they present makes their replacement a priority and the budget will be adjusted if necessary to account for any remaining defective switches.

### 9.5.3 Timing Factors

The SMD-20 replacement program is scheduled to be completed in 2016 and the porcelain box switches in 2015.

### 9.5.4 Cost Factors

It is not expected that cost will be a problem in completing the replacement of defective SMD-20 switches. The budgeted amounts for this program have been increased in 2014 and 2015 in order to achieve the replacement target.

### 9.5.5 Other Factors

The location of the defective switches throughout the system can impact the replacement program. Some of these switches are located within customer backyards or on commercial property, making access more difficult. For switch replacements that will cause outages to commercial customers, crews work to minimize disruptions.

## 9.6 Renewable Energy Generation (if applicable)

N/A

## 9.7 Leave-To-Construct (if applicable)

N/A

## 9.8 Project Details and Justification

### 9.8.1 TH01 Porcelain Switch Replacement

| | |
|---|---|
| **Project Name:** | TH01 Porcelain Switch Replacement |
| **Project Number:** | 92008645 |
| **Capital Cost:** | $249,513 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 450 customers/1250 kVA |
| **Project Scope** | |
| 15kV porcelain switches have been failing and causing either pole fires, which are expensive to repair, or interrupting customers off a transformer. Areas where 13.2kV voltage conversion was done appear to be problem areas. This project will replace approximately 136 porcelain switches along the overhead of the TH01 circuit. | |
| **Priority** | |
| Safety issue | |
| **Work Plan** | |
| There are 136 locations on the TH01 to replace switches. HOL Limited design standards were reviewed, like-for-like replacement will apply in locations that cannot fit the new specifications. The project will begin in Q1 of 2015 and continue until completion within the same year. Isolation is required at every location for crew safety. Switches will be inspected before operating because cracked switches can be a dropping hazard. | |
| **Customer Impact** | |
| Customers will be given 48 hours of notice before isolation, with crews going door to door. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars. | |

### 9.8.2 TH06 Porcelain Switch Replacement

| | |
|---|---|
| **Project Name:** | TH06 Porcelain Switch Replacement |
| **Project Number:** | 92008647 |
| **Capital Cost:** | $145,902 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 250 customers/2200 kVA |

**Project Scope**

15kV porcelain switches have been failing and causing either pole fires, which are expensive to repair, or interrupting customers off a transformer. Areas where 13.2kV voltage conversion was done appear to be problem areas. This project will replace approximately 74 porcelain switches along the overhead of the TH06 circuit.

**Priority**

Safety issue

**Work Plan**

There are 74 locations on the TH06 to replace switches. HOL Limited design standards were reviewed, like-for-like replacement will apply in locations that cannot fit the new specifications. The project will begin in Q1 of 2015 and continue until completion within the same year. Isolation is required at every location for crew safety. Switches will be inspected before operating because cracked switches can be a dropping hazard.

**Customer Impact**

Customers will be given 48 hours of notice before isolation, with crews going door to door. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.

### 9.8.3 SMD-20 Switch Replacement

| | |
|---|---|
| **Project Name:** | SMD-20 Switch Replacement (3 year program) |
| **Project Number:** | 92007746 |
| **Capital Cost:** | $1,250,000 |
| **O&M:** | N/A |
| **Start Date:** | 2013 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Health & Safety, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | City-Wide |

**Project Scope**

HOL was informed by S&C Electric Canada that their 27.6kV SMD-20 polymer and porcelain switches manufactured between 2004 and 2011 were defective and experienced failure when operated with a load break tool. In response to this identified design flaw, HOL Limited initiated a multi-year replacement program to replace these switches. S&C will refurbish any of these switches at no cost to HOL Limited, however they will not cover any of the labour costs associated with the replacement or removal of these switches.

**Priority**

Score = 1.23

**Work Plan**

The replacement program began in 2013 and targeted the defective polymer switches first, followed by the remaining porcelain switches. The 3-year program was limited by resources in the first year and only 80 switches were replaced. The budgeted amounts for this program were increased in 2014 and 2015 in order to achieve the 3 year replacement target.

**Customer Impact**

The defective SMD-20 switches present a safety hazard to HOL crews. This was the primary concern and the reason for immediate program implementation. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.

### 9.8.4 Queens Sub Porcelain Box Switch Replacement

| | |
|---|---|
| **Project Name:** | Queens Sub Porcelain Box Switch Replacement |
| **Project Number:** | 92008663 |
| **Capital Cost:** | $100,213 |
| **O&M:** | N/A |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Health & Safety, Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1665 customers |

**Project Scope**

Porcelain box switches have been identified for removal due to issues of mechanical fracturing. Existing porcelain box switches will be replaced with new 27.6kV "V Type" disconnect switches.

**Priority**

Score = 0.99

**Work Plan**

The original estimate included changing more porcelain box switches, however the on-going City of Ottawa project – Alta Vista Transit Corridor (OH removal) reduced and eliminated the switches on Old Riverside Drive near the Queens substation, as well crews where already working in the area on the Alta Vista Transit Corridor so doing these projects around the same time will reduce travel time and set-up costs.

**Customer Impact**

The defective porcelain box switches present a safety hazard to HOL crews. Customers will gain a more reliable system from this replacement program because an overhead switch failure can result in outages affecting more customers and for a longer duration. Overhead switches are placed strategically in order to minimize outage impact and protect system equipment. Hence, this project will save reactive replacement costs and make better use of customer dollars.

### 9.8.5 Fernbank Reclosers

| | |
|---|---|
| **Project Name:** | Fernbank Reclosers |
| **Project Number:** | 92010170 |
| **Capital Cost:** | $165,000 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 5000 customers/4000 kVA |

**Project Scope**

The scope of the Fernbank Reclosers project is to install two three phase Cooper 27.6kV reclosers with SCADA communication and operation. One recloser will be installed on the TFXF4 and the other on the TFXF5 located on the pole line on Fernbank Road. The reclosers will help sectionalize these feeders as they grow in length and can sectionalize faults to limit the number of customers impacted.

**Priority**

Score = 0.52

**Work Plan**

Renewal construction of the pole line along Fernbank Road was completed in 2015 with provisions to allow for installation of these reclosers. Backup circuits are available so that the recloser and external power supply can be installed, tested, commissioned and put into service without an outage.

**Customer Impact**

Reliability is expected to improve in the Stittsville community, by the introduction of these two new feeders from Terry Fox MTS. The installation of these two reclosers will limit customers downstream to short interruptions during momentary faults and sectionalize sustained faults to limit as few customers as possible.

### 9.8.6 TFXF1 Huntmar Recloser

| | |
|---|---|
| **Project Name:** | TFXF1 Huntmar Recloser |
| **Project Number:** | 92010172 |
| **Capital Cost:** | $83,000 |
| **O&M:** | N/A |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Risk of Failure |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1960 customers/17.3 MVA |

**Project Scope**

The scope of the TFXF1 Huntmar Recloser project is to install one three phase Cooper 27.6kV recloser with SCADA communication and operation on the TFXF1 on the pole line on Huntmar Road. The reclosers will help sectionalize this feeder as it grows in length and can sectionalize faults to limit the number of customers impacted.

**Priority**

Score = 0.52

**Work Plan**

Renewal construction of the Hydro One owned pole line along Huntmar Road to accommodate the addition of HOL's TFXF1 feeder was completed in 2015 with provisions to allow for installation of this recloser. A backup circuit is available so that the recloser and external power supply can be installed, tested, commissioned and put into service without an outage.

**Customer Impact**

Reliability is expected to improve in the Kanata North community, by the introduction of the TFXF1 feeder from Terry Fox MTS. The installation of this recloser will limit customers downstream to short interruptions during momentary faults and sectionalize sustained faults to limit as few customers as possible.

# 10 Metering

## 10.1 Project Details and Justification

### 10.1.1 Remote Disconnect Smart Meter

| | |
|---|---|
| **Project Name:** | Remote Disconnect Smart Meter |
| **Project Number:** | 92003564 |
| **Capital Cost:** | 2016 to 2020 - $6.8M |
| **O&M:** | N/A |
| **Start Date:** | 2016 |
| **In-Service Date:** | 2016 to 2020 yearly individual in service dates |
| **Investment Category:** | System Renewal |
| **Main Driver:** | Assets at end of service life due to Functional Obsolescence |
| **Secondary Driver(s):** | N/A |
| **Customer/Load Attachment** | 36,000 customers each with up to 50 KW |
| **Project Scope** | |
| This project will install approximately 36,000 remote disconnect meters over the 2016 to 2020 time period. This will provide the capability to turn power on and off at the service point remotely. This reduces the expense requirement as this will eliminate the requirement to send a meter technician to the premise to disconnect the meter as well as reconnect the meter when required. This will also eliminate the need to install power limiters based on timer functionality for non-payment during the winter months along with the associated expense of travelling to the premise. | |
| **Priority** | |
| | |
| **Work Plan** | |
| The work plan involves installing the remote disconnect meters on some of the locations that are required to be sampled according to Measurement Canada, new installations, inside meter locations and defective meter replacements. There will be approximately 3,000 to 8,000 meters installed per year. | |
| **Customer Impact** | |
| Remote disconnect meters reduce the expense requirements associated with travelling to the premise for disconnect and reconnect requirements.<br>The meters can also be used as part of the collections processes when funds have not been received for past usage.<br>The meters can reduce the time required to have the disconnect or reconnect function performed which can increase customer satisfaction. Eg For apartments where the power was turned off when previous customer moved out, the disconnect meter can be used to turn power on quicker when the customer requests power.<br>The remote disconnect meter can also be used with the scheduled remote batch capability to emulate a physical timer on a service during winter months when permanently disconnecting power is not desirable.<br>The remote capability also provides enhanced safety for the meter technician if it is in a difficult to access or dangerous location and a disconnect or reconnect function is required.<br>The disconnect meters will have the normal verification periods as other meters as per Measurement Canada guidelines. | |

# System Service

# 1 Stations New Capacity

## 1.1 New South 27.6kV Substation

### 1.1.1 Project/Program Summary

With the south of Ottawa expanding rapidly, there is a need in the short term for additional distribution capacity. The purpose of this project is to supply the upcoming demand with the construction of a new 230kV to 27.6kV substation containing two 75MVA transformers. HOL, in conjunction with the Integrated Regional Resource Planning (IRRP) process, has deemed that a new station was the most feasible solution to address future capacity issues. The new station will also contribute to improving reliability by initiating a series of asset replacements and upgrades, and by eventually creating backup ties between the new station feeders and existing circuits. The total cost of this project is divided into phases over the next six years, with an anticipated commissioning date of December 2020. Hydro One Networks Inc. is involved in this project because the required 230kV transmission line extending into the South Nepean area does not currently exist.

### 1.1.2 Project/Program Description

#### 1.1.2.1 *Current Issues*

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The map below shows the major anticipated development projects in the South Nepean area, followed by brief descriptions of each project.

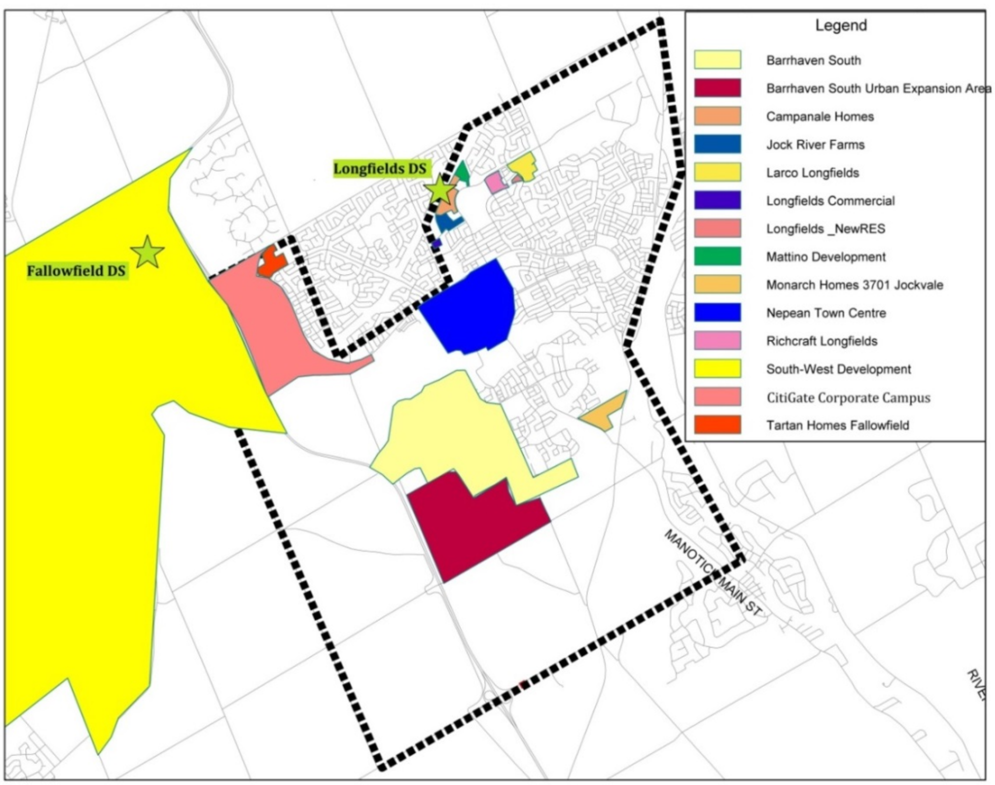



**Figure 56 - Proposed Development Areas**

**Barrhaven South** – The community design plan is to create a complete residential community containing a full range of housing choices and a broad complement of support services and facilities. This includes residential housing units, commercial buildings, community centres and schools. The expected load is 15.5MVA.

**Barrhaven South Urban Expansion** – The expected load is 12MVA by 2032.

**Campanale Homes** – This is a residential development for 136 residential units and 19 apartment units. The expected load is 6.2MVA in 2015.

**Jock River Farms** – This is a residential development for 186 units. The expected load is 476KVA in 2014.

**Larco Longfields** – This is a residential development for 220 units and two apartment buildings. The expected load is 863KVA in 2016.

**Longfields Commercial** – A church will be constructed with an expected load of 750KVA.

**Longfields New Residential** – This area is being rezoned from institutional to residential. Based on the area, the expected load is 50KVA.

**Mattino Developments** – This is a residential development for 126 units and four low density apartment buildings. The expected load is 722KVA in 2016.

**Monarch Homes** – This is a residential subdivision containing 194 single family homes, 73 street homes and 73 town homes. This is an extension to the Stonebridge Community. The expected load is 810KVA in 2015.

**Nepean Town Centre** – This development will require a significant load increase of 121MVA. It will include commercial buildings, office buildings, a shopping district and 18,300 residential units. The current feeder capacity supplying the area from Fallowfield DS will not be capable of sustaining the load throughout the duration of the project.

**Richcraft Longfields** – This is a residential development for 283 units. The expected load is 725KVA in 2015.

**CitiGate Corporate Campus** – This is an upcoming business park for 70 commercial buildings and office buildings. The expected load is 40MVA around 2020.

**Tartan Homes Fallowfield** – This project is the continuation of residential developments being constructed along Fallowfield and Strandherd Road. There are 250 homes for an expected load of 655KVA in 2015.

#### 1.1.2.2 *Program/Project Scope*

This project is for the design and construction of a new 230kV to 27.6kV substation with two 45/60/75MVA transformers in the Barrhaven/Manotick area. The station will be designed to have 6-8 feeders and a breaker and a half configuration, however the planning and construction of the station feeders are out of the scope of this project. This project addresses the inability of HOL's distribution system to supply the expected load in five years and involves acquiring land, designing and constructing all civil and electrical components of the substation, and the tender of all equipment and services. The station will include two transformers, 230kV breakers, 230kV air break switches, switchgear, potential transformers, DC system, relay panels, transformer foundations with oil containment and civil structures. HOL is working closely with Hydro One and the Independent Electricity System Operator (IESO) in the IRRP process to plan a new 230kV transmission supply for Ottawa's south region, as currently none exists.

#### 1.1.2.3 *Main and Secondary Drivers*

The main driver of this project is the need to supply the future expected load in this growing area. The forecasted load for the next 20 years in the South Nepean area indicates that the area's capacity limitations will be reached within the next five years. In the case of a single station contingency, the remaining capacity would not be enough to supply the required load in this area. Ongoing development worsens the situation which indicates why this project is required to meet the demand.

As a secondary driver for this project, reliability will be improved by eventually creating ties to other 27.6kV stations, specifically Fallowfield DS, Longfields DS, Limebank MS and the new 27.6kV Richmond South DS.

#### 1.1.2.4 *Performance Targets and Objectives*

The primary objective of this project is to have the new station commissioned and on-line by December 2020. Within this goal, various milestones must be met including the procurement of land, environmental assessment and City of Ottawa approval, extension of a new transmission line, civil and electrical station design, tendering of all major equipment and services, and finally construction and commissioning. In conjunction with this new station, other projects are being planned and implemented in order to prepare the area for a 27.6kV voltage upgrade once the station has been constructed.

### 1.1.3 Project/Program Justification

#### 1.1.3.1 *Alternatives Evaluation*

##### 1.1.3.1.1 Alternatives Considered

Based on the forecasted load in the South Nepean area for the next 20 years, under normal operation, the stations in this area would reach their capacity limitations in the next five years. The impact of CDM was also considered to offset load. However, since most of the load is coming from new developments which already have many design efficiencies, CDM will have minimal effect. In the case of a single station contingency, the remaining capacity would not be adequate to supply the load. It was decided that the best solution was to build a new station in the Barrhaven/Manotick area.

The alternatives to this project would be to provide additional station capacity at either of the two existing 27.6kV stations in the area – Fallowfield DS and Longfields DS. The Fallowfield substation was recently upgraded from one 25MVA transformer supplying two circuits to two 25MVA transformers supplying four circuits in total. The capacity of the station was doubled and it is therefore not possible to add the needed capacity unless a new transmission line is extended to Fallowfield DS. Longfields DS is supplied by the 22M24 and 22M26 44kV circuits from Nepean TS. There is no capacity available to upgrade Longfields substation to satisfy the expected load.

#### 1.1.3.1.2 Evaluation Criteria

The best alternative was chosen based on feasibility and location. The other option to increasing system capacity in a given area is to upgrade the capacity of existing stations. This is only possible if conductor thermal ratings and transmission supply constraints allow it. Location is also an important consideration, as the ideal solution is to provide capacity close by to the demand to minimize voltage drop and reliability risks.

#### 1.1.3.1.3 Preferred Alternative

Due to the inability of the existing stations to be upgraded such that they may provide sufficient capacity, it is clear that constructing a new station is the preferred alternative.

The first reason is that it is a more feasible option. Upgrading Fallowfield DS would require another transmission line and since this station already supplies a heavy load, the outages that would be required to add capacity would disrupt many customers. Upgrading Longfields DS is not a feasible option since it is supplied by HOL’s 44kV system. The 44kV conductor supplying Longfields substation is the largest size available, 556 MCM, and the thermal capacity of these feeders would not allow a capacity upgrade large enough to meet the demand.

The second reason is that the location of the new station will be more central to the expected growth. Fallowfield DS and Longfields DS are currently much further north than the proposed developments, so feeders are currently travelling long distances to supply the few customers who are situated near the southern boundary of HOL’s service territory.  The proposed location for the new station is closer to the upcoming developments which will minimize voltage drop and threats to reliability, such as lightning or pole damage.

### 1.1.3.2 *Project/Program Timing & Expenditure*

The total station construction project cost is expected to be $21,255,370 (does not include transimission lines). The yearly cost estimates in the table below extend into 2021, but the date range has been restricted to 2020 for the purpose of this business case. In general, HOL aims to minimize the costs associated with all projects. For station projects, this includes putting all equipment and work out for tender. Major station equipment is usually customized for each project and HOL considers the submitted bids from various equipment manufacturers. The same is true of contractor labour, with the lowest bid typically being chosen unless there are additional considerations, such as incompatible scheduling. The considered contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain required timelines.

Additionally, HOL minimizes the controllable costs of station projects in several other ways. For example, a competitive Request For Proposal (RFP) process is used to determine consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet HOL’s needs and have a good understanding of HOL’s internal processes and standards.

The use of in-house project management allows for the efficient use of resources and experience from similar past projects. Best practices for project management at HOL are based on the Project Management Institute (PMI) best practices.

Workforce planning is used to ensure that internal resource requirements are identified early. External resource requirements are identified early to ensure that the project runs smoothly and efficiently.

| Historical ($M) | | | | Future ($M) | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| - | - | - | - | 0.06 | 0.14 | 1.50 | 5.54 | 6.67 | 5.84 |

**Table 57 - Project Expenditures**

#### 1.1.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to satisfy the upcoming load growth in the South Nepean area. It is an essential system service project to supply the expected future capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Constructing a new station is the most cost-effective solution to provide the required demand. The other alternatives are not very feasible and the location of this new station will provide a better electrical and geographical balance between supply points. |
| **Customer** | This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. Not only will development projects be given adequate electrical supply, but the new station presents several opportunities to enhance the system. This project will contribute to a larger system plan to convert the entire south to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities including: Barrhaven, Manotick, Riverside South, Richmond and Kanata. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. Other projects have been planned to prepare the South Nepean area for this voltage conversion, including project 92008686 Rideau Valley Voltage Conversion and project 92008543 Prince of Wales Voltage Conversion. These related projects involve asset replacements, which further improves system reliability. |
| **Safety** | Building a new station will address the predicted thermal overload of existing feeders and station transformers that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | The new station will be supplied on the high side by Hydro One Networks Inc.'s 230kV transmission line. The provincial utility has been heavily involved in the |

| | |
|---|---|
| | development of this project from the beginning, as it requires a new transmission line. Both utilities will coordinate to ensure the success of this project, although construction details have not yet been decided. |
| **Economic Development** | This project will facilitate the connection of new loads and future growth in this area of the city. |
| **Environment** | N/A |

**Table 58 - Project Benefits**

### 1.1.4 Prioritization

#### 1.1.4.1 *Consequences of Deferral*

The purpose of this project is to address an upcoming capacity issue; as a result the most important consequence of deferral would be the inability to service the required load in approximately five years. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new station feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience long outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

#### 1.1.4.2 *Priority*

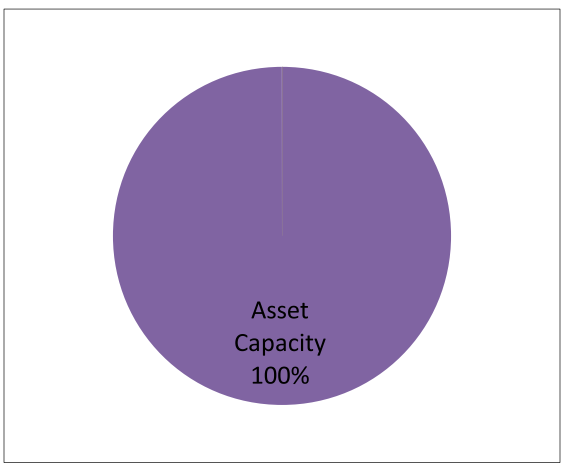



**Figure 57 - Project Avoided Risk**

Project Score = 0.72

### 1.1.5 Execution Path

#### 1.1.5.1 *Implementation Plan*

Adherence to the implementation plan and key milestones for this project is necessary to ensure that sufficient capacity will be provided in this area when needed. The plan is typical of most new stations, with the exception of Hydro One Networks Inc.'s (HONI) involvement from the beginning. Hydro One is planning a new 230kV supply to the south of Ottawa, as no transmission lines currently exist. The success of Hydro One's transmission project is essential in achieving the objectives of this New South 27.6kV Substation project.

The schedule is as follows: The HONI study agreement will be completed and the Environmental Assessment process and preliminary design will be started in 2015. Land procurement and finalizing the Environmental Assessment is expected to take place by December 2015. Major material procurement and a detailed design will be started by December 2016. The detailed design should be completed by December 2017. Construction will follow and commissioning is planned by December 2020.

This project is coordinated with other asset replacement and upgrade projects, to prepare the entire area for a 27.6kV voltage conversion. These projects are all related and will involve making connections between feeders to achieve a more reliable system.

#### 1.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

The construction of HOL's new substation is dependent upon the availability of Hydro One Networks Inc.'s new transmission supply line. HOL cannot proceed with their project unless a 230kV supply is available. Due to this important requirement, HOL has maintained active communication with Hydro One in planning the new transmission line via the IRRP process.

This project must also gain Environmental Assessment approval and City of Ottawa consultation. The environmental assessment is not expected to be an issue as HOL's current station design standards minimize environmental risk with features such as oil containment. Through the environmental assessment process HOL will engage the community and work towards finding the most suitable location for the station. As the proposed area is more rural at this time, selection of a site should be well coordinated with development plans.

#### 1.1.5.3 *Timing Factors*

Planned City development is the driver for this project, and it is unlikely that the timing and priority of this project will change. It is necessary to supply the proposed load and there are no other feasible solutions. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as site plans for new developments in the area have already begun to be submitted to HOL. For the timing and priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

#### 1.1.5.4 *Cost Factors*

The land acquisition process may affect the final cost of the project. The exact location of the new station remains undecided, but the cost of acquiring this land could vary according to the current ownership or any easements.

The tender process for major station equipment and labour services will also affect the final cost of the project.

#### 1.1.5.5 *Other Factors*

While the main risk factors were identified previously, it should be noted that building a new station alone does not resolve any capacity issues. The station feeder routes must be planned, designed and constructed, which is not within the scope of this project. Due to the magnitude of the growing area, several smaller projects are being planned in conjunction with the new station project. These smaller projects involve upgrading current 8.32kV equipment to 27.6kV-rated equipment, building new line extensions for eventual ties, and existing station upgrades such as the Richmond South DS voltage conversion. HOL currently has projects underway to prepare for the larger voltage conversion, with the new station feeders to be planned in the short term.

### 1.1.6 Renewable Energy Generation (if applicable)

It is likely that there will be large customer generation projects in the South Nepean Area in the near future. These Feed-In-Tariff (FIT) projects currently have limited distribution feeders to connect to. This is because HOL only has confirmation of select station transformers being capable of handling reverse flow. For example, only one of the two transformers at Fallowfield DS is known to be capable of handling reverse flow, therefore generation potential is limited. It is planned that the new station will have reverse flow capability on both transformers, thus increasing the number of renewable energy generation projects possible.

### 1.1.7 Leave-To-Construct (if applicable)

N/A

### 1.1.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | New South 27.6kV Substation |
| **Capital Cost:** | $21,255,370 |
| **O&M:** | N/A |
| **Start Date:** | January 2015 |
| **In-Service Date:** | December 2020 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 150 MVA |

| **Project Scope** |
|---|
| Complete design and construction of a new 230kV to 27.6kV distribution substation<br>2 x 75MVA transformers, protection, oil containment<br>New 230kV transmission supply<br>Land acquisition and approvals required |
| **Work Plan** |
| Land procurement, Detailed Design, Tender of major equipment<br>Station construction – Foundations, oil containment, transformer installation, switches, breakers, switchgear, relays, Protection & Control equipment<br>Commissioning target date - December 2020 |
| **Customer Impact** |
| Available distribution capacity to supply new loads for upcoming development<br>Reliability improvement associated with replacement of aging assets and equipment upgrades<br>Reduced outage durations with eventual backup supply |

## 1.2 Hinchey New Switchgear Lineup

### 1.2.1 Project/Program Summary

There are significant plans for growth in the downtown core of Ottawa. This is driven by both intensification and infill projects including the new proposed light rail transit system and the expansion of Tunney's Pasture. These projects will stress the available capacity in the area. Hinchey TH substation currently has two transformers; however, they each have an idle winding. This project will utilize these idle windings and connect them to two new switchgear lineups. This will increase the capacity at Hinchey TH substation from 37.5MVA to 75MVA.

### 1.2.2 Project/Program Description

#### 1.2.2.1 *Current Issues*

Hinchey TH is a 13.2kV indoor substation located at the corner of Scott Street and Hinchey Avenue. Hinchey TH supplies electricity to the area North of Wellington Street W., East of Churchill Avenue, and West of Bronson Avenue. Hinchey TH currently has two transformers; however, they each have an idle winding. The anticipated load growth is expected to push the substation past its capacity.

#### 1.2.2.2 *Program/Project Scope*

Due to the anticipated load growth in this area, the new switchgear lineups will be built utilizing the idle winding on both of the station's 115kV/13.2kV transformers. The installation configuration of the two switchgear lineups which make up the buss-pair is shown in Figure 58. This depicts where the proposed lineup will be compared to the existing one.

The new installation will include two transformer breakers, a buss tie breaker, two switchgear lineups complete with buss work, and 14 feeder breakers. These switchgears will be delivered and installed by a connection to the transformer's third winding. Four new protection and control panels will also be installed with protection and communication equipment. Once the switchgear has been completely installed, existing feeders connected to the current switchgears will be transferred in order to balance the load among the two buss pairs. This will also eliminate many hair pinned breakers. This increases reliability because it reduces the exposure of each of the hair pinned circuits to their customers by roughly 50%. Finally, relay settings will be updated in correspondence with the new configuration.

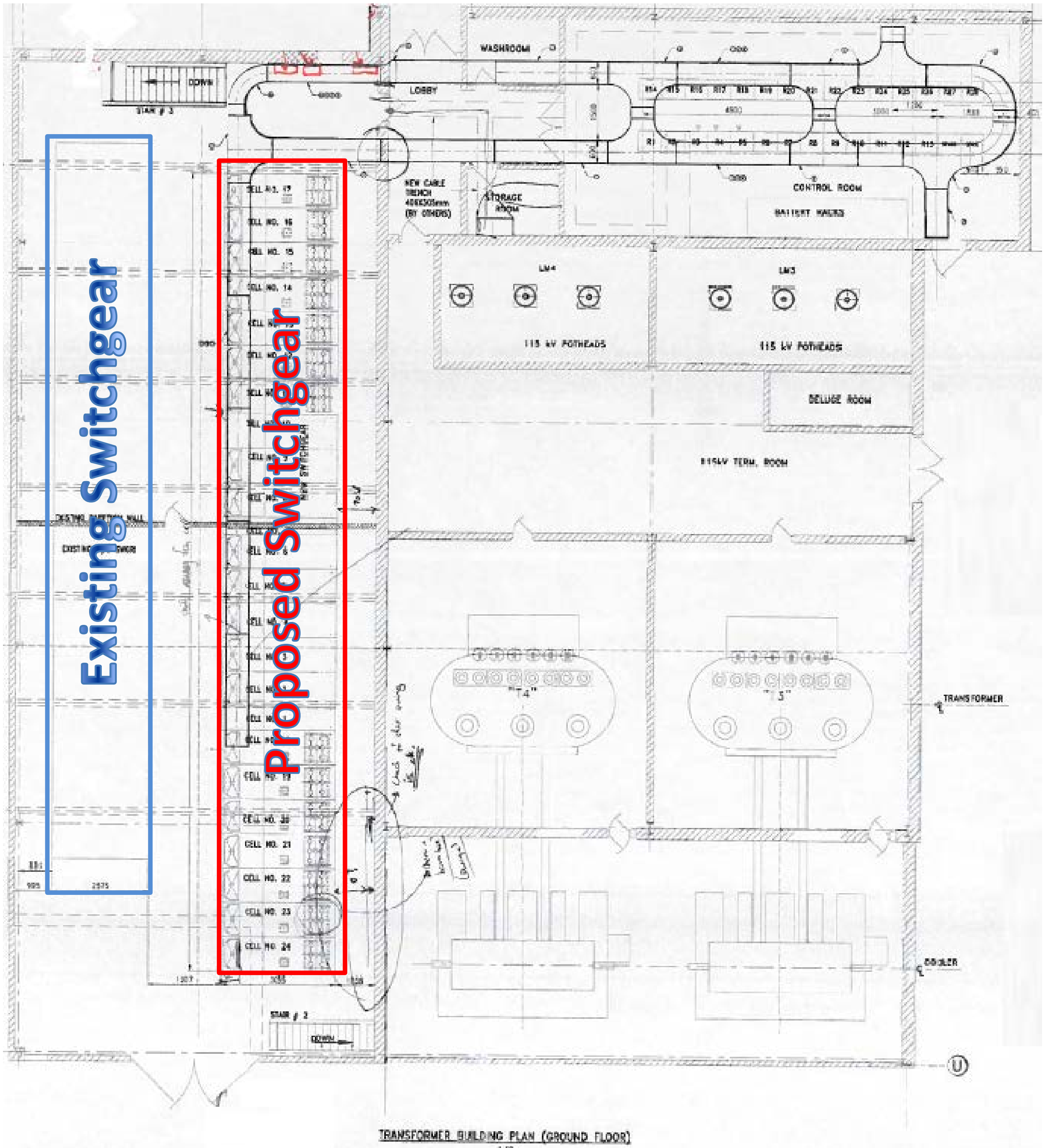



Figure 58 - Proposed Hinchey TH Substation Layout

### 1.2.2.3 *Main and Secondary Drivers*

The main driver for this project is the expected changes in load that will constrain this station's ability to provide consistent service delivery. It is anticipated that 33.7MVA of new load will be realized in the next ten years. The secondary driver for this project is that the current space for new feeders is limited. As of today all of the breaker positions are occupied by feeders and five out of the twelve positions contain hair pinned circuits. The addition of the new switchgear breaker positions will increase room for future supply and allow for the removal of the hair pinned circuits. This increases reliability because it reduces the exposure of each of the hair pinned circuits and their customers by 50%.

#### 1.2.2.4 *Performance Targets and Objectives*

The main objective of this project is to increase the capacity at Hinchey TH substation. By utilizing the third winding of each of the two transformers the capacity will rise from 37.5MVA to 75MVA. This will allow Hinchey TH to continue to supply reliable power to the increasing demand in the region.

### 1.2.3 Project/Program Justification

#### 1.2.3.1 *Alternatives Evaluation*

##### 1.2.3.1.1 Alternatives Considered

In order to meet the increasing load in the downtown Ottawa area, specifically the geographical area surrounding Hinchey TH substation, two alternatives were considered:

1) Feeder extension: Under this scenario Hinchey TH substation will be at capacity and unable to supply new loads. In order to supply the increasing demand, numerous circuits would be required from Lisgar TL, Carling TM, or Lincoln Heights TD substations. A large amount of infrastructure is necessary to supply the demand from these other stations which are a minimum of 2.3km away.
2) Utilize idle third winding: This alternative involves the installation of the new switchgear lineups. Hinchey TH substation was built with two three winding transformers and enough room for 4 switchgear lineups. Due to the loading in the area at the time, only one of the two free windings from each transformer were utilized and two switchgear lineups were installed creating one buss-pair. The area around Hinchey TH substation has since grown and the future load has been forecasted to increase above the current station's limited time rating. This option will see two new switchgear lineups installed and connected using the idle third winding of the two transformers.

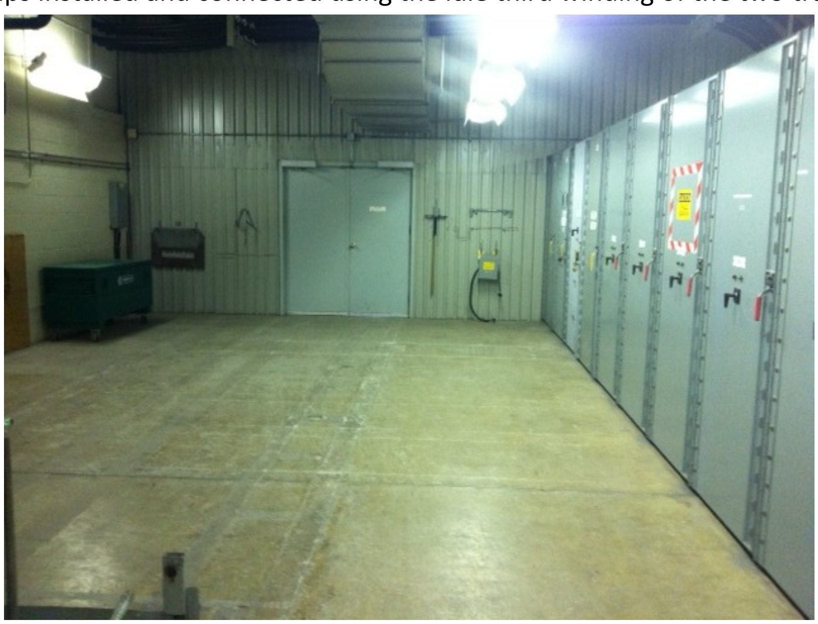


**Figure 59 - Existing Switchgear Lineup**

#### 1.2.3.1.2 Evaluation Criteria

The main evaluation criteria used to determine the best option were the cost between the two projects and the practicality. Both costs associated with the alternatives are those that will enable 37.5MVA of new capacity. The estimated net present values of revenue requirements for each option are:

**Alternative 1: $13,682,919**

**Alternative 2: $11,282,899**

Further criteria that were used to evaluate the alternatives are timing of the project, safety, and future planning.

#### 1.2.3.1.3 Preferred Alternative

Due to the evaluation criteria, Alternative 2 is the preferred alternative. Alternative 2, which involves utilizing the third winding of the transformers and constructing two new switchgear lineups with accompanying protection and control, is $2.4M cheaper than Alternative 1 which involves extending circuits from the nearest stations. The costs associated with both alternatives are that which will bring 37.5MVA of capacity to the area. Therefore Alternative 1 costs $364,878/MVA and option 2 costs $300,877/MVA.

Alternative 2 is also the more practical option. It is HOL's ideology that each substation is to supply customers within its geographic area. Extending circuits from other stations to areas outside of their ideal boundaries would defeat this strategy as well as increase the exposure for outages on the circuits. Alternative 2 also allows for the removal of hair pinned circuits at Hinchey TH substation. This increases reliability because it reduces the exposure of each of the hair pinned circuits and their customers by 50%. Alternative 1 does not improve the spare feeder positions at Hinchey. It also will take numerous feeder positions at other stations and is likely to result in hair pinned breakers.

Furthermore, the need for the additional capacity has been forecasted for 2015. Due to the scope of work involved, Alternative 1 is likely to demand more time and resources which could prolong the project past the needed time frame. It is also more disruptive to the public as civil duct structures will require sidewalk excavation. This also poses safety risks to the general public. While HOL has excellent safety mitigation practices, Alternative 2 does not contribute to the safety risk to the public.

### 1.2.3.2 *Project/Program Timing & Expenditure*

As shown in Table 59, the bulk of the costs associated with this project have already been incurred. Hydro One requires a connection and cost recovery agreement for any capacity work they are asked to do. This payment outlines the work that is necessary for Hydro One to complete the request to extend the third winding of the transformers. It also covers the installation cost of the switchgear lineups (not the cost of the switchgears themselves). Moving forward costs for this project include the switchgear lineups, as well as the costs of the protection and control panels and their installation.

As a strategy to minimize expenditures within the project, HOL tenders for all equipment such as switchgears and relays. In addition, HOL completes all feasible installations in house which are done using industry best practices. However, since the substation's transformers are owned by Hydro One, they are the only ones that can complete specific parts of the scope of work and therefore, these costs are not in HOL's control.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | 1.141 | 6.162 | 2.555 | 0.969 | | | | | |

**Table 59 - Project Expenditures**

#### 1.2.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | By eliminating the hair pinned breakers, System Operations will be able to identify which circuit had a fault if it tripped the breaker more easily. This will result in a faster location of the fault and therefore a quicker restoration. |
| **Customer** | This investment is the most cost-effective option. Therefore the customer, as a ratepayer, is less impacted than they would be if another alternative was chosen. Customers being supplied by hair pinned circuits will also have a decreased number of outages due to the circuits transitioning to a single breaker. This reduces the exposure of each hair pinned circuit by 50%. Finally, the project will benefit future customers in this area by increasing the available capacity in the area to supply the new load. |
| **Safety** | The new switchgear has an explosion resistant design which will protect the worker in the event of a failure. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | In order to accomplish this project on a specified time frame, HOL and Hydro One must coordinate with respect to the installation of the joint-purchased switchgear. |
| **Economic Development** | This project allows for future development to have sufficient capacity in place to acquire a timely connection. This will be important with the development of Bayview yards and the expansion of Tunney's Pasture. In addition to these large load areas, intensification is occurring along neighbouring properties. |
| **Environment** | N/A |

**Table 60 - Project Benefits**

### 1.2.4 Prioritization

#### 1.2.4.1 *Consequences of Deferral*

The deferral of this project would lead to difficulty to serve the increase in load that is expected. New load would have to be supplied from adjacent stations which are a considerable distance from the load center requiring long circuit extensions. Expensive civil infrastructure upgrades may be required to accommodate this alternative.

#### 1.2.4.2 *Priority*

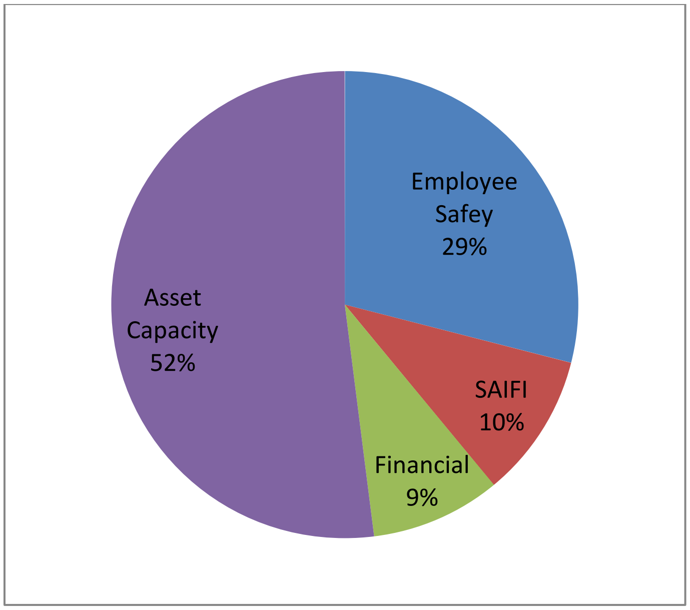



**Figure 60 - Project Avoided Risk**

Score = 1.373

### 1.2.5 Execution Path

#### 1.2.5.1 *Implementation Plan*

The design and estimates for this project have already been completed. Currently Hydro One is working on the replacement of the two transformers at Hinchey TH substation. This work is scheduled to be complete in 2015. Once the work is complete the implementation of the new switchgears will commence. This coordination with Hydro One is essential as the switchgears cannot begin to be installed until the transformers are replaced.

The construction of the switchgears will begin with Hydro One installing the first new switchgear lineup. These breakers will allow for the installation of seven HOL feeder cells, to be installed by HOL. Hydro One will then install the tie breaker which will allow for the isolation between the two new switchgear lineups. The second new switchgear lineup will then be installed by Hydro One. These breakers will allow again, for the installation of additional feeder cells. Finally HOL will install the protection and control panels and program the relays for feeder protection and switchgear operation.

Furthermore, under Hydro One's scope of work they will have to upgrade the high side protection and control due to the increased capacity at the station, replace the fire suppression system, replace the heating, ventilating, and air conditioning system, and replace the station service.

Currently there are no foreseen internal resource constraints. However, when dealing with external parties there is always a risk. Timely procurement of the equipment, contract negotiations, and agreement on design is essential for the project to be completed on time and on budget.

#### 1.2.5.2 *Risks to Completion and Risk Mitigation Strategies*

This installation of the switchgears will be occurring in 2015. There are currently no foreseeable risks that will cause this project not to be completed. There are, however, risks that could affect this projects timeline and cost. These are further explained in the sections below.

#### 1.2.5.3 *Timing Factors*

Currently Hydro One is completing work inside Hinchey TH substation in order to facilitate the installation of the switchgears. This work has delayed the project and the switchgear installation has been pushed from 2014 to 2015. HOL has little control over the timeline of this work.

Further delays could arise from untimely procurement of the assets. This risk is mitigated by early planning and ordering equipment in advance. However, if upon delivery the assets are found to be faulty or damaged they will need to be reordered. This will add significant delay to the project. This risk is mitigated by taking into consideration the experience with various venders while making a decision on which vendor to use.

#### 1.2.5.4 *Cost Factors*

The project delays mentioned above could have an economic impact on this project if it is not completed in time for the increase in load. In this case interim solutions will be required. This will either be in the form of constructing new circuits to the load area or operating equipment above their ratings which degrades their life expectancy. Both of these options will incur increased project costs.

### 1.2.6 Renewable Energy Generation

N/A

### 1.2.7 Leave-To-Construct

N/A

### 1.2.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Hinchey New Switchgear |
| **Capital Cost:** | $11.28M |
| **O&M:** | N/A |
| **Start Date:** | Q2 2012 |
| **In-Service Date:** | Q4 2015 |
| **Investment Category:** | System Service |
| **Main Driver:** | Need for additional capacity |
| **Secondary Driver(s):** | Additional breaker positions needed |
| **Customer/Load Attachment** | Future customers will benefit from the capacity upgrade (33.7MVA by 2024) |

**Project Scope**

The new installation will include two transformer breakers, a buss tie breaker, two switchgear lineups complete with buss work, and 14 feeder breakers. These switchgears will be delivered and installed by a connection to the transformer's third winding. Four new protection and control panels will also be installed with protection and communication equipment.

**Work Plan**

The design and estimates for this project have already been completed. Currently Hydro One is working on the replacement of the two transformers at Hinchey TH substation. This work should be done Q1 2015. Once the work is complete the implementation of the new switchgears will commence. The switchgears will then be installed, along with the feeder cells. Finally, the protection and control panels will be built.

**Customer Impact**

This project will allow for future customers to be connected due to the increase in capacity. It will also see a number of current customer's reliability improve because the exposure of the hair pinned circuits will be reduced. The customers fed from a circuit that is transferred to one of the new busses may experience a temporary outage while switching is completed. The alternative chosen is also expected to be the most cost-effective. Therefore, having the lowest effect on ratepayers.

## 1.3 Lisgar Transformation Upgrade

### 1.3.1 Project/Program Summary

There are significant plans for growth in the City of Ottawa's downtown core. The growing load is being driven by both intensification and infill projects including the new proposed light rail transit. These projects will push the available capacity in the area to its limit. It is anticipated that Lisgar TL will experience 30MVA of new load within the next ten years. Currently the substation does not have the transformer capability to supply this increase in demand. This need is expected to occur by 2016 and has been identified through the integrated regional planning process led by the IESO.

HOL also expects there to be an increase in embedded generation that will be connected to Lisgar TL. The existing transformer's reverse power flow capability is limiting and inadequate to allow for a large amount of additional generation. An upgrade of the transformers will allow for reverse power flow to be utilized.

### 1.3.2 Project/Program Description

#### 1.3.2.1 *Current Issues*

There are currently two transformers at Lisgar TL. These transformers are both owned by Hydro One and are rated at 45/60/75MVA. Currently one of the transformers is approaching its end of life. However, the other transformer is relatively new because of an electrical failure that caused the need for its replacement. Due to the level of expected load growth from projects such as the Light Rail Transit and Lebreton Flats development and the anticipated embedded generation, HOL will be requesting Hydro One to complete a transformation upgrade. These discussions have already begun.

#### 1.3.2.2 *Project/Program Scope*

HOL has identified a need for capacity upgrade in its downtown service territory. This need has also been identified by the IESO as part of the integrated regional resource plan for the Ottawa area. HOL has requested Hydro One to commence a study on a detailed analysis indicating the work that will be implemented, the associated work schedule, and a Class B estimate (+/-25%) for upgrading both transformers at Lisgar TL substation to a rating of 60/80/100MVA. Currently, it is not anticipated that upgrades to the buss work will be part of this project's scope.

#### 1.3.2.3 *Main and Secondary Drivers*

The main driver for this project is the expected increase in load that will constrain the ability of this substation to provide adequate power to customers. It is anticipated that 30MVA of new load will be realized in the next 10 years and this is above Lisgar TL substation's capacity. A secondary driver for this project is that HOL anticipates a large amount of embedded generation in the near term. Currently Lisgar TL substation is limited by the reverse power flow capability of its transformers. The upgrade will see this limitation removed.

#### 1.3.2.4 *Performance Targets and Objectives*

The objectives of this project are to allow HOL to adequately supply the growing load within downtown Ottawa and connect future embedded generation. These objectives will be accomplished by upgrading the transformers to increase their capacity and allow reverse power flow.

### 1.3.3 Project/Program Justification

#### 1.3.3.1 *Alternatives Evaluation*

##### 1.3.3.1.1 Alternatives Considered

In order to meet the objectives mentioned in section 1.3.2.4 above, several alternatives were considered:

1) Line extensions: This option would see the current transformers at Lisgar TL substation not upgraded and left as is with a limited time rating of 83MVA. Under this alternative the substation will be loaded to its capacity. Circuits from nearby stations would then be extended into the Lisgar TL substation geographic area to supply the additional load. There are three substations that have been identified as being able to supply this additional capacity due to their location. However, due to the expected load growth, this solution is only anticipated to be sufficient for 5-8 years at which time a station capacity upgrade will be required. Furthermore, this alternative does not provide Lisgar TL substation with reverse power flow capabilities.
2) Upgrade one transformer: This option would see the current 40 year old transformer upgraded. This would lead to a mismatch in transformer ratings, but due to the age of the non-upgraded transformer the substation's limited time rating will be increased to 96MVA. Based on the expected load growth, this solution is anticipated to be sufficient for 4-5 years. At this time line extensions or the upgrade of the second transformer will be needed due to Lisgar TL substation being at capacity. This option will allow up to 30MW of generation to be connected due to reverse power flow capability. In addition, by allowing more load capacity at Lisgar TL substation, further embedded generation can be connected due to the minimum station loading having increased.
3) Upgrade both transformers: This alternative would see both of the transformers at Lisgar TL upgraded. This would increase the substation's limited time rating to 144MVA, however due to the rating of the buss, the station would be operated to a rating of 115MVA. This option is sufficient to supply the increasing load growth around Lisgar TL substation for the foreseeable future. By replacing both of the transformers, the reverse flow capability will be increased to 40MW. In addition, by allowing more load capacity at Lisgar TL substation, further embedded generation can be connected due to the minimum station loading having increased.

##### 1.3.3.1.2 Evaluation Criteria

The evaluation criteria used to determine the best option was based on meeting the aforementioned objectives. While meeting these objectives is the primary focus, cost is also a factor that was largely considered.

#### 1.3.3.1.3 Preferred Alternative

The preliminary preferred alternative is option 3 which will see both of the current 45/60/75MVA transformers upgraded to a rating of 60/80/100MVA. However, this decision will be re-evaluated after the study that Hydro One is currently performing has concluded.

Upon the completion of Hydro One's study, it is likely that either alternative 2 or 3 will be chosen. This is due to the forecasted load growth and the ability to connect embedded generation. It is also HOL's preferred planning method to supply an area by the closest geographical station if possible. This limits the exposure of the circuits feeding our customers. Alternative 1 does not provide a solution to the objective of adding embedded generation at Lisgar TL substation. The decision on whether to implement alternative 2 or 3 will be largely driven by cost differences and the feasible timing of the upgrade.

### 1.3.3.2 *Project/Program Timing & Expenditure*

Hydro One is currently developing a study on the work that will be needed for the project of upgrading two transformers at Lisgar TL substation. This will include the schedule of work and a cost estimate. This study will be completed in 2015. It is currently planned that in order to meet the anticipated load forecast this project should be implemented in 2016. Therefore, it is expected that if the decision to replace both transformers is chosen then they will be upgraded in 2016 and 2017.

Due to the substation being owned by Hydro One, all work will be sole sourced through them. Therefore HOL does not have much control over the costs associated with the transformation upgrade. However, HOL has requested Hydro One to complete a study on the alternative of upgrading both transformers in order to identify the work needed and the estimated cost so that the best decision can be made.

### 1.3.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | The increase in capacity at Lisgar TL substation will allow for easier operations during high demand periods. Without the upgrade, any demand that would put Lisgar TL substation over its limited time rating would need to be shifted to stations that it is interconnected with to safely operate the station's transformers. This will not be necessary once the transformers have been upgraded. |
| **Customer** | The benefit to customers that is likely to come from this project is that the most cost-effective option to meet the increase in load will be chosen. This will be done by considering each option and making an informed decision based on meeting the needs. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | The need for increased capacity in this area has been identified within the integrated regional resource plan working group led by the IESO. However, due to the timeline of the plan, HOL has had to pursue this option before its release. |
| **Economic Development** | One of the drivers for this project is to allow for the anticipated development in downtown Ottawa. This includes the development of Lebreton Flats, a light rail transit station, and future expansions.<br>This project also looked to allow for the connection of embedded generation. All of these projects lead to economic growth for Ottawa by allowing their |

| | |
|---|---|
| | connection. |
| **Environment** | Much of the generation being contracted by the IESO in Ontario is of the renewable fuel type. By allowing for an increased amount of generation at Lisgar TL substation, more renewable generation can be connected. This generation can be used to offset other forms of electrical production that utilize harmful fossil fuels. |

**Table 61 - Project Benefits**

### 1.3.4 Prioritization

#### 1.3.4.1 *Consequences of Deferral*

If this project is deferred, HOL risks not having enough capacity to supply the requested load. This will lead to either HOL's assets being over loaded or the installation of new circuits from other substations. Neither of these options is preferred as the former reduces the life of HOL's assets and the latter will have a large impact on the customers financially.

#### 1.3.4.2 *Priority*

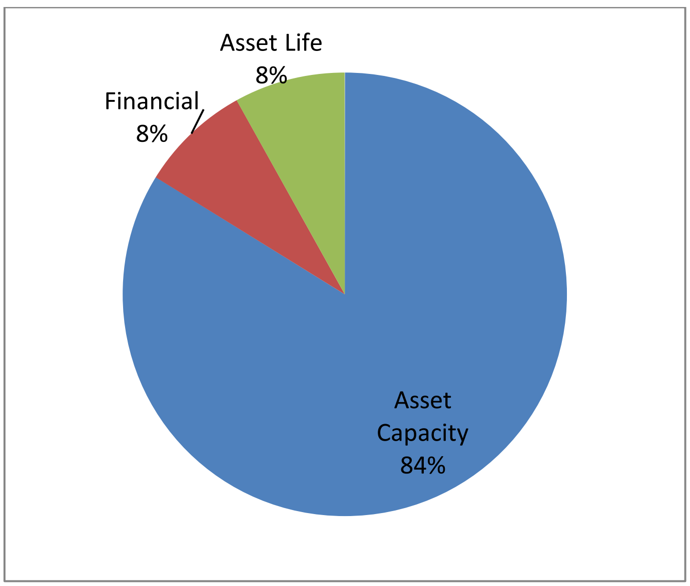



**Table 62 - Project Avoided Risk**

Score = 0.72

### 1.3.5 Execution Path

#### 1.3.5.1 *Implementation Plan*

Hydro One is currently undergoing a detailed study on the work that will be required to upgrade both transformers at Lisgar TL substation. This report will also specify the schedule of work and a cost estimate. Upon receiving the completed study in 2015, HOL will make a decision to ask Hydro One to upgrade either one or both of the transformers. The implementation of this project will then be carried out by Hydro One at the request of HOL as they are the owner of Lisgar TL substation's transformers. The current plan is to have one transformer upgraded by the end of 2016 and if the option of upgrading both transformers is chosen, then the second transformer will be upgraded in 2017.

#### 1.3.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project is currently in the beginning phases of planning. The need is known, but the optimal solution is still being determined. The result of Hydro One's study on upgrading both transformers could enlighten the need for various upgrades at Lisgar TL substation that have not been identified. Based on the costs associated with this upgrade a more feasible alternative may be chosen and this project will not be completed. However, there are also risks that could affect this projects timeline and cost. These are further explained in the sections below.

#### 1.3.5.3 *Timing Factors*

There are several factors that can affect the timing of this project. First is the completion of Hydro One's study on the alternative to replace both transformers at Lisgar TL substation. This is currently limiting the progress of the project since HOL's final decision will come after reviewing the study.

The timely procurement of equipment is also a major factor that can cause delays in the project. Transformers can take over a year to procure and therefore must be ordered as soon as possible from the manufacturer. Any delay in delivery will directly result in a prolonged schedule of work. In order to mitigate this risk HOL will request Hydro One to procure transformers once the final decision has been made.

#### 1.3.5.4 *Cost Factors*

Due to the fact the Hydro One owns the transformers at Lisgar TL substation all work will be sole sourced through them. Therefore HOL has little control in the costs associated with the project's work. HOL has mitigated this risk by requesting a study to be completed by Hydro One in order to determine the costs associated with upgrading both transformers. This is an attempt to make an informed decision about which alternative to pursue.

### 1.3.6 Renewable Energy Generation

This project is mainly being driven due to the lack of capacity to connect new load at Lisgar TL substation. However, by upgrading the transformers at the substation there is an additional benefit from their ability to accept reverse power flow. This increases the amount of embedded generation that can be connected. Hydro One has specified that the alternative of upgrading the transformer that is near end of life will achieve 30MW of reverse power flow. The alternative to upgrade both transformers allows for 40MW of reverse power flow to be achieved.

### 1.3.7 Leave-To-Construct

N/A

### 1.3.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Lisgar Transformation Upgrade |
| **Capital Cost:** | Awaiting outcome of Hydro One study |
| **O&M:** | N/A |
| **Start Date:** | Q1 2014 |
| **In-Service Date:** | Q4 2017 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity need |
| **Secondary Driver(s):** | Renewable energy generation connection |
| **Customer/Load Attachment** | Future customers will be affected (30MVA by 2024) |

**Project Scope**

HOL has identified a need for capacity upgrade in its downtown service territory. This need has also been identified by the IESO as part of the integrated regional resource plan for the Ottawa area. HOL has requested Hydro One to commence a study on a detailed analysis indicating the work that will be implemented, the associated work schedule, and a Class B estimate (+/-25%) for upgrading both transformers at Lisgar TL substation to a rating of 60/80/100MVA. Currently, it is not anticipated that upgrades to the buss work will be part of this project's scope.

**Work Plan**

Hydro One is currently undergoing a detailed study on the work that will be required to upgrade both transformers at Lisgar TL substation. This report will also specify the schedule of work and a cost estimate. Upon receiving the completed study in 2015, HOL will make a decision to either ask Hydro One to upgrade one or both of the transformers. The implementation of this project will then be carried out by Hydro One at the request of HOL as they are the owner of Lisgar TL substation's transformers. The current plan is to have one transformer upgraded by the end of 2016 and if the option of upgrading both transformers is chosen, then the second transformer will be upgraded in 2017.

**Customer Impact**

The impact to customers will be those that come in the future. It is expected that 30MVA of demand will be required over the next ten years. These customers will need the ability to be supplied with reliable power.

## 1.4 Limebank Transformer Upgrade

### 1.4.1 Project/Program Summary

The Limebank Transformer Upgrade project involves the installation of a new station transformer with protection and new distribution feeders to meet the growing capacity requirements close to the station. In addition to the capacity driver, there are also reliability benefits gained by completing this project through the splitting of existing circuits and ties to other substations.

### 1.4.2 Project/Program Description

#### 1.4.2.1 *Current Issues*

Limebank MS is currently at its planning capacity limit. Large increases in load are forecasted in the area directly adjacent to the substation. In particular, the Riverside South Community Design Plan encompasses an area of 1,800 hectares around the substation and involves the development of a rapid transit corridor, residential areas, and an employment area.

#### 1.4.2.2 *Program/Project Scope*

The project is located in the south part of the City of Ottawa at 4389 Limebank Road at HOL's Limebank MS substation. The existing substation consists of two 33MVA station transformers. This project will be adding another station transformer to the station with provisions for a fourth transformer in the future.

The assets in scope for this project include the following:

- A new third 115KV to 27kV 33MVA station transformer with an online tap changer
- Installation of a 115kV high voltage disconnect switch
- Installation of 115kV high side SF6 breaker
- Protection upgrade including Potential Transformers, Current Transformers, Protection & Control Relays, Protection & Control Building
- New 27.6kV Switchgear and Switchgear Building
- Four new distribution circuits
- Ground grid installation
- Noise abatement and oil containment
- Oil containment for existing station transformers T1 and T2 (required by the Ministry of Environment)

#### 1.4.2.3 *Main and Secondary Drivers*

The primary driver for this project is capacity. There is significant load growth forecasted in the ideal supply range of Limebank substation. In particular, the Riverside South Community Design Plan (CDP) is forecasting load which exceeds the planning capacity of Limebank substation. The Riverside South CDP encompasses an area of 1,800 hectares and involves the development of a rapid transit corridor, residential areas, and an employment area. The geographic plan of the Riverside South CDP is shown in Figure 61.

A secondary driver for the Limebank Transformer Upgrade is reliability. Along with the new station transformer, additional breaker positions will be available for new circuits coming out of Limebank station. These new circuits will split existing circuits coming out of Limebank MS, reducing customer exposure to outages, as well as making ties with circuits from nearby stations including Uplands MS, Longfields DS, Fallowfield DS, and Leitrim MS.

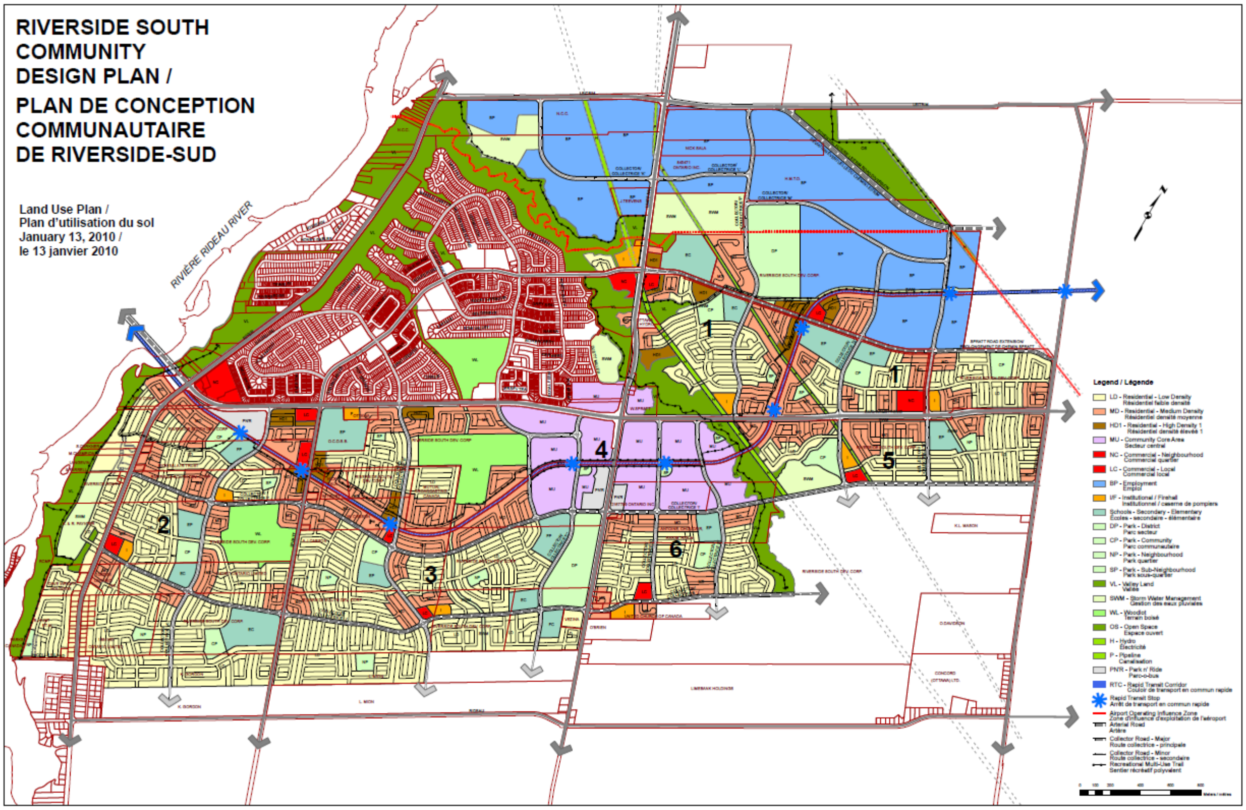



**Figure 61 - Riverside South Community Design Plan**

### 1.4.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to increase the planning supply capacity in the surrounding area of the substation by 33MVA.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency within the station by installing the new transformer lineup sufficiently far away from the existing line up in case of failure
- Increasing the contingency of existing Limebank circuits and ties with other substation circuits through additional new feeders
- Planning for environmental concerns by installing proper oil containment for the new transformer and upgrading the oil containment of the existing transformers

### 1.4.3 Project/Program Justification

#### 1.4.3.1 *Alternatives Evaluation*

The primary objective of this project is to increase the planned supply capacity in the area surrounding the substation.

##### 1.4.3.1.1 Alternatives Considered

**Feeder ties with other stations**

Limebank substation has existing feeder ties with the surrounding 27.6kV substations Leitrim MS, Uplands MS, Longfields DS, and Fallowfields MTS. Figure 62 below shows a map of the area surrounding Limebank MS along with the Limebank feeders, other 27.6kV substations, and the Riverside Community area highlighted. In order to meet the capacity needs of the Limebank Station area, feeder ties with other stations are being considered.

**Limebank Transformer Upgrade with provision for future transformer**

The upgrade of a new 33 MVA transformer with feeders at Limebank MS substation is considered.

**Limebank Transformer Upgrade with two additional transformers**

The upgrade of two new 33 MVA transformers with feeders at Limebank MS substation is considered.

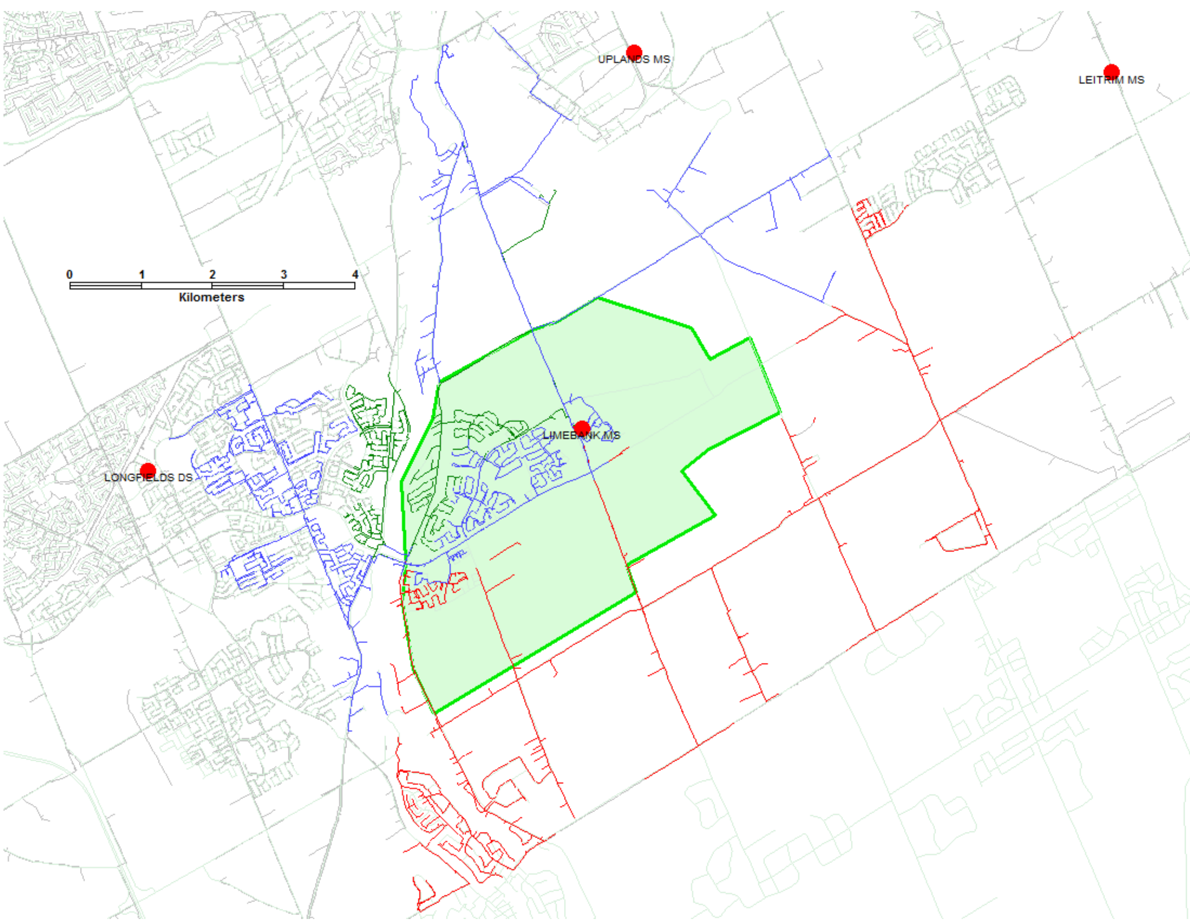



**Figure 62 - Riverside South Community Design Plan are (light green area) shown in reference to surrounding substations. Existing Limebank circuits are also shown.**

#### 1.4.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, cost, and long term capacity sustainability.

#### 1.4.3.1.3 Preferred Alternative

The preferred alternative is the Limebank transformer upgrade with provision for future transformer.

The full ranking of alternatives is:

1. Limebank transformer upgrade with provision for future transformer
2. Limebank transformer upgrade with two additional transformers
3. Feeder ties with other stations

| | Reliability | Cost | Long Term Capacity Sustainability |
|---|---|---|---|
| **Limebank transformer upgrade with provision for future transformer** | Ideal – splitting of feeders at Limebank MS substation is simple and feeder length to load centers is minimized | Upgrade cost of new transformer line-up and feeders with provision for future transformer | Ideal – load growth is located near Limebank MS substation and there is provision for future growth |
| **Limebank transformer upgrade with two additional transformers** | Ideal – splitting of feeders at Limebank MS substation is simple and feeder length to load centers is minimized | Upgrade cost of two new transformer line-ups and feeders | Ideal – load growth is located near Limebank MS substation and long term capacity exists |
| **Feeder ties with other stations** | Splitting of feeders at Limebank MS is more complex and feeder length to load centers is longer | Upgrade cost of new transformer line-ups and feeders at other stations | Non-ideal – load growth near Limebank MS substation would be supplied by stations geographically further away |

**Table 63 - Alternatives Comparison**

**Feeder ties with other stations**
Both Leitrim MS and Uplands MS have reached their supply planning capacities and would require upgrades to supply new load around the Limebank substation area. Both these substations currently have a single transformer and therefore are not ideal for contingency planning.

Longfields DS has reached its supply planning capacity and would require transformer upgrades to supply additional feeder capacity to the Limebank substation area.

Fallowfield MTS  has reached its supply planning capacity in addition to being 13km west from the Limebank substation area.

Limebank MS substation is ideally situated to supply the load growth as it is located within the Riverside Community Design Plan.

**Limebank Transformer Upgrade with two additional transformers**
Upgrading capacity at Limebank MS substation is ideal for both long term sustainability and reliability. Locating new capacity beside the future load growth center allows for minimized feeder lengths and for simple splitting of existing feeders from Limebank MS substation.

It has been determined that the upgrade of a single 33MVA transformer at Limebank MS will suffice planning capacity until at least 2024.

Upgrading the station with a second new transformer would provide long term capacity benefits. However, this second new transformer would not be required until approximately 2024 and would incur additional costs to the project in 2014 and 2015.

**Limebank transformer upgrade with provision for future transformer**
Upgrading capacity at Limebank MS substation is ideal for both long term sustainability and reliability. Locating new capacity beside the future load growth center allows for minimized feeder lengths and for simple splitting of existing feeders from Limebank MS substation.

It has been determined that the upgrade of a single 33MVA transformer at Limebank MS will be sufficient for planning capacity until at least 2024.

As there is capacity forecasted beyond 2024, it is rational to make provisions for a second future new transformer. This alternative also ensures that risk is minimized in the case that load is not realized. The costs of this second transformer are out of scope for this alternative.

#### 1.4.3.2 *Project/Program Timing & Expenditure*

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | 1.04 | 5.47 | 1.62 | 0.23 | | | | | |

**Table 64 - Project Expenditure**

HOL has minimized the controllable costs of this project by implementing a number of measures.

- A competitive Request for Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meet the needs of HOL and are able to maintain timelines required.

- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

#### 1.4.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. The contingency is improved by installing the new transformer lineup sufficiently far away from the existing line up in case of failure. Additionally, more available feeder positions are introduced by this project, allowing for the splitting of load for customers and more ties between feeders for contingent switching. |
| **Customer** | This project gives future customers the station capacity to be able to connect new load in the future. Additionally, this project should increase reliability in the area through new feeder positions. |
| **Safety** | Building a new transformer will address the predicted thermal overload of the existing station transformer that would occur in the future. Overloading the system can lead to risks such as equipment damage and safety hazards which this project will mitigate Proper protection coordination in the station improves the safety of employees and the public. |
| **Cyber-Security, Privacy** | Not Applicable |
| **Co-ordination, Interoperability** | Not Applicable |
| **Economic Development** | This project enables infrastructure for economic growth in the area. In particular Riverside South Community Development Plan, which includes lands reserved for employment blocks. |
| **Environment** | This project includes oil containment for the new transformer along with refurbished oil containment for the existing transformers. This protects oil from seeping into the environment in case of oil leaks or catastrophic failure. It is no longer acceptable to use Polychlorinated Biphenyl (PCBs) oil in transformer insulation, and the new transformer will use a safer chemical. Oil containment will be included to minimize environmental damage, should a transformer leak. |

**Table 65 - Project Benefits**

### 1.4.4 Prioritization

#### 1.4.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load in the near future. Deferring capacity upgrades risks thermal overload for an extended period of time which could lead to equipment damage and customer outages.

This project will enable the creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that reduced contingency and therefore reliability in the case of an outage.

#### 1.4.4.2 *Priority*

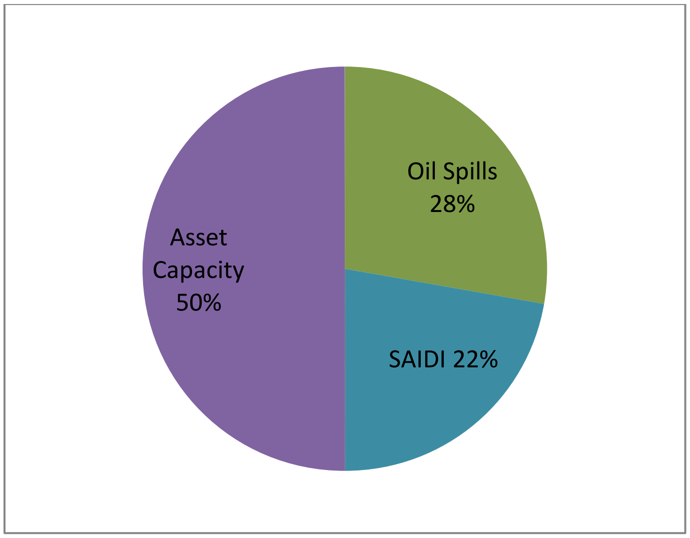



**Figure 63 - Project Avoided Risk**

Project Score: 1.44

### 1.4.5 Execution Path

#### 1.4.5.1 *Implementation Plan*

The implementation plan for the Limebank Transformer Upgrade is as follows:

- The design and major equipment for this project were procured in 2012 and 2013.
- The first phase of civil construction was completed in 2013 by contractors
- The second phase of civil construction was completed in 2014 by contractors
- Electrical construction began in 2014 by HOL station electricians and technicians
- The new transformer is to be energized by end of 2014
- New feeders will be egressed by end of 2014 and Q1 of 2015
- Oil containment refurbishment for existing station transformers will occur in Q3 of 2015

#### 1.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

The construction of a substation transformer is dependent upon the availability of Hydro One Networks Inc.'s transmission supply line. HOL cannot proceed with their project unless supply is available. Due to this important requirement, HOL has maintained heavy communication with Hydro One.

This project must also gain Environmental Assessment approval and City of Ottawa approval.

#### 1.4.5.3 *Timing Factors*

Coordination with Hydro One is required for transmission connection for the new transformer lineup.

#### 1.4.5.4 *Cost Factors*

In order to gain Environmental Assessment approval, additional refurbishment of the oil containment for the existing transformer at Limebank MS was required.

#### 1.4.5.5 *Other Factors*

Noise abatement was introduced as part of the scope of this project due to the stations close proximity to a residential neighbourhood.

#### 1.4.5.6 *Renewable Energy Generation (if applicable)*

Not applicable.

### 1.4.6 Leave-To-Construct (if applicable)

Not applicable.

### 1.4.7 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Limebank Transformer Upgrade |
| **Capital Cost:** | $8.36 M |
| **O&M:** | $0 |
| **Start Date:** | 2012 |
| **In-Service Date:** | 2014 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 33MVA |

**Project Scope**

The project is located in the south part of the City of Ottawa at 4389 Limebank Road at HOL's Limebank MS substation. The existing substation consists of two 33MVA station transformers. This project will be adding another station transformer to the station with provisions for a fourth transformer in the future. The assets in scope for this project include the following:

- A new third 115KV to 27kV 33MVA station transformer with an online tap changer
- Installation of a 115kV high voltage disconnect switch
- Installation of 115kV high side SF6 breaker
- Protection upgrade including Potential Transformers, Current Transformers, Protection & Control Relays, Protection & Control Building
- New 27.6kV Switchgear and Switchgear Building
- Four new distribution circuits
- Ground grid installation
- Noise abatement and oil containment
- Oil containment for existing station transformers T1 and T2 (required by the Ministry of Environment)

**Work Plan**

The work plan for the Limebank Transformer Upgrade is as follows:

- The design and major equipment for this project were procured in 2012 and 2013.
- The first phase of civil construction was completed in 2013 by contractors
- The second phase of civil construction was completed in 2014 by contractors
- Electrical construction began in 2014 by HOL station electricians and technicians
- The new transformer is to be energized by end of 2014
- New feeders will be egressed by end of 2014 and Q1 of 2015
- Oil containment refurbishment for existing station transformers will occur in Q3 of 2015

**Customer Impact**

This project gives existing and future customers the station capacity to be able to connect new load. Additionally, this project will increase reliability in the area through new feeders which allow for splitting of customer load and more ties between feeders for contingent switching. The contingency of the station is improved by installing the new transformer lineup sufficiently far away from the existing line up in case of failure.

## 1.5 Leitrim T1

### 1.5.1 Project/Program Summary

The core purpose of the Leitrim T1 project is to add 25MVA of transformation capacity and one additional circuit egress to the single transformer substation Leitrim MS. This project will bring additional and contingent transformation to Leitrim MS Substation, potentially allowing for either T1 or T2 to be brought out of service without impacting the customers it serves.

### 1.5.2 Project/Program Description

#### 1.5.2.1 *Current Issues*

Leitrim MS is currently a single transformer substation. This results in operational difficulties whenever servicing or maintenance of station equipment is required. Additionally, in the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency.

The circuits at Leitrim MS, the 249F1 and 249F2, have also consistently been HOL's worst performing feeders. The primary issue with these feeders are overhead exposure over long feeder lengths.

Capacity is forecasted to increase with the realization of the Leitrim Community Design Plan.

#### 1.5.2.2 *Program/Project Scope*

This project is located at 4294 Hawthorne Road in the former municipality of Gloucester, at Leitrim MS substation. This project will bring additional and redundant transformation to Leitrim MS Substation, potentially allowing for either T1 or T2 to be brought out of service without impacting the customers it serves.

The scope of this project includes: the relocation of the incoming 44kV supply; installation of a motorized high side air break switch; high side breaker; high side PT feeding the transformer; and a new 25MVA transformer complete with a seismically rated foundation and full oil containment. On the low side, a circuit switcher and structure mounted Current Transformers (CTs) will feed back into the existing low side bus. In addition, a secondary tie breaker will be installed in between the two existing buses. On the P&C/SCADA side, the new transformer will be protected by differential protective relaying and the secondary bus will be protected by overcurrent relaying. The scope also includes the construction of an additional recloser (249F3) bringing the total number of circuits fed by the station to four (4). The load side of this new egress feeder is out of scope and will be taken care of by a distribution project. Further, the scope includes the installation of an automatic transfer switch capable of feeding the station's AC service from the low-side bus of either T1 or T2, serving the new standard P&C "house" containing most of the protective relaying, power supplies, and communications gear. Lastly, the service road used to access the substation will also require minor modifications to accommodate the finished substation.

The ground grid and fencing will be upgraded as well.

#### 1.5.2.3 *Main and Secondary Drivers*

The primary driver for this project is reliability. In its current state, Leitrim MS only has a single transformer. In the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency. Restoration of load in the event of a prolonged outage is dependent on feeder ties with either Uplands MS or Limebank MS, which may be constrained in their loading during peak times and require lengthy switching. Additionally, this project introduces another station feeder position. A new circuit will allow for the potential to split existing circuits coming out of Leitrim MS, reducing customer exposure to outages, as well as make ties with circuits from nearby stations such as Uplands MS and Limebank MS.

Secondary drivers include the ability to maintain either transformer at the station as well as an increase in available capacity at Leitrim MS.

#### 1.5.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to achieve the station contingency realized by a second 25MVA transformer lineup.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency of existing Leitrim circuits and ties with other substation circuits through an additional feeder
- Planning for environmental concerns by installing proper oil containment
- Additional available transformation capacity at the station

### 1.5.3 Project/Program Justification

#### 1.5.3.1 *Alternatives Evaluation*

The primary driver of this project is providing more contingency to Leitrim MS with a secondary driver of increasing capacity.

##### 1.5.3.1.1 Alternatives Considered

**Feeder Ties with Other Stations**

Leitrim MS substation has existing feeder ties with the surrounding 27.6kV substations Limebank MS and Uplands MS. Figure 64 below shows the trunk circuitry of each station in the area and ties. In order to meet the reliability needs and capacity needs of Leitrim MS, feeder ties with other stations are considered as an alternative.

**Second Transformer and Feeder (Leitrim T1)**

The addition of a new 25MVA transformer and additional egress feeder out of Leitrim MS substation is considered as an alternative.

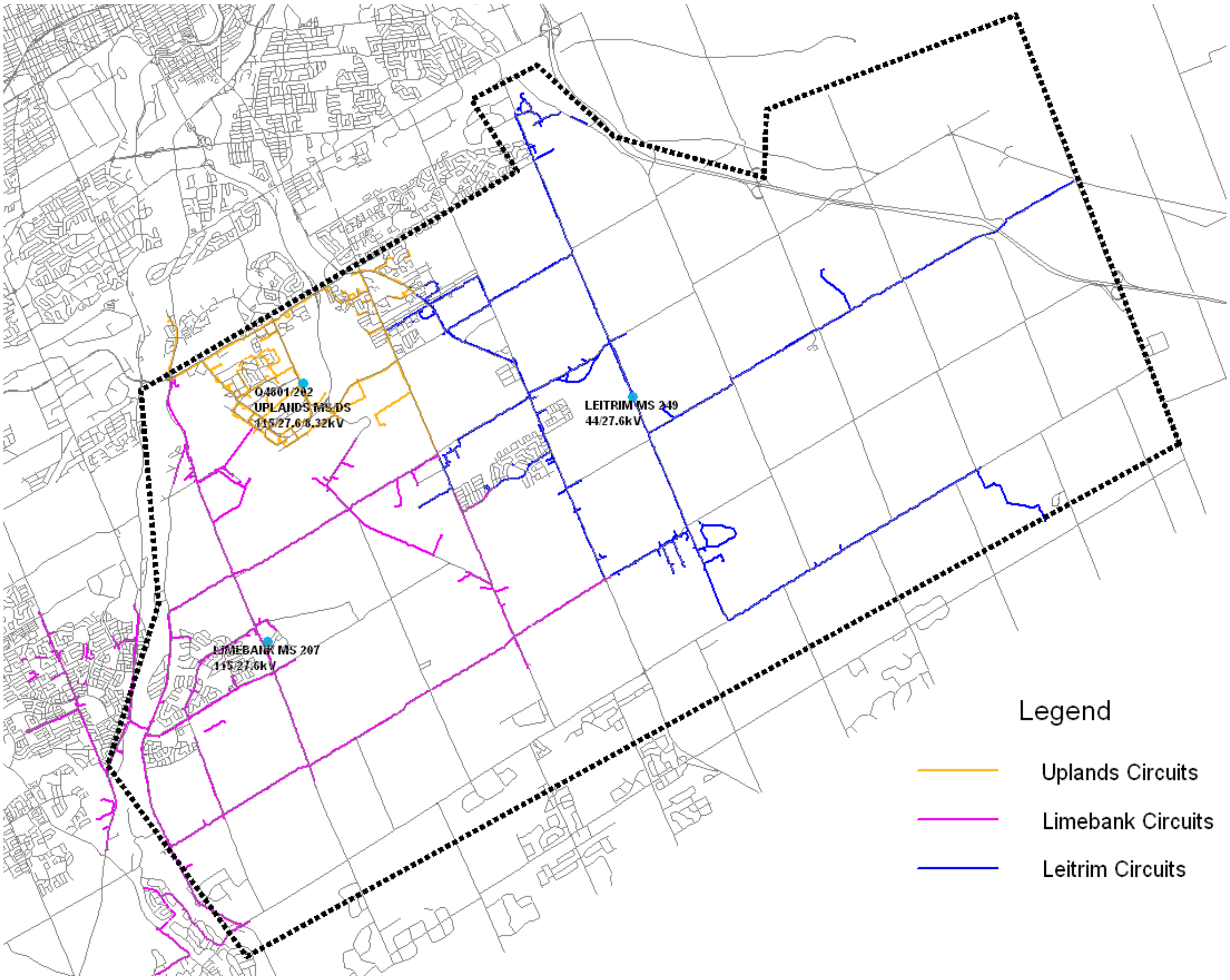



**Figure 64 - Leitrim MS in relation to tie stations Uplands MS and Limebank MS**

#### 1.5.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, capacity, cost, and power quality.

#### 1.5.3.1.3 Preferred Alternative

The preferred alternative is the upgrade of Second Transformer and Feeder (Leitrim T1).

The full ranking of alternatives is:

1. Second Transformer and Feeder (Leitrim T1).
2. Feeder Ties with Other Stations

| | Second Transformer and Feeder (Leitrim T1) | Feeder Ties with Other Stations |
|---|---|---|
| **Reliability** | Improved reliability compared to feeder solution | Worse reliability compared to Leitrim station solution |
| **Capacity** | Meets capacity requirements | Meets capacity requirements |
| **Power Quality** | No power quality issues | Possibility of voltage sags at end of line trunk customers |
| **Cost** | $3.05M | $5.33M |

**Table 66 - Project Alternatives**

**Second Transformer and Feeder (Leitrim T1)**
Adding a second transformer and new feeder at Leitrim MS substation improves reliability through transformer lineup contingency, new feeder splitting and tie potential. Leitrim MS would be self-sufficient as a station for restoration in the case of a single transformer trip or station feeder trip.

The new transformer would also provide additional capacity planning in the area.

Power quality issues such as voltage sag should not be an issue in the case of contingent feeding with the second transformer as the existing distance from station to end-of-line would not change.

The total cost of this alternative is approximately $3.05M.

**Feeder Ties with Other Stations**
Leitrim MS substation has existing feeder ties with the surrounding 27.6kV substations Limebank MS and Uplands MS. In order to accommodate an equivalent of 25MVA of contingency capacity, upgrades would be required at either Uplands MS or Limebank MS. Uplands MS is a single transformer station and scheduled to have a second transformer installed in 2018 for its own capacity forecast and reliability needs. Limebank MS will have provisions to install a fourth 33MVA transformer lineup with an estimated need install date of 2024.

This alternate involves the option of installing the fourth transformer at Limebank MS in order to meet the reliability and capacity needs of Leitrim MS, prior to the original planned install date of 2024. In addition to a new transformer at Limebank MS, a dedicated feeder would be required to egress from the station and tie to Leitrim MS.

Estimation of the cost of this alternative is based on installing a new dedicated pole line with a single three phase circuit a distance of 10km from Limebank station to tie into the nearest existing Leitrim 249F2 circuit at Bank Street and Rideau Road. The cost per kilometer of an overhead dedicated circuit is estimated to be $333,000 based on $20,000 per pole and 60m between poles. Therefore, for 10km of circuit, it is estimated the cost is $3.33M. The cost of the breaker position at Limebank MS has not been considered. An estimated preliminary cost of the new transformer at Limebank MS is $2.0M. Therefore the total cost of this alternate is approximately $5.33M.

From a capacity standpoint, this alternative will provide the same benefits as adding new transformer capacity at Leitrim MS since 25MVA amounts to one fully dedicated, fully loaded circuit.

From a reliability perspective, this option is not as preferable as upgrading at Leitrim MS. This is because no new feeder positions are added at Leitrim MS itself, where new load growth is forecasted. Additionally, there is more exposure on supply coming from long overhead feeders compared with local station supply.

A dedicated backup supply line from Limebank MS to Leitrim MS may result in power quality issues for some customers due to long feeder lengths. The distance from Limebank MS to end-of-line trunk Leitrim MS customers is approximately 20km. This could result in voltage sag issues.

#### 1.5.3.2 *Project/Program Timing & Expenditure*

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | | | | 0.84 | 2.21 | | | | |

**Table 67 - Project Expenditures**

HOL has minimized the controllable costs of this project by implementing the following measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resource requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

#### 1.5.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. Additionally, another feeder position is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. |
| **Customer** | This project increases station reliability through a new transformer line up. A new feeder position enables increasing distribution reliability in the area as well. Additionally, this project provides capacity to be able to connect customers and future load. |
| **Safety** | Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public. |
| **Cyber-Security, Privacy** | Not Applicable |
| **Co-ordination, Interoperability** | Not Applicable |
| **Economic Development** | This project enables electrical capacity infrastructure for economic growth in the area. |
| **Environment** | This project includes oil containment for the new transformer. This keeps oil from seeping into the environment in case of oil leaks or catastrophic failure. Oil containment will be included to minimize environmental damage, should the transformer leak. |

**Table 68 - Project Benefits**

### 1.5.4 Prioritization

#### 1.5.4.1 *Consequences of Deferral*

Since the purpose of this project is to address the issue of station transformer reliability as well as capacity at Leitrim MS, the most important consequence of deferral would be outage risks and the inability to service future load.

This project will enable the potential creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which results in reduced contingency and therefore reliability in the case of an outage.

#### 1.5.4.2 *Priority*

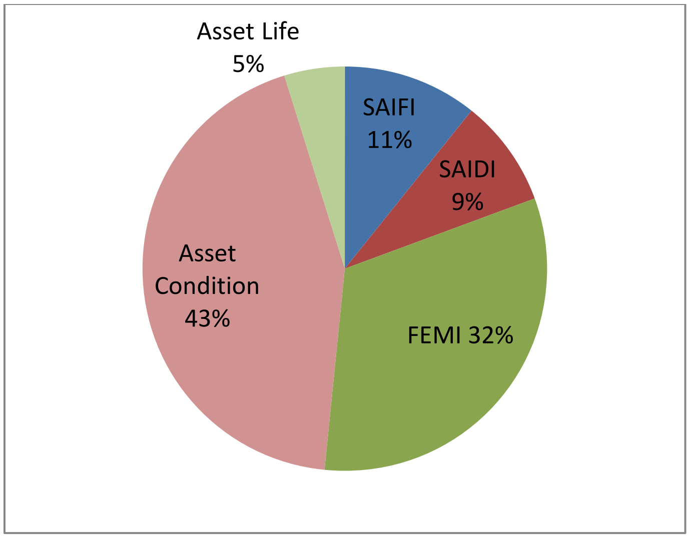



**Table 69 - Project Avoided Risk**

Project score: 0.62.

### 1.5.5 Execution Path

#### 1.5.5.1 *Implementation Plan*

The implementation plan for the Leitrim T1 project is as follows:

- The design and major equipment procurement is to occur in 2015.
- The delivery of equipment and construction is to begin in 2016.
- The project is to be completed by Q2 2018.

#### 1.5.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project may require the clearance of some trees on the north side of the existing property of Leitrim MS. Consequently, it will require an Environmental Assessment approval. Consultants will be engaged in early assessment to mitigate this risk.

#### 1.5.5.3 *Timing Factors*
The final design of this project will occur in 2015 although possible changes in design may affect project timing. Work scheduling of internal station resources in coordination with other HOL station work is a timing risk.

#### 1.5.5.4 *Cost Factors*
The final design of this project will occur in 2015. Possible changes in design may affect final project cost.

#### 1.5.5.5 *Other Factors*
None identified.

### 1.5.6 Renewable Energy Generation (if applicable)
Not applicable.

### 1.5.7 Leave-To-Construct (if applicable)
Not applicable.

### 1.5.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Leitrim T1 |
| **Capital Cost:** | $3.05 M |
| **O&M:** | $0 |
| **Start Date:** | 2015 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Capacity |
| **Customer/Load Attachment** | 25MVA |

**Project Scope**

The scope of this project includes the relocation of the incoming 44kV supply, installation of a motorized high side air break switch, high side breaker, high side PT feeding the transformer, a new 25MVA transformer, complete with a seismically rated foundation and full oil containment. On the low side, a circuit switcher and structure mounted CTs will feed back into the existing low side bus. In addition, a secondary tie breaker will be installed in between the two existing buses. On The P&C/SCADA side, the new transformer will be protected by differential protective relaying and the secondary bus will be protected by overcurrent relaying. The scope also includes the construction of an additional recloser (249F3) bringing the total number of circuits fed by the station to four (4). The load side of this new egress feeder is out of scope and will be taken care of by a distribution project. Further, the scope includes the installation of an automatic transfer switch capable of feeding the station's AC service from the low-side bus of either T1 or T2, serving the new standard P&C "house" containing most of the protective relaying, power supplies, and communications gear. Lastly, the service road used to access the substation will also require minor modifications to accommodate the finished substation.
The ground grid and fencing will be upgraded as well.

**Work Plan**

The implementation plan for the Leitrim T1 project is as follows:

- The design and major equipment procurement to occur in 2015.
- The delivery of equipment and construction to begin in 2016.
- The project to be completed by Q2 2018.

**Customer Impact**

This project improves the reliability of the station assets by installing contingent assets through a new transformer lineup. Additionally, another feeder position is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Finally, this project provides capacity to be able to connect customers and future load.

## 1.6 Casselman T1

### 1.6.1 Project/Program Summary

Originally Casselman MS substation was made up of a single transformer lineup.

There are two phases to the Casselman T1 project. The first phase involves adding a new 44-8.32kV 16.6MVA transformer lineup to provide additional and contingent transformation to Casselman MS. The second phase involves replacing and upgrading the existing transformer line up to achieve a reliable distribution supply from two transformers along with proper protection coordination. Three additional three phase reclosers are also part of phase two of the project, which will enable more reliable distribution in the area.

### 1.6.2 Project/Program Description

#### 1.6.2.1 *Current Issues*

Casselman MS was originally a single transformer substation. This configuration results in operational difficulties whenever servicing or maintenance of station equipment is required. Casselman MS is physically isolated from other HOL distribution lines. The original distribution contingency at HOL's Casselman MS was through a connection with Hydro One's Casselman DS substation. Casselman MS substation is located approximately 50km east of HOL's closest operational facility. Furthermore, in late 2011, the single transformer experienced an oil leak leading to an emergency replacement.

#### 1.6.2.2 *Program/Project Scope*

The project is located in the village of Casselman at 29 Racine Street at HOL's Casselman MS substation. The original substation consisted of a single 10MVA transformer lineup.

The scope of Phase 1 of the project includes:

- Addition of new refurbished 44-8.32kV 16.6MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and tie breaker with disconnect switches
- New P&C panels including new Remote Terminal Unit (RTU) and high side, transformer and bus relays.
- New 8.32kV overhead bus with 3 recloser feeder positions for future

The scope of Phase 2 of the project includes:

- Purchase new 44-8.32kV 12MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and disconnect switch
- New P&C panel including new high side transformer and bus relays.

#### 1.6.2.3 *Main and Secondary Drivers*

The primary driver for this project is reliability. In its original state, Casselman MS only has a single transformer. In the event of a transformer or station feeder interruption, there is no redundancy within the station for contingency. Restoration of load in the event of a prolonged outage, as well as offloading for maintenance activities, is dependent on feeder ties with Hydro One's Casselman DS. This project removes the dependence on another distribution company. Additionally, this project introduces three additional recloser positions. New circuits will allow for the potential to split existing circuits coming out of Casselman MS, reducing customer exposure to outages, as well as make ties with existing circuits.

Secondary drivers include the ability to maintain either transformer at the station as well as an increase in the available capacity at Casselman MS.

#### 1.6.2.4 *Performance Targets and Objectives*

The primary objective of implementing this project is to achieve the station contingency realized by a second transformer lineup.

Additional planning objectives that are met by this project include:

- Planning for the long term dependence of the new station assets through the implementation of proper protection
- Increasing the contingency of existing Casselman circuits and ties with other substation circuits through additional feeder positions
- Planning for environmental concerns by installing proper oil containment
- Additional available transformation capacity at the station

### 1.6.3 Project/Program Justification

The primary driver of this project is to provide long term increased reliability through HOL station or distribution assets that have proper protection coordination.

#### 1.6.3.1 *Alternatives Evaluation*

##### 1.6.3.1.1 Alternatives Considered

**Second Transformer Lineup and Provision for Three Reclosers (Casselman T1)**

This alternative includes the installation of a second transformer lineup along with protection for station assets and the provision for three future reclosers.

**Do-Nothing (Remain Single Transformer Lineup)**

This alternative involves keeping Casselman MS station as a single transformer lineup configuration.

##### 1.6.3.1.2 Evaluation Criteria

The criteria used to evaluate the alternatives are reliability, long term sustainability, and cost.

##### 1.6.3.1.3 Preferred Alternative

The preferred alternative is the Second Transformer Lineup and Provision for Three Reclosers (Casselman T1).

The second preferred alternative is Do-Nothing (Remain Single Transformer Lineup).

| | Second Transformer Lineup and Provision for Three Reclosers (Casselman T1) | Do-Nothing (Remain Single Phase Transformer Lineup) |
|---|---|---|
| **Reliability** | Second station transformer lineup available for contingency. Provision for future feeders allows for splitting of customers and load and ability to make new feeder ties. Proper station protection and coordination. | Reliability is impacted as a result of dependency on distribution tie with separate utility. No provision for future feeders. Fused station protection puts station assets at higher risk. |
| **Long Term Sustainability** | HOL contingency assets. Ability to transfer load between station transformers and schedule station maintenance and upgrades. Additional capacity for future load growth. | Dependency on Hydro One distribution for maintenance, contingency, and scheduling. |
| **Cost** | $4.74M | Ongoing costs associated with coordination with Hydro One for maintenance and lost revenue during contingency will continue indefinitely into the future. |

**Table 70 - Project Alternatives**

**Second Transformer Lineup and Provision for Three Reclosers (Casselman T1)**
Adding a second transformer and provision for future feeder at Casselman MS station improves reliability through transformer lineup contingency and new feeder splitting and tie potential. Casselman MS would be self-sufficient as a station in the case of a single transformer trip or station feeder trip.

This project includes protection and control coordination to ensure the safety of the station assets.

The new transformer would also provide additional capacity planning in the area.

The total cost of this alternative is approximately $4.74M.

**Do-Nothing (Remain Single Transformer Lineup)**
This option would have Casselman MS station stay with a single transformer lineup configuration. This option would result in a continued dependence on Hydro One distribution for maintenance, contingency, and scheduling whenever work is required at Casselman MS. No provisions for new circuits are included in this alternative and the protection of the lineup will remain fused. Ongoing costs associated with coordination with Hydro One for maintenance and lost revenue during contingency will continue indefinitely into the future.

### 1.6.3.2 *Project/Program Timing & Expenditure*

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | 0.60 | 2.21 | 1.93 | | | | | | |

**Table 71 - Project Expenditures**

HOL has minimized the controllable costs of this project by implementing a number of measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

#### 1.6.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project enables HOL to have backup station assets in contingency situations. This will create the ability to transfer load between station transformers and schedule station maintenance and upgrades. Additionally, provision for new recloser positions is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Both the new transformer lineup and the provision for future feeders will improve reliability. |
| **Customer** | This project will increase station reliability in the area through a new transformer line up. Provision for new recloser positions enables increasing distribution reliability in the area as well. Additionally, this project provides capacity to be able to connect customers and future load. |
| **Safety** | Building a new transformer lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public. |
| **Cyber-Security, Privacy** | Not Applicable |
| **Co-ordination, Interoperability** | Not Applicable |
| **Economic Development** | This project enables electrical capacity infrastructure for economic growth in the area. |
| **Environment** | This project includes oil containment for both transformers. This protects oil from seeping into the environment in case of oil leaks or catastrophic failure. Oil containment will be included to minimize environmental damage, should a transformer leak. |

**Table 72 - Project Benefits**

### 1.6.4 Prioritization

#### 1.6.4.1 *Consequences of Deferral*

Since the purpose of this project is to address the issue of station transformer reliability at Casselman MS, the most important consequence of deferral would be outage risks and the indefinite dependence of the station on another distribution utility.

This project will enable the potential creation of ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that potential reduced contingency and therefore reliability in the case of an outage.

#### 1.6.4.2 *Priority*

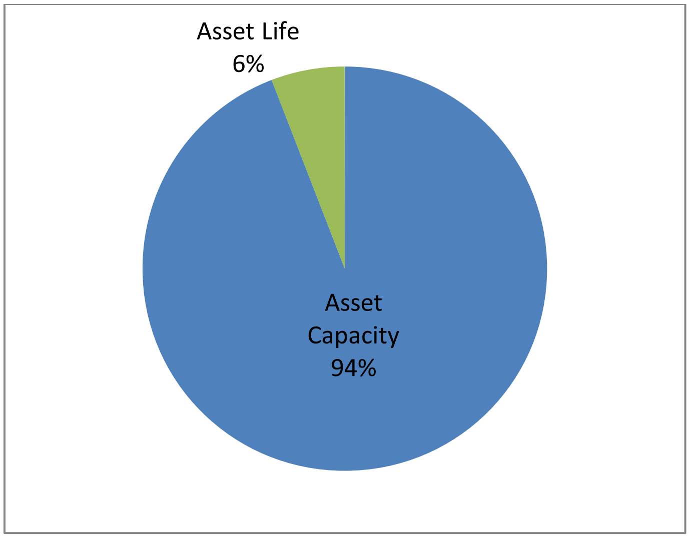



**Figure 65 - Project Avoided Risk**

Project Score: 0.510

### 1.6.5 Execution Path

#### 1.6.5.1 *Implementation Plan*

The implementation plan for phase one of the Casselman T1 project is as follows:

- Design and major equipment procurement began in 2012
- Delivery of equipment, and construction to begin in 2013
- Project to be completed by Q2 2014

The implementation plan for phase two of Casselman T1 project is as follows:

- Design and major equipment procurement occurring in 2014
- Delivery of equipment, and construction to begin in 2014
- Project to be completed by Q4 2015

#### 1.6.5.2 *Risks to Completion and Risk Mitigation Strategies*

Construction work is scheduled during the winter of 2015. This represents a risk as winter work may be slower and faces additional weather challenges. This risk is mitigated through awareness and planning for winter work.

#### 1.6.5.3 *Timing Factors*

Work scheduling of internal station resources in coordination with other HOL station work is a timing risk.

#### 1.6.5.4 *Cost Factors*

None identified.

#### 1.6.5.5 *Other Factors*

None identified.

### 1.6.6 Renewable Energy Generation (if applicable)

Not applicable.

### 1.6.7 Leave-To-Construct (if applicable)

Not applicable.

### 1.6.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Casselman T1 |
| **Capital Cost:** | $4.74M |
| **O&M:** | $0 |
| **Start Date:** | 2012 |
| **In-Service Date:** | 2015 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Capacity |
| **Customer/Load Attachment** | 16.6MVA |

**Project Scope**

The scope of Phase 1 of the project includes:

- Addition of new refurbished 44-8.32kV 16.6MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and tie breaker with disconnect switches
- New P&C panels including new RTU and high side, transformer and bus relays.
- New 8.32kV OH bus with 3 recloser feeder positions for future

The scope of Phase 2 of the project includes:

- Purchase new 44-8.32kV 12MVA transformer
- New transformer foundation and containment
- Addition of 44kV SF6 breaker and disconnect switch
- New 15kV outdoor secondary bus breaker and disconnect switch
- New P&C panel including new high side, transformer and bus relays.

**Work Plan**

The implementation plan for phase one of Casselman T1 project is as follows:

- Design and major equipment procurement began in 2012
- Delivery of equipment, and construction to begin in 2013
- Project to be completed by Q2 2014

The implementation plan for phase two of Casselman T1 project is as follows:

- Design and major equipment procurement occurring in 2014
- Delivery of equipment, and construction to begin in 2014
- Project to be completed by Q4 2015

**Customer Impact**

This project enables HOL to have backup station assets in contingency situations. There will be the ability to transfer load between station transformers and schedule station maintenance and upgrades. Additionally, provision for new recloser positions is introduced by this project, allowing the potential for splitting of load for customers and more ties between feeders for contingent switching. Both the new transformer lineup and the provision for future feeders will improve reliability. Building a new transformer will lineup will allow for more accessible maintenance on transformer lineups as well as a sharing of load on each transformer to avoid thermal overload. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Proper protection coordination in the station improves the safety of employees and the public.

## 1.7 Richmond South DS

### 1.7.1 Project/Program Summary

In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The two substations that supply Richmond and the surrounding area with 8.32kV are Richmond North DS and Richmond South DS which have a combined capacity of 11.72MVA. These two stations would not be capable of supplying the 20 year, 45MVA load forecast and as Richmond North DS is limited by its 44kV supply, Richmond South DS was identified for transformation upgrade. The decision for a 27.6kV voltage conversion was driven by the limitation of the 8.32kV lines to extend long distances and maintain adequate voltage levels, increased operability to transfer load to neighboring 27.6kV stations. The conversion is also driven by a single customer, Trans Canada, who is requesting a dedicated feeder to supply them 20MVA for their Energy East Pumping Station, located in the Richmond area.

### 1.7.2 Project/Program Description

#### 1.7.2.1 *Current Issues*

Current issues of Richmond South DS include deteriorating reliability due to failure of aging infrastructure and power quality issues which can be attributed to the length of the feeders and the limitation of 8.32kV to supply the distances without a significant voltage drop. The projected load growth in the area supplied from Richmond South DS will become an issue for the 8.32kV system within a five-year timeframe.

#### 1.7.2.2 *Program/Project Scope*

The Richmond South DS project will encompass the complete removal of all existing 8.32kV equipment from the site and will add two (2) taps off the S7M 115kV transmission line, six (6) primary disconnect switches, two (2) primary circuit breakers, two (2) 115/27.6kV 45/60/75MVA transformers, metal clad switchgear lineup adequate for six (6) feeders, a protection and control building with associated equipment to monitor and protect all station equipment and two (2) 28/8.32kV 4MVA transformers. The two 8.32kV transformers will maintain the existing 8.32kV load until all distribution conversion to 27.6kV is complete, as well as provide backup support for Richmond North DS and Munster DS until adequate ties between these two stations can be installed.

Phase 1, which will include all work and expenses to occur within 2015, includes preliminary design as well as Hydro One and IESO consultations.

Phase 2, which will include all work and expenses to occur within 2016, includes design completion and first progress payments for major equipment.

Phase 3, which will include all work and expenses to occur within 2017, includes the start of construction and arrival of major equipment. The 2017 construction will incorporate Hydro One requiring re-construction of their dead-end structures within the station yard to allow for two taps to two

115/27.6/8.32kV lineups, which includes all infrastructure required from the transmission tap to the distribution egress. All major civil work for one complete 115/27.6/8.32kV lineup will be completed as the existing 115/8.32kV lineup will be maintained until energization of the first 115/27.6/8.32kV lineup.

Phase 4, which will include all work and expenses to occur within 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/27.6/8.32kV lineup, removal of the existing 115/8.32kV lineup and completion of civil work and start of electrical construction for the second 115/27.6/8.32kV lineup.

Phase 5, which will include all work and expenses to occur within 2019, includes final commissioning of the second 115/27.6/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.

#### 1.7.2.3 *Main and Secondary Drivers*

The main driver of this project is to supply the future expected load in this growing area. The forecasted load for the next 20 years in the Richmond area indicates that its capacity limitations will be reached within the next five years. In the case of a single station contingency, the remaining capacity would not be enough to supply the required load in this area. Ongoing development worsens the situation which is why this project is required to meet the demand.

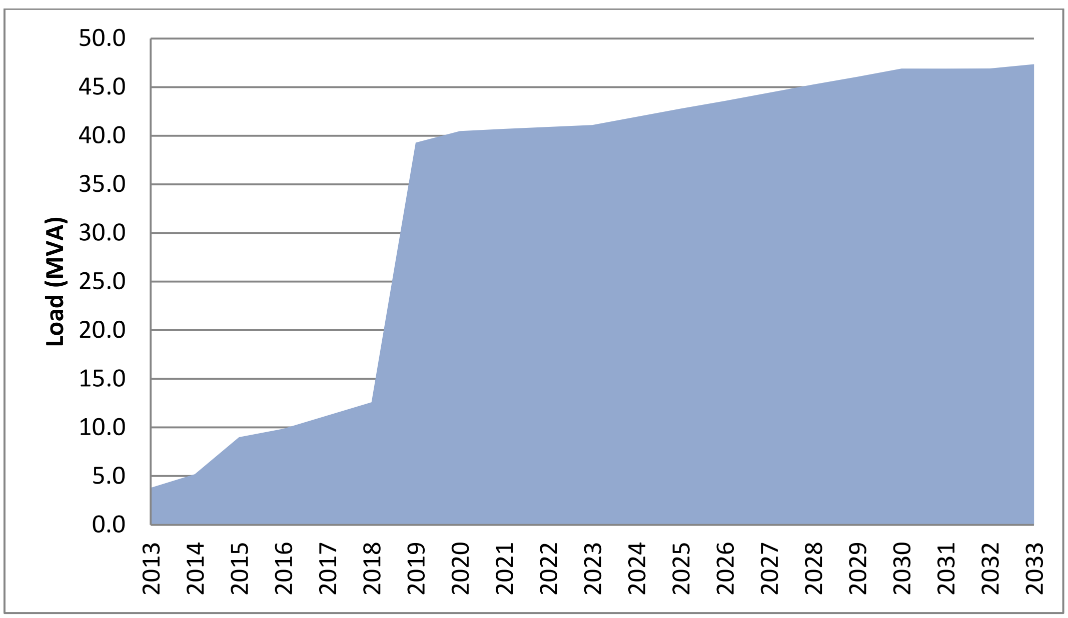



**Figure 66 - Richmond South Load Profile**

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The following outlines the development projects in the Richmond area.

**Richmond Community Design Plan (CDP)**

The Village of Richmond CDP was initiated in 2008 and covers a planning period from 2010 to 2030. Based on this plan the residential capacity is planned to increase from approximately 1,550 dwelling units to between 4,400 and 5,500 units (including existing), for an increase of 2,850 – 3,950 which accounts for a load increase of 7.3 MVA – 10.1 MVA (using an estimate of 2.56 kVA/unit).

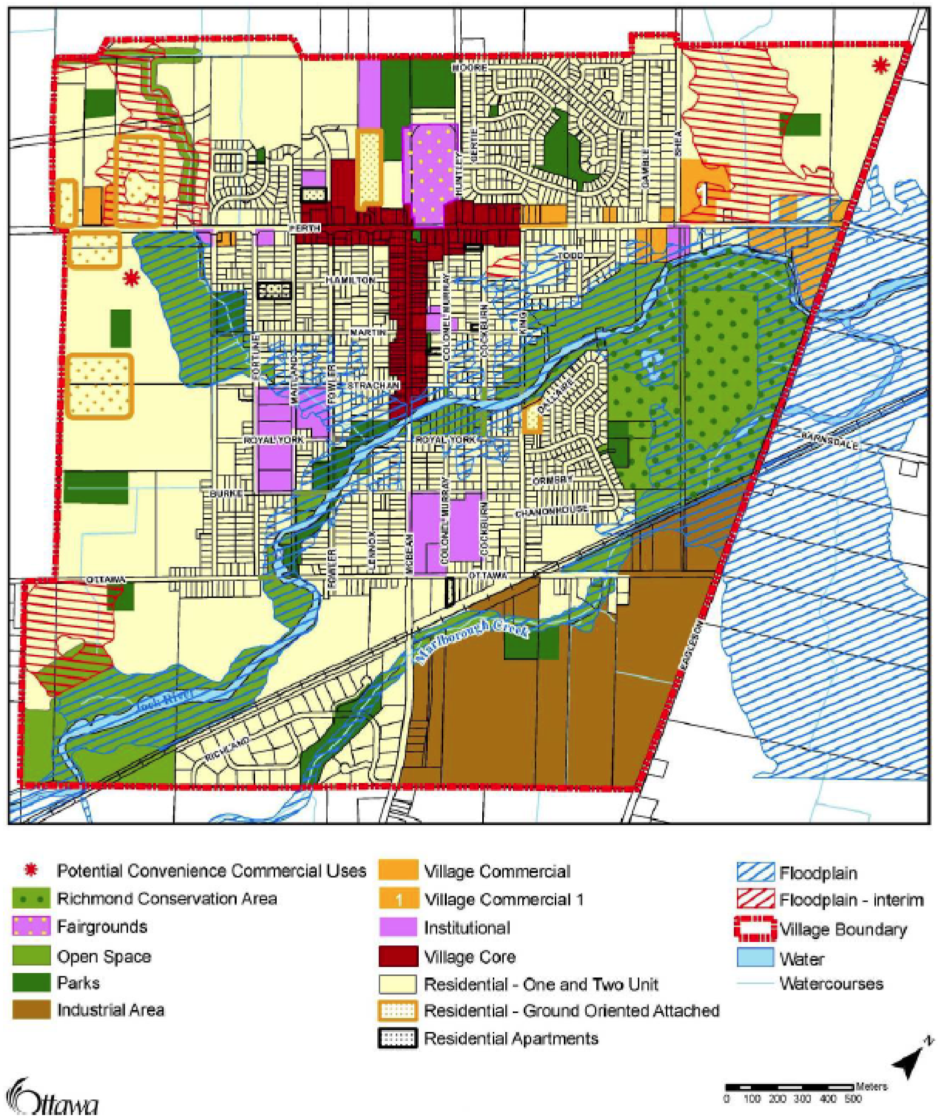



**Figure 67 - Richmond CDP Proposed Land Use**

## Industrial Lands

The Richmond CDP describes the Industrial Lands as providing “an opportunity for industrial and employment-generating uses that require large parcels of land and that are not always compatible with residential uses”. The maximum building height in this area is restricted to the equivalent of three or four storeys with the following permitted uses: light industrial, office, printing plant, service and repair shop, small batch brewery, warehouse and heavy equipment and vehicle sales, rental and servicing, research, technology, nurseries, greenhouses, catering, places of assembly, broadcasting and training. Existing areas with a similar profile have a load estimate within the range of 10 – 20 MVA/km$^2$ depending on particular uses. The proposed industrial lands cover approximately 0.9 km$^2$ which would predict a load profile within the range of 9 – 18 MVA. For planning purposes the low end, 9 MVA, will be used, assuming that no large industrial plants will be developed on these lands.


**Figure 68 - Industrial Lands Demonstration Plan**

**Western Development Lands**

Growth in the Western Development Lands will primarily consist of detached dwellings, townhouses, parks, open space, a school and a pathway system. The density and unit mix provisions for this area are shown in the chart below.

| Dwelling Type | Max Density Units/Net Ha | Unit Mix (% of Total) |
|---|---|---|
| **One & Two Units Large Lots** | 17 | 2-7% Minimum |
| **One & Two Units Small Lots** | 30 | 58-78% Maximum |
| **Townhouses** | 45 | 20-35% Minimum |
| **Townhouses with Rear Lanes** | 80 | |
| **Back-to-Back Townhouses** | 99 | |

**Table 73 - Proposed Density**


**Figure 69 - Western Development Lands Demonstration Plan**

The Western Development Lands Demonstration Plan was developed through a workshop hosted by Mattamy Homes in December 2008. Since that time, Mattamy has developed a plan for a section of the western area, which is described below.

**Mattamy Homes Residential**

The Mattamy development covers the southern portion of the Western Development Lands and will account for approximately 1000 units, or 2.5 MVA of load. They will be submitting the Draft Plan of Subdivision to the City of Ottawa in 2013 with closings to begin around 2017 since it is currently outside of their five year plan.

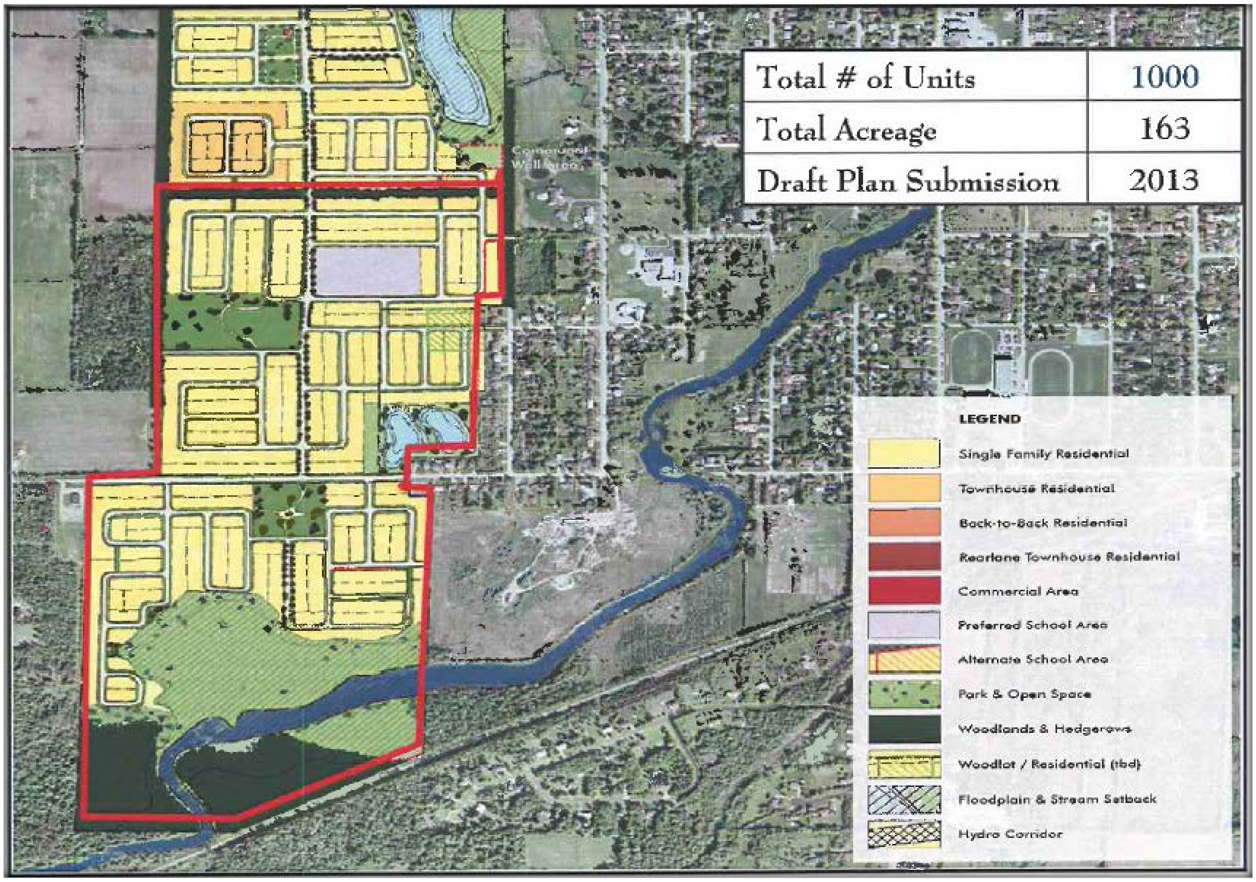



**Figure 70 - Mattamy's Richmond West Development**

### Northeast Development Lands

The Demonstration plan for the Northeast Development Lands is show below. The plans for this area follow the same general outline as the Western Development Lands.


**Figure 71 - Northeast Development Lands Demonstration Plan**

**Richmond Village Square**

The development known as Richmond Village Square is a commercial plaza that will consist of six single storey buildings for a total of 7,039 $m^2$. Using an estimate of 75.38 $W/m^2$ gives a load estimate of 590 kVA. The servicing for this site will consist of 3 x 1000 kVA transformers, and using an estimate of 60% connected capacity provides a load estimate of 1.8 MVA.  A load estimate of 1.0 MVA will be used for planning purposes.

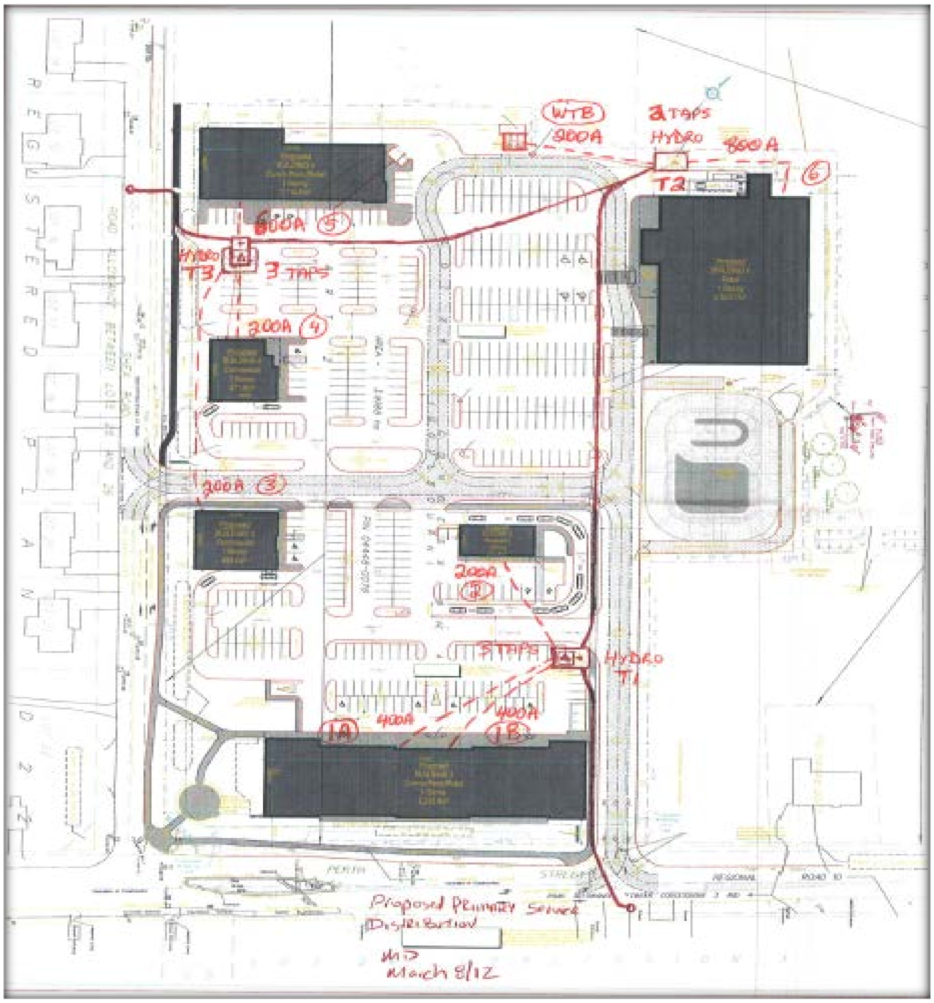



**Figure 72 - Richmond Village Square Layout**

**Trans Canada's Energy East Pumping Station**

Trans Canada's Energy East Pumping Station is an oil pumping station that is being constructed approximately 3km outside the village of Richmond. Trans Canada has requested a dedicated supply feeder as they are anticipating a load requirement of 11MVA in 2017 and 20MVA in 2018 onward. As required by the Distribution System Code, a customer requiring this amount of capacity will contribute financially to the required distribution and station upgrades. It is anticipated that Trans Canada will be contributing $3M towards the Richmond South DS project.

As a secondary driver for this project, reliability will be improved by eventually creating ties to other 27.6kV stations, specifically Janet King DS, Bridlewood DS, Terry Fox MTS, Fallowfield DS and the New South 27.6kV Substation.

#### 1.7.2.4 *Performance Targets and Objectives*

The primary objective of this project is to have the first line-up at Richmond South DS constructed and commissioned supplying load by Q4 of 2018, following with the completion of the second line-up in Q3 2019. Within this goal, various milestones must be met including: an environmental assessment, IESO System Impact Assessment approval, City of Ottawa approval, Hydro One Transmission upgrades, civil and electrical station design, tendering of all major equipment and services, and finally construction and commissioning. In conjunction with this station rebuild, other projects are being planned and implemented in order to prepare the area for a 27.6kV voltage upgrade once the station has been constructed.

### 1.7.3 Project/Program Justification

#### 1.7.3.1 *Alternatives Evaluation*

##### 1.7.3.1.1 Alternatives Considered

Due to the timing requirements of this project, alternatives are limited. Surrounding stations do not have the station nor feeder capacity to support the load being anticipated for the village of Richmond and the Trans Canada Energy East Pumping Station. Feeder extensions from the newly constructed Terry Fox TS station will help with temporary supply of load growth, however due to increasing load requirements in Stittsville that will require the capacity from Terry Fox MTS, upgrading Richmond South DS is the only feasible option.

**Alternative #1:** Upgrading Richmond South DS will encompass the complete removal of all existing 8.32kV equipment from the site and will add two (2) taps off the S7M 115kV transmission line, six (6) primary disconnect switches, two (2) primary circuit breakers, two (2) 115/27.6kV 45/60/75MVA transformers, metal clad switchgear lineup adequate for six (6) feeders, a protection and control building with associated equipment to monitor and protect all station equipment and two (2) 28/8.32kV 4MVA transformers.

This option is the most direct route to supply the load growth expected in the Richmond area for the long term future.

**Alternative #2:** In order to achieve the capacity requirements in the Richmond area the following projects would need to be undertaken:

1. 44kV line extension from South March for dual supplies for Richmond North DS and Munster DS
2. One (1) 15MVA 44/8.32kV transformer installed at Richmond North DS and infrastructure to support Two (2) new feeders
3. One (1) 15MVA 44/8.32kV transformer installed at Munster DS and infrastructure to support two (2) new feeders

4. Two (2) 15MVA 115/8.32kV transformers installed at Richmond South DS and infrastructure to support four (4) feeders
5. Line extensions along Franktown Road, Shea Road, Huntley Road, Perth Road, Bleeks Road Garvin Road and Brownlee Road in order to meet the anticipated development areas.

#### 1.7.3.1.2 Evaluation Criteria

**Costs:**

Alternative #1: $17.543M with a $3M contribution from Trans Canada

Alternative #2: $31.44M

**Ability to supply load:**

Both alternatives offer the ability to supply existing and future load, however HOL does not possess the manpower required to complete all work associated with Alternative #2 in time to meet the load development requirements.

**Reliability Benefits:**

Both alternatives would offer significant increases in reliability. However with the direction of the surrounding communities including Kanata, Stittsville and Barrhaven, proceeding with 27.6kV, Alternative #1 would offer the greatest reliability benefits as this would allow for an increased number of feeders ties.

#### 1.7.3.1.3 Preferred Alternative

Due to the reliability benefit, alternative costs and limited time before capacity is required, Alternative #1 is the preferred alternative.

### 1.7.3.2 *Project/Program Timing & Expenditure*

The total project cost is $17,543,000 and the project is anticipated to be completed in 2019. HOL has minimized the controllable costs of this project by implementing a number of measures:

- A competitive Request For Proposal (RFP) process was used for determining consulting resources. These consultants are retained for a minimum 3 year timeframe to ensure that they are able to efficiently meet our needs and have a good understanding of HOL's internal processes and standards.
- All contractors and vendors are selected through a competitive RFP process. These contractors and vendors are pre-screened to ensure that they have the abilities and expertise to meeting the needs of HOL and are able to maintain timelines required.
- The use of in house project management allowed for efficient use of resources and experience from past projects within HOL. Project management best practices at HOL are based on PMI (Project Management Institute).
- Workforce planning is used to ensure internal resources requirements are identified early. If outside resources are required this is identified early in the project to ensure the roll out is implemented smoothly and efficiently.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| $0 | $0 | $0 | $0 | $0 | $0.139 | $3.315 | $10.42 | $2.269 | $1.40 |

Table 74 - Project Expenditures

### 1.7.3.3 *Benefits*

Key benefits that will be achieved by implementing the Richmond South DS project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to satisfy the upcoming load growth in the Richmond area. It is an essential system service project to supply the needed capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Re-constructing the station is the most cost-effective solution for supplying the required demand. |
| **Customer** | This project will achieve two objectives: to supply future demand and to improve reliability in the south-west of the city. Not only will development projects be given adequate electrical supply, but the upgraded station presents several opportunities to improve the system. This project will contribute to a larger system plan to convert the entire west area to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities: Richmond, Munster, Kanata, Stittsville and Barrhaven. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. Other projects have been planned to prepare the West area for this voltage conversion, including project 92010186 Richmond South Voltage Conversion – McBean, 92010188 Richmond South Voltage Conversion – Shea, 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, 92010926 Richmond South Voltage Conversion – Huntley, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. These related projects involve asset replacement, which further improves system reliability. |
| **Safety** | Upgrading the station will address the predicted thermal overload of existing feeders and station transformers that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Protection and control relays will be brought up to current HOL standards that reduce safety concerns as much as possible. |
| **Cyber-Security, Privacy** | N/A |

| | |
|---|---|
| **Co-ordination, Interoperability** | The new station will be supplied on the high side by Hydro One Networks Inc.'s 115kV transmission line, with provisions that this line may be upgraded to 230kV. The provincial utility has been heavily involved in the development of this project from the beginning, as it requires an upgraded transmission line. Both utilities will coordinate to ensure the success of this project, although construction details have not yet been decided. |
| **Economic Development** | This project will enable ongoing growth and development in the city as it will provide the necessary electrical supply. |
| **Environment** | The environmental impacts of a distribution station revolve around the station transformers. Oil containment will be included to eliminate environmental damage, should a transformer leak. |

**Table 75 - Project Benefits**

### 1.7.4 Prioritization

#### 1.7.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load by 2019. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new station feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience longer outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

#### 1.7.4.2 *Priority*

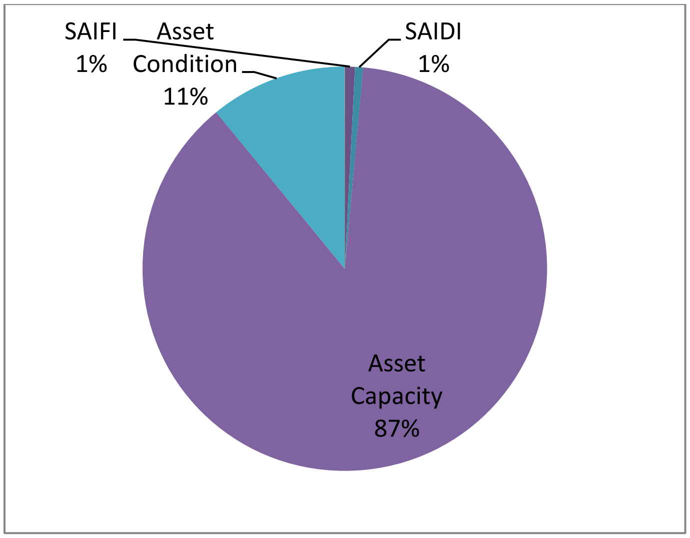



**Figure 73 - Project Avoided Risk**

Project Score = 0.822

### 1.7.5 Execution Path

#### 1.7.5.1 *Implementation Plan*

Phase 1, which will include all work and expenses to occur within 2015, includes preliminary design as well as Hydro One and IESO consultations.

Phase 2, which will include all work and expenses to occur within 2016, includes design completion and first progress payments for major equipment.

Phase 3, which will include all work and expenses to occur within 2017, includes the start of construction and arrival of major equipment. The 2017 construction will incorporate Hydro One re-constructing their dead-end structures within the station yard to allow for two taps to two 115/28/8.32kV lineups; all infrastructure required from the transmission tap to the distribution egress. All major civil work for one complete 115/28/8.32kV lineup will be completed as the existing 115/8.32kV lineup will be maintained until energization of the first 115/28/8.32kV lineup.

Phase 4, which will include all work and expenses to occur within 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/28/8.32kV lineup, removal of the existing 115/8.32kV lineup and completion of civil work and start of electrical construction for the second 115/28/8.32kV lineup.

Phase 5, which will include all work and expenses to occur within 2019, includes final commissioning of the second 115/28/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.

#### 1.7.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks include failing to get the following approvals: environmental assessment, IESO System Impact Assessment approval and City of Ottawa approval. Any delay from Hydro One Transmission upgrades, civil and electrical station design, delivery of all major equipment and completion of services would also be a risk to the ability to supply of the new growth. HOL will engage the stakeholders that could have an impact on these associated risks on a consistent basis to ensure that project milestones are met. Adjustments will be made as needed throughout the project to ensure timely completion to prevent thermal overloading of equipment.

#### 1.7.5.3 *Timing Factors*

Planned City development and Trans Canada's Energy East Pumping Station are the drivers for this project, and it is unlikely that the timing and priority of this project will change. It is necessary to supply the proposed load and there are no other feasible solutions to supply this load otherwise. If City or Trans Canada's developments are delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as site plans for new developments in the area have already begun to be submitted to HOL. For the timing and priority of this project to change, these developments would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

#### 1.7.5.4 *Cost Factors*

The tender process for major station equipment and labour services will also affect the final cost of the project. HOL typically takes the lowest bid and these costs will remain unknown until 2016.

#### 1.7.5.5 *Other Factors*

Trans Canada has recently filed their application with the National Energy Board for approval to construct their oil pipeline and pumping stations. There exists a risk that they will not be granted this approval and as a result HOL will require a letter of credit to ensure that the work required to supply them is paid for if they cannot meet their load expectations.

### 1.7.6 Renewable Energy Generation (if applicable)

While it is not expected that Richmond South DS itself will directly connect to any renewable energy generation sources, the transformers and station infrastructure will be purchased with reverse flow capability so that renewable energy generations can be connected to Richmond South DS feeders.

### 1.7.7 Leave-To-Construct (if applicable)

Not applicable.

### 1.7.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Richmond South DS |
| **Capital Cost:** | $17.657M |
| **O&M:** | $0 |
| **Start Date:** | 2015 – Q1 |
| **In-Service Date:** | 2019 – Q3 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 3,069 Customers/16,500kVA |

**Project Scope**

In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The two substations that supply Richmond and the surrounding area with 8.32kV are Richmond North DS and Richmond South DS which have a combined capacity of 11.72MVA. These two stations would not be capable of supplying the 20 year, 45MVA load forecast and as Richmond North DS is limited by its 44kV supply, Richmond South DS was identified for transformation upgrade. The decision for 27.6kV voltage conversion was driven by the limitation of 8.32kV to extend long distances and maintain adequate voltage levels, increased operability to transfer load to neighboring 27.6kV stations and by a single customer, Trans Canada, who are requesting a dedicated feeder to supply them 20MVA for their Energy East Pumping Station, located in the Richmond area.

**Work Plan**

Phase 1, to be complete in 2015, includes preliminary design as well as Hydro One and IESO consultations. Phase 2, to be complete in 2016, includes design completion and first progress payments for major equipment. Phase 3, to be complete in 2017, includes the start of construction and arrival of major equipment. Phase 4, to be completed in 2018, includes construction of the protection and control building, installation of switchgear in the building, electrical construction and commissioning of the first 115/28/8.32kV lineup. Phase 5, to be completed in 2019, includes final commissioning of the second 115/28/8.32kV lineup, clean-up and issuance of the final drawings and completion of all project closure procedures.

**Customer Impact**

Available distribution capacity to supply new loads for upcoming development
Reliability improvement associated with replacement of aging assets and equipment upgrades
Reduced outage durations with eventual backup supply

# 2 Line Extensions

## 2.1 TM1AH Capacity Upgrade

### 2.1.1 Project/Program Summary

HOL expects an increase in demand along Richmond Road and in the Westboro neighbourhood in the near future. This is due to the expected intensification along Richmond Road as described in the Richmond Road/Westboro Community Design Plan. In order to supply this new load, HOL has planned an underground line extension project in order to maximize the usefulness of an overhead circuit feeding this area.

### 2.1.2 Project/Program Description

#### 2.1.2.1 *Current Issues*

Currently, the existing circuit (TM1AH) consists of a section of underground cable which transitions to overhead for the remainder of the circuit. As of today the underground section is the limiting factor with a design capacity limit of 425 amps. However, the overhead circuit has a design rating of 600 amps. By installing a parallel underground cable and connecting it to the existing overhead circuit the full capacity of the circuit can be realized. Figure 74 below shows the load growth area (blue), the existing TM1AH circuit (red), the proposed parallel circuit (green), and the point of connection (yellow).

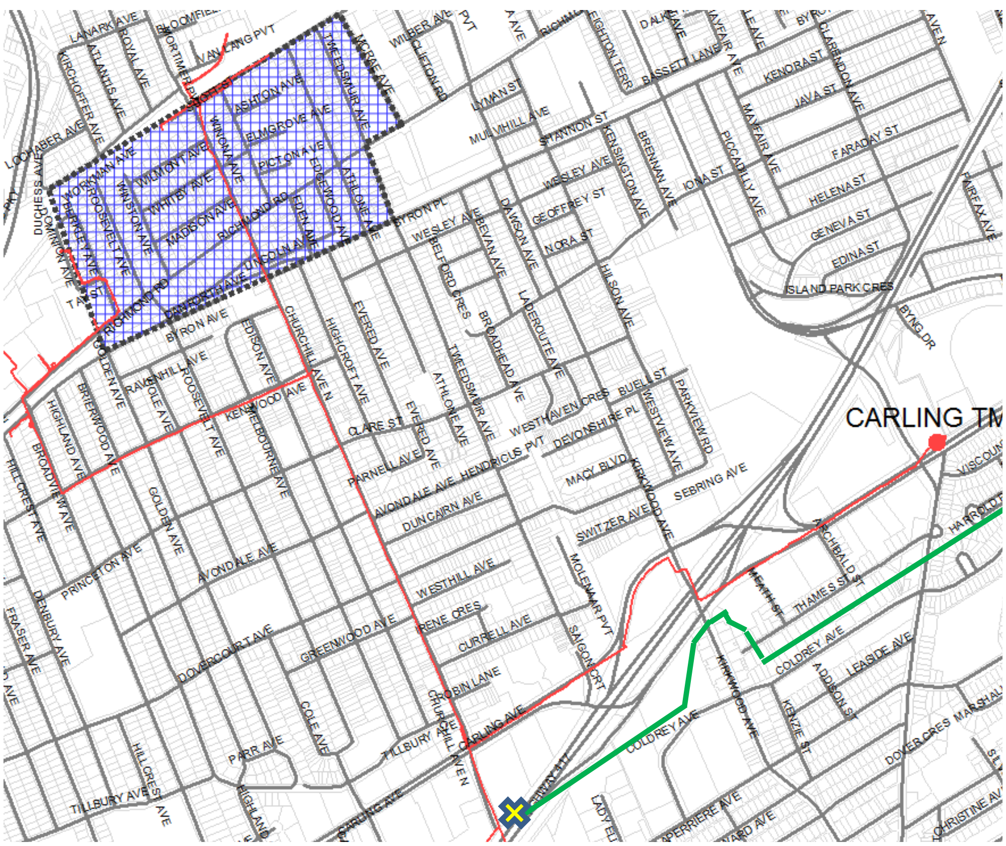



**Figure 74 - Proposed Parallel Circuit**

#### 2.1.2.2 *Project/Program Scope*

There is a currently existing civil structure installed along the desired route which is along Carling Avenue from Merivale Road (Carling TM Station) to Churchill Avenue North. The required material will consists of 1800 meters of 500MCM EPR cable, three overhead switches, and a new pole to be able to accommodate the cable`s transition from underground to overhead.

#### 2.1.2.3 *Main and Secondary Drivers*

The main driver behind this project is the anticipated load growth in the area fed by this circuit. Currently the existing circuits in the area are at their planned capacity. Therefore additional capability is needed.

#### 2.1.2.4 *Performance Targets and Objectives*

The main objective of this project is to increase the capacity in the Richmond Road/Westboro area. By installing a parallel cable from Carling TM substation to Churchill Avenue North and connecting into the existing overhead circuit an additional 175 amps (4MVA) of capacity can be realized.

### 2.1.3 Project/Program Justification

#### 2.1.3.1 *Alternatives Evaluation*

##### 2.1.3.1.1 Alternatives Considered

In order to meet the increasing demand along Richmond Road and in the Westboro area, two alternatives were considered:

1) Install parallel egress: In this scenario HOL will install 1800 meters of underground cable in parallel with the existing cable (TM1AH) to maximize the usefulness of the overhead portion of the circuit. This scenario will add 4MVA of capacity to the area at a relatively low cost due to the existing infrastructure.
2) Install a new looped circuit: In this scenario HOL will construct a new looped circuit to the area of demand which will provide 9.5MVA of capacity. This work would consist of installing ~7200 meters of conductor. Due to the limited civil structure in the area, ~1800 meters of duct bank would need to be installed; however, it is much more likely that this distance would be supplied via overhead circuitry. This in itself introduces new challenges such as upgrading current poles to account for the new load or acquiring easements for the installation of new poles.

##### 2.1.3.1.2 Evaluation Criteria

The main evaluation criteria used was the cost between the projects. However, disruption and safety concerns to the public and environmental impact were also considered. To ensure the alternatives were being evaluated equally the cost per MVA was calculated. The total project cost and cost per MVA are:

**Alternative 1: $888,216 & $222,054/MVA**

**Alternative 2: $3,728,501 & $392,474/MVA**

#### 2.1.3.1.3 Preferred Alternative

Due to the costs of the two options, Alternative 1 is more preferable than Alternative 2. By having the electrical capacity in the area, customer developments will be more likely to happen since there will not be a large system expansion cost associated with their project. The benefits of this project are explained in section 3.3. Alternative 1 also requires no civil work to be done. Therefore there is no need to dig up the sidewalk which on top of disturbing the environment creates a safety hazard. HOL mitigates these risks by applying best practices, but the ultimate mitigation technique is avoiding the risk altogether.

### 2.1.3.2 *Project/Program Timing & Expenditure*

This project is scheduled for implementation in 2016. However, there is the potential for demand work to advance the need date. At this point the cost will be transferred from the sustainment budget to the demand budget and an economic evaluation will be assessed. The expected timeline for the project will be six weeks to pull the cable through the existing duct structures and complete connections. Additionally, two weeks have been estimated for the work associated with a new pole.

In order to minimize costs HOL will tender for all necessary equipment. HOL will complete all labour required for the project in house, however, if resources are not available the work will be tendered.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | | | | | 0.998 | | | | |

**Table 76 - Project Expenditures**

### 2.1.3.3 *Benefits*

The main benefit of this project is the ability to supply a further 4MVA to the Richmond Road/Westboro area. This capacity will serve the anticipated near term future growth. By having the ability to supply load in this area it is expected to increase the likelihood of economic development. Finally, the operators will be able to load this circuit to a higher amount to serve other customers in the case of a fault on an interconnected circuit.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project allows HOL operators to more effectively use the circuit TM1AH to backup interconnected circuits if there is a fault on those circuits. |
| **Customer** | Due to the planning and proactive action taken by HOL through this project, future customers will have the electrical supply available within a timely manner up to the identified 4MVA. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | As a result of electrical capacity in the anticipated future customer's area, it is more likely that load will be willing to connect since there are no extensive costs for electrical supply. When there is a large cost to developers due to system expansion it can slow the willing connections and stall projects. This project will |

| | |
|---|---|
| | eliminate that problem. |
| **Environment** | N/A |

**Table 77 - Project Benefits**

### 2.1.4 Prioritization

#### 2.1.4.1 *Consequences of Deferral*

If this project is deferred it is expected that there will be insufficient capacity to supply new load in the area. Once a request for connection has been made HOL will be under a time constraint to provide power. The shortened time frame typically leads to increased costs. Also, due to the lack of current capacity and the cost of connection it is likely that a small demand customer will be unable to connect. This project will drive economic development in the Richmond Road/Westboro area.

#### 2.1.4.2 *Priority*

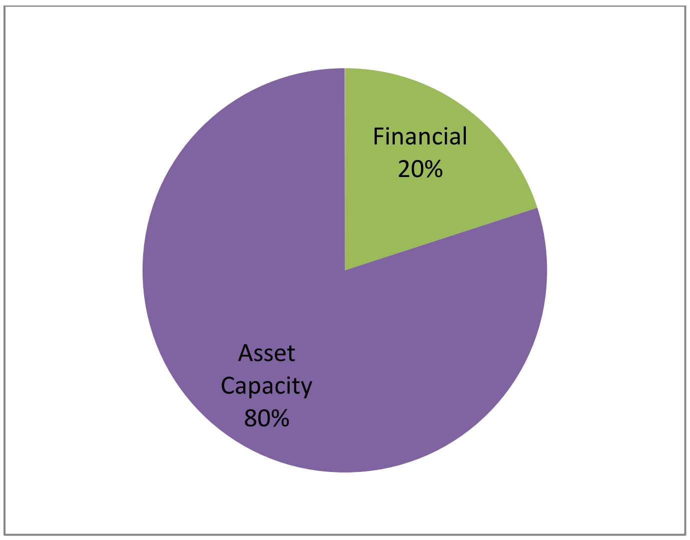



**Figure 75 - Project Avoided Risk**

Score = 0.3

### 2.1.5 Execution Path

#### 2.1.5.1 *Implementation Plan*

Due to the existing underground infrastructure there will be no need for additional easements or permits. The 1800 meters of 500 MCM EPR cable will be pulled through the duct bank from Carling substation to Churchill Avenue North by HOL underground crews. A new pole is required to install the additional equipment needed to connect this circuit. The stronger pole as well as the riser equipment and switch will be installed and the necessary plant will be transferred. Finally the cable will be terminated at the station. Currently, there are no open breakers at Carling substation which means the new cable will be hair pinned with an existing circuit. Therefore the relay protection for the chosen breaker will need to be updated. A scheduled outage will be necessary in order to safely connect the cable at the substation

#### 2.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project's objective is to provide additional capacity to the Richmond Road/Westboro area. However, there is the risk that more than 4MVA of capacity will be needed in the near term. If this is the case it may be necessary to install a new circuit to the area and this project will be put on hold. HOL will continue to monitor the area plans in order to quantify the need. There are, however, other risks that could affect this projects timeline and cost. These are further explained in the sections below.

#### 2.1.5.3 *Timing Factors*

This project is currently planned to be completed in 2016. However, if the demand materializes before that date it will need to be done earlier to meet the need.

There are not any foreseeable timing risks associated with the project work as the infrastructure is already in place.

#### 2.1.5.4 *Cost Factors*

If the project must be completed sooner than planned, due to demand, the cost could rise. This is the typical case due to resource constraints.

### 2.1.6 Renewable Energy Generation

N/A

### 2.1.7 Leave-To-Construct

N/A

### 2.1.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | TM1AH Capacity Upgrade |
| **Capital Cost:** | $0.88M |
| **O&M:** | N/A |
| **Start Date:** | Q1 2016 |
| **In-Service Date:** | Q4 2016 |
| **Investment Category:** | System Service |
| **Main Driver:** | Additional capacity need |
| **Secondary Driver(s):** | N/A |
| **Customer/Load Attachment** | Future customers will be affected by having the capacity to connect/ 4MVA worth of load |
| **Project Scope** | |
| There is a currently existing civil structure installed along the desired route which is along Carling Avenue from Merivale Road (Carling TM Station) to Churchill Avenue North. The required material will consists of 1800 meters of 500MCM EPR cable, three overhead switches, and a new pole to be able to accommodate the cable`s transition from underground to overhead. | |
| **Work Plan** | |
| Due to the existing underground infrastructure there will be no need for additional easements or permits. The 1800 meters of 500 MCM EPR cable will be pulled through the duct bank from Carling substation to Churchill Avenue North by HOL underground crews. A new pole is required to install the additional equipment needed to connect this circuit. The stronger pole will be installed and the necessary plant will be transferred as well as the ne riser equipment and switch installed. Finally the cable will be terminated at the station. Currently there are no open breakers at Carling substation which will cause the new cable to be hair pinned with an existing circuit. Therefore the relay protection for the chosen breaker will need to be updated. A scheduled outage will be necessary in order to safely connect the cable at the substation | |
| **Customer Impact** | |
| This project will allow for future customers to be connected due to the increase in capacity. The parallel cable will allow for an additional 4MVA of load to be supplied. | |

## 2.2 Alta Vista Tie

### 2.2.1 Project/Program Summary

This project will facilitate the interconnection of Overbrook TS, Russell TS and Riverdale TS in order to increase the flexibility of the system. It will allow the transfer of load from Overbrook TS and Russell TS which are approaching their maximum load capacity at peak.

This business case will describe the project, look at the alternatives considered to meet its objectives and provide an overview of the execution plan.

### 2.2.2 Project/Program Description

#### 2.2.2.1 *Current Issues*

Overbrook TS, Riverdale TS and Russell TS substations are currently poorly interconnected limiting the ability to provide system backup and transfer load. Overbrook TS and Russell TS are approaching their maximum load capacity at peak and will require capacity upgrades if load continues to grow.

Intensification with the development in the Terminal Lands will continue to grow, pushing the load capacity limit of Overbrook TS and Riverdale TS.

#### 2.2.2.2 *Assets in Scope*

The Riverdale TS feeder TR3UQ will then be extended 1.5km from Queens DS, along Riverside Drive to the intersection of Alta Vista Drive and Industrial Ave, terminating at a 4-way 3 position switch. The interconnecting circuits, Overbrook TS feeder 1802 and Russell TS feeder 5306, are located in close proximity to this intersection and will only require a minor extension to connect to the switchgear. The extension along Riverside Drive will require 480m of new concrete encased ducts and two (2) new manholes. The project will utilize existing duct structures where available.

#### 2.2.2.3 *Main and Secondary Drivers*

The main driver of this project is to support the expected changes in load to maintain the system's ability to provide consistent service delivery. This project will facilitate the transfer of load between Riverdale TS, Overbrook TS and Russell TS. This will enable the deferral of a station capacity upgrade by transferring the load to a station with available capacity.

As a secondary driver, this project will provide reliability benefits by allowing more flexibility when restoring customers from an interruption by interconnecting the circuits.

#### 2.2.2.4 *Performance Targets and Objectives*

The objective of this project will be to facilitate the transfer of load between the three (3) stations for reliability improvements and capacity planning to help defer investments.

### 2.2.3 Project/Program Justification

#### 2.2.3.1 *Alternatives Evaluation*

##### 2.2.3.1.1 Alternatives Considered

Riverdale TS, Overbrook TS and Russell TS are physically separated by the Rideau River and Highway 417 which limit the ability to create inter-station ties.

**Alternative #1:** Use existing feeders from Riverdale TS, Overbrook TS and Russell TS to connect to a common switching point.

Overbrook TS feeder 1802 and Russell TS feeder 5306 are located in close proximity at Industrial Ave and Sandford Fleming Ave.

**Alternative #2:** Use a new feeder from Riverdale TS or Russell TS to tie with an existing feeder from Overbrook TS.

##### 2.2.3.1.2 Evaluation Criteria

**Cost:**
Alternative #1: $1.658M

Alternative #2: $2.1M

**Ability to supply load:**
Alternative #1: The current circuit loading of all three circuits is such that any one (1) can take the entire loading of one (1) other circuit. This will provide the ability to off-load 3.4MVA from Overbrook TS or 2.7MVA from Russell TS onto Riverdale TS.

Alternative #2: With the extension of a new feeder from Riverdale TS, both Overbrook TS and Russell TS feeders can be supplied from Riverdale TS. This would result in the ability to transfer 6.1MVA to Riverdale TS. This alternative does not provide the opportunity to off-load from Riverdale TS.

**Reliability Benefits:**
Both options will provide the same interconnection between the stations in the area improving system flexibility to manage load and quickly restore power from unplanned outages.

##### 2.2.3.1.3 Preferred Alternative

Alternative #1 is the preferred alternative as it will meet the short-term needs of transferring load from Overbrook TS or Russell TS to Riverdale TS and will also allow flexibility with long-term load forecasts by transferring load away from Riverdale TS.

### 2.2.3.2 *Project/Program Timing & Expenditure*

| Historical ($k) | | | | | | Future ($k) | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| | | | | $929 | $729 | | | | |

**Table 78 - Project Expenditures**

#### 2.2.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project will improve system operations by interconnecting the 3 stations and provide the flexibility to transfer load between stations. |
| **Customer** | The customers connected to these circuits, which includes the Riverside Hospital, will see a reduction in time to restore power and also increased redundancy by being connected to multiple sources. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | HOL will coordinate part of this project with the City of Ottawa's Alta Vista Transportation Corridor (AVTC) project which affects the area around Queens DS. |
| **Economic Development** | N/A |
| **Environment** | N/A |

**Table 79 - Project Benefits**

### 2.2.4 Prioritization

#### 2.2.4.1 *Consequences of Deferral*

If this project is deferred, it may result in the inability of the system to manage new load effectively and create overload conditions.

#### 2.2.4.2 *Priority*

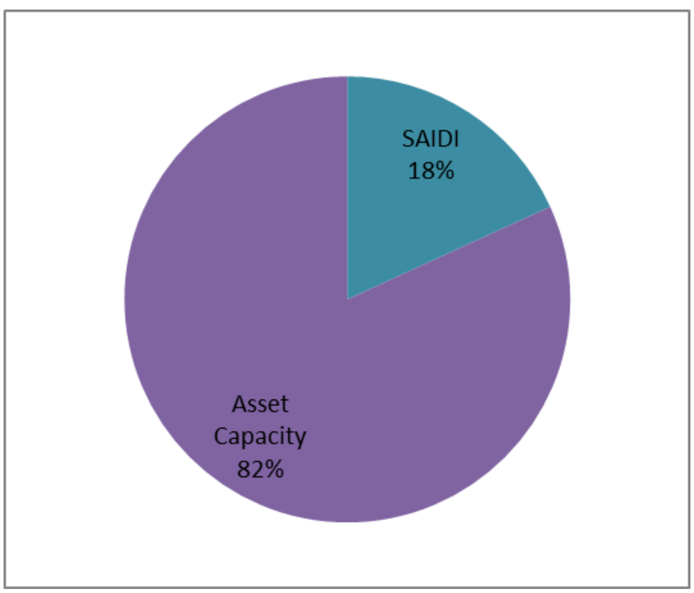



**Figure 76 - Project Avoided Risk**

Project Score: 0.88

### 2.2.5 Execution Path

#### 2.2.5.1 *Implementation Plan*
This project will begin in 2014 with the installation of civil works along Riverside Drive, Industrial Avenue, and Sandford Fleming Avenue. Civil works include the installation of 480m of new concrete encased ducts and two manholes. The purchase of the switchgear will also take place this year.

In 2015, feeder TR3AQ from Riverdale TS will be extended 1.5 km from Queens DS to Alta Vista Drive and connect to the newly installed switchgear. Lie-along feeders 5306 and 1802 from Russell TS and Overbrook TS will also be terminated to this switchgear.

#### 2.2.5.2 *Risks to Completion and Risk Mitigation Strategies*
Typical risks to completion include:

- Obtaining road cut permits from the City of Ottawa;
- Coordinating activities in areas where multiple parties are working;
- Getting approval for traffic plans where required

It is standard practice to engage early and communicate plans for future work with the City of Ottawa and residence to coordinate effort and potential resources.

#### 2.2.5.3 *Timing Factors*
Coordination with the City of Ottawa's Alta Vista Transportation Corridor (AVTC) project required that the civil structures around Queens DS be in place in order to remove the overhead structures by 2015.

#### 2.2.5.4 *Cost Factors*
A large part of the cost savings on this project is reliant on the use of existing duct structures along Riverside Drive. HOL will mitigate this risk by inspecting the duct structures well in advance of the cable installation to ensure the availability of ducts. If there is insufficient duct capacity, additional excavation and civil works will need to be completed prior to the cable installation.

#### 2.2.5.5 *Other Factors*
Not applicable.

### 2.2.6 Renewable Energy Generation (if applicable)
Not applicable.

### 2.2.7 Leave-To-Construct (if applicable)
Not applicable.

### 2.2.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Alta Vista Tie |
| **Capital Cost:** | $1.658M |
| **O&M:** | N/A |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 11.2 MVA |

**Project Scope**

This project will facilitate the interconnection of Overbrook TS, Russell TS and Riverdale TS in order to increase the flexibility of the system to transfer of load from Overbrook TS and Russell TS which are approaching their maximum load capacity at peak.

The Riverdale TS feeder TR3UQ will then be extended 1.5km from Queens DS, along Riverside Drive to the intersection of Alta Vista Drive and Industrial Ave, and terminating at a 4-way 3 position switch. The interconnecting circuits, Overbrook TS feeder 1802 and Russell TS feeder 5306, are located in close proximity to this intersection and will only require a minor extension to connect to the switchgear. The extension along Riverside Drive will require 480m of new concrete encased ducts and two (2) new manholes. The project will utilize existing duct structures where available.

**Work Plan**

This project will begin in 2014 with the installation of civil works along Riverside Drive, Industrial Avenue, and Sandford Fleming Avenue. Civil works include the installation of 480m of new concrete encased ducts and two manholes. The purchase of the switchgear will also proceed this year.
In 2015, feeder TR3AQ from Riverdale TS will be extended 1.5 km from Queens DS to Alta Vista Drive and connect to the newly installed switchgear. Lie-along feeders 5306 and 1802 from Russell TS and Overbrook TS will also be terminated to this switchgear.

**Customer Impact**

The customers connected to these circuits, which includes the Riverside Hospital, will see a reduction in time to restore and also increased redundancy by being connected to multiple sources.

## 2.3 Orleans TS Feeder

### 2.3.1 Project/Program Summary

Hydro One is constructing the new Orleans TS station. HOL has purchased one of the breakers at this station and will use this feeder to interconnect with Cyrville MTS and Bilberry TS to improve reliability and service new load from the development of the East Urban Community.

This business case will describe the project, look at the alternatives considered to meet objectives, and provide an overview of the execution plan.

### 2.3.2 Project/Program Description

#### 2.3.2.1 *Current Issues*

Bilberry TS feeders 77F2 & 77F6 are on HOL's worst feeders list for impact on reliability.

Cyrville MTS feeder CYRF3 has a long radial section extending out Renaud Road and Mer Bleue Road with no backup on this section.

The City of Ottawa has approved the development of the East Urban Community which expands North and South of Renaud Road and West of Mer Bleue Road.

#### 2.3.2.2 *Program/Project Scope*

This project will extend out a new feeder 2.3km from Hydro One's new Orleans TS along Mer Bleue Road to connect with Cyrville MTS feeder CYRF3 at Renaud Road and Bilberry TS feeder 77M2 North on Mer Bleue Road.

The project involves the installation of 500m of concrete encased ducts and XLPE cable, two (2) padmounted switchgear, 28 wood poles, and 1.8km of overhead conductor.

Also included in the cost of the project is the purchase of a breaker position at Hydro One's Orleans TS.

#### 2.3.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve reliability. Bilberry TS feeder 77M2 is one of HOL's worst performing feeders. Cyrville feeder CYRF3 is a long radial feeder in this area. This new feeder from Orleans TS will provide an integral backup to both these circuits.

The secondary driver is to provide the ability to service new customers in the East-Urban Development lands.

#### 2.3.2.4 *Performance Targets and Objectives*

The objectives of this project are to improve reliability on Bilberry TS feeder 77M2 as one of HOL's worst performing feeders and to prevent Cyrville MTS feeder CYRF3 from getting worse.

It's expected that these two feeders will see a significant reduction in interruption durations.

### 2.3.3 Project/Program Justification

#### 2.3.3.1 *Alternatives Evaluation*

##### 2.3.3.1.1 Alternatives Considered

**Alternative #1:**
Extend a new feeder from Orleans TS to connect with Cyrville MTS feeder CYRF3 and Bilberry TS feeder 77M2. This alternative would require the construction of the egress from Orleans TS and the infrastructure required to extend South on Mer Bleue Road.

This option would enable use of the new capacity available at Orleans TS.

**Alternative #2:**
Extend Cyrville MTS feeder CYRF3 North along Mer Bleue Road to connect with Bilberry feeder 77M2. This alternative will require the construction of infrastructure required to extend North on Mer Bleue Road to connect CYRF3 to 77M2.

This option would limit the available capacity for new load as both feeders are already loaded.

##### 2.3.3.1.2 Evaluation Criteria

**Costs:**
Alternative #1: $4,546,000

Alternative #2: $800,000

**Ability to service new load:**
Alternative #1: The connection of the Bilberry TS and Cyrville MTS feeders to the new Hydro One Orleans TS will allow for an additional 16MVA of capacity to supply new load.

Alternative #2: The connection of the Cyrville MTS and Bilberry TS feeders will only provide the ability to add 4MVA of new capacity to service new load which is insufficient for the projected 6MVA load required to service phase 1 of the East Urban community. To meet this loading requirement another line extension from Cyrville MTS would be required.

**Reliability:**
Alternative #1: Customer outage duration and frequency will be improved by having three (3) stations interconnected from multiple sources.

Alternative #2: Customer outage duration will be reduced by having two (2) stations connected together.

#### 2.3.3.1.3 Preferred Alternative

Alternative #1 is the preferred option as it will provide added reliability benefits to HOL's feeders. Orleans TS is ideally located to service the load growth in this area and will reduce the overall exposure to unplanned interruptions.

This option also meets the secondary objective which is to have a long-term service plan for the new growth in the area.

### 2.3.3.2 *Project/Program Timing & Expenditure*

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| | | | | 1.709 | 2.837 | | | | |

**Table 80 - Project Expenditures**

### 2.3.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project will improve system operation efficiency by interconnecting the new Orleans TS to Cyrville MTS and Bilberry TS which will provide an alternative source when restoring outages. |
| **Customer** | By integrating Orleans TS into the distribution system in South Orleans, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.<br><br>This project will also increase the available capacity in the area of Renaud Road and Mer Bleue Road for the upcoming developments to the North. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | This project will coordinate with the proposed City road alignment of Mer Bleue Road. |
| **Economic Development** | N/A |
| **Environment** | N/A |

**Table 81 - Project Benefits**

## 2.3.4 Prioritization

### 2.3.4.1 *Consequences of Deferral*

The deferral of this project would limit HOL's ability to purchase a breaker position in Hydro One's new Orleans TS and would necessitate looking at other alternatives to meet the objectives.

#### 2.3.4.2 *Priority*

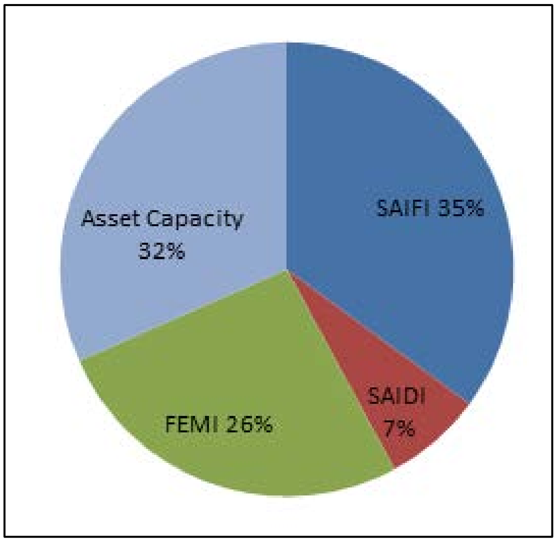



Figure 77 - Project Avoided Risk

Project Score: 0.76

### 2.3.5 Execution Path

#### 2.3.5.1 *Implementation Plan*

The project will begin with the purchase of the breaker position from Hydro One. Construction of the egress from the station will begin in 2014.

In 2015, the pole line will be extended South from Orleans TS, down Mer Bleue Road to Renaud Road. to make connection with CYRF3. The connection to 77M3 to the North of the station egress will also be completed.

#### 2.3.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 2.3.5.3 *Timing Factors*

This project is dependent on Hydro One completing the construction of Orleans TS.

#### 2.3.5.4 *Cost Factors*

Factors that can affect the costs of this project:

- Existing trees on the proposed feeder alignment,
- Finding rock when excavating pole holes,
- Acquiring easements on private property.

#### 2.3.5.5 *Other Factors*

Not applicable.

### 2.3.6 Renewable Energy Generation (if applicable)

Not applicable.

### 2.3.7 Leave-To-Construct (if applicable)

Not applicable.

### 2.3.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92009734 - Orleans TS Feeder |
| **Capital Cost:** | $4,546,000 |
| **O&M:** | $0 |
| **Start Date:** | 2014 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Capacity |
| **Customer/Load Attachment** | 28MVA |

**Project Scope**

This project will extend out a new feeder 2.3km from Hydro One's new Orleans TS along Mer Bleue Road to connect with Cyrville MTS feeder CYRF3 at Renaud Road and Bilberry TS feeder 77M2 North on Mer Bleue Road.
The project involves the installation of 500m of concrete encased ducts and XLPE cable, two (2) padmounted switchgear, 28 wood poles, and 1.8km of overhead conductor.
Also included in the cost of the project is the purchase of a breaker position at Hydro One's Orleans TS

**Work Plan**

The project will begin with the purchase of the breaker position from Hydro One. Construction of the egress from the station will begin in 2014.
In 2015, the pole line will be extended South from Orleans TS, down Mer Bleue Road to Renaud Road to make connection with CYRF3. The connection to 77M3 to the North of the station egress will also be completed.

**Customer Impact**

By integrating Orleans TS into the distribution system in South Orleans, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.

This project will also increase the available capacity in the area of Renaud Road and Mer Bleue Road for the upcoming developments to the North.

## 2.4 Fernbank Road Line Extension

### 2.4.1 Project/Program Summary

This project is to extend two feeders from Terry Fox MTS along Fernbank Road in order to facilitate the transfer of load from Hydro One's Alexander DS feeder ALEXF3 by 2016, support future growth along Fernbank Road, and support the connection of the TransCanada Ottawa East pumping station in 2017.

This business case will describe the project, look at the alternatives considered to meet objectives and provide an overview of the execution plan.

### 2.4.2 Project/Program Description

#### 2.4.2.1 *Current Issues*

Hydro One has requested that HOL transfer load from Hydro One's Alexander DS feeder ALEXF3 by 2016 in order for them to service upcoming developments to the North of Stittsville. The closest station that HOL could possibly transfer the load to is Janet King DS however this station does not have the capacity to support the load transfer.

The TransCanada Ottawa East pumping station is planned to be constructed in the South of Stittsville by 2017 and has requested HOL for a 10MW connection.

HOL's new Terry Fox MTS will be in service in 2014 and is well situated to support load growth in the South of Kanata and Stittsville. A line extension from this station would be ideal to support the short-term load transfer and future growth planned on the North side of Fernbank Road.

#### 2.4.2.2 *Project Scope*

The scope of this project is to extend two (2) 27.6kV feeders from Terry Fox Drive to Stittsville Main Street. The project will make use of the existing 8.32kV feeder where applicable by converting to 27.6kV to reduce cost.

Phase 1 includes a 1.7km line extension of two (2) circuits from Terry Fox Drive to Founder Road. This includes the installation of thirty (30) poles and the replacement of four (4) transformers to accommodate the change in voltage.

Phase 2 includes a 1.3km line extension of two (2) circuits from Founder Road to Shea Road. This included the installation of 21 poles and the replacement of six (6) transformers to accommodate the change in voltage.

Phase 3 includes a 1.5km line extension of two (2) circuits from Shea Road to Stittsville Main Street. This will include the installation of 4 new poles, reframing 25 poles to accommodate another circuit and replacing 11 transformers to accommodate the change in voltage.

#### 2.4.2.3 *Main and Secondary Drivers*

The main driver of this project is to support the expected changes in load to maintain the system's ability to provide consistent service delivery. Hydro One is requesting that HOL offload the Alexander DS ALEXF3 feeder by 2016 because of load growth in their service territory at the North end of Stittsville.

This project will also support upcoming load growth with the construction of the TransCanada Ottawa East pumping station in 2017.

The secondary driver of this project is to provide reliability benefits to the system in Kanata and Stittsville. These two new circuits will provide backup to four (4) other circuits in order to improve the flexibility of the system to quickly restore power.

#### 2.4.2.4 *Performance Targets and Objectives*

The main objectives of this project are to be in a position to offload Hydro One's feeder ALEXF3 by 2016 and support the upcoming development of the TransCanada Ottawa East pumping station in 2017.

Secondary objectives are to align with future City of Ottawa road widening of Fernbank Road to prevent the need to relocate poles at a future date and to improve system ties by connecting feeders between stations.

### 2.4.3 Project/Program Justification

#### 2.4.3.1 *Alternatives Evaluation*

##### 2.4.3.1.1 Alternatives Considered

Due to the timing requirements of this project, alternatives are limited. Surrounding stations do not have the station nor feeder capacity to support the load being added to the HOL system. A feeder extension from the newly constructed Terry Fox MTS station is the only feasible option.

**Alternative #1:** Routing considered is along Fernbank Road. This route would extend two feeders from Terry Fox Drive east along Fernbank Road to Stittsville Main Street.

This option is the most direct route to make feeder connection to offload ALEXF3. It would make use of the existing 8.32kV feeders along Fernbank Road by converting the services fed from it to 27.6kV and upgrading pole structures where necessary to allow for two feeder pole framing.

**Alternative #2:** Routing considered is along Flewellyn Road. This route would extend two feeders south on Terry Fox Drive from Fernbank Road to Flewellyn Road, west on Flewellyn Road to Stittsville Main Street, and then north on Stittsville Main Street.

This option would make use of the existing 8.32kV feeders along Flewellyn Road by converting the services fed from it to 27.6kV and upgrading pole structures where necessary to allow for two feeders. Many of the existing 8.32kV poles are undersized and will require upgrade to support two feeder pole framing.

##### 2.4.3.1.2 Evaluation Criteria

**Costs:**

Alternative #1: $1.533M

Alternative #2: $4.633M

**Ability to supply load:**
Alternative #1: Feeders will allow for the off-loading of ALEXF3, be in a good position to extend to the TransCanada pumping station, and support new growth on the North side of Fernbank Road.

Alternative #2: Feeders will allow for the off-loading of ALEXF3 and be in a good position to extend to the TransCanada pumping station. The City of Ottawa's urban boundary is Fernbank Road with upcoming planned developments on the north side of Fernbank Road it would be difficult to service this load with this route option.

**Reliability Benefits:**
Both options will provide the same interconnection between stations in the area improving system flexibility to manage load and quickly restore unplanned outages.

##### 2.4.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to lower costs and the ability to supply future load developments.

Alternative #2 would allow for better expansion to the TransCanada pumping station however it involves a much larger scope than alternative #1 due the number poles that would require upgrading to support the two new feeders and the number of transformers that would to be converted to 27.6kV.

### 2.4.3.2 *Project/Program Timing & Expenditure*

This project will start in 2012 and continue over 3 years.

| Historical ($k) | | | | | | Future ($k) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| | | 473 | 23 | 530 | 507 | | | | |

**Table 82 - Project Expenditures**

### 2.4.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project will improve system operation efficiency by interconnecting the new Terry Fox MTS to the distribution system in Stittsville and provide an alternative source when restoring outages. |
| **Customer** | By integrating Terry Fox MTS into the distribution system in Stittsville, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.<br><br>This project will also increase the available capacity in the area of Fernbank Road for the upcoming developments to the North. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | This project will coordinate with the City of Ottawa's plans to widen Fernbank Road. Poles will be set referencing the proposed plans so as to not interfere with the future road widening. |
| **Economic** | This project supports the connections to the TransCanada East Pipeline by |

| | |
|---|---|
| **Development** | servicing the Ottawa East pumping station. |
| **Environment** | N/A |

**Table 83 - Project Benefits**

### 2.4.4 Prioritization

#### 2.4.4.1 *Consequences of Deferral*

Deferring this project will result in the inability to transfer load from Hydro One's Alexander DS feeder ALEXF3 in 2016 which will in turn affect Hydro One's ability to utilize this feeder to connect future customers.

Another consequence of deferral is that it will delay the line extension needed to connect the TransCanada Ottawa East pumping station which is scheduled to be connected in 2017.

#### 2.4.4.2 *Priority*

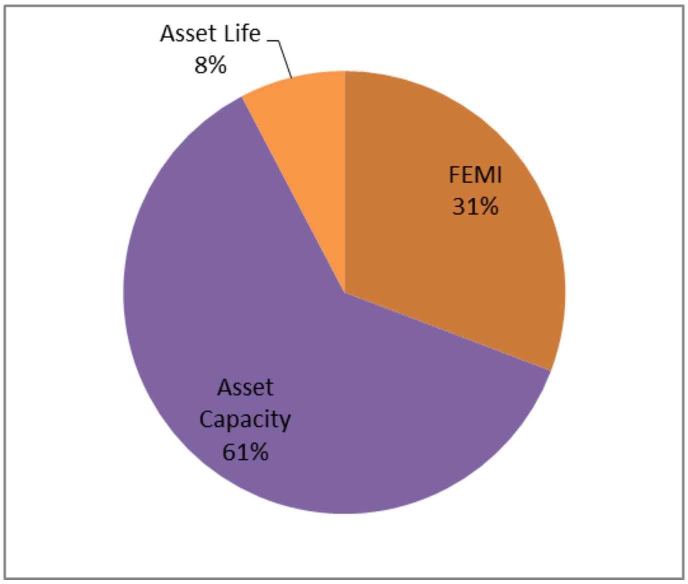



**Figure 78 - Project Avoided Risk**

Project Score: 0.39

### 2.4.5 Execution Path

#### 2.4.5.1 *Implementation Plan*

Phase 1 in 2012 included a 1.7km line extension of two (2) circuits from Terry Fox Drive to Founder Road. This includes the installation of thirty (30) poles and the replacement of four (4) transformers to accommodate the change in voltage. This will be coordinated to align with the City's proposed road widening.

Phase 2 in 2014 includes a 1.3km line extension of two (2) circuits from Founder Road to Shea Road. This included the installation of twenty-one (21) poles and the replacement of six (6) transformers to accommodate the change in voltage.

Phase 3 in 2015 includes a 1.5km line extension of two (2) circuits from Shea Road to Stittsville Main Street. This will include the installation of four (4) new poles, reframing twenty-five (25) poles to accommodate another circuit and the replacement of eleven (11) transformers to accommodate the change in voltage.

#### 2.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 2.4.5.3 *Timing Factors*

This project was dependent on the in-service date of Terry Fox MTS. With Terry Fox MTS now being complete and in-service, there are no more timing factors from this project.

The timing of the project is being driven by the requirement from HONI to offload Hydro One's Alexander DS feeder ALEXF3 by 2016 and the requirement to have a line in place to service the TransCanada Ottawa East pumping station by 2017.

#### 2.4.5.4 *Cost Factors*

Factors that can affect the costs of this project:

- Existing trees on the proposed feeder alignment,
- Finding rock when excavating pole holes,
- Acquiring easements on private property.

#### 2.4.5.5 *Other Factors*

Not applicable.

### 2.4.6 Renewable Energy Generation (if applicable)

Not applicable.

### 2.4.7 Leave-To-Construct (if applicable)

Not Applicable.

### 2.4.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92006253 - Fernbank Road Line Extension |
| **Capital Cost:** | $1.533M |
| **O&M:** | $0 |
| **Start Date:** | 2012 – Q1 |
| **In-Service Date:** | 2015 – Q4 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity Upgrade |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 2779 Customers |
| **Project Scope** | |
| The scope of this project is to extend two (2) 27.6kV feeders from Terry Fox Drive to Stittsville Main Road. The project will make use of the existing 8.32kV feeder where applicable by converting to 27kV to reduce cost. | |
| **Work Plan** | |
| 2012 – Phase 1: Starting from Terry Fox Drive to Founder Road<br>2014 – Phase 2: Founder Road to Shea Road<br>2015 – Phase 3: Shea Road to Stittsville Main Street | |
| **Customer Impact** | |
| By integrating Terry Fox TS into the distribution system in Stittsville, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly.<br><br>This project will also increase the available capacity in the area of Fernbank Road for the upcoming developments to the North. | |

## 2.5 West 44kV Line Extension

### 2.5.1 Project/Program Summary

The West 44kV Line Extension project is to extend the 22M25 Nepean TS 44kV feeder a distance of 20km to tie into the A9M3 South March TS 44kV feeder. The A9M3 sub-transmission line supplies 4 substations and does not have an alternate tie outside of the South March TS substation. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road and then along Fallowfield Road to Shea Road.

### 2.5.2 Project/Program Description

#### 2.5.2.1 *Current Issues*

Current issues in the West service territory include deteriorating reliability due to failure of aging infrastructure of the A9M3 44kV sub-transmission line. The A9M3 supplies two customers and four substations that account for 9500 customers and 33MVA peak load. The A9M3 has been identified as one of the top ten worst performing feeders in 2013 and in 2014. This feeder radially supplies these customers with no source of back-up, which prevents sectionalisation of line segments for routine maintenance and asset replacements. This has led to aging infrastructure that, upon failure, has no source of back-up which leads to prolonged outages.

#### 2.5.2.2 *Program/Project Scope*

The scope of this project is to extend one (1) 44kV circuit to tie Nepean TS to South March TS. This includes extending the 22M25 feeder from the corner of Moodie Drive and West Hunt Club Road to the corner of Fallowfield Road and Shea Road to tie with the A9M3 via West Hunt Club Road, Old Richmond Road and then Fallowfield Road. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road to Fallowfield Road. The 8.32kV line along Fallowfield Road will be constructed to allow for future voltage conversion to 27.6kV.

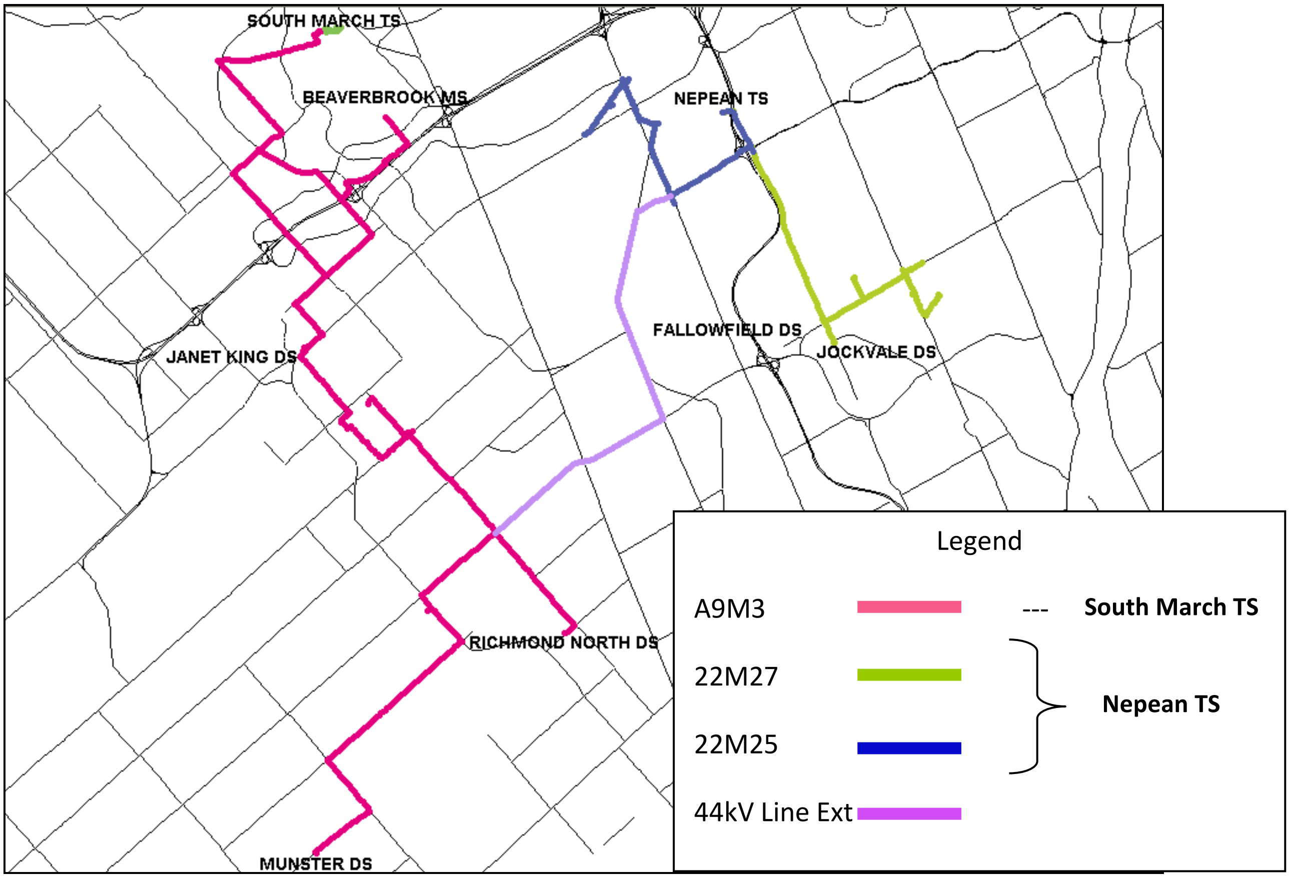



**Figure 79 - 44kV Line Extension Route**

Phase 1, which will include all work and expenses to occur within 2015, includes 3.6km line extension from the intersection of Moodie Drive and West Hunt Club Road to the intersection of Old Richmond Road and Hope Side Road. Extension of the 22M25 44kV feeder is the main focus of Phase 1, but the existing 8.32kV 47F6 and 145F3 feeders on the effected poles will have the conductor and insulators upgraded to allow for future capacity increases. Seventy-one (71) poles need to be replaced with taller poles in order to meet HOL standard clearances between circuits and road grade. A 44kV air break switch will be installed at the beginning of the line extension at the corner of Moodie Drive and West Hunt Club Road that will allow for circuit sectionalisation when required. Six (6) 8.32kV overhead transformers that are located along the affected pole line will be replaced to renew equipment approaching end of life condition. HOL anticipates clearance limitations when crossing beneath Hydro One's 500kV corridor along Old Richmond Road and has proposed shorter poles to accommodate the 22M25 44kV circuit and an underground concrete encased duct system to accommodate the 145F3 8.32kV circuit.

Phase 2, which will include all work and expenses to occur within 2016, includes a 2.1km line extension from the intersection of Hope Side Road and Old Richmond Road to the intersection of Old Richmond Road and Fallowfield Road. Extension of the 22M25 44kV feeder is the main focus of Phase 2, but the existing 145F3 8.32kV feeder on the effected poles will have the conductor and insulators upgraded to allow for future capacity increases. Also included on this pole line is an extension of the BRDF2 27.6kV circuit starting from Hope Side Road. A future project will extend FAL02 to the corner of Fallowfield Road and Old Richmond Road that will create a tie between Bridlewood MS and Fallowfield MTS. Seventy-two (72) poles require replacement with taller poles in order to meet HOL standard clearances between circuits and road grade. Fifteen (15) 8.32kV overhead transformers that are located along the effected pole line will be replaced to renew equipment approaching end of life condition. Within the village of Fallowfield these 15 transformers are located within proximity that amalgamation may be possible to reduce the number of transformers required. HOL anticipates that substantial tree trimming will be required in order to meet HOL conductor to tree clearance standards.

Phase 3, which will include all work and expenses to occur within 2017, includes a 4.7km line extension from the intersection of Old Richmond Road and Fallowfield Road to the intersection of Fallowfield Road and Shea Road. Extension of the 22M25 44kV feeder is the main focus of Phase 2, but the existing 145F3 8.32kV feeder on the effected poles will have the conductor and insulators upgraded to allow for future voltage conversion to 27.6kV and capacity increases. A future project will extend TFXF5 to the corner of Fallowfield Road and Eagleson Road that will create a tie between Terry Fox MTS and Fallowfield MTS. Seventy-five (75) poles require replacement with taller poles in order to meet HOL standard clearances between circuits and road grade. Eleven (11) 8.32kV overhead transformers that are located along the effected pole line will be replaced to renew equipment approaching end of life condition. The transformers will contain dual winding primaries that will allow them to be transferred to 27.6kV supply voltage. A 44kV Joslyn VBM automated switch will be installed at the connection point between the A9M3 and the 22M25 at the corner of Fallowfield Road and Shea Road that will allow for circuit transferability when required.

#### 2.5.2.3 *Main and Secondary Drivers*

The primary driver of this project is to provide an alternate sub-transmission supply to customers and substations supplied by A9M3. Reliability on this line has been deteriorating because there is no alternate source to facilitate maintenance and repairs. The A9M3 has been identified as one the top ten worst performing feeders in both 2013 and 2014. The completion of this project will provide a tie between the A9M3 and the 22M25, which will allow for sectionalization so that future work can be done on this line targeted to improve the feeder's reliability.

#### 2.5.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability on the A9M3. The alternate supply point will provide switchable means of supply during emergency situations that will directly improve SAIDI, but will also allow for sectionalization of sections with failing assets for replacement that will improve SAIFI.

Secondary objectives are to align with future City of Ottawa road widening of Old Richmond Road to prevent the need to relocate poles at a future date and to improve system ties by connecting feeders between stations.

### 2.5.3 Project/Program Justification

#### 2.5.3.1 *Alternatives Evaluation*

#### 2.5.3.1.1 Alternatives Considered

Capacity on the A9M3 exceeds the asset planning rating for circuits with an approximate load of 430 amps. There are limited alternative circuits that are loaded lightly enough to support the A9M3 circuit for contingency circumstances. The A9M4 from South March TS and 22M25 from Nepean TS are the only two circuits loaded lightly enough to support the A9M3. The cost implications of extending the A9M4 from its existing location would require extensive asset upgrades and re-routing of other circuits along the existing route. The cost analysis alone suggests the 22M25 circuit tie is the preferred alternative.

**Alternative #1:** Routing considered is along West Hunt Club Road, Old Richmond Road and Fallowfield Road. This route would extend the 22M25 from Nepean TS to tie the A9M3 South March TS.

This option is the most direct route to make feeder connections to improve reliability of the A9M3. It would make use of the existing 8.32kV routing along West Hunt Club Road, Old Richmond Road and Fallowfield Road that have assets approaching end of life condition.

**Alternative #2:** Routing considered is along Station Road, March Road, Eagleson Road and Fallowfield Road. This route would extend the A9M4 feeder east on Station Road, south on March Road and Eagleson Road and then west on Fallowfield Road to tie with the A9M3 at Shea Road.

This option would make use of the existing 44kV, 27.6kV and 8.32kV feeders along these routes and would require re-routing of 27.6kV and 8.32kV feeders to an underground system. This would be required to remain in compliance with HOL standards which limits the number of feeders on a pole to three (3) and dictates that 44kV remain overhead.

#### 2.5.3.1.2 Evaluation Criteria

**Costs:**
Alternative #1: $6.243M

Alternative #2: $7.880M

**Ability to supply load:**
Alternative #1: The 22M25 is loaded lightly enough to support the A9M3 for load transferability for construction and emergency circumstances.

Alternative #2: The A9M4 is loaded lightly enough to support the A9M3 for load transferability for construction and emergency circumstances.

**Reliability Benefits:**
Both options will provide improved reliability, however Alternative #1 allows for interconnection ties between South March TS and Nepean TS, whereas Alternative #2 allows for interconnections between two (2) feeders from the same substation.

#### 2.5.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to lower costs and the ability to support the A9M3 load. The interconnection ties between South March TS and Nepean TS will provide an improved level of reliability.

Alternative #2 would have the ability to support the A9M3 load, but expansion costs of the A9M4 comparatively to Alternative #1 are too expensive.

### 2.5.3.2 *Project/Program Timing & Expenditure*

The total project cost is $6,243,000 and the project is anticipated to start in 2015 and conclude in 2017. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| $0 | $0 | $0 | $0 | $0 | $2.141 | $1.995 | $2.107 | $0 | $0 |

**Table 84 - Project Expenditures**

### 2.5.3.3 *Benefits*

Key benefits that will be achieved by implementing the West 44kV Line Extension project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to improve the reliability of the A9M3 and creates an additional tie between South March TS and Nepean TS. It is an essential system service project needed to be capable of isolating sections of the A9M3 for asset replacement. System operation efficiency will be improved by the new automated switch that will allow for quick transferability from System Office during contingency circumstances. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. The construction of this line is the most cost-effective solution capable of improving the reliability of the A9M3 feeder. |
| **Customer** | This project will achieve reliability improvements for customers supplied by the A9M3 sub-transmission line. The alternate supply will allow for sectionalisation that had been previously not been available, in order to complete routine maintenance and asset replacements. The alternate supply and automated switches will directly help to improve the impact on SAIDI and future projects that will be permitted as a result of completion of this project will allow for renewed infrastructure that will ultimately improve SAIFI. |
| **Safety** | The infrastructure in place today is beginning to approach end of life and poses a small risk of failure and safety concern. By renewing the infrastructure, the safety risk is significantly reduced. |
| **Cyber-Security, Privacy** | Not Applicable. |
| **Co-ordination, Interoperability** | This project will coordinate with the City of Ottawa's plans to widen Old Richmond Road.  Poles will be set referencing the proposed plans as to not |

| | |
|---|---|
| | interfere with the future road widening. |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, it will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project. |
| **Environment** | Not Applicable. |

**Table 85 - Project Benefits**

### 2.5.4 Prioritization

#### 2.5.4.1 *Consequences of Deferral*

Deferring this project will result in further deterioration of infrastructure that currently supports the A9M3. The reliability of this feeder can be expected to continue to deteriorate, which contributes highly to the total system reliability statistics due to the number of customers the A9M3 supplies.

#### 2.5.4.2 *Priority*

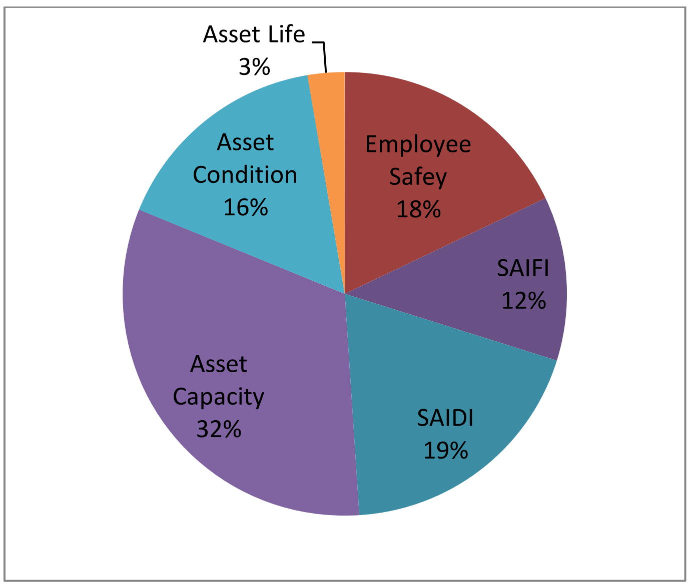



**Figure 80 - Project Avoided Risk**

Project Score: 1.117

### 2.5.5 Execution Path

#### 2.5.5.1 *Implementation Plan*

Phase 1 in 2015 includes a 3.6km line extension of the 22M25 feeder from Moodie Drive to Hope Side Road via West Hunt Club Road and Old Richmond Road. This includes the replacement of seventy-one (71) poles, six (6) transformers and installation of 120m of underground infrastructure to accommodate the 8.32kV circuit in order to meet the clearances required under the Hydro One 500kV tower line. This will be coordinated to align with the City's proposed road widening.

Phase 2 in 2016 includes a 2.1km line extension of the 22M25 and BRDF2 feeders from Hope Side Road to Fallowfield Road. This includes the replacement of seventy-two (72) poles and fifteen (15) transformers.

Phase 3 in 2017 includes a 4.7km line extension of the 22M25 and BRDF2 feeders from Old Richmond Road to Shea Road. This will include the replacement of seventy-five (75) poles, and eleven (11) transformers to accommodate the change in voltage.

#### 2.5.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 2.5.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions. Other factors that may affect the timing of this project include on-going work with the City of Ottawa to establish the future road cross sections and roundabouts expected to be installed along West Hunt Club Road and Old Richmond Road in 2015/2016.

#### 2.5.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

#### 2.5.5.5 *Other Factors*

Not applicable.

### 2.5.6 Renewable Energy Generation (if applicable)

Not applicable.

### 2.5.7 Leave-To-Construct (if applicable)

Not applicable.

### 2.5.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92008531 – West 44kV Line Extension |
| **Capital Cost:** | $6.243M |
| **O&M:** | $0 |
| **Start Date:** | 2015 – Q3 |
| **In-Service Date:** | 2017 – Q4 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | Aging Infrastructure |
| **Customer/Load Attachment** | 9500 Customers/33,000kVA |

**Project Scope**

The West 44kV Line Extension project is to extend the 22M25 Nepean TS 44kV feeder a distance of 20km to tie into the A9M3 South March TS 44kV feeder. The A9M3 sub-transmission line supplies 4 substations and does not have an alternate tie outside of the South March TS substation. The conductor and insulators of the 47F6 Belles Corners DS 8.32kV feeder along West Hunt Club Road and the 145F3 Jockvale DS 8.32kV feeder along Old Richmond Road will be upgraded to allow for increased capacity and provide renewed infrastructure. Services in the village of Fallowfield along Old Richmond Road will be replaced and amalgamated where possible to improve street aesthetics. The BRDF2 Bridlewood MS 27.6kV feeder will be extended starting from the corner of Hope Side Road and Old Richmond Road along Old Richmond Road and then along Fallowfield Road to Shea Road.

**Work Plan**

Phase 1, to be complete in 2015, includes a 3.6km line extension of the 22M25 feeder by replacement of seventy-one (71) poles, six (6) transformers and installation of 120m of underground infrastructure to accommodate the 8.32kV circuit in order to meet the clearances required under the Hydro One 500kV tower line. Phase 2, to be completed in 2016, includes a 2.1km line extension of the 22M25 and BRDF2 feeders by replacement of seventy-two (72) poles and fifteen (15) transformers. Phase 3, to be completed in 2017, includes 4.7km line extension of the 22M25 and BRDF2 feeders by replacement of seventy-five (75) poles, and eleven (11) transformers to accommodate the change in voltage.

**Customer Impact**

By integrating 22M25 and A9M3 feeders with automated switches into the distribution system, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Richmond, Stittsville and Kanata areas for the upcoming developments.

## 2.6 Springbrook Drive Trunk

### 2.6.1 Project/Program Summary

The Springbrook Drive Trunk project is intended to extend an underground trunk system along Springbrook Drive from Hazeldean Road to Abbott Street. The exiting trunk system that supplies this neighbourhood is located in areas inaccessible for the majority of the year and has not received adequate required maintenance and has resulted in a number of outages due to failed equipment, which was ranked in the top ten of worst performing feeders in 2014. The intent is to remove the existing pole line upon completion of the underground trunk system. Changes from the distribution layout are expected to improve operability through improved trunk ties and by isolation of three-phase customers from single-phase customers onto separate loop systems. The conclusion of the Springbrook Drive Trunk project will directly connect to 92010176 – Abbott Street Trunk project for the purposes of improved system operability.

### 2.6.2 Project/Program Description

#### 2.6.2.1 *Current Issues*

Current issues in the Stittsville community include deteriorating reliability due to failure of aging infrastructure. The community supply design was not constructed with adequate means of a trunk system that would allow for transferability amongst feeders. The duration of outages (SAIDI) has been greatly impacted as a result. Distribution loops in this area contain single phase and three phase transformers, which have required single phase switching to be completed and has resulted in three phase transformer failures due to ferroresonce.

#### 2.6.2.2 *Program/Project Scope*

The scope of this project is illustrated below, which is to extend one (1) 27.6kV circuit from to tie JKGF5 to JKGF4 and incorporate changes to the distribution layout to enhance operability. This includes extension through the use of a concrete duct system to encase trunk cables and through the use of two (2) switchgears, separate the three-phase customers, from single-phase customers, onto a dedicated three-phase loop. The trunk system will start at Hazeldean Road; continue south along Springbrook Drive and Moss Hill Trail to Abbott Street where the trunk will tie in with the Abbott Street Trunk project, which will be completed in 2016. As part of this project the old trunk system which is inaccessible for the majority of the year will be removed. This pole line contains seventeen (17) poles that will be removed upon completion of the underground system. Also being removed is a switchgear supplied off of the overhead system, which can be removed through minor cable work and single-phase transformer phase changes.

Phase 1, which will include all work and expenses to occur within 2016, includes 0.9km of concrete encased cable extensions from the intersection of Hazeldean Road and Springbrook Drive to approximately the intersection of Springbrook Drive and Earl Rock Way. The extent of Phase 1 is at the installation of the second switchgear and an isolated loop will be created between switchgears for the two (2) three-phase customers. Two (2) primary pedestals are located within the distribution along Springbrook Drive and their locations will be used to locate switchgears.

Phase 2, which will include all work and expenses to occur within 2017, includes 1.0km of concrete encased cable extension from the intersection of Springbrook Drive and Earl Rock Way to the intersection of Moss Hill Trail and Abbott Street. The concrete duct will commence at the location of the second switchgear from Phase 1 and extend to tie in on Abbott Street with the Abbott Street Trunk project. Approximately 730m of direct buried duct and cable will be required which will allow for the removal of 2 primary pedestals that do not provide adequate switching and protection capability and have also reached end of life condition. A change of phase for nine (9) transformers will enable the removal of a switchgear, which will no longer serve a purpose and contribute to saving in operating and maintenance costs. Seventeen (17) poles from the aging pole line will be removed upon completion of the underground trunk system.

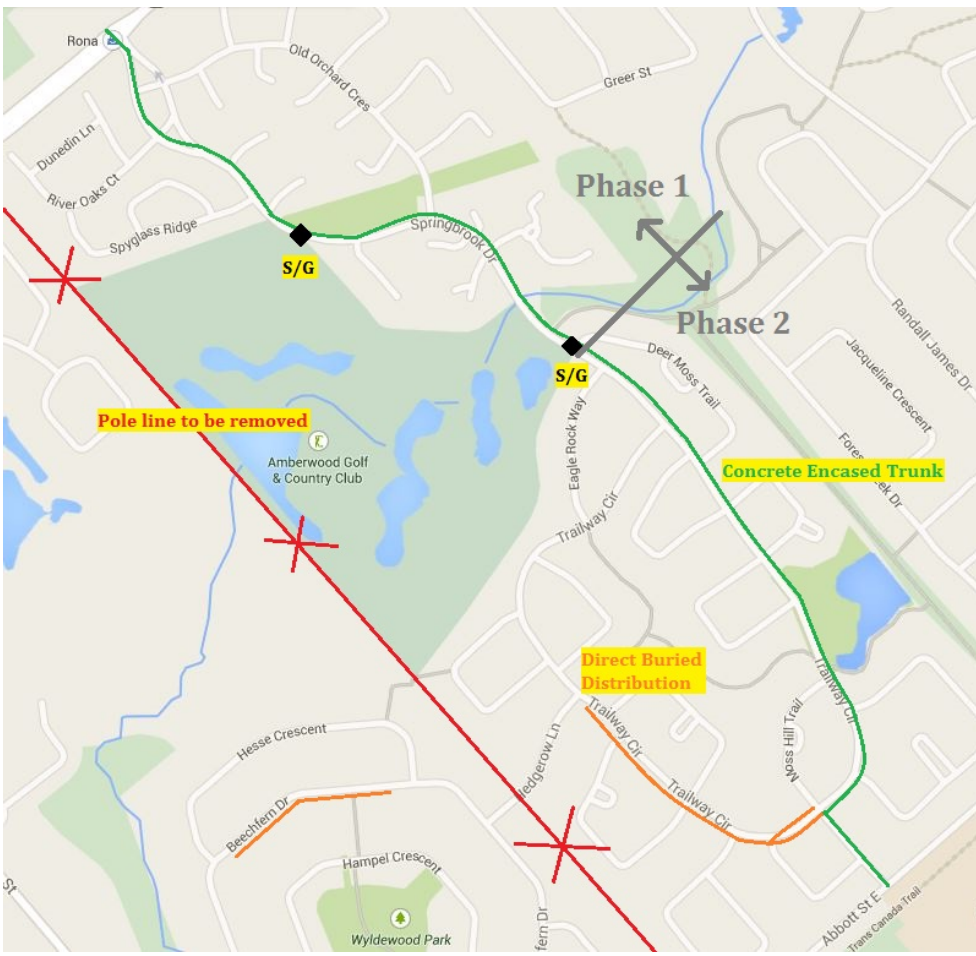



Figure 81 - Springbrook Drive Trunk Scope

### 2.6.2.3 *Main and Secondary Drivers*

The main driver of this project is the improvement of reliability in the Amberwood community. The ALXF3 which is the main supply system for this community is from an overhead pole line that is inaccessible for the majority of the year and has been accountable for a number of outages caused by defective equipment. The ALXF3 has been identified as one of the top ten worst performing feeders in 2014. Renewed infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

The secondary driver of this project is the improvement of system operability by separating the three phase transformers from the single phase transformers. When required, isolation becomes simple and eliminates the possible impacts of ferroresonce.

#### 2.6.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability in the Amberwood community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

A secondary objective is to remove an overhead pole line that supports the ALXF3 feeder which has proven to be historically unreliable.

### 2.6.3 Project/Program Justification

#### 2.6.3.1 *Alternatives Evaluation*

##### 2.6.3.1.1 Alternatives Considered

Reliability in the Amberwood community has been greatly impacted by the aging infrastructure of the existing pole line and the inaccessibility of the lines has contributed to deteriorating levels of SAIDI. New accessible infrastructure on the street boulevard is the most effective means of improving reliability.

**Alternative #1:** Routing considered is along Springbrook Drive. This route would extend the JKGF5 from Hazeldean Road to Abbott Street. This option is the most direct route to make feeder connection to improve reliability in the Amberwood community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

**Alternative #2:** Routing considered is along the existing pole line route. This route would replace the existing poles and infrastructure through the backyards and swamp from Hazeldean Road to Abbott Street. Renewed infrastructure would immediately improve SAIFI however due to the inaccessibility of the pole line throughout much of the year any outage would contribute greatly to increased SAIDI. Aging infrastructure and system operability would continue to be an issue.

##### 2.6.3.1.2 Evaluation Criteria

**Costs:**
Alternative #1: $2.363M

Alternative #2: $1.360M

**Ability to supply load:**
Both alternatives will make it possible to continue to supply load, however system operability will be enhanced by Alternative #1.

**Reliability Benefits:**
Alternative #1: New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

Alternative #2: Renewed infrastructure would immediately improve SAIFI however due to inaccessibility of the pole line throughout much of the year any outage would contribute greatly to increased SAIDI.

#### 2.6.3.1.3 Preferred Alternative

Alternative #1 is the preferred feeder route due to reliability benefits associated with this alternative. The costs associated with Alternative #2 are considerably cheaper however the reliability of the Amberwood community is the primary driver of this project and would be better served by Alternative #1.

### 2.6.3.2 *Project/Program Timing & Expenditure*

The total project cost is $2,363,000 and construction is anticipated to start in 2016 and conclude in 2017. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| $0 | $0 | $0 | $0 | $0 | $0 | $0.99 | $1.373 | $0 | $0 |

**Table 86 - Project Expenditures**

### 2.6.3.3 *Benefits*

Key benefits that will be achieved by implementing the Springbrook Drive Trunk project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is a necessary step to improve reliability in the Amberwood community. It is an essential system service project needed in order to improve system operation efficiency by constructing a trunk system with automated switchgear that will provide alternative sources when restoring outages. This should inevitably contribute to reducing SAIDI. Construction of the Springbrook Drive Trunk system is not the most cost-effective solution; however, it has the greatest benefit for improving the reliability in the Amberwood community. |
| **Customer** | This project will achieve reliability improvement for customers in the Amberwood community. The trunk extension and connection with 92010176 - Abbott Street Trunk created a four (4) feeder tie from Terry Fox MTS and Janet King DS which will directly help to improve the impact on SAIDI and renewed infrastructure that will ultimately improve SAIFI. |
| **Safety** | The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By removing the failing infrastructure, the safety risk is eliminated. |
| **Cyber-Security, Privacy** | Not Applicable. |
| **Co-ordination, Interoperability** | Not Applicable. |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used |

| | |
|---|---|
| | extensively to complete the project. |
| **Environment** | Not Applicable. |

**Table 87 - Project Benefits**

### 2.6.4 Prioritization

#### 2.6.4.1 *Consequences of Deferral*

Deferring this project will result in further deterioration of infrastructure that currently supports the ALXF3 circuit. The reliability of this feeder can be expected to continue to degrade, which contributes highly to the total system reliability statistics due to the number of customers the ALXF3 circuit supplies.

#### 2.6.4.2 *Priority*

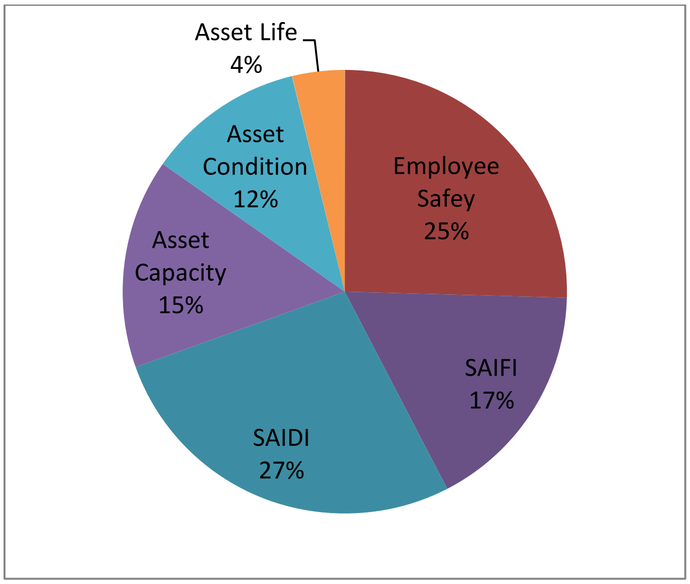



**Figure 82 - Project Avoided Risk**

Project Score: 0.997

### 2.6.5 Execution Path

#### 2.6.5.1 *Implementation Plan*

Phase 1 in 2016 includes a 0.9km line extension of the JKGF5 feeder from Hazeldean Road to Earl Rock Way via Springbrook Drive. This includes 900m of concrete duct encased cable, two (2) new automated switchgears and removal of two (2) end of life condition primary pedestals.

Phase 2 in 2017 includes a 1.0km line extension of the JKGF5 feeder from Earl Rock Way to Abbott Street via Springbrook Drive and Moss Hill Trail. This includes 1000m of concrete encased cable, 730m of direct buried duct encased cable, changing the phase configuration of nine (9) transformers, removal of one (1) switchgear and removal of seventeen (17) poles that are at end of life condition.

#### 2.6.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 2.6.5.3 *Timing Factors*
Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

#### 2.6.5.4 *Cost Factors*
Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

#### 2.6.5.5 *Other Factors*
Not applicable.

### 2.6.6 Renewable Energy Generation (if applicable)
Not applicable.

### 2.6.7 Leave-To-Construct (if applicable)
Not applicable.

### 2.6.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92010174 – Springbrook Drive Trunk |
| **Capital Cost:** | $2.363M |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q2 |
| **In-Service Date:** | 2017 – Q3 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | System Operability |
| **Customer/Load Attachment** | 2779 Customers/11,187kVA |

**Project Scope**

The Springbrook Drive Trunk project is intended to extend an underground trunk system along Springbrook Drive from Hazeldean Road to Abbott Street. The exiting trunk system that supplies this neighbourhood is located in areas inaccessible for the majority of the year and has not received adequate required maintenance and has resulted in a number of outages due to failed equipment, which was ranked in the top ten of worst performing feeders in 2014. The intent is to remove the existing pole line upon completion of the underground trunk system. Changes from the distribution layout are expected to improve operability through improved trunk ties and by isolation of three-phase customers from single-phase customers onto separate loop systems. The conclusion of the Springbrook Drive Trunk project will directly connect to 92010176 – Abbott Street Trunk project for the purposes of improved system operability.

**Work Plan**

Phase 1, to be completed in 2016, includes 0.9km of concrete encased cable extension, installation of two (2) automated switchgears and an isolated loop will be created between switchgears for the two (2) three-phase customers. Phase 2, to be completed in 2017, includes 1.0km of concrete encased cable extension, approximately 730m of direct buried duct and cable, removal of 2 primary pedestals, a change of phase for nine (9) transformers and removal of seventeen (17) poles and a switchgear upon completion of the underground trunk system.

**Customer Impact**

By integrating new infrastructure and automated switchgear into the distribution system in Stittsville, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Stittsville area for the upcoming developments.

## 2.7 Abbott Street Trunk

### 2.7.1 Project/Program Summary

The Abbott Street Trunk project is intended to extend a part overhead and part underground trunk system along Abbott Street from Stittsville Main Street to Shea Road. This project will tie together four (4) projects that are targeted specifically to improve reliability in the Stittsville community. These four projects include:

- 92008567 – Stittsville Main Cable Replacement & S/G Upgrades,
- 92010174 – Springbrook Drive Trunk,
- 92008535 – GRC 44 to 27,
- 92010178 – Granite Ridge Trunk

Through the completion of the Abbott Street Trunk and tying of these four (4) projects, the Stittsville community will have a mesh network trunk system that will reduce the number of customers between protective devices (SAIFI) and provide improved system operability that will allow for a reduction to the duration of outages (SAIDI). This will strengthen ties between Janet King DS and Terry Fox MTS which includes connections amongst four (4) feeders: JKGF4, JKGF5, TFXF1 and TFXF5.

### 2.7.2 Project/Program Description

#### 2.7.2.1 *Current Issues*

Current issues in the Stittsville community include deteriorating reliability due to failure of aging infrastructure. The community supply design was not constructed with adequate means of a trunk system that would allow for transferability amongst feeders. The duration of outages (SAIDI) has been greatly impacted as a result.

#### 2.7.2.2 *Program/Project Scope*

The scope of this project is illustrated below in Figure 83, which is to extend one (1) 27.6kV circuit from to tie Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles and two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through a concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

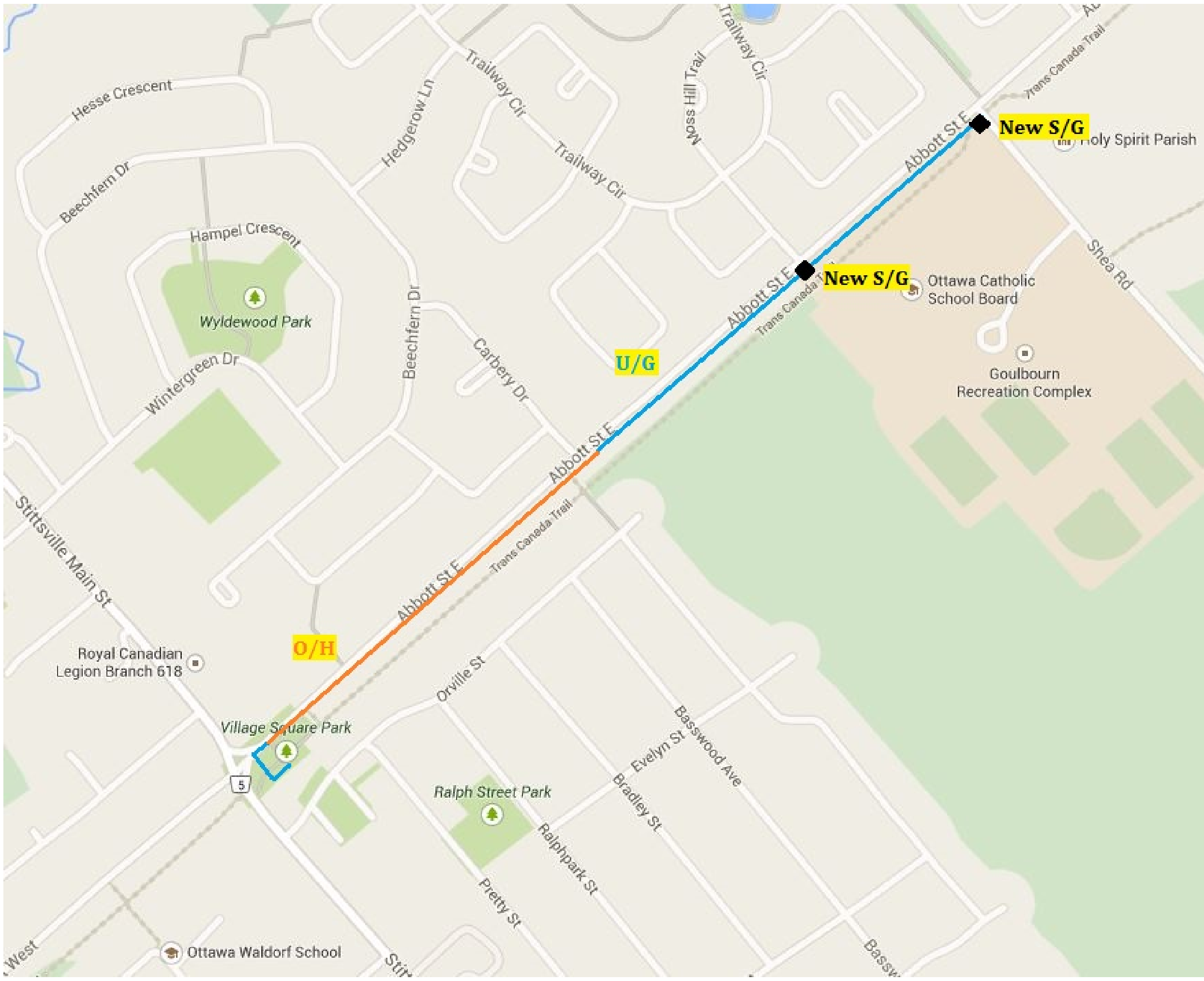


Figure 83 - Abbott Street Trunk Scope

### 2.7.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve reliability in the Stittsville community. Through various trunk extension projects and tying them all together via the Abbott Street Trunk project, extensive trunk ties will be created between four (4) feeders from Janet King DS and Terry Fox. Renewed infrastructure will directly improve SAIFI and automated switchgears will allow for monitoring and control that will directly reduce the impact on SAIDI.

### 2.7.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve reliability in the Stittsville community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will directly reduce the impact on SAIDI.

## 2.7.3 Project/Program Justification

### 2.7.3.1 *Alternatives Evaluation*

##### 2.7.3.1.1 Alternatives Considered
Reliability in the Stittsville community has been greatly impacted by the aging infrastructure. On-going trunk upgrades have been initiated to improve the service the customers have historically experienced.

**Alternative #1:** Routing considered is along Abbott Street. This route would extend the JKGF4 feeder from Stittsville Main Street to Shea Road. This option is the most direct route to make a feeder connection to improve reliability in the Stittsville community. New infrastructure will directly improve SAIFI and automated switchgear will allow for monitoring and control that will allow for fast transferability amongst four (4) feeders which directly reduces the impact on SAIDI.

**Alternative #2:** This alternative is to not proceed with the project. By not proceeding with this project there are no costs however reliability will be greatly impacted by leaving Stittsville Main Cable Replacement & S/G Upgrades, Springbrook Drive Trunk, GRC 44 to 27, and Granite Ridge Trunk as radially complete projects with no interconnection ties.

##### 2.7.3.1.2 Evaluation Criteria
**Costs:**
Alternative #1: $1.023M

Alternative #2: $0.00

**Ability to supply load:**
The area surrounding Abbott Street has been fully developed and has adequate means of supplying the existing load.

**Reliability Benefits:**
Alternative #1: Tying together Stittsville Main Cable Replacement & S/G Upgrades, Springbrook Drive Trunk, GRC 44 to 27, and Granite Ridge Trunk projects will directly improve SAIFI. Automated switchgear will allow for monitoring and control that will allow for fast transferability amongst four (4) feeders directly reducing the impact on SAIDI.

Alternative #2: This alternative has no reliability benefits.

##### 2.7.3.1.3 Preferred Alternative
Alternative #1 is the preferred feeder route due to reliability benefits associated with this alternative. The costs associated with Alternative #2 are considerably less costly; however, the reliability of the Stittsville community is the primary driver of this project and would be better served by Alternative #1.

#### 2.7.3.2 *Project/Program Timing & Expenditure*
The total project cost is $1,023,000 and it is anticipated to be completed in 2016. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| $0 | $0 | $0 | $0 | $0 | $0 | $1.023 | $0 | $0 | $0 |

**Table 88 - Project Expenditures**

#### 2.7.3.3 *Benefits*

Key benefits that will be achieved by implementing the Abbott Street Trunk project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to improve reliability in the Stittsville community. It is an essential system service project needed in order to improve system operation efficiency by interconnecting the new Terry Fox TS to the distribution system in Stittsville and provide an alternative source when restoring outages. This should inevitably contribute to reducing SAIDI. Construction of the Abbott Street Trunk system is not the most cost-effective solution; however, it has the greatest benefit for improving the reliability in the Stittsville community. |
| **Customer** | This project will achieve reliability improvements for customers in the Stittsville community. The trunk extension and tying together of four (4) feeders from Terry Fox MTS and Janet King DS will directly help to improve the impact on SAIDI and renewed infrastructure that will ultimately improve SAIFI. |
| **Safety** | The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the safety risk is significantly reduced. |
| **Cyber-Security, Privacy** | Not Applicable. |
| **Co-ordination, Interoperability** | Not Applicable. |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project. |
| **Environment** | Not Applicable. |

**Table 89 - Project Benefits**

### 2.7.4 Prioritization

#### 2.7.4.1 *Consequences of Deferral*

The consequence of deferring this project is the further deterioration of infrastructure that currently supplies the Stittsville community. Reliability for this area can be expected to continue to deteriorate, which contributes highly to the total system reliability statistics due to the number of customers in the community.

#### 2.7.4.2 *Priority*

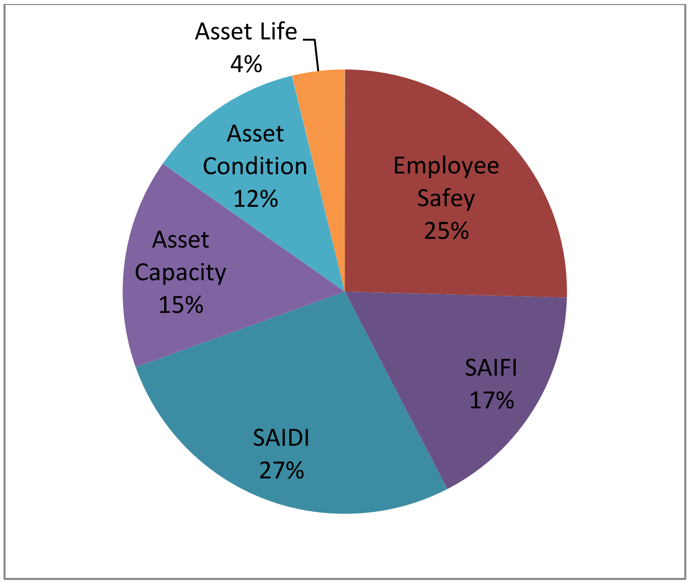



**Figure 84 - Project Avoided Risk**

Project Score: 0.787

### 2.7.5 Execution Path

#### 2.7.5.1 *Implementation Plan*

This project is to be entirely completed in 2016 and includes the extension of the JKGF4 from Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles and two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through a concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

#### 2.7.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 2.7.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

#### 2.7.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

#### 2.7.5.5 *Other Factors*

Not applicable.

### 2.7.6 Renewable Energy Generation (if applicable)

Not applicable.

### 2.7.7 Leave-To-Construct (if applicable)

Not applicable.

### 2.7.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92010176 – Abbot Street Trunk |
| **Capital Cost:** | $1.023M |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q2 |
| **In-Service Date:** | 2016 – Q3 |
| **Investment Category:** | System Service |
| **Main Driver:** | Reliability |
| **Secondary Driver(s):** | N/A |
| **Customer/Load Attachment** | 4903 Customers/21,321kVA |

**Project Scope**

The Abbott Street Trunk project is intended to extend part overhead and part underground trunk system along Abbott Street from Stittsville Main Street to Shea Road. This project will tie together four (4) projects that are targeted specifically to improve reliability in the Stittsville community. These four projects include:

- 92008567 – Stittsville Main Cable Replacement & S/G Upgrades,
- 92010174 – Springbrook Drive Trunk,
- 92008535 – GRC 44 to 27,
- 92010178 – Granite Ridge Trunk

Through the completion of Abbott Street Trunk and tying of these four (4) projects, the Stittsville community will have a mesh network trunk system that will reduces the number of customers between protective devices (SAIFI) and provides improved system operability that will allow for reduced duration of outages (SAIDI). This will strengthen ties between Janet King DS and Terry Fox MTS which includes connections amongst four (4) feeders: JKGF4, JKGF5, TFXF1 and TFXF5.

**Work Plan**

The scope of this project, to be completed entirely in 2016, is to extend one (1) 27.6kV circuit from to tie Stittsville Main Street to Shea Road which will tie together four (4) feeders JKGF4, JKGF5, TFXF1 and TFXF5. This includes extension through use of existing 8.32kV routing by replacing nine (9) poles, two (2) transformers while converting the voltage to 27.6kV and installing six (6) new poles along Abbott Street. Further extension through concrete duct system to encase 660m of trunk cable and through the use of two (2) automated switchgears, will allow for ties to be made to Springbrook Drive Trunk, GRC 44 to 27 and Granite Ridge Trunk.

**Customer Impact**

By integrating Terry Fox MTS feeders and automated switchgear into the distribution system in Stittsville, it will improve the flexibility of the system and improve reliability. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the Stittsville area for the upcoming developments.

# 3 System Voltage Conversion

## 3.1 Woodroffe UW Voltage Conversion

### 3.1.1 Project/Program Summary

HOL's 4.16kV substations are experiencing a decrease in demand as larger developments convert existing 4.16kV supplies to a 13.2kV supply. This decreases the financial usefulness of the 4.16kV substation. Coupled with the need to replace infrastructure and equipment, a voltage conversion project has the potential to make economic sense. The Woodroffe UW voltage conversion is a prime example of this. The Woodroffe UW 4.16kV substation's structures and equipment were identified as nearing end of life and due for replacement. The option of maintaining the 4.16kV system and replacing the necessary equipment was compared to the option of upgrading the area's distribution system to be operated at 13.2kV and supplied by Woodroffe TW located at the same address. Based on a financial evaluation completed in 2011 it was recommended to pursue the latter option. Physical construction for this project started in 2013 and is on schedule to be complete in 2015.

### 3.1.2 Project/Program Description

#### 3.1.2.1 *Current Issues*

Currently much of the residential and small commercial loads North of Baseline Road from Clyde Avenue to Pinecrest Park are supplied by the 4.16kV system from the Woodroffe UW susbstation. The switchgear and transformers are approaching their end of life and a solution is required. In addition the neighbourhood was constructed circa 1957 and most of the poles and distribution equipment are nearing their end of life.

#### 3.1.2.2 *Program/Project Scope*

The voltage conversion requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment is upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the projects closing 9 4.16kV circuits will be replaced by 3 13.2kV circuits, over 600 poles will have been replaced or upgraded, and over 200 transformers will have been replaced. Most of the work needed for the conversion (pole, transformer, conductor, and insulator upgrades) is able to be done while the load remains supplied by the 4.16kV system through communicated outages. However, due to the change in voltages, transformer protection and settings will need to be updated once the supply is connected to the 13.2kV system.

Neither the decommissioning of the Woodroffe UW switchgear and transformers nor the replacement of the Woodroffe TW switchgear is in scope for this project.

#### 3.1.2.3 *Main and Secondary Drivers*

The main driver for this project is the anticipated end of life of the Woodroffe UW switchgear (~2016) and the near term end of life of the 13.2kV/4.16kV station transformers (2021-2026). A secondary driver for this project is that various distribution assets are also nearing their end of life. These include poles and the Woodroffe TW switchgear. In order to complete the necessary stations work the 4.16kV system equipment must be retrofitted in order to be able to accommodate the 13.2kV supply.

#### 3.1.2.4 *Performance Targets and Objectives*

The main objective of this project is to identify and pursue the most cost-effective option to remedy the end of life assets associated with the 4.16kV system at Woodroffe UW substation. This is accomplished by taking a detailed look at potential alternatives and developing a cost estimate.

This project also has the potential to complete work that would be scheduled as separate projects at a future date. This includes pole replacement and replacement of the porcelain box switches on the Woodroffe UW system. The replacement of these assets will improve the reliability to the customers in this area.

### 3.1.3 Project/Program Justification

#### 3.1.3.1 *Alternatives Evaluation*

##### 3.1.3.1.1 Alternatives Considered

There were two options evaluated in order to deal with the main drivers:

1) Asset replacement: This scenario would involve replacing the Woodroffe UW 4.16kV switchgear and transformers as they approached their end of life. It would also encompass the replacement of all distribution equipment and structures when required. All of these assets would be due for replacement by 2026.
2) Voltage conversion: This scenario involves the conversion of the existing 4.16kV supply from Woodroffe UW substation to the 13.2kV supply from Woodroffe TW. This requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment will be upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the project's closing over 600 poles and over 200 transformers will have been upgraded or replaced.

##### 3.1.3.1.2 Evaluation Criteria

The main evaluation criteria used to assess the alternatives was cost which can be seen below in Table 90. These costs represent initial estimates for the project and were completed in 2011. Either option presented adequate solutions to the ageing infrastructure which is why cost is the core evaluation metric. In addition, future costs and man hours associated with maintaining the equipment were considered.

Additionally, reliability was evaluated between having the equipment upgraded today as opposed to being replaced at their respective end of life.

| Revenue Requirements | Alternative 1 - Asset Replacement | Alternative 2 - Voltage Conversion |
|---|---|---|
| **Annual Operation Expenses** | $401,403 | $0.00 |
| **Net Income** | $3,222,849 | $1,960,926 |
| **Debt Interest Recovery** | $2,937,418 | $1,787,257 |
| **Depreciation Expense** | $2,968,750 | $1,866,798 |
| **Income Tax** | $2,431,272 | $1,479,295 |
| **Net Present Value of Revenue Requirements** | **$11,961,692** | **$7,094,275** |

**Table 90 - Alternatives Cost Analysis**

##### 3.1.3.1.3 Preferred Alternative

Based on the cost estimates developed in 2011 the preferred alternative to overcome the main driver is Alternative 2 which is the conversion of the 4.16kV system to 13.2kV. This alternative was chosen due to the estimate being $4.9M less than the cost to replace all of the aging equipment and infrastructure. The decommissioning of the 4.16kV switchgear also eliminates the need for equipment maintenance. This results in a savings of both future costs and resources.

Additionally, the voltage conversion will implement new equipment in the very near term. This will provide increased reliability to the customers served previously by the Woodroffe UW substation. Alternative 1 would have seen the assets replaced as they met their end of life. Therefore there is a greater chance of that option seeing reduced reliability by comparison.

#### 3.1.3.2 *Project/Program Timing & Expenditure*

Due to the amount of scope associated with this project work is carried out year round. The project was broken up into three phases and it is crucial that each phase is done on time because of the switchgear replacement project that is planned for 2016. The actual and anticipated costs associated with this project are shown in the table below.

HOL attempts to reduce project costs by tendering out all work that is unable to be done in house due to the type of work and resource constraints. HOL also tenders the equipment and infrastructure that will be installed. Furthermore, with respect to this project, commercial services have been transitioned from vault transformers to padmounted transformers. This reduces the amount of transformers on the system and eliminates maintenance and replacement costs in the future. Also due to the increased capacity of 13.2kV circuits compared to 4.16kV circuits, single phase feeders can support areas that used to be fed by three phases. This reduces equipment costs by decreasing the number of circuits and material needed.

As explained in section 5.4 below, unexpected rock that was discovered when drilling pole holes caused an increase in work time. However, this project has a specific deadline it is required to meet due to the switchgear replacement project slated for 2016. In order to stay on schedule more resources were deployed which elevated the price of the project.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| | 0.038 | 4.384 | 6.081 | 5.368 | | | | | |

**Table 91 - Project Expenditures**

#### 3.1.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | The decommissioning of the Woodroffe UW substation will make operation measures simpler. This is because there are fewer devices that need to be coordinated during any switching operation or outages. |
| **Customer** | The main benefit to customers that were specifically fed by the Woodroffe UW substation is an increase in reliability. Many assets that were replaced as a result of this project were nearing their end of life. The new equipment that has been installed has a higher reliability compared to the older equipment. Additionally, HOL chose the cheapest option known at the time in order to pass the least cost on to the ratepayers. The additional costs that came through unpredicted ground conditions are likely to have been incurred if the other alternative was chosen. Therefore, there are still overall cost savings with this project. |
| **Safety** | As a result of the conversion project, many assets that were approaching end of life in the near term were replaced. These assets have a lower likelihood of failing. This results in a safer and higher performing system. |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | Coordination with telecommunication companies was essential in this project as they had plant on the poles that were being replaced. Bell Canada also owned 30% of the poles that were being replaced or worked on. Early communication with the telecommunication companies has led to an easier execution of the project. |
| **Economic Development** | N/A |
| **Environment** | An outcome from converting the 4.16kV system to 13.2kV is the reduction in the number and size of transformers. This is because more power can be supplied from the increased voltage. Due to the reduced number of transformers, it is less likely that there will be an oil leak. Also due to the reduction in size of the transformers there is a lower volume of oil at risk. |

**Table 92 - Project Benefits**

### 3.1.4 Prioritization

#### 3.1.4.1 *Consequences of Deferral*

This project needs to be completed in order to prepare for a subsequent project, which will initially see the 4.16kV switchgear decommissioned and the 13.2kV switchgear replaced. Any delay in completing the voltage conversion will carry over to the project of replacing the switchgear. This will lead to increased costs due to resource rescheduling. It will also carry the risk of the switchgear failing due to its end of life state.

#### 3.1.4.2 *Priority*

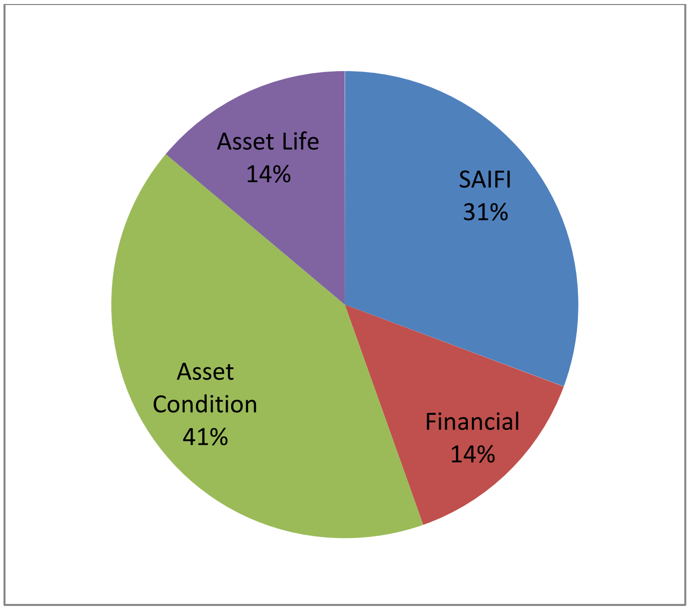



**Figure 85 - Project Avoided Risk**

Score = 0.343

### 3.1.5 Execution Path

#### 3.1.5.1 *Implementation Plan*

Due to the size of this project, the implementation plan spans three years. Each year three 4.16kV circuits are converted into one 13.2kV circuit. This is further broken down into approximately 16 phases which group together numerous streets. This allows work to be done in a planned and methodical fashion. To take advantage of work efficiencies and cost benefits, all pole equipment was replaced or upgraded at the same time the pole was replaced. This includes the installation of pole mount transformers, insulators, fused switches, etc.

The first phase involves the transition of the 4.16kV circuits UW04, UW13, and UW14. These circuits supply the area West of Woodroffe Avenue. The second phase involves the transition of the 4.16kV circuits UW03, UW05, and UW07. Finally, the third phase involves the transition of the 4.16kV circuits UW01, UW02, and UW06. These circuits supply the area East of Agincourt Road and West of Maitland Avenue. In total more than 600 poles and 200 transformers were replaced/ installed.

Currently HOL is implementing projects to replace porcelain switches due to their historical failures. These have the potential to cause either pole fires, which are dangerous and expensive, or interrupting customers. The Woodroffe UW system had 42 switches which are being replaced as part of the voltage conversion project.

#### 3.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

This project is nearing the completion of its second phase. The third and final phase will be completed in 2015. There are currently no foreseeable risks that will jeopardize this project. There are, however, risks that could affect this projects timeline and cost. These are further explained in the sections below.

#### 3.1.5.3 *Timing Factors*

There are several factors that have been identified as having the potential to delay this project. Firstly, around 30% of the poles being replaced or worked on are owned by Bell Canada. Therefore a joint collaboration is required for timely completion of pole work. Telecommunication plant needs to be transferred to new poles so that the former poles can be removed. This can greatly delay the process. HOL has mitigated this measure by involving Bell Canada early on in discussions about the work that is involved.

Secondly, due to the amount of work involved with this project there is the risk of being limited by resources. HOL has mitigated this risk by tendering out work to K-Line who is an approved contractor. K-Line offers a sizeable crew and equipment that will minimize the risk of delay due to a lack of resources.

Finally, in phase two and expected in phase three there has been a larger than expected amount of rock in the ground. This affects the installations of poles due to the hole needing to be drilled. HOL has mitigated the delay this might have on timing by allowing the contractor to employ more resources into the work. This mitigation step was taken due to the timing of the switchgear replacement project.

#### 3.1.5.4 *Cost Factors*

As mentioned above, in phase two and expected in phase three there has been a larger than expected amount of rock in the ground. In order to stay within the time frame of this project HOL has requested the contractor to spend more resources which will increase costs to the project.

Also, during this project, ageing equipment was replaced that may not have fallen into the original scope. This was due to the cost efficiency of having crews, equipment, and vehicles working in the area. Although these assets may not have been at their end of life, it was deemed that they were old enough to justify replacement in parallel with the voltage conversion project.

### 3.1.6 Renewable Energy Generation

N/A

### 3.1.7 Leave-To-Construct

N/A

### 3.1.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Woodroffe UW Voltage Conversion |
| **Capital Cost:** | $15.835M |
| **O&M:** | N/A |
| **Start Date:** | Q4 2012 |
| **In-Service Date:** | Q4 2015 |
| **Investment Category:** | System Service |
| **Main Driver:** | Woodroffe UW switchgear and transformers approaching end of life |
| **Secondary Driver(s):** | Increased reliability by replacing old distribution equipment and poles |
| **Customer/Load Attachment** | 1500 customers/ 4.5MVA of load |

**Project Scope**

The Woodroffe UW 4.16kV substation's structures and equipment were identified as nearing end of life and due for replacement. It was estimated that a more cost-effective solution would be to convert the 4.16kV loads to 13.2kV. The voltage conversion requires the replacement and upgrade of existing equipment in order to be operated at the increased voltage. In addition, equipment is upgraded to meet current HOL standards that may have been developed after their original installation. In total, by the projects closing 9 4.16kV circuits will be replaced by 3 13.2kV circuits, over 600 poles will have been replaced or upgraded, and over 200 transformers will have been replaced.

**Work Plan**

The three year project is broken into three phases. Each phase involves three 4.16kV circuits which are converted into one 13.2kV circuit. This is further broken down into approximately 16 phases which group together streets by proximity. This allows work to be done in a planned and methodical fashion. To take advantage of work efficiencies and cost benefits, all pole equipment was replaced or upgraded at the same time the pole was replaced. This includes the installation of pole mount transformers, insulators, fused switches, etc.

**Customer Impact**

The main benefit to the ~1500 customers that were specifically fed by the Woodroffe UW substation is an increase in reliability. Many assets that were replaced as a result of this project were nearing their end of life. The new equipment that has been installed has a higher reliability compared to the older equipment. Additionally, HOL chose the cheapest option known at the time in order to pass the least cost on to the ratepayers. The additional costs that came through unpredicted ground conditions are likely to have been incurred if the other alternative was chosen. Therefore, there are still overall cost savings to the rate payer with this project.

## 3.2 Prince of Wales Voltage Conversion

### 3.2.1 Project/Program Summary

This project is a line upgrade along Prince of Wales Drive in the preparation of a future voltage conversion from 8.32kV to 27.6kV. This project will address the upcoming load growth while improving system reliability. 70 customers will be affected on the 8.32kV FAL03 circuit from Fallowfield DS along Prince of Wales Drive, between Woodroffe Avenue and Barnsdale Road. The project will upgrade the existing 8.32kV overhead line with new poles, conductors and transformers which will be rated for 27.6kV. No voltage conversion will take place yet. A second 27.6kV-carrying circuit will be extended along Prince of Wales Drive. Although independent from each other, this project is being done for the same purpose as the Rideau Valley Voltage Conversion (92008686), to prepare the area for the increased capacity that will accompany the New South 27.6kV Substation (92008537).

### 3.2.2 Project/Program Description

#### 3.2.2.1 *Current Issues*

The south region of Ottawa is expected to develop and expand rapidly over the next few years. It is estimated that HOL's current distribution system will not be fully capable of supporting the load growth. Expansion based on city plans in the South Nepean area is shown below.

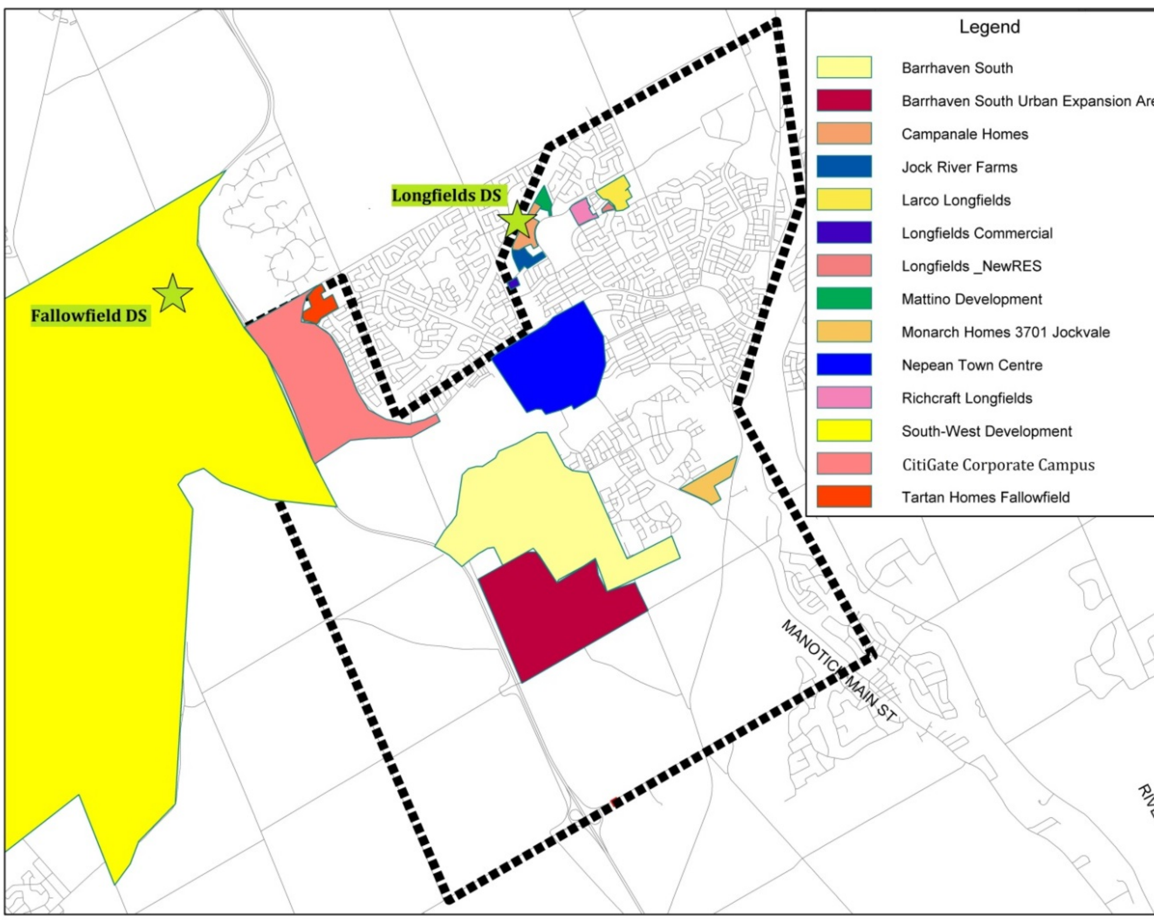



**Figure 86 – Proposed Developments**

In order to meet demand, the distribution system must be upgraded to a higher voltage. Although some portions of the south are supplied by a 27.6kV system, many areas still only have an 8.32kV supply. The overall goal is to convert the entire south area to a 27.6kV voltage supply, to support upcoming development while maintaining a reliable system.

In order to achieve the overall goal, a new 27.6kV distribution station with 6-8 feeders will be constructed to provide additional capacity to the area, as described in the business case for the New South 27.6kV Substation (92008537) project. The new station feeders will create ties with existing feeders, which will be upgraded in voltage rating. Converting the majority of the supply in the area to 27.6kV will enable backup connections between stations and feeders. Hence, reliability will be improved while anticipated capacity issues are resolved. Other major projects that have contributed or will contribute to the overall goal for the area include: Richmond South DS voltage conversion to 27.6kV, Limebank MS transformer upgrade, Fallowfield DS capacity upgrade and the transformer protection and base replacement at Longfields DS.

It can be seen in the above figures that there is proposed development on the east side of Highway 416, which is currently supplied by 8.32kV feeders. There are multiple projects taking place in the short term to prepare this section for a voltage upgrade. This includes both the Prince of Wales Voltage Conversion and the Rideau Valley Voltage Conversion projects. Another project is planned for 2016, to extend the voltage conversion preparation from where the Prince of Wales Voltage Conversion project left off. This 2016 project will bring two circuits further south along Prince of Wales Drive and then north on Greenbank Road.

The purpose of the Prince of Wales Voltage Conversion project is to prepare Prince of Wales Drive for a 27.6kV voltage conversion of the existing line, while a second 27.6kV line is extended from Woodroffe Avenue to Barnsdale Road. Although the current 8.32kV line is being upgraded to 27.6kV-rated equipment, no voltage conversion will take place within the scope of this project. After construction, Prince of Wales Drive will have a single pole line carrying two circuits – one carrying 27.6kV and the other rated for 27.6kV, but carrying 8.32kV. This project will begin construction in March 2015, following the work for the Rideau Valley Voltage Conversion, and is expected to be completed before the end of 2015.

#### 3.2.2.2 *Program/Project Scope*

This project involves the replacement of 72 poles which are currently in poor condition. New poles, conductors, 16/4.8kV dual rated overhead transformers and all related equipment will be installed to carry two 27.6kV rated circuits. Further, customer-owned insulators will be replaced on existing customer-owned poles. Secondary services will be transferred and the existing pole line, transformers and associated hardware will be removed. Tree trimming and the transfer of communication lines is also included. As an addition to the original project scope, step-down transformers will be installed at the radial supply to Nicolls Island.

At the intersection of Woodroffe Avenue and Prince of Wales Drive, there currently exist two circuits at different voltages – an 8.32kV and a 27.6kV 7F2 circuit from Limebank MS. Only the 8.32kV circuit currently continues south along Prince of Wales Drive. This project will upgrade the existing 8.32kV circuit to be rated for 27.6kV, but the voltage will remain at 8.32kV until conversion is needed. This project will also extend the 27.6kV circuit from Woodroffe Avenue to Barnsdale Road. The plan is illustrated on the following map.

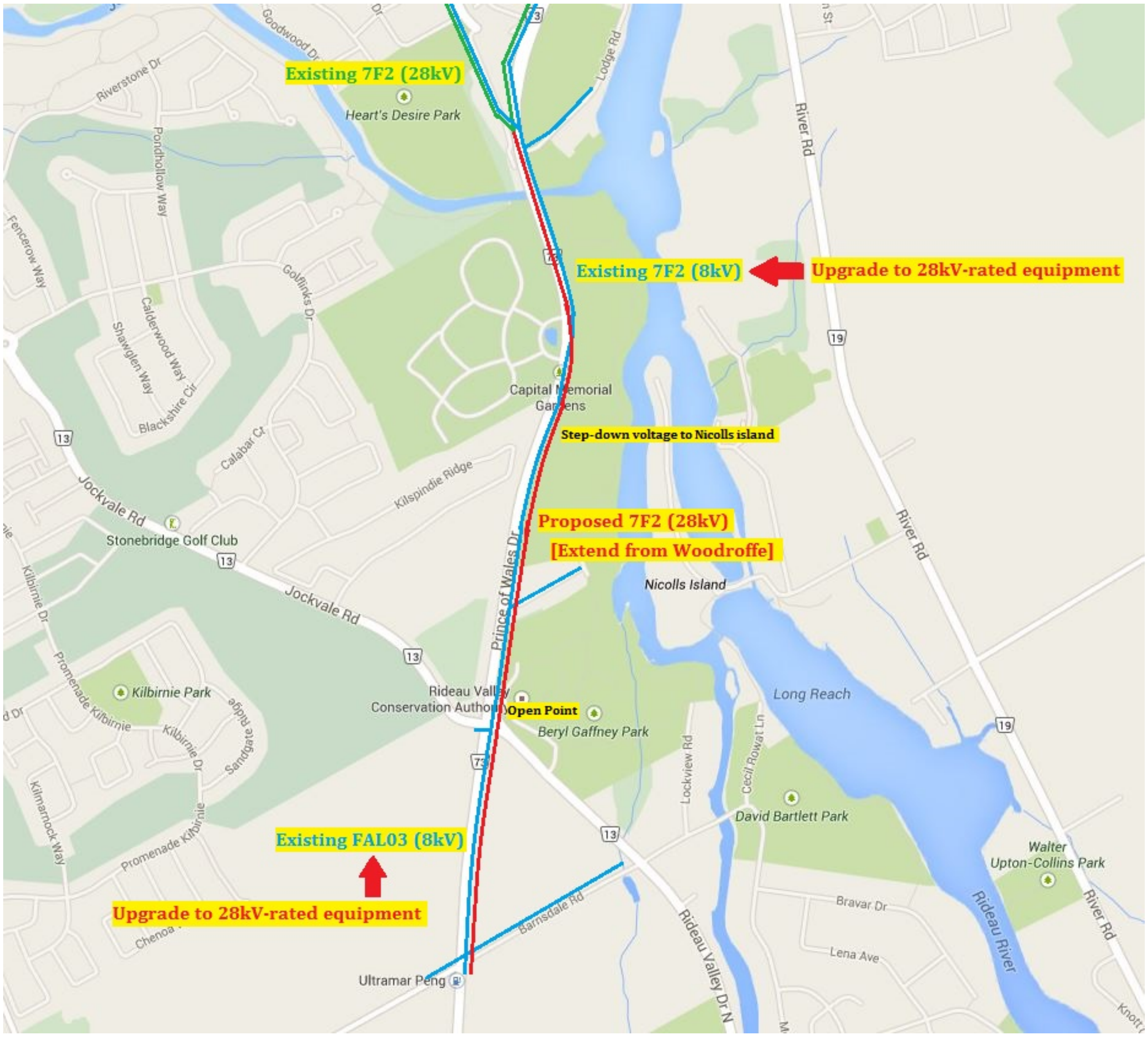



**Figure 87 - Proposed Conversion Plan**

It is important to note that no voltage conversion will take place within the scope of this project, only the preparation for it because of capacity restrictions at the stations. The upgraded existing line will have capacity for 27.6kV but will remain at 8.32kV for now, until more capacity becomes available. The 27.6kV line will be extended to Barnsdale Road and will continue to carry a voltage of 27.6kV.

### 3.2.2.3 *Main and Secondary Drivers*

The main driver of this project is the upcoming load growth in the area. It is expected that the area's capacity limitations will be reached within the next five years. The 8.32kV circuits in the south of

Barrhaven are being prepared for a conversion to 27.6kV, which will be needed to satisfy the demand. As a secondary driver for this project, reliability will be improved with the replacement of aging assets. The poles along Prince of Wales Drive are in bad condition and the installation of new poles and related equipment will decrease the likelihood of failure. Additionally, when the New South 27.6kV Substation is complete, the two circuits along Prince of Wales Drive will be prepared to accept ties with the new substation feeders, thus improving reliability by creating backup loops to decrease restoration time in the event of an outage.

With the additional station capacity underway at Limebank MS, two circuits from this station are planned to be dedicated to supplying the south region. It is expected that this additional capacity will be available by 2016, therefore it is worth preparing Prince of Wales Drive for this upgrade. Furthermore, there is an asset replacement project planned for 2016 in which the two circuits on Prince of Wales Drive will extend further south along the same road, then north on Greenbank Road.

This will enable the new developments around the Barnsdale/Greenbank intersection to receive adequate supply in 2016. In this sense, the Prince of Wales Voltage Conversion project is important in providing a tie for the 2016 asset replacement project, while continuing to work towards the overall goal of upgrading the South to a 27.6kV system.

#### 3.2.2.4 *Performance Targets and Objectives*

The primary objective of this project is to prepare Prince of Wales Drive for an upcoming voltage conversion. This involves the replacement of all utility poles, overhead transformers, primary conductors and related assets, as well as the extension of a 27.6kV circuit from Woodroffe Avenue. The replacement of aging assets will contribute to improving reliability in the area. The upgrade will allow a voltage conversion within the next few years as needed and will create the possibility for eventual backup ties with the New South 27.6kV Substation feeders and existing lines. The project will be deemed a success if all of the core objectives are met in a timely manner while minimizing the impact to HOL's customers.

### 3.2.3 Project/Program Justification

#### 3.2.3.1 *Alternatives Evaluation*

##### 3.2.3.1.1 Alternatives Considered

Due to the nature of this project and its contribution to the overall goal of upgrading the supply voltage in the south, there were no specific alternatives to upgrading and expanding the system along Prince of Wales Drive.

Circuits from Limebank MS on the east side of the Rideau River are needed to help fulfill the future capacity requirements in the south. These circuits only cross the river at two locations, Manotick Island and the new Strandherd Bridge. Manotick Island currently carries the 27.6kV 7F4 circuit but a large portion of the conductor is undersized and would therefore require a major upgrade to be capable of supplying the south. This was not a feasible option. Thus, the only other option was to utilize the 7F2 circuits to the north of Prince of Wales Drive, at Woodroffe Avenue.

Although there were limited options in extending circuits from Limebank MS to the south, there were several alternatives which were considered in planning the scope of this project. They were: Creating a single-circuit tie at the intersection of Prince of Wales Drive and Jockvale Road; Servicing a portion of Barnsdale Road from either Prince of Wales Drive or from Rideau Valley Drive (thus including in the scope of one project or the other); Cancelling the Nicolls Island project and accounting for the island within the scope of the Prince of Wales Voltage Conversion project.

#### 3.2.3.1.2 Evaluation Criteria

The evaluation criteria for alternatives to the project itself are based on feasibility and cost. A utility must anticipate and provide the needed services in an efficient manner. The evaluation criteria for alternatives to the project scope are based on minimizing cost, reliability considerations and external influences. HOL strives to minimize cost and customer interruptions. This involves planning ahead for future work that is expected to occur in the same area as the project in question.

#### 3.2.3.1.3 Preferred Alternative

Due to the need for Limebank MS to contribute to the south supply, it was determined that upgrading and extending the circuits along Prince of Wales Drive was the only feasible solution to prepare for upcoming capacity requirements. That being said, there were several preferred alternatives found within the scope of this project.

First, it is desired to connect the existing circuit along Jockvale Road to one of the circuits on Prince of Wales Drive. This would create an additional backup loop to improve reliability and enable reduced outage durations.

Approximately 515m of existing single-phase conductor at the end of Jockvale Road would be upgraded to a 3-phase line. Then a 250m line extension would be needed to connect the two segments. This connection was planned, however it was learned that the City of Ottawa is planning a road widening for Jockvale Road. This means that any new pole line extension would be relocated in two years, so HOL decided to postpone this connection until the road widening is completed. That being said, the scope of this project was altered to include bringing a circuit across Prince of Wales Drive, to be used in the future connection with Jockvale Road. Crossing the street now and installing a switch will avoid a second traffic disruption and customer outage later.

Secondly, it was decided to supply the customers on Barnsdale Road (between Prince of Wales Drive and Rideau Valley Drive) from Prince of Wales Drive as opposed to Rideau Valley Drive. Since the supply originates from Fallowfield DS, it is better planning to supply the customers from a point closer upstream to the source. Rideau Valley Drive is supplied radially so reliability will be improved for customers residing on that section of Barnsdale Road.

Finally, supplying customers on Nicolls Island from a step-down transformer on Prince of Wales Drive was added to the scope of this project. Originally, Nicolls Island had been planned as a separate project. The plan was to prepare the customers on Nicolls Island for a voltage conversion to 27.6kV as well. This would require pole replacements, new insulators, dual overhead transformers, new frames and conductors. There are 16 single-phase customers on the island, and it is unlikely that the electrical demand will increase. Growth on this small island is not supported by Parks Canada, the City of Ottawa or the Rideau Valley Conservation Authority due to septic and potable water challenges, unstable land, and ease of access problems for emergency vehicles. The greatest challenge is that the only access to the site is an old bridge with limited weight capacity. It would therefore be difficult to transport our vehicles and equipment to site. In terms of the cost savings, approximately $300K is saved by not doing a voltage conversion of Nicolls Island.

#### 3.2.3.2 *Project/Program Timing & Expenditure*

The total cost of this project is $1,474,559. HOL is minimizing the cost of this project by coordinating construction schedules with the Rideau Valley Voltage Conversion (92008686) project. HOL's own crew will work on both projects together, beginning with Rideau Valley. Doing these projects at the same time is convenient due to their close proximity, and this is expected to save $1M in time and labour costs. Additionally, the decision to install a step-down transformer to service Nicolls Island as opposed to preparing it for a voltage conversion saves a considerable amount of money which can be allocated towards other sustainment projects. The cost to do a voltage conversion of Nicolls Island would have been in the range of $400K, while installing a single-phase step-down transformer is estimated at $93K. This represents a cost saving of over $300K.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| - | - | - | - | 1.47 | - | - | - | - | - |

**Table 93 - Project Expenditures**

#### 3.2.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is a necessary contribution to the overall goal of upgrading supply capacity in the south of Ottawa. System operation efficiency will be improved with the double circuit loop that will be created in 2016, once the asset replacement project is complete on Prince of Wales Drive and Greenbank Road. Once the new 27.6kV substation is built, this project will contribute to creating a more interconnected system which will lead to faster restoration times, thus reducing SAIDI. It is expected that SAIFI will also be reduced by replacing aging assets proactively. It is known that the equipment on Prince of Wales Drive is in poor condition. Within the scope of this project, the most cost-effective alternatives were chosen. For instance, servicing Nicolls Island with a single-phase step-down transformer rather than doing a voltage conversion saves HOL hundreds of thousands of dollars. Coordinating this project with the Rideau Valley Voltage Conversion (92008686) project will also save a large amount of construction and labour costs. |
| **Customer** | This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. While this particular project is being driven by the need for increased capacity, HOL is taking this opportunity to better the system. The planned feeder connections will contribute to reducing outage durations and eliminating radial segments that exist in the current distribution system. By replacing assets in preparation for a voltage upgrade, this not only brings equipment up to current standard but also improves the asset condition. |

| | |
|---|---|
| **Safety** | Rebuilding and upgrading this pole line will address the predicted thermal overload of existing feeders that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk. Replacing aging assets will also contribute to eliminating potential safety hazards, by installing stronger poles and removing old transformers. |
| **Cyber-Security, Privacy** | Not Applicable |
| **Co-ordination, Interoperability** | Not Applicable |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but extending circuits within HOL's service territory will inevitably lead to additional operation and maintenance. HOL's own crews will handle the construction of the project, with a contractor handling the pole holes and anchors. |
| **Environment** | Not Applicable |

**Table 94 - Project Benefits**

### 3.2.4 Prioritization

#### 3.2.4.1 *Consequences of Deferral*

The completion of this project is important in providing adequate capacity to the anticipated development in the next few years. Preparing for a future voltage conversion and extending a second circuit along Prince of Wales Drive is crucial in order to supply the upcoming demand in the area. This project will enable a looped supply for the expected development near Greenbank Road and Barnsdale Road. Since this project addresses a capacity issue, the consequence of deferring the project would be the inability to service the required load. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they required. The eventual failure of the system to keep up with demand validates the necessity of this project.

This project involves the replacement of aging assets such as poles, conductors and transformers which will improve system reliability. Poles along Prince of Wales Drive are currently in poor condition, and replacing them will minimize their likelihood of failure.

#### 3.2.4.2 *Priority*

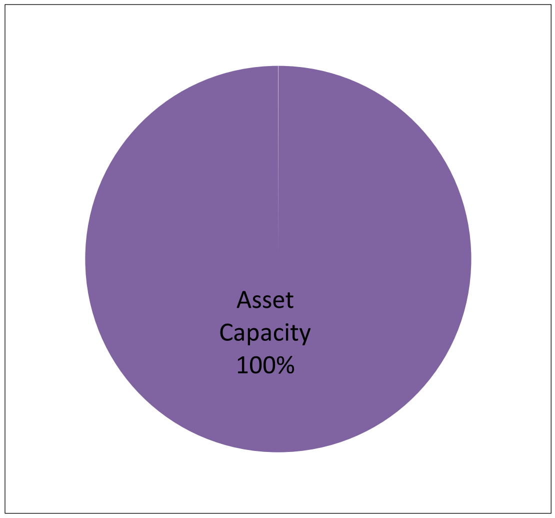



**Table 95 - Project Avoided Risk**

Project Score = 0.24

### 3.2.5 Execution Path

#### 3.2.5.1 *Implementation Plan*

This project is scheduled to begin construction in March 2015. The implementation plan involves installing new poles, conductors and transformers for the new double circuit pole line. Both circuits will be rated for 27.6kV, although only one circuit will carry 27.6kV while the other remains at 8.32kV for now. Then the existing pole line will be removed along with old transformers and other associated hardware.

This project will be done in conjunction with the Rideau Valley Voltage Conversion (92008686) project. The Rideau Valley Voltage Conversion (92008686) project will begin construction first in February 2015, followed by the Prince of Wales Voltage Conversion (92008543) project in March 2015. This order is simply a reflection of the 92008686 project design and drawings being completed first. HOL's own 11-person construction crew will work on these two projects, with a contractor to take care of pole holes and anchors. Pole replacements and framing will be completed first, starting with Rideau Valley. Following the pole replacements, conductor will be strung for both projects simultaneously. Although not dependent on each other, doing these projects together is expected to save considerable time and labour, thus reducing the overall project cost.

#### 3.2.5.2 *Risks to Completion and Risk Mitigation Strategies*

Project drawings have been submitted to the City of Ottawa for municipal consent. Once approved, HOL will request a road cut permit. Receiving municipal consent is not expected to be an issue; however, the process is known to take time. HOL is aware of the typical approval time and submitted the drawings in anticipation of the planned construction date. Crews are prepared to proceed with surveying and staking once municipal consent is approved. Approval has already been granted by the City of Ottawa for tree trimming.

Limebank MS recently received an upgrade, with the addition of a station transformer to provide more capacity to the Riverside South and Barrhaven areas. This upgrade affects the long term capability of Limebank substation to provide adequate supply to the South Nepean area. This project is proceeding as planned, with an anticipated commissioning and energization date in December 2014. All construction for this project is complete.

#### 3.2.5.3 *Timing Factors*

As with all projects involving asset replacement, timing can be affected due to unforeseen events, such as encountering rock beneath the surface of the soil or facing extreme weather conditions. Any events that arise and were not planned for will likely affect the timing of the project, either causing a delay or moving it ahead of schedule. HOL does not foresee any problems in completing this project in 2015.

The procurement of equipment and materials may affect the project timing, but this is not expected. HOL has already ordered material in 2014 which will be delivered at the end of December 2014 and beginning of January 2015.

Planned City development is the driver for this project, and it is unlikely that the priority of this project will change. It is necessary to increase the electrical supply in the area of load growth. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as this project contributes to expanding supply in the South Nepean area and extends needed circuits from Limebank substation. For the priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

#### 3.2.5.4 *Cost Factors*

It is possible that construction crews will encounter more rock beneath the surface than anticipated when installing new poles, but this is unlikely as there is an existing pole line along Prince of Wales Drive.

#### 3.2.5.5 *Other Factors*

One public communication package will be created for both the Prince of Wales project and the Rideau Valley project. Letters of notification was done in 2014, as customers will experience planned outages and potential construction on or around their properties. Customer input is not expected to cause any problems as there is already an existing pole line along Prince of Wales Drive.

### 3.2.6 Renewable Energy Generation (if applicable)

N/A

### 3.2.7 Leave-To-Construct (if applicable)

N/A

### 3.2.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Prince of Wales Voltage Conversion |
| **Capital Cost:** | $1,474,559 |
| **O&M:** | N/A |
| **Start Date:** | March 2015 |
| **In-Service Date:** | Fall 2015 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | Approximately 70 customers |
| **Project Scope** | |
| Replace 72 poles, frame for double circuit, string new 27.6kV conductors<br>Install new dual overhead transformers<br>Replace customer owned insulators on existing customer owned poles<br>Transfer secondary services and remove existing pole line and associated hardware<br>Tree trimming | |
| **Work Plan** | |
| Install poles and framing for Rideau Valley Voltage Conversion project first<br>Install poles and framing for Prince of Wales Voltage Conversion project next<br>String new conductor for both projects together | |
| **Customer Impact** | |
| Available distribution capacity to supply new loads for upcoming development<br>Reliability improvement associated with replacement of aging assets and equipment upgrades<br>Reduced outage durations by allowing for future double circuit loop | |

## 3.3 Rideau Valley Voltage Conversion

### 3.3.1 Project/Program Summary

The project is a line upgrade along Rideau Valley Drive in the preparation of a future voltage conversion from 8.32kV to 27.6kV. This project will contribute to upgrading the electrical capacity in the South Nepean area while improving system reliability. 37 customers will be affected on the 8.32kV FAL03 circuit from Fallowfield DS along Rideau Valley Drive, south of Prince of Wales Drive and extending as far as the current circuit to 4174 Rideau Valley Drive, including customers along Lockview Road. The project will upgrade the existing 8.32kV single-phase overhead line with new poles, conductors and transformers which will be 3-phase and rated for 27.6kV. No voltage conversion will take place yet. Although independent from the Prince of Wales Voltage Conversion (92008543), this project is being done for the same purpose, to prepare the area for the increased capacity that will accompany the New South 27.6kV Substation (92008537).

### 3.3.2 Project/Program Description

#### 3.3.2.1 *Current Issues*

The south region of Ottawa is expected to develop and expand rapidly over the next few years. It is estimated that HOL's current distribution system will not be fully capable of supporting the load growth. Expansion based on city plans in the South Nepean area is shown below.

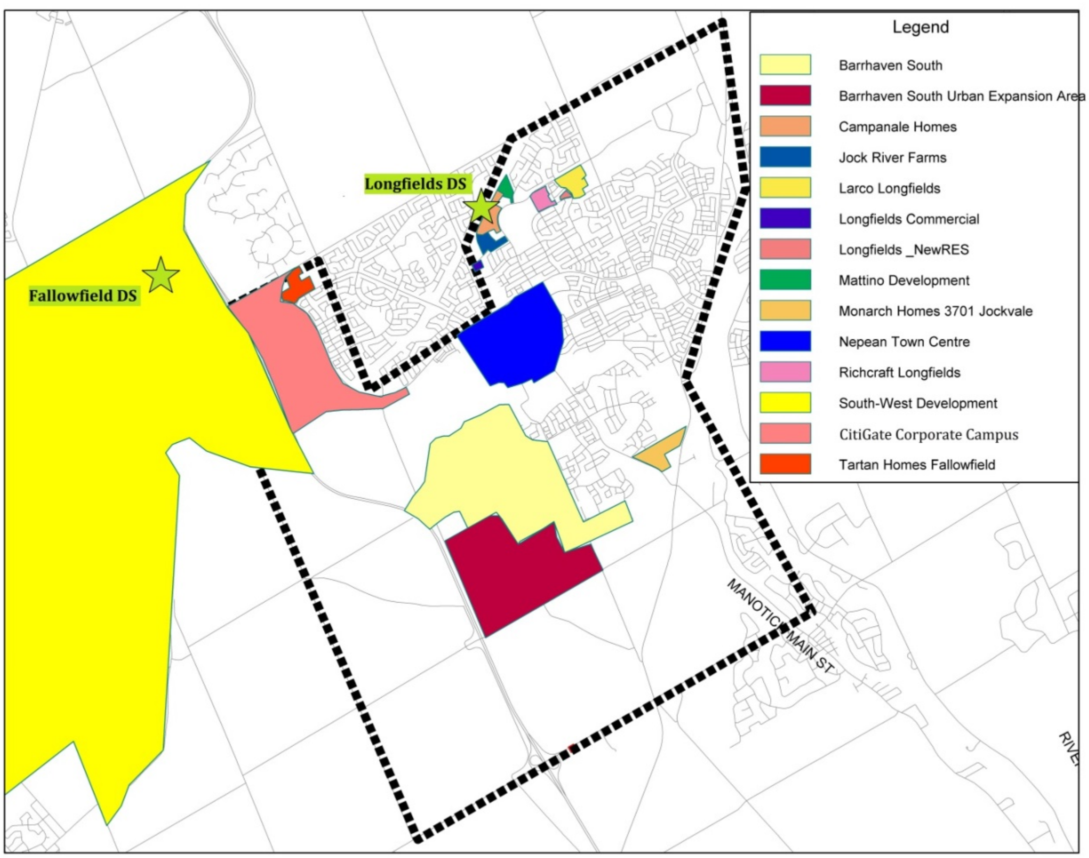



**Figure 88 - Proposed Developments**

In order to meet demand, the distribution system must be upgraded to a higher voltage. Although some portions of the south are supplied by a 27.6kV system, many areas still only have an 8.32kV supply. The overall goal is to convert the entire south area to a 27.6kV voltage supply, to support upcoming development while maintaining a reliable system.

In order to achieve the overall goal, a new 27.6kV distribution station with 6-8 feeders will be constructed to provide additional capacity to the area, as described in the business case for the New South 27.6kV Substation (92008537) project. The new station feeders will create ties with existing feeders, which will be upgraded in terms of their voltage rating. Converting the majority of the supply in the area to 27.6kV will enable backup connections between stations and feeders. Hence, reliability will be improved while anticipated capacity issues are resolved. Other major projects that have contributed or will contribute to the overall goal for the area include: Richmond South DS voltage conversion to 27.6kV, Limebank MS transformer upgrade, Fallowfield DS capacity upgrade and the transformer protection and base replacement at Longfields DS.

It can be seen in the above figures that there is proposed development on the east side of Highway 416, which is currently supplied by 8.32kV feeders. There are multiple projects taking place in the short term to prepare this section for a voltage upgrade. This includes both the Prince of Wales Voltage Conversion and the Rideau Valley Voltage Conversion projects.

The purpose of the Rideau Valley Voltage Conversion project is to prepare Rideau Valley Drive for a 27.6kV voltage conversion of the existing line. Although the current 8.32kV line is being upgraded to 27.6kV-rated equipment, no voltage conversion will take place within the scope of this project. This project will begin construction in February 2015, coordinating with the Prince of Wales Voltage Conversion project, and is expected to be completed before the end of 2015.

#### 3.3.2.2 *Program/Project Scope*

This project involves the replacement of the existing single-phase pole line, including 56 poles and 9 overhead transformers. New poles will be framed for one 3-phase 27.6kV circuit and new insulators and conductors will be installed. The new overhead transformers will be 16/4.8kV dual rated. Customer-owned insulators will be replaced on existing customer-owned poles. Secondary services will be transferred and the existing pole line and associated hardware will be removed. The plan is illustrated on the following map.

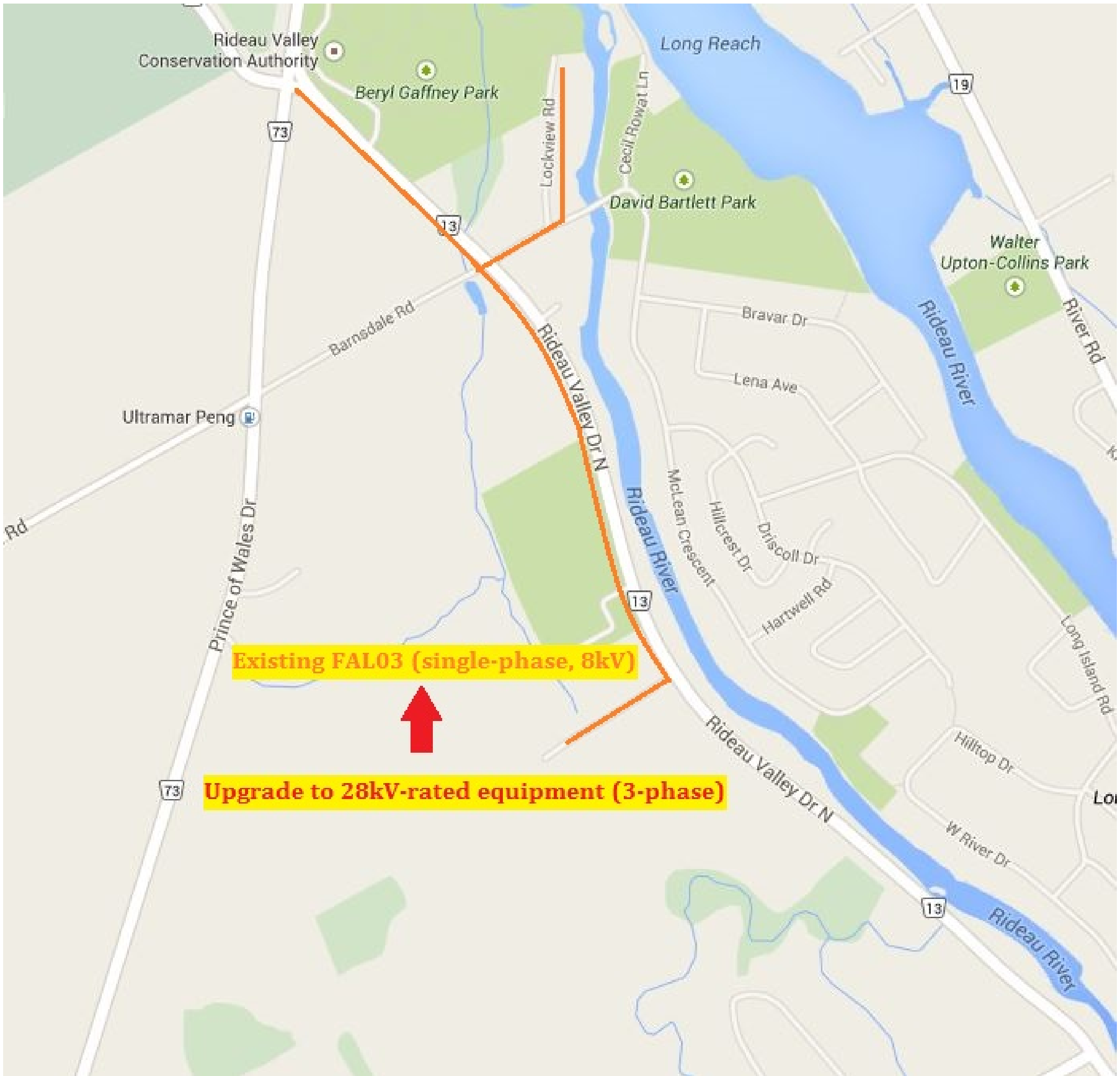



**Figure 89 - Proposed Conversion**

Not included in the scope of this project is the installation of new civil structures, the digging of pole holes, the installation of anchors, tree trimming or the transfer of communication lines. It is also important to note that this project does not include the voltage conversion itself, only the preparation for it because of capacity restrictions at the stations. The upgraded existing line will have capacity for 27.6kV but will remain at 8.32kV for now, until more capacity becomes available.

#### 3.3.2.3 *Main and Secondary Drivers*

The main driver of this project is the upcoming load growth in the area. It is expected that the area's capacity limitations will be reached within the next five years. The 8.32kV circuits in the south of Barrhaven are being prepared for a conversion to 27.6kV, which will be needed to satisfy the demand. As a secondary driver for this project, reliability will be improved with the replacement of aging assets.

The poles along Rideau Valley Drive are in bad condition and the installation of new poles and related equipment will decrease the likelihood of failure.

Additionally, when the New South 27.6kV Substation is complete, the circuit along Rideau Valley Drive will be prepared to accept ties with the new substation feeders, thus improving reliability by creating backup loops to decrease the restoration time in the event of an outage. It will also be prepared to accept the eventual tie with the 7F4 circuit that currently services Manotick Island and crosses the Rideau River to the southern portion of Rideau Valley Drive.

An important consideration which acted as a driver for the timing of this project is the magnitude of the cost savings as a result of coordinating this project with the Prince of Wales project. Construction and labour costs are expected to be $1M lower than if these two projects were to be carried out separately.

#### 3.3.2.4 *Performance Targets and Objectives*

The primary objective of this project is to prepare Rideau Valley Drive for an upcoming voltage conversion. This involves the replacement of all utility poles, overhead transformers, primary conductor and related assets, as well as an upgrade from the current single-phase line to a 3-phase circuit. The replacement of aging assets will contribute to improving reliability in this area. The upgrade will allow a voltage conversion within the next few years as needed and will create the possibility for eventual backup ties with the New South 27.6kV Substation feeders and existing lines. The project will be deemed a success if all of the core objectives are met in a timely manner while minimizing the impact to HOL's customers.

### 3.3.3 Project/Program Justification

#### 3.3.3.1 *Alternatives Evaluation*

##### 3.3.3.1.1 Alternatives Considered

The value of completing this project is found in its contribution to the overall goal of upgrading the supply voltage in the south, combined with reliability improvements. The section of overhead line to be upgraded is currently radial, and will be extended to create a tie with the 7F4 feeder from Limebank MS. This would provide backup to both circuits and utilize the upgraded transformer capacity at Limebank substation. Another alternative to this project would be to leave the existing single-phase supply as is, and install a step-down transformer at the intersection of Prince of Wales Drive and Rideau Valley Drive. This would be a temporary solution to allow the Prince of Wales Voltage Conversion to proceed, however it is desired for planning purposes to upgrade this line by the time the new station feeders are ready for construction.

##### 3.3.3.1.2 Evaluation Criteria

The evaluation criteria for project alternatives are based primarily on feasibility, reliability considerations and cost. A utility must anticipate and provide the needed services in an efficient manner. HOL strives to minimize project costs and customer interruptions. This involves planning ahead for future work that is expected to occur in the same area as the project in question.

###### 3.3.3.1.3 Preferred Alternative

The FAL03 circuit being upgraded in this project is currently radial. The 7F4 feeder is also radial along Rideau Valley Drive, and is found a few spans away from the project boundary. It is desired to connect the two segments and create a backup tie for both circuits.

Unfortunately, it was found that a large portion of the 7F4 feeder supplying Manotick Island is currently supplied through undersized conductor. Therefore, the circuit is currently unable to provide the required capacity and the Island will require an upgrade before a connection between the two circuits can be made. This upgrade was too large and costly to be considered feasible within the scope of this project.

There is also a significant advantage to the timing of this project, in coordinating it with the Prince of Wales Voltage Conversion (92008543) project. Rideau Valley Drive could have maintained adequate supply in the short term by installing a step-down transformer at the tap to Prince of Wales Drive. However, the upgrade of this line is important in contributing to the overall goal for the system, as it will provide a tie point for new feeders. It was decided that it would be cost-efficient to do this project simultaneously with the Prince of Wales project. Due to the close proximity, approximately $1M is saved in construction and labour costs by doing these projects together. As an added consideration, the poles along Rideau Valley drive are in poor condition so HOL is taking advantage of the situation by addressing two issues at once.

#### 3.3.3.2 *Project/Program Timing & Expenditure*

The total cost of this project is $1,035,465. HOL is minimizing the cost of this project by coordinating construction schedules with the Prince of Wales Voltage Conversion (92008543) project. HOL's own crew will work on both projects together, beginning with Rideau Valley. Doing these projects at the same time is convenient due to their close proximity, and this is expected to save $1M in time and labour costs.

| Historical ($M) | | | | Future ($M) | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| - | - | - | - | 1.04 | - | - | - | - | - |

**Table 96 - Project Expenditures**

#### 3.3.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is an important contribution to the overall goal of upgrading supply capacity in the south of Ottawa. System operation efficiency will be improved by providing an alternate supply route around Barnsdale Road, along with the ability to accommodate a future backup connection. Once the New South 27.6kV Substation is built, this project will contribute to creating a more interconnected system which will lead to faster restoration times, thus reducing SAIDI. It is expected that SAIFI will also be reduced by replacing aging assets proactively. It is known that the equipment on Rideau Valley Drive is in poor condition. Coordinating this project with the Prince of Wales Voltage Conversion (92008543) project is a cost-effective decision that saves a large amount of construction and |

| | |
|---|---|
| | labour costs. |
| **Customer** | This project will achieve two objectives: to supply future demand and to improve reliability in the south of the city. While this particular project is being driven by the need for increased capacity, HOL is taking this opportunity to better the system. The planned feeder connections will contribute to reducing outage durations and eliminating radial segments that exist in the current distribution system. By replacing assets in preparation for a voltage upgrade, this not only brings equipment up to current standard but also improves the asset condition. |
| **Safety** | Replacing aging assets will also contribute to eliminating potential safety hazards, by installing stronger poles and removing old transformers. |
| **Cyber-Security, Privacy** | (Not applicable) |
| **Co-ordination, Interoperability** | (Not applicable) |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but extending circuits within HOL's service territory will inevitably lead to additional operation and maintenance. HOL's own crews will handle the construction of the project, with a contractor handling the pole holes and anchors. |
| **Environment** | (Not applicable) |

**Table 97 - Project Benefits**

### 3.3.4 Prioritization

#### 3.3.4.1 *Consequences of Deferral*

The completion of this project is important to providing adequate capacity for the anticipated development in the next few years. Preparing for a future voltage conversion is crucial in order to supply the upcoming demand in the area. This project will enable an alternate circuit route to customers on Rideau Valley Drive while providing the capability for future backup from the southern portion of the road. Although this project contributes towards the overall goal of upgrading the supply voltage in the south to address capacity limitations, it is not an essential component in the immediate future. However, HOL has decided to proceed with this project due to its importance in the short term, and the significant cost savings in preparing this segment of the system at the same time as the Prince of Wales project, which is required in 2015. For this reason, the consequence of deferring this project would be a much larger future cost.

This project involves the replacement of aging assets such as poles, conductors and transformers which will improve system reliability. Poles along Rideau Valley Drive are currently in poor condition, and replacing them will decrease their likelihood of failure.

#### 3.3.4.2 *Priority*

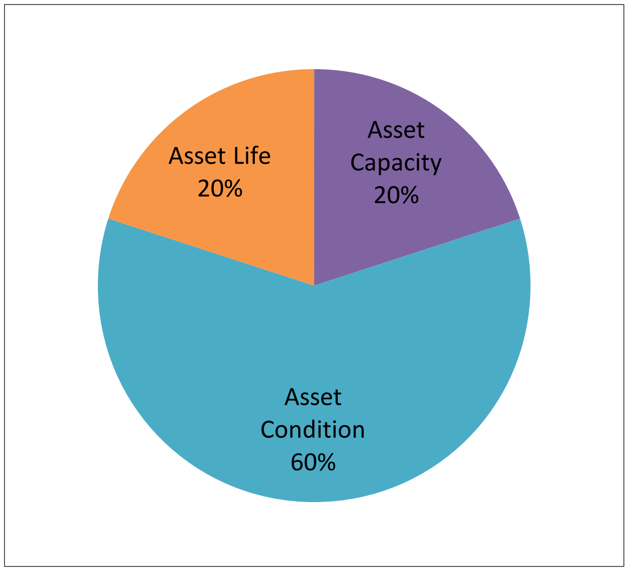



**Figure 90 - Project Avoided Risk**

Project Score = 0.42

### 3.3.5 Execution Path

#### 3.3.5.1 *Implementation Plan*

This project is scheduled to begin construction in the middle of February 2015. The implementation plan involves installing new primary and secondary poles, replacing customer owned insulators on existing customer owned poles, framing the new 27.6kV poles, and stringing new conductors. New primary conductors will be tensioned and tied along with the neutral. Then new overhead transformers will be installed as well as a 266MCM field spun bus. Secondary services will be transferred and the existing pole line and associated hardware will be removed.

This project will be done in conjunction with the Prince of Wales Voltage Conversion (92008543) project. The Rideau Valley Voltage Conversion (92008686) project will begin construction first, followed by the Prince of Wales Voltage Conversion (92008543) project. This order is simply a reflection of the 92008686 project design and drawings being completed first. HOL's own 11-person construction crew will work on these two projects, with a contractor to take care of pole holes and anchors. Pole replacements and framing will be done first for either project, starting with Rideau Valley, then conductor will be strung for both projects simultaneously. Although not dependent on each other, doing these projects together is expected to save considerable time and labour, thus reducing the overall project cost.

#### 3.3.5.2 *Risks to Completion and Risk Mitigation Strategies*

Project drawings have been submitted to the City of Ottawa for municipal consent. Once approved, HOL will request a road cut permit. Receiving municipal consent is not expected to be an issue, however the process is known to take time. HOL is aware of the typical approval time and submitted the drawings in anticipation of the planned construction date. Crews are prepared to proceed with surveying and staking once municipal consent is approved.

#### 3.3.5.3 *Timing Factors*

As with all projects involving asset replacement, timing can be altered due to unforeseen events, such as encountering rock beneath the surface of the soil or facing extreme weather conditions. Any events that arise and were not planned for will likely affect the timing of the project, either causing a delay or moving it ahead of schedule. HOL does not foresee any problems in completing this project in 2015.

The procurement of equipment and materials may affect the project timing, but this is not expected. HOL has already ordered material in 2014 which will be delivered in the middle of December 2014. Transformers and conductors still have yet to be ordered.

Planned City development is the driver for this project, and it is unlikely that the priority of this project will change. It is necessary to increase the electrical supply in the area of load growth. If City development is delayed for any reason, it is possible that this project could be shifted slightly but this is unlikely, as this project contributes to expanding supply in the South Nepean area. For the priority of this project to change, City development would have to be delayed and HOL would have to have a sudden change in priorities due to an unexpected requirement.

#### 3.3.5.4 *Cost Factors*

It is possible that construction crews will encounter more rock beneath the surface than anticipated when installing new poles, but this is unlikely as there is an existing pole line along Rideau Valley Drive.

#### 3.3.5.5 *Other Factors*

One public communication package will be created for both the Prince of Wales project and the Rideau Valley project. These letters of notification will be done in 2014, as customers will experience planned outages and potential construction on or around their properties. Customer input is not expected to cause any problems as there is an existing pole line along Rideau Valley Drive already.

### 3.3.6 Renewable Energy Generation (if applicable)

N/A

### 3.3.7 Leave-To-Construct (if applicable)

N/A

### 3.3.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Rideau Valley Voltage Conversion |
| **Capital Cost:** | $1,035,465 |
| **O&M:** | N/A |
| **Start Date:** | February 2015 |
| **In-Service Date:** | Fall 2015 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 37 customers/782 kVA |

**Project Scope**

Replace 56 poles, frame for double circuit, string new 27.6kV conductors
Install new dual overhead transformers
Replace customer owned insulators on existing customer owned poles
Transfer secondary services and remove existing pole line and associated hardware

**Work Plan**

Install poles and framing for Rideau Valley Voltage Conversion project first
Install poles and framing for Prince of Wales Voltage Conversion project next
String new conductor for both projects together

**Customer Impact**

Available distribution capacity to supply new loads
Reliability improvement associated with replacement of aging assets and equipment upgrades
Reduced outage durations by allowing for future backup circuit

## 3.4 Richmond Voltage Conversion

### 3.4.1 Project/Program Summary

In the West 8.32kV Regional Planning Study, the projected developments were assessed for construction, timing and associated load. Anticipated developments in the Richmond village area include commercial, light industrial and residential developments. In 2012, Richmond was identified to increase in size by 600% over a 20 year horizon. The Richmond Voltage Conversion project is intended to upgrade infrastructure that has reached end of life to be capable of sustaining the expected load growth. The decision for a 27.6kV voltage conversion was driven by the limitation of 8.32kV circuits in terms of capacity, their inability to extend long distances and maintain adequate voltage levels and to allow for increased operability to transfer load to neighboring 27.6kV stations. Conversion from 8.32kV to 27.6kV is the long-term goal of all areas within the Stittsville, Kanata and Barrhaven communities in order improve reliability and eliminate on-going power quality issues with the 8.32kV system.

### 3.4.2 Project/Program Description

#### 3.4.2.1 *Current Issues*

Current issues in the village of Richmond include deteriorating reliability due to failure of aging infrastructure and power quality issues which can be attributed to the length of the feeders and the limitation of 8.32kV to supply the distances without significant voltage drop. The projected load growth in the village of Richmond will become an issue for the 8.32kV system within a five-year timeframe.

#### 3.4.2.2 *Program/Project Scope*

The scope of this project is to extend two (2) 27.6kV feeders along the major streets in the village of Richmond. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along the major streets will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the major roads undergoing re-construction will be converted during the project. The Richmond Voltage Conversion includes eleven (11) sub-projects divided in order to phase the construction in Richmond, but still have infrastructure in place for the energization of the upgraded Richmond South DS.

Phase 1, which will include all work and expenses to occur within 2016, includes two projects, 92010186 Richmond South Voltage Conversion – McBean and 92010188 Richmond South Voltage Conversion – Shea. The scopes of these two projects include the replacement of sixty-two (62) poles, eighteen (18) overhead transformers, 95m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

Phase 2, which will include all work and expenses to occur within 2017, includes four projects: 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, and 92010926 Richmond South Voltage Conversion – Huntley. The scopes of these four projects include the replacement of 104 poles, thirty (30) overhead transformers, four (4) padmounted transformers, 365m of direct buried cable with concrete encased cable and installation of three (3) new gang-operated automated switches.

Phase 3, which will include all work and expenses to occur within 2018, includes five projects, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. The scopes of these five projects include the replacement of 127 poles, thirty-five (35) overhead transformers, seven (7) padmounted transformers, 545m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

### 3.4.2.3 *Main and Secondary Drivers*

The main driver of this project is to supply the future expected load in the village of Richmond. The forecasted load for the next 20 years in the Richmond area indicates that the area's capacity limitations will be reached within the next five years. The 8.32kV system currently supplying the village of Richmond is not capable of supplying the increased capacity without exceeding thermal limitations of the infrastructure and would worsen the power quality issues that have been experienced by customers in this area.

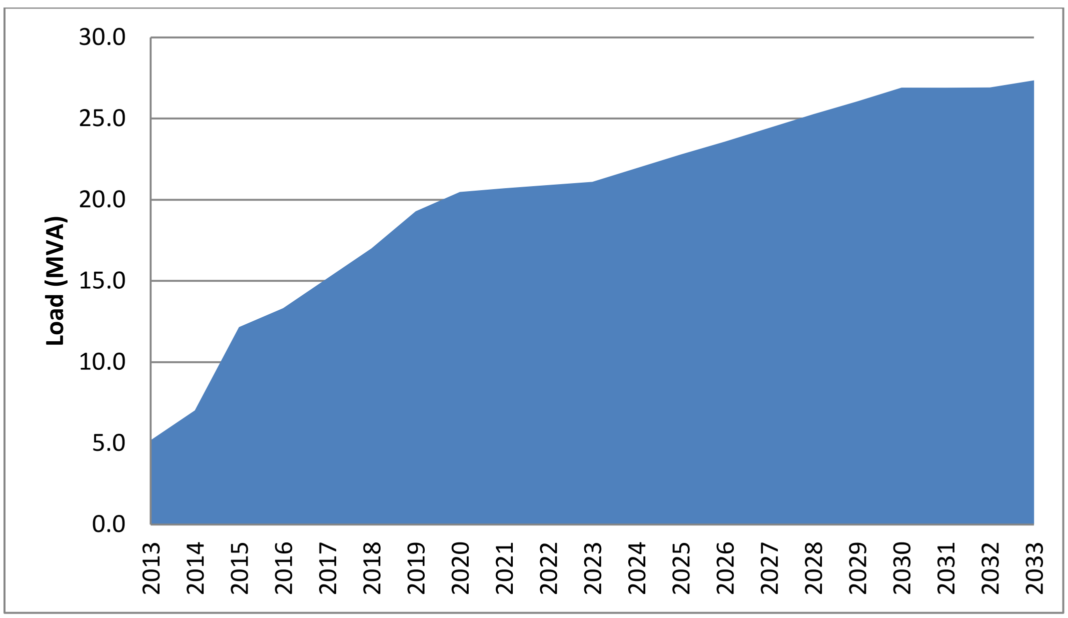



**Figure 91 - Richmond Village Load Profile**

There are many City of Ottawa development plans that have been reviewed to estimate the load demand over the next twenty years. The following outlines the development projects in the Richmond area.

**Richmond Community Design Plan**

The Village of Richmond CDP was initiated in 2008 and covers a planning period from 2010 to 2030. Based on this plan the residential capacity is planned to increase from approximately 1,550 dwelling units to between 4,400 and 5,500 units (including existing), for an increase of 2,850 – 3,950 which accounts for a load increase of 7.3 MVA – 10.1 MVA (using an estimate of 2.56 kVA/unit).

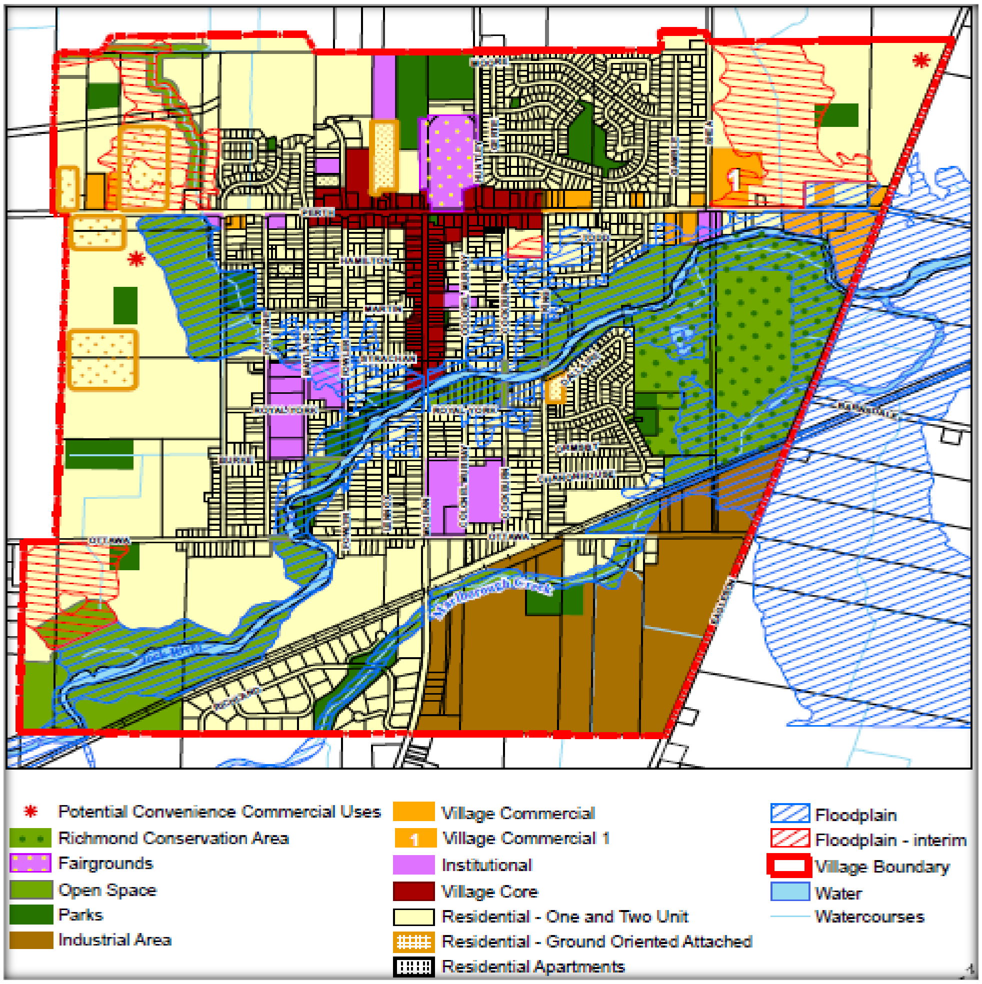



**Figure 92 - Richmond CDP Land Use**

## Industrial Lands

The Richmond CDP describes the Industrial Lands as providing “an opportunity for industrial and employment-generating uses that require large parcels of land and that are not always compatible with residential uses”. The maximum building height in this area is restricted to the equivalent of three or four storeys with the following permitted uses: light industrial, office, printing plant, service and repair shop, small batch brewery, warehouse and heavy equipment and vehicle sales, rental and servicing, research, technology, nurseries, greenhouses, catering, places of assembly, broadcasting and training. Existing areas with a similar profile have a load estimate within the range of 10 – 20 MVA/km$^2$ depending on particular uses. The proposed industrial lands cover approximately 0.9 km$^2$ which would predict a load profile within the range of 9 – 18 MVA. For planning purposes the low end, 9 MVA, will be used, assuming that no large industrial plants will develop on these lands.


Figure 93 - Industrial Lands Demonstration Plan

**Western Development Lands**

Development in the Western Development Lands will primarily consist of detached dwellings, townhouses, parks, open space, a school and a pathway system. The density and unit mix provisions for this area are contained in the chart below.

| Dwelling Type | Max Density Units/Net Ha | Unit Mix (% of Total) |
|---|---|---|
| **One & Two Units Large Lots** | 17 | 2-7% Minimum |
| **One & Two Units Small Lots** | 30 | 58-78% Maximum |
| **Townhouses** | 45 | 20-35% Minimum |
| **Townhouses with Rear Lanes** | 80 | |
| **Back-to-Back Townhouses** | 99 | |

Table 98 - Proposed Density


**Figure 94 - Western Development Lands Demonstration Plan**

The Western Development Lands demonstration plan was developed through a workshop hosted by Mattamy Homes in December 2008. Since that time Mattamy has developed a plan for a section of the western area, which is described below.

**Mattamy Homes Residential**

The Mattamy development covers the southern portion of the Western Development Lands and will account for approximately 1000 units, or 2.5 MVA of load. They have submitting the Draft Plan of Subdivision to the City of Ottawa in 2013 with closings to begin around 2017 since it is currently outside of their five year plan.

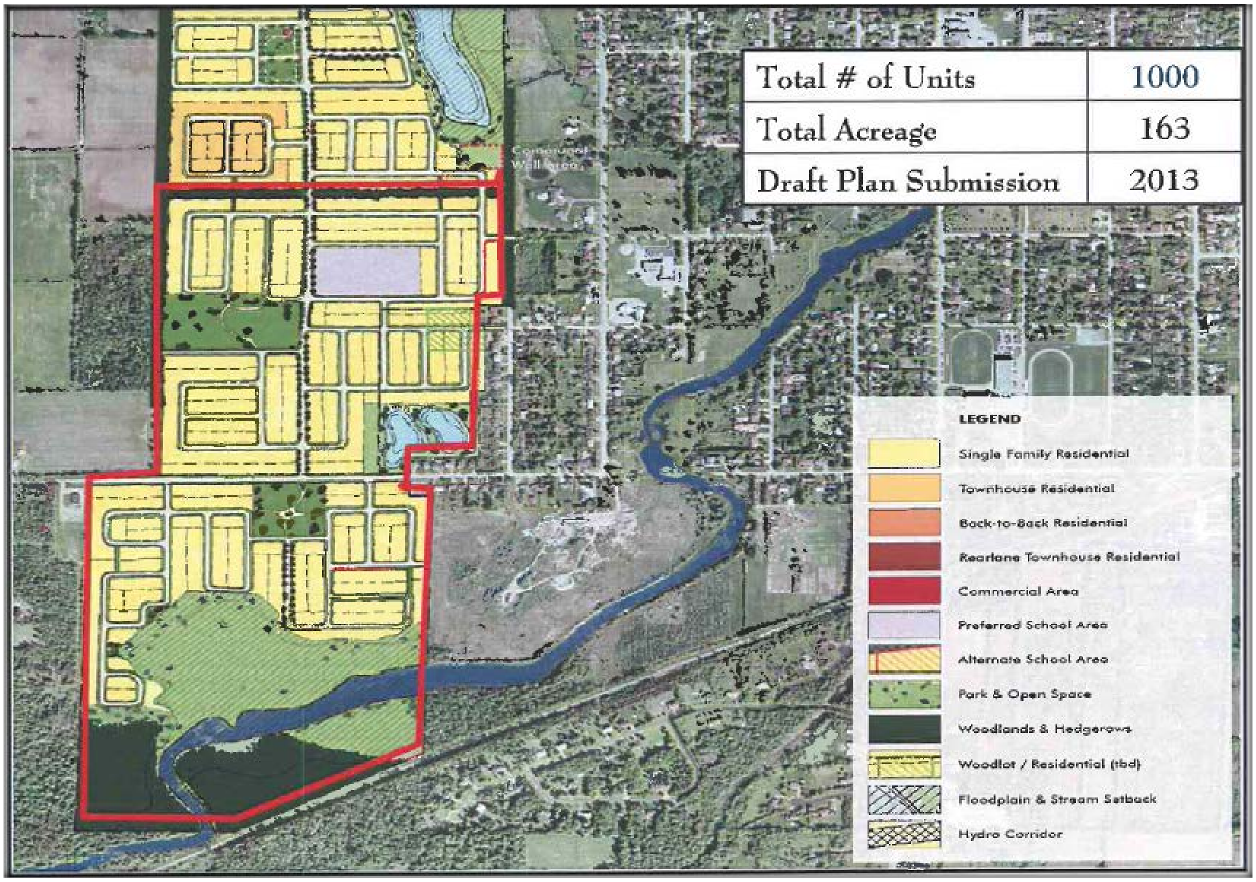



Figure 95 - Mattamy's Richmond West Development

## Northeast Development Lands

The plans for this area follow the same general outline as that for the Western Development Lands.


Figure 96 - Northeast Development Lands Demonstration Plan

## Richmond Village Square

The development known as Richmond Village Square is a commercial plaza that will consist of six single storey buildings for a total of 7,039 $m^2$. Using an estimate of 75.38 $W/m^2$ gives a load estimate of 590 kVA. The servicing for this site will consist of 3 x 1000 kVA transformers, and using an estimate of 60% of connected capacity provides a load estimate of 1.8 MVA.  A load estimate of 1.0 MVA will be used for planning purposes.

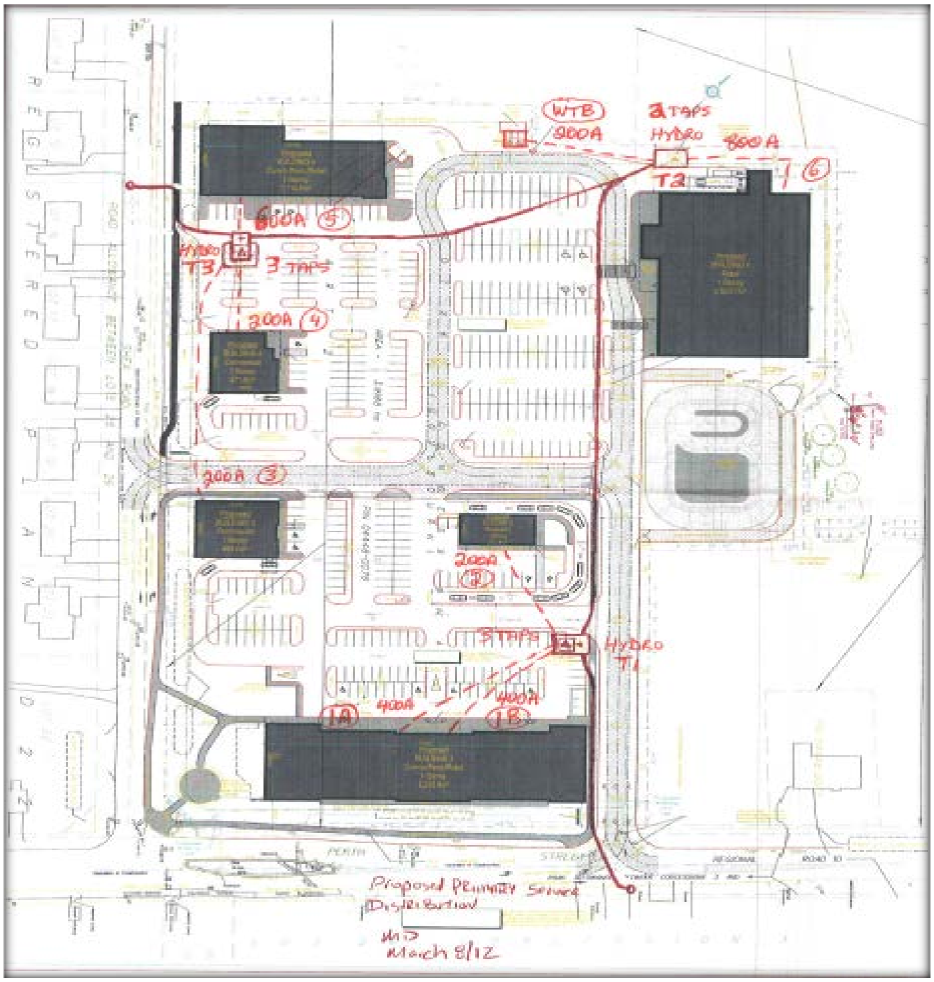



Figure 97 - Richmond Village Square Layout

As a secondary driver for this project, power quality will be improved as well as reliability by eventually creating ties to other 27.6kV stations, specifically Janet King DS, Bridlewood DS, Terry Fox MTS, Fallowfield DS and the New South 27.6kV Substation.

### 3.4.2.4 *Performance Targets and Objectives*

The main objective of this project is to be capable of supplying the new growth, while maintaining and improving power quality and reliability for customers in the village of Richmond. Conversion will directly allow developments in the village of Richmond to proceed on schedule and with adequate supply. The Richmond Voltage Conversion projects are expected to be completed in time for energization of Richmond South DS and the new 27.6kV supply.

A secondary objective is to improve reliability and power quality in the village of Richmond. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

Conversion will also directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system.

### 3.4.3 Project/Program Justification

#### 3.4.3.1 *Alternatives Evaluation*

##### 3.4.3.1.1 Alternatives Considered

The infrastructure in the Richmond 8.32kV system has reached end of life and requires upgrading to meet load growth requirements, reliability and power quality targets. The following eleven (11) projects have been identified to facilitate the required upgrades in order to meet these objectives:

- 92010186 Richmond South Voltage Conversion – McBean
- 92010188 Richmond South Voltage Conversion – Shea
- 92010920 Richmond South Egress – Garvin East
- 92010922 Richmond South Voltage Conversion – Perth East
- 92010924 Richmond South Voltage Conversion – Perth West
- 92010926 Richmond South Voltage Conversion – Huntley
- 92010954 Richmond South Voltage Conversion – King
- 92010956 Richmond South Voltage Conversion – Fortune
- 92010958 Richmond South Voltage Conversion – Ottawa
- 92010960 Richmond South Voltage Conversion – Burke
- 92010962 Richmond South Voltage Conversion – Eagleson

**Alternative #1:** includes the completion of all eleven (11) projects with infrastructure to support 27.6kV.

**Alternative #2:** includes the completion of all eleven (11) projects with infrastructure to support 8.32kV; direct replacements of all assets like for like.

##### 3.4.3.1.2 Evaluation Criteria

**Costs:**

Alternative #1: $8.32M

Alternative #2: $8.32M

Labour costs account for the majority of project costs and as a result material cost increments between 8.32kV and 27.6kV are considered negligible.

**Ability to supply load:**

Alternative #1: The 8.32kV system in the village of Richmond has reached end of life and cannot support additional load growth without compromising the power quality issues further. The renewal of infrastructure with 27.6kV in this area will permit further load growth.

Alternative #2: The 8.32kV system in the village of Richmond has reached end of life and cannot support additional load growth without compromising the power quality issues further.

**Reliability Benefits:**
Both alternatives would benefit reliability in the community by renewing infrastructure and ties created between feeders would ultimately reduce SAIDI.

#### 3.4.3.1.3 Preferred Alternative

Alternative #1 is the preferred alternative due to its ability to supply the anticipated future load growth, and reliability benefits associated with this alternative.

### 3.4.3.2 *Project/Program Timing & Expenditure*

The total project cost is $8,320.427 and is anticipated to be completed in 2018. HOL aims to minimize the costs and meet the deadlines associated with all projects by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| $0 | $0 | $0 | $0 | $0 | $0 | $1.64 | $3.02 | $3.66 | $0 |

**Table 99 - Project Expenditures**

### 3.4.3.3 *Benefits*

Key benefits that will be achieved by implementing the Richmond Voltage Conversion project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to satisfy the upcoming load growth in the village of Richmond. It is an essential system service project to supply the needed capacity. System operation efficiency will be improved by the new station feeders' ability to connect with other 27.6kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This should inevitably contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Voltage conversion is the most cost-effective solution to provide the required demand and renew aging infrastructure. |
| **Customer** | This project will achieve two objectives: to supply future demand and to improve reliability in the south-west end of the city. Not only will development projects be given adequate electrical supply, but the feeder ties present several opportunities to improve the system. This project will contribute to a larger system plan to convert the entire south-west to a 27.6kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities: Richmond, Munster, Kanata, Stittsville and Barrhaven. The various upcoming ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system. These projects involve asset replacement, which further improves system reliability. |
| **Safety** | The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the |

| | |
|---|---|
| | safety risk is significantly reduced. |
| **Cyber-Security, Privacy** | Not Applicable. |
| **Co-ordination, Interoperability** | The Richmond Voltage Conversion projects will coincide with ongoing developments in the village of Richmond and will reduce the last minute expansion requirements from developers to service the new developments. |
| **Economic Development** | This project is not expected to contribute directly to economic growth or job creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project. |
| **Environment** | The infrastructure in place today has begun approaching end of life and poses a small risk of failure and environmental concern. By replacing the infrastructure, the environmental risk is significantly reduced. |

**Table 100 - Project Benefits**

### 3.4.4 Prioritization

#### 3.4.4.1 *Consequences of Deferral*

Since the purpose of this project is to address an upcoming capacity issue, the most important consequence of deferral would be the inability to service the required load in 2019. Allowing the system to experience thermal overload for an extended period of time would lead to equipment damage and customer outages. Customers working or living in the proposed developments would simply not have the electricity they require. The eventual failure of the system to keep up with demand validates the necessity of this project.

The new 27.6kV feeders will create ties with other stations and backup other feeders. This presents an additional consequence of deferral, which is that the current radial segments of other feeders in the area will remain radial for a longer period of time. If an outage occurs on these segments, the affected customers will likely experience long outage times.

This project also promotes a series of equipment upgrade projects, to prepare the area for the larger 27.6kV voltage conversion. This involves replacing aging assets such as poles, conductors and transformers which inherently improves system reliability.

#### 3.4.4.2 *Priority*

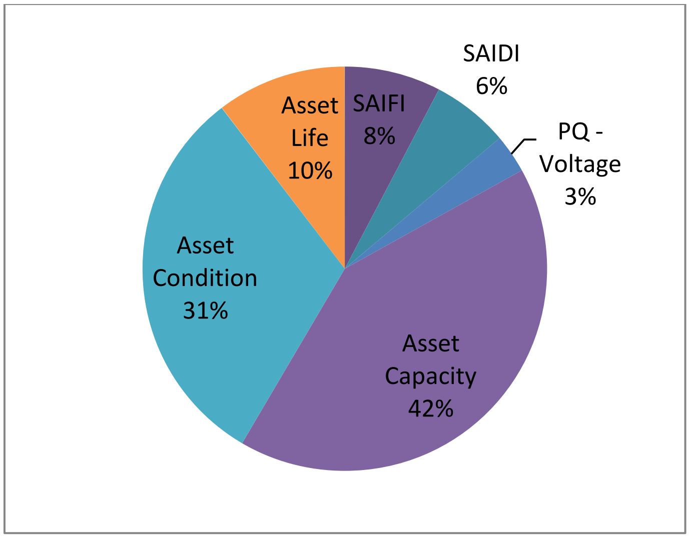



**Figure 98 - Project Avoided Risk**

Project Score: 0.867

### 3.4.5 Execution Path

#### 3.4.5.1 *Implementation Plan*

Phase 1, which will include all work and expenses to occur within 2016, includes two projects, 92010186 Richmond South Voltage Conversion – McBean and 92010188 Richmond South Voltage Conversion – Shea. The scopes of these two projects include replacement of sixty-two (62) poles, eighteen (18) overhead transformers, 95m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

Phase 2, which will include all work and expenses to occur within 2017, includes four projects: 92010920 Richmond South Egress – Garvin East, 92010922 Richmond South Voltage Conversion – Perth East, 92010924 Richmond South Voltage Conversion – Perth West, and 92010926 Richmond South Voltage Conversion – Huntley. The scopes of these four projects include replacement of 104 poles, thirty (30) overhead transformers, four (4) padmounted transformers, 365m of direct buried cable with concrete encased cable and installation of three (3) new gang-operated automated switches.

Phase 3, which will include all work and expenses to occur within 2018, includes five projects, 92010954 Richmond South Voltage Conversion – King, 92010956 Richmond South Voltage Conversion – Fortune, 92010958 Richmond South Voltage Conversion – Ottawa, 92010960 Richmond South Voltage Conversion – Burke, and 92010962 Richmond South Voltage Conversion – Eagleson. The scopes of these five projects include replacement of 127 poles, thirty-five (35) overhead transformers, seven (7) padmounted transformers, 545m of direct buried cable with concrete encased cable and installation of two (2) new gang-operated automated switches.

#### 3.4.5.2 *Risks to Completion and Risk Mitigation Strategies*

Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 3.4.5.3 *Timing Factors*

Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions. Any delays in energization of the upgraded Richmond South DS will result in delays for energizing the 27.6kV feeders.

#### 3.4.5.4 *Cost Factors*

Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

#### 3.4.5.5 *Other Factors*

Not applicable.

### 3.4.6 Renewable Energy Generation (if applicable)

Not applicable.

### 3.4.7 Leave-To-Construct (if applicable)

Not applicable.

### 3.4.8 Project Details and Justification

| **Project Name:** | Richmond Voltage Conversion - Shea |
|---|---|
| **Capital Cost:** | $665,000 |
| **O&M:** | $0 |
| **Start Date:** | 2016 |
| **In-Service Date:** | 2016 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Shea Road, from Garvin Road to Perth Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along McBean Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along McBean Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of twenty-four (24) poles and seven (7) overhead transformers, all to be completed in 2016.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion - McBean |
| **Capital Cost:** | $971,000 |
| **O&M:** | $0 |
| **Start Date:** | 2016 |
| **In-Service Date:** | 2016 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,189 Customers/4,222kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along McBean Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along McBean Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along McBean Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of twenty-seven (27) poles, eleven (11) overhead transformers and 175m of direct buried cable to be encased with concrete encased cable, all to be completed in 2016.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system.  The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond South Egress – Garvin East |
| **Capital Cost:** | $438,279 |
| **O&M:** | $0 |
| **Start Date:** | 2017 |
| **In-Service Date:** | 2017 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to egress three (3) 27.6kV feeders along Garvin Road, from Richmond South DS to Shea Road. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The three (3) feeders being constructed along Garvin Road will have one feeder energized at 8.32kV to continue supply to existing customers and two feeders at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Huntley Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of ten (10) poles, 200m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2017.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion - Huntley |
| **Capital Cost:** | $1,094,105 |
| **O&M:** | $0 |
| **Start Date:** | 2017 |
| **In-Service Date:** | 2017 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,972 Customers/6,254kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Huntley Road, from Garvin Road to Perth Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Huntley Road will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Huntley Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of thirty-seven (37) poles, twelve (12) overhead transformers, three (3) padmounted transformers, 90m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2017.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Perth East |
| **Capital Cost:** | $965,169 |
| **O&M:** | $0 |
| **Start Date:** | 2017 |
| **In-Service Date:** | 2017 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Perth Street, from Huntley Road to Eagleson Road. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Perth Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Perth Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of thirty-seven (37) poles, fourteen (14) overhead transformers and installation of one (1) gang-operated automated switch, all to be completed in 2017.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Perth West |
| **Capital Cost:** | $525,298 |
| **O&M:** | $0 |
| **Start Date:** | 2017 |
| **In-Service Date:** | 2017 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 976 Customers/2,983kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Perth Street, from Huntley Road to Fortune Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Perth Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Perth Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of twenty (20) poles, four (4) overhead transformers, one (1) padmounted transformers and 75m of direct buried cable to be encased with concrete encased cable, all to be completed in 2017.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – King |
| **Capital Cost:** | $967,556 |
| **O&M:** | $0 |
| **Start Date:** | 2018 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along King Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along King Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along King Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of thirty-two (32) poles, nine (9) overhead transformers, two (2) padmounted transformers, 170m of direct buried cable to be encased with concrete encased cable and installation of one (1) gang-operated automated switch, all to be completed in 2018.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Fortune |
| **Capital Cost:** | $774,500 |
| **O&M:** | $0 |
| **Start Date:** | 2018 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 976 Customers/2,983kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Fortune Street, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Fortune Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Fortune Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of twenty-two (22) poles, six (6) overhead transformers, three (3) padmounted transformers and 250m of direct buried cable to be encased with concrete encased cable, all to be completed in 2018.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Ottawa |
| **Capital Cost:** | $821,750 |
| **O&M:** | $0 |
| **Start Date:** | 2018 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Ottawa Street, from Eagleson Road to McBean Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Ottawa Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Ottawa Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of thirty-two (32) poles, nine (9) overhead transformers, two (2) padmounted transformers and 125m of direct buried cable to be encased with concrete encased cable, all to be completed in 2018.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Burke |
| **Capital Cost:** | $475,320 |
| **O&M:** | $0 |
| **Start Date:** | 2018 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,860 Customers/5,793kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Burke Street, from McBean Street to Fortune Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Burke Street will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Burke Street will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of thirteen (13) poles and four (4) overhead transformers, all to be completed in 2018.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system. The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

| | |
|---|---|
| **Project Name:** | Richmond Voltage Conversion – Eagleson |
| **Capital Cost:** | $622,450 |
| **O&M:** | $0 |
| **Start Date:** | 2018 |
| **In-Service Date:** | 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Capacity |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 1,097 Customers/4,049kVA |

**Project Scope**

The scope of this project is to extend two (2) 27.6kV feeders along Eagleson Road, from Perth Street to Ottawa Street. The upgrade of Richmond South DS will continue to supply 8.32kV for the existing customers as well as 27.6kV for the voltage conversion to be completed in a phased approach. The two (2) feeders being constructed along Eagleson Road will have one feeder energized at 8.32kV to continue supply to existing customers and one feeder at 27.6kV to begin the voltage conversion. All services supplied from the pole line along Eagleson Road will be converted during the project. The intent is to have this infrastructure in place for the energization of the upgraded Richmond South DS.

**Work Plan**

Work break down for this projects includes replacement of twenty-eight (28) poles, seven (7) overhead transformers and nineteen (19) poles that require change of insulators, all to be completed in 2018.

**Customer Impact**

By integrating new Richmond South DS feeders into the distribution system in Richmond, it will improve the flexibility of the system.  The average number of customer hours per interruption should diminish significantly. This project will also increase the available capacity in the village of Richmond for the upcoming developments.

## 3.5 Goulbourn Street Voltage Conversion

### 3.5.1 Project/Program Summary

The Goulbourn Street Voltage conversion is intended to fix power quality issues experienced by customers in and around Goulbourn Street in Stittsville. This community has seen significant change since the time of its first development. Properties have experienced multiple severances of land in order to build multiple homes and have resulted in unbalanced load and over loading of the one phase supplying this area, which has ultimately led to low voltage experienced by these customers. By converting these customers and looing them in with the 27.6kV JKGF4 feeder, renewed infrastructure and balancing load amongst the phases will eliminate their low voltage issues. Limited expansion is required in order to have 27.6kV available to the area. Conversion from 8.32kV to 27.6kV is the end goal of all areas within the Stittsville community in order improve reliability and eliminate power quality issues on-going with the 8.32kV system.

### 3.5.2 Project/Program Description

#### 3.5.2.1 *Current Issues*

Current issues in the Goulbourn Street community include deteriorating power quality due to land splitting for residential development that has resulted in unexpected customers being added to a single 8.32kV phase at the end of the 44F1 feeder. Aging infrastructure has also contributed to the degradation of power the customers are experiencing.

#### 3.5.2.2 *Program/Project Scope*

The scope of this project is illustrated below, which is to extend one (1) 27.6kV phase from JKGF4 along Goulbourn Street to convert the 8.32kV to 27.6kV and incorporate changes to the distribution layout to enhance operability. This includes a 90m extension along Cypress Gardens through the use of a direct buried duct system to encase the single phase cable, that will then rise up to the existing 8.32kV overhead system on Goulbourn Street. Incorporated in this project will be the replacement of forty-seven (47) poles, nine (9) overhead transformers, five (5) padmounted transformers and a total of 220m of direct buried duct encased trunk. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced. The 27.6kV phases will then meet at a primary pedestal located on Elm Crescent which will be used to complete the residential developments. Completion of the developments in the community will create a tie between JKGF4 and TFXF5 that will improve reliability to this community.

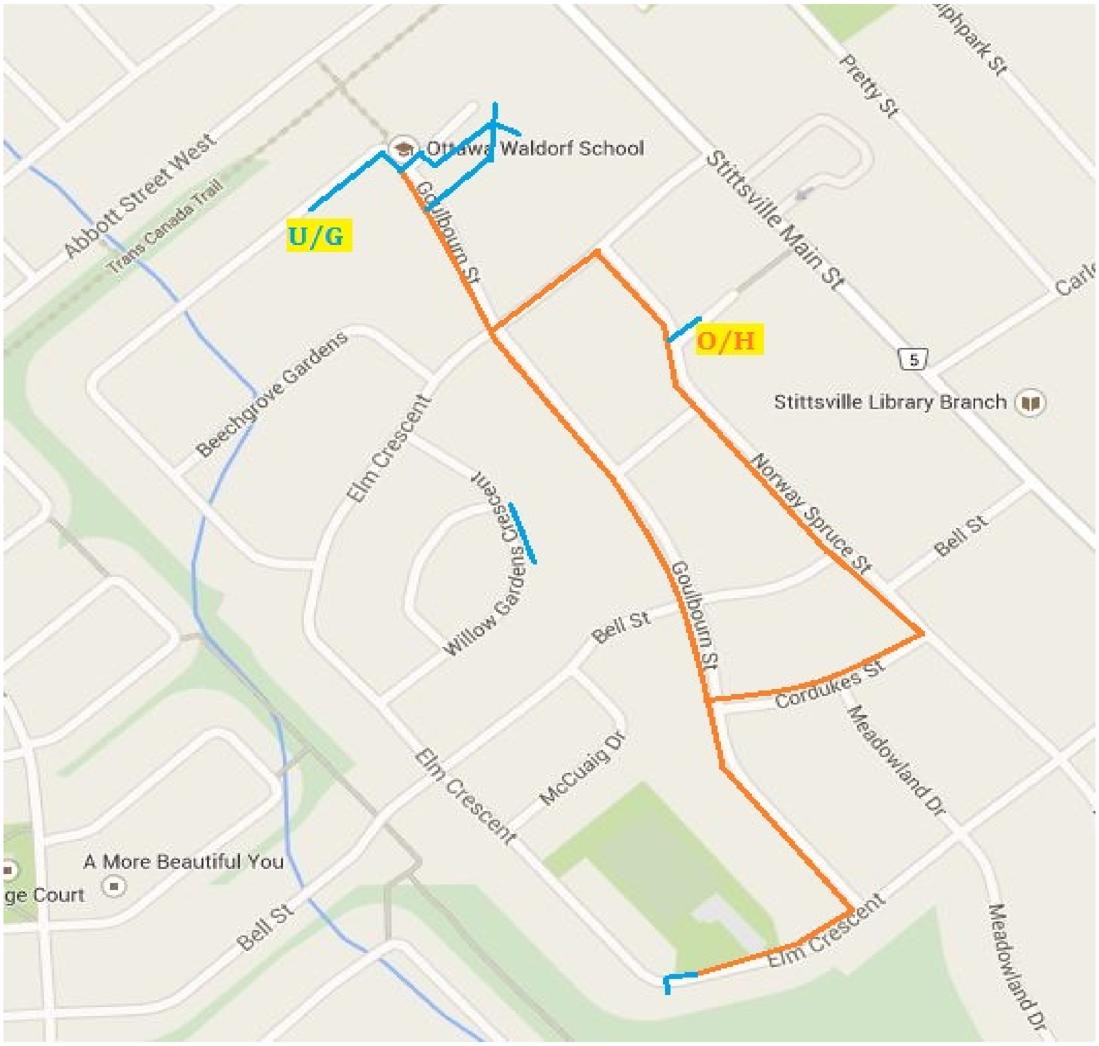



Figure 99 - Goulbourn Street Voltage Conversion Scope

### 3.5.2.3 *Main and Secondary Drivers*

The main driver of this project is to improve power quality on the 8.32kV system around Goulbourn Street. The area is supplied from 8.32kV by a single phase from 44F1 and due to the load and the location of the neighbourhood at the end of the feeder; customers have experienced voltage drops below acceptable limits during summer peak periods. The 27.6kV system is within 90m of the 8.32kV and requires minimal adjustment in order to extend a phase to convert the 27.6kV. Converting the customers on Goulbourn Street will improve the power quality that these customers experience, but will also benefit the customers remaining on the 8.32kV system.

The secondary driver of this project is to improve reliability as the 8.32kV system in this neighbourhood is radially supplied with no source of alternate supply. Through the completion of the development in this neighbourhood, a tie will be created between TFXF5 and JKGF4 which will be beneficial to more customers as a result of the conversion. Renewed infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

#### 3.5.2.4 *Performance Targets and Objectives*

The main objective of this project is to improve power quality experienced by customers in the community surrounding Goulbourn Street. Conversion will directly benefit the customers being converted and those remaining on the 8.32kV system. This project will directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system.

A secondary objective is to improve reliability in the Goulbourn Street community. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

### 3.5.3 Project/Program Justification

#### 3.5.3.1 *Alternatives Evaluation*

##### 3.5.3.1.1 Alternatives Considered

Power quality in the Goulbourn Street community has been greatly impacted by the increasing number of customers on a radial 8.32kV supply at the end of the feeder, due to land splitting that has occurred.

**Alternative #1:** Routing considered is along Goulbourn Street. This route would extend the JKGF4 from Cypress Gardens to Elm Crescent. This option is the most direct route to extend 27.6kV to be capable of converting the 8.32kV infrastructure. Conversion will directly benefit the customers being converted and those remaining on the 8.32kV system. This project will directly reduce the impact on the System Average RMS Variation Frequency Index (SARFI) used to measure power quality issues in the system. New infrastructure will directly improve SAIFI and the feeder ties will directly reduce the impact on SAIDI.

**Alternative #2:** Routing considered is along Elm Crescent and Goulbourn Street. This route would replace the existing forty-one (41) poles and single phase 8.32kV infrastructure with three phases of the 44F1 8.32kV feeder. Having all three phases would permit the balancing of load across each phase. Also required would be a three phase voltage regulator to be installed on Stittsville Main Street that would provide the ability to better regulate voltage at the end of the 44F1 feeder and in the Goulbourn Street community.

##### 3.5.3.1.2 Evaluation Criteria

**Costs:**

Alternative #1: $0.802M

Alternative #2: $0.940M

**Ability to supply load:**

Alternative #1: The 8.32kV system in the Goulbourn Street community cannot support additional load growth without compromising the power quality issues further. Extension of 27.6kV into this area will permit further load growth, which this area has experienced due to large lot sizes being split to accommodate more residential homes.

Alternative #2: This option will permit load growth in the Goulbourn Street community, but may not completely eliminate the power quality issues due to its location at the end of the 44F1 8.32kV feeder.

**Reliability Benefits:**
Both alternatives would benefit reliability in the community by renewing infrastructure; however Alternative #1 would create a tie between two feeders that would ultimately reduce SAIDI.

#### 3.5.3.1.3 Preferred Alternative

Alternative #1 is the preferred alternative due to power quality improvements, project costs and reliability benefits associated with this alternative.

### 3.5.3.2 *Project/Program Timing & Expenditure*

The total project cost is $802,000 and the project is anticipated to be completed in 2016. HOL aims to minimize the costs and meet the deadlines associated with all projects, by completing pre-planning of the construction schedule and ensuring vehicles, staff and material are all available for start of construction.

| Historical ($M) | | | | | | Future ($M) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| $0 | $0 | $0 | $0 | $0 | $0 | $0.802 | $0 | $0 | $0 |

**Table 101 - Project Expenditures**

### 3.5.3.3 *Benefits*

Key benefits that will be achieved by implementing the Goulbourn Street Voltage Conversion project are summarized below.

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | This project is required to improve reliability in the Goulbourn Street community. It is an essential system service project needed in order to improve power quality issues and system operation efficiency by interconnecting the new Terry Fox TS to the distribution system in Stittsville and provide an alternative source when restoring outages. This should inevitably contribute to reducing SARFI and SAIDI. Re-constructing the infrastructure on Goulbourn Street is the most cost-effective solution and has the greatest benefit of improving the power quality and reliability in the Goulbourn Street community. |
| **Customer** | This project will achieve power quality and reliability improvement for customers in the Goulbourn Street community. The conversion of 8.32kV to 27.6kV should eliminate the power quality issues experienced by these customer and renewed infrastructure that will ultimately improve SAIFI. |
| **Safety** | The infrastructure in place today has begun approaching end of life and poses a small risk of failure and safety concern. By replacing the infrastructure, the safety risk is significantly reduced. |
| **Cyber-Security, Privacy** | Not Applicable. |
| **Co-ordination, Interoperability** | Not Applicable. |
| **Economic** | This project is not expected to contribute directly to economic growth or job |

| | |
|---|---|
| **Development** | creation, but due to the number of assets being replaced in this project, will inevitably require operation and maintenance. Contractor labour will be used extensively to complete the project. |
| **Environment** | Not Applicable. |

**Table 102 - Project Benefits**

### 3.5.4 Prioritization

#### 3.5.4.1 *Consequences of Deferral*

The consequence of deferring this project will result in further power quality issues experienced by customers of the Goulbourn Street community. Infrastructure that currently supplies this community will continue to deteriorate and both power quality and reliability can be expected to continue to worsen, which contributes highly to the total system SARFI and reliability statistics due to the number of customers in the community.

#### 3.5.4.2 *Priority*

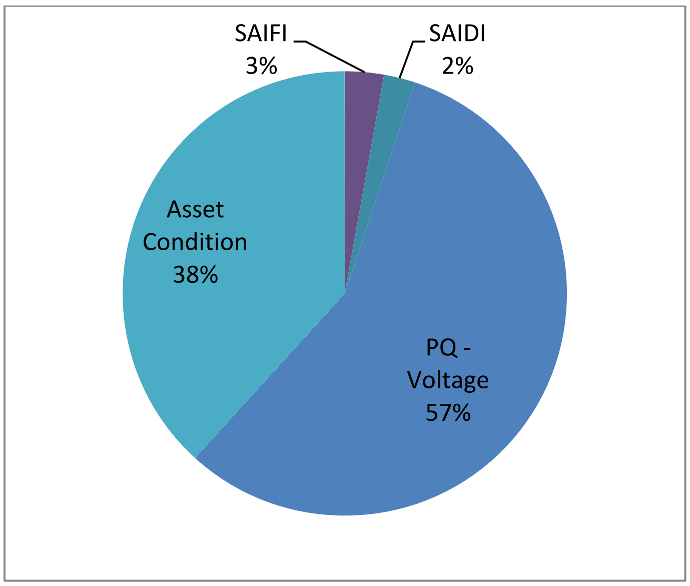



**Table 103 - Project Avoided Risk**

Project Score: 0.235

### 3.5.5 Execution Path

#### 3.5.5.1 *Implementation Plan*

This project is to be entirely completed in 2016 and includes extension of JKGF4 90m along Cypress Gardens through use of direct buried duct system to encase the single phase cable, that will then rise up to the existing 8.32kV overhead system on Goulbourn Street. Incorporated in this project will be the replacement of forty-seven (47) poles, nine (9) overhead transformers, five (5) padmounted transformers and a total of 220m of direct buried duct encased trunk. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced.

#### 3.5.5.2 *Risks to Completion and Risk Mitigation Strategies*
Risks that may affect this project are easement acquisition, existing location of trees, and bedrock. HOL takes many steps in the design phase of the project to minimize these risks by investigating them early on.

#### 3.5.5.3 *Timing Factors*
Factors affecting the timing of this project include easement acquisition, City of Ottawa Municipal Consent, customer outage limitations and weather conditions.

#### 3.5.5.4 *Cost Factors*
Factors that may affect costs of the project include costs associated with digging through rock and delays due to weather conditions.

#### 3.5.5.5 *Other Factors*
Not applicable.

### 3.5.6 Renewable Energy Generation (if applicable)
Not applicable.

### 3.5.7 Leave-To-Construct (if applicable)
Not applicable.

### 3.5.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | 92010184 – Goulbourn Street Voltage Conversion |
| **Capital Cost:** | $0.802M |
| **O&M:** | $0 |
| **Start Date:** | 2016 – Q1 |
| **In-Service Date:** | 2016 – Q4 |
| **Investment Category:** | System Service |
| **Main Driver:** | Power Quality |
| **Secondary Driver(s):** | Reliability |
| **Customer/Load Attachment** | 200 Customers/500kVA |
| **Project Scope** | |
| The Goulbourn Street Voltage conversion is intended to fix power quality issues experienced by customers in and around Goulbourn Street in Stittsville. This community has seen significant change since the time of its first development. Properties have experienced multiple severances of land in order to build multiple homes and have resulted in unbalanced load and over loading of the one phase supplying this area, which has ultimately led to low voltage experienced by these customers. By converting these customers and looing them in with the 27.6kV JKGF4 feeder, renewed infrastructure and balancing load amongst the phases will eliminate their low voltage issues. Limited expansion is required in order to have 27.6kV available to the area. Conversion from 8.32kV to 27.6kV is the end goal of all areas within the Stittsville community in order improve reliability and eliminate power quality issues on-going with the 8.32kV system. | |
| **Work Plan** | |
| The scope of this project, to be completed in 2016, is to extend one (1) 27.6kV phase from JKGF4 to convert the 8.32kV to 27.6kV. This includes 220m direct buried duct system to encase the single phase cable extension, replacement of forty-seven (47) poles, nine (9) overhead transformers, and five (5) padmounted transformer. Also included will be the change of phase on five (5) transformers that will allow each phase of the feeder to most efficiently extend through the neighbourhood and remain relatively balanced. | |
| **Customer Impact** | |
| By integrating 27.6kV into the distribution system in the Gouldbourn Street community, it will improve system power quality and reliability. The number of customers experiencing power quality issues should diminish significantly. This project will also increase reliability through development completion and integrating with Terry Fox feeders on Fernbank Road. | |

# 4 Distribution Automation

## 4.1 Telecommunications Master Plan

### 4.1.1 Project/Program Summary

The Telecommunications Master Plan is a project to focus all of the HOL communications spending into one core network architecture. With a single converged network, HOL will make efficient use of its telecommunication budget while at the same time establishing the capacity that will accommodate all future traffic needs. This network plan involves a mix of radio systems which comprise the Field Area Network (FAN) connected to a core Wide Area Network (WAN) made up primarily of high capacity fibre optic links. Therefore, this project will involve the architecting, design, procurement, and construction of a complete communications network solution.

### 4.1.2 Project/Program Description

#### 4.1.2.1 *Current Issues*

Currently, HOL makes use of a variety of communications technologies and services across various business units including:

- SCADA Communications:
  - A leased fibre optic network connecting 41 locations (substations, SCADA head offices) across the service territory with low bandwidth serial communications channels. This system was installed by a predecessor utility (Ottawa Hydro) in the early to mid-1990's and was divested at the time of deregulation. Therefore as the assets are approaching the end of their useful life, and given the size of the network, replacement should begin in the very near future.
  - Leased public owned telephone service (POTS) lines connect several substations with the SCADA head-end using legacy serial modem technology. These links are particularly expensive considering their low capacity. Furthermore, due to the age of the modems used for these lines a replacement in the near term is preferable.
  - Leased 3G/4G services providing higher-capacity links to substations that are equipped with distribution automation equipment and sensors. This hardware is fairly new however the services are costly for data intensive locations.
  - Two serial radio systems (both licensed and un-licensed 900MHz spectrum) connect various automation devices to substations and the SCADA head offices. These low cost technologies will be carried forward into the proposed network as a connection from the substations to the surrounding distributed sensors and devices. The hardware involved in these networks has been installed for several years and can be reused in the proposed network.
  - A pilot WiMAX network which is being trialed as a new point-to-multipoint communications system to reach distant substations and devices that are outside of the feasible reach of a private fibre network (e.g. rural substations).
- Corporate communications:

- Leased high-capacity data services are used to connect the various offices to each other for network connectivity between sites. This asset is not owned by HOL.
- Microwave point-to-point radio links. These links are designed to provide a backup communication path in the event of a failure in the leased data link. The radio equipment is owned by HOL while the spectrum is licensed from Industry Canada.
- Office telephone lines are leased however in-building infrastructure is at a significantly advanced age and is requiring repair.

The fibre optical cable assets proposed in this project have a typical lifespan of 25 years which will make this an excellent long term investment. This network will be designed in a highly reliable configuration to accommodate all SCADA and Office communications traffic with sufficient capacity to handle future growth.

While the age of the assets discussed above is not the primary driver of this project, many parts of the network that HOL uses are nearing their end of life. Given the time required to deploy a large communications network, it is important that the planning begin at once.

The bulk of the communications assets are not owned by HOL but are approaching the end of their expected life span (particularly the leased SCADA fibre network). Due to its size, complexity, and cost, it is important that the planning phase for a replacement begin immediately. As a result, this project aims to systematically consolidate all of the disparate communications systems into one coherent wide area network to accommodate all of HOL's network communications needs.

Without a comprehensive network built and operated by HOL, we will be forced into unfavorable contracts with service providers that will charge based on the amount of data capacity required. This will result in a financially untenable situation as the demand for data increases exponentially as the amount of smart grid devices and sensors are deployed on the distribution system.

#### 4.1.2.2 *Program/Project Scope*

This project encompasses the communications needs of HOL across its entire service territory. Therefore, the scope of this project is exceptionally wide as there will be multiple stakeholders across the organization and the project will span a significant geographical area.

At the conclusion of this project, HOL will own and operate the following assets:

- A high capacity fibre optic network which will provide connectivity between all offices and the bulk of the centrally located substations.
- A point to multi-point microwave or WiMAX radio network which will provide connectivity to rurally located substations and to field equipment requiring broadband network connections (e.g. distribution automation groups, AMI gatekeepers etc.)
- A point to multi-point unlicensed radio network which will provide connectivity to end-point equipment in the local proximity to a higher bandwidth node. (e.g. individual distribution automation equipment, sensors, smart meters etc.)

Therefore, all communications equipment owned or leased by HOL and communications services purchased by HOL will fall within the scope of this project. The overall objective of this project is to eliminate both legacy communications equipment, and the use of expensive communications services. These will be replaced with a private, high bandwidth network capable of securely handling all of HOL's communications needs.

#### 4.1.2.3 *Main and Secondary Drivers*

The primary driver for this telecommunications master plan project is to ensure the long term financial viability of the HOL field (SCADA) and office networks. This is due in part to the fact that customers of the 21st century are more demanding than ever before. They expect service providers to be pro-active, responsive and cost-effective. HOL customers are no different. They expect us to be fully aware of the distribution system performance at all times: outages, brown outs, voltage disturbances, and power quality issues. In the age of electronics, all of these issues are critical to our customers. These new expectations are reshaping how utilities will deliver service now and in the future. HOL believes the Smart Grid is the future.

In 2012, HOL commissioned a study called Grid Transformation Action Plan (GTAP) which articulated what the Smart Grid means in the context of both the Ontario electricity market and HOL's distribution system. Amongst the conclusions of this study was the idea that the Smart Grid has three key qualities: it is instrumented, intelligent, and interconnected. Although power systems have remained virtually unchanged over the years, how they are monitored and restored has changed greatly in the last 25 years. New automated switches, sensors and smart meters all connected to a high speed network help make the system more reliable and efficient. This is the Smart Grid. By merging the distribution system with high-performance communications, HOL will achieve its goal of providing reliable service and value to its customers and shareholder.

Therefore, the primary drivers for this project are:

- The long term financial viability of HOL's communications needs.
- To accommodate the ever increasing communications needs of intelligent devices and distribution automation (i.e. to accommodate the 'Smart Grid').

The secondary drivers for this project are:

- To create a private network that can be fully controlled by HOL in the interest of improving the cyber-security of the SCADA system thereby protecting the critical infrastructure of the nation's capital city.
- To expand connectivity and allow each and every substation to become a data aggregation point capable of communicating with thousands of devices.

#### 4.1.2.4 *Performance Targets and Objectives*

With a unified communications infrastructure connecting the bulk of the HOL substations, the ability to collect and utilize data from the field will be dramatically improved both in terms of bandwidth and reliability. As mentioned in the introduction, HOL has invested wisely in intelligent devices and sensors within the substation environment. By having these devices connected to each other and the office through reliable high speed links, a vast array of smart-grid applications will become available for implementation. These include:

- Bringing device and operational data into the asset management system, enabling more intelligent maintenance and investment
- Real-time collection of fault data for calculating the fault location, thereby reducing outage time and person-hours lost to discovering the root cause
- Device coordination between substations and field devices, allowing for automatic fault isolation which could significantly reduce outage statistics

One of the most important benefits of the core network strategy is enhanced financial strength. As discussed in the introduction above, HOL currently has several different systems with independent communications links. The consolidation of these communications links onto a core network will help monetize HOL's communications dollars. While there will still be the need to reach each individual device with a link, a core wide area network (WAN) will allow each and every substation to become a data aggregation point for many types of devices. Moving these aggregation points from the main office further into the field will reduce the distance to each individual sensor and allow for the use of lower cost wireless links (such as unlicensed 900MHz or WiMAX). Furthermore, by having a high capacity core network the future growth of data intensive field connections (as driven by Smart Grid applications) will be easily accommodated, thereby containing future costs per connection.

In addition to data coming in from the field, the core WAN network will allow corporate data traffic to be accessible from the substations. This connectivity will serve to increase the productivity of the outdoor staff by allowing access to documents and drawings without the need for expensive cellular connectivity or the delays of returning to the corporate office. Further productivity gains may be realized with the IT operations staff as well. This is due to the fact that a single core WAN infrastructure will serve to reduce overall complexity (with use of similar hardware) of the HOL communications networks. The reduced complexity will aid in monitoring and maintenance of a single network.

The most important aspect of this telecommunications master plan is that it aligns well with our corporate strategy - the customer. With a fully interconnected grid, this utility will be able to make use of advanced Smart Grid technologies which could drastically improve the customer experience. From the reduction of both the frequency and duration of outages, to making more information available in a timely manner; the customer experience will be enhanced. While there will still be a need to proactively analyze and act on the state of the intelligent devices, the communications infrastructure provides the invaluable ability to collect the data from the field.

### 4.1.3 Project/Program Justification

#### 4.1.3.1 *Alternatives Evaluation*

##### 4.1.3.1.1 Alternatives Considered

HOL evaluated four main alternatives for the communications master plan. Alternative one would be to maintain the status quo; with each application continuing to use and maintain its own separate infrastructure on a case by case basis (e.g. Meter data collection and SCADA uses separate backhaul infrastructure). The second and third alternatives involve the design and construction of a complete wireless or fibre system to cover the entire HOL service territory (e.g. Entirely wireless system or entirely Fibre based system). Finally, the fourth alternative would create a hybrid network which would see a core wide area network made primarily from fibre links with wireless systems providing connectivity where most appropriate (e.g. the Field Area Network and to remote substations).

#### 4.1.3.1.2 Evaluation Criteria

Each of these alternatives was evaluated against the following criteria:

1) Cost-effectiveness
   a) Is the current infrastructure cost-effective or sustainable?
   b) Is the considered alternative more cost efficient in the long term?
   c) Is it sustainable as a HOL owned asset?
2) Functionality
   a) Can the considered alternative accommodate the current data requirements?
   b) Can the considered alternative accommodate the future growth in data traffic?
   c) Can the considered alternative accommodate different traffic priorities?
3) Future expandability
   a) Is the considered alternative expandable to accommodate future needs?
4) Security (both cyber-security and in terms of reliability
   a) Is the considered alternative more or less secure against cyber-attack?
   b) Is the considered alternative more or less reliable than the current network?

#### 4.1.3.1.3 Preferred Alternative

The preferred alternative is to create a hybrid-network with a core comprised of a fibre optical network between the main office locations and the majority of substations augmented with wireless systems to connect field devices and remote substations. This hybrid network offers the most functionality and the best overall connectivity. In addition, the core fibre network offers the highest cyber-security and reliability while the peripheral wireless networks will aid in balancing the overall cost of the network. The hybrid-network approach is the most cost efficient over the long term, particularly as more and more data intensive sensors and devices are deployed across HOL's service territory. As each device is deployed, a pre-planned network will easily accommodate the new connections with limited ongoing cost as opposed to the cost growth from purchasing new data services from an outside vendor as is typically done today.

Beyond the preferred alternative were the two monolithic network solutions of an all fibre network and an all wireless network. While both of these solutions can provide the connectivity required, they do not have the cost advantages of the hybrid topology. Finally, the least preferred alternative is to do nothing and continue to deploy connections on individual disparate communications networks. This 'do nothing' alternative will become unsustainably expensive as smart devices and sensors become necessary across the distribution grid.

### 4.1.3.2 *Project/Program Timing & Expenditure*

As described in the above sections, the communications system proposed in this Telecommunications Master Plan is a significantly large undertaking. In order to fully deploy the hybrid network it will involve over 10 years of capital investment as well as ongoing OM&A expenses. While this may seem to be an overly ambitious expenditure, the project is broken down into three phases of investment in order to ease the transition to a new communications infrastructure.

Phase 1 of the project is the initial design and construction of the core high-speed optical network, including pilot projects and their associated studies. Included here is the equipment required to transition the current leased fibre from a low-speed serial link to a high-speed network connection. This phase also sees the installation of new fibre optical cable in order to bring the network up to the required level of redundancy for passing all of HOL's network traffic.

Phase 2 of the project is focused on expansion of the fibre network to connect additional substations to the core wide area network. More importantly is the installation of the wireless equipment needed to connect field area devices to base station radios located within selected substations.

Finally, phase 3 is designed to incrementally replace the leased fibre optic cable with HOL owed infrastructure. This will prevent the need from entering into another unfavorable lease and to replace infrastructure that would be at the end of its useful life.

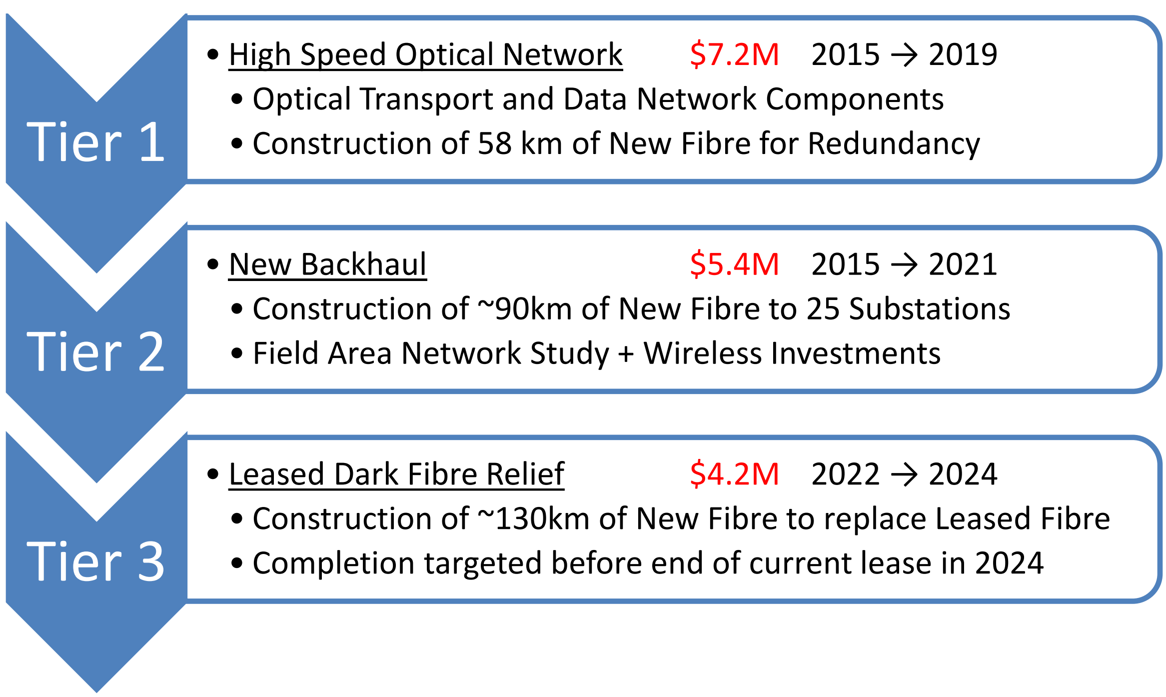
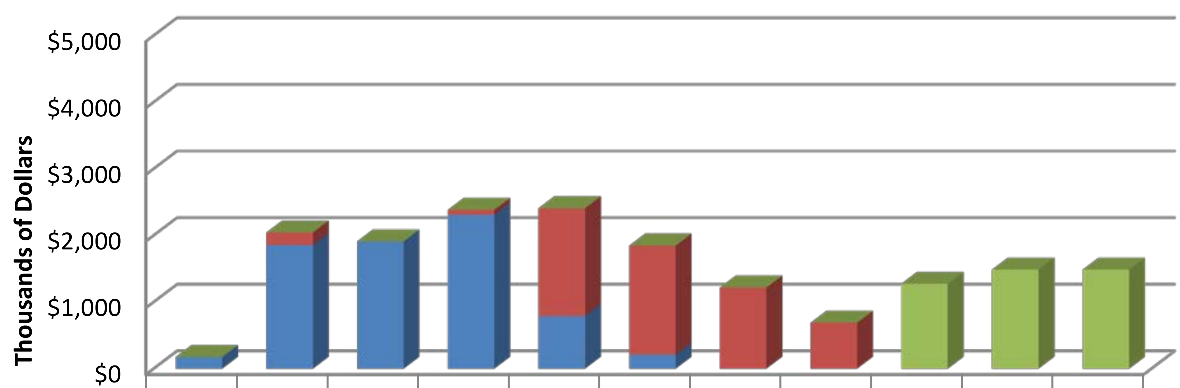



**Figure 100 - Project Timing**

The following chart illustrates the breakdown in the capital expenditure for each year and shows the category in which the investments are made. While this initial plan shows a steady stream of investment over the next 10 years, the modular nature of the proposed infrastructure means that individual investments can be shifted around into more favorable years.




| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total | $175 | $2,044 | $1,910 | $2,383 | $2,408 | $1,846 | $1,218 | $689 | $1,274 | $1,487 | $1,487 |
| Tier 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,274 | $1,487 | $1,487 |
| Tier 2 | $0 | $189 | $0 | $77 | $1,616 | $1,638 | $1,218 | $689 | $0 | $0 | $0 |
| Tier 1 | $175 | $1,855 | $1,910 | $2,306 | $792 | $208 | $0 | $0 | $0 | $0 | $0 |

**Figure 101 - ROM Capital Investment by Year and Tier**

Due to the transformational nature of this telecommunications plan, the analysis of the impacts on the OM&A budget is significantly more complicated. Therefore, the following section will address the assumptions that were made in three parts; IT costs, communications cost reductions, and avoided future costs. Following the description of the assumptions, the total impacts on the operations budget will be combined in a high level analysis summary.

One key area of HOL that will be impacted by this network infrastructure change is the IT department. While a larger and more advanced network will increase the demands on IT resources, the fact that it will be designed for manageability as a single network will serve to streamline operations. To address this increased demand there will be a need for additional resources. Furthermore, there will be associated costs for a network operations centre, network management systems, and associated software licenses.

As described earlier one of the drivers for creating a new core wide area network is to control the current communications costs. With the construction of the new high-speed network, HOL will be able to eliminate both the fibre lease and the leased public telephone lines. These leased network costs together with the cellular and licensed radios represent a significant burden on the overall OM&A budget. Unfortunately, given the size and the complexity of the leased infrastructure, it will take several years before these lease costs transition to the maintenance and operational costs associated with a private infrastructure. Therefore, until the communications master plan is complete, the majority of this expenditure will remain in the annual budget.

Most importantly, this telecommunications master plan is about controlling the future costs of communications as the HOL distribution system is transformed into a smarter grid. With the increased interconnectedness as demanded by smart grid applications, this core WAN strategy will provide all of the required connectivity at a drastically lower cost than the current solutions. In order to realize these savings it is assumed that HOL will be incrementally transitioning to a fully connected and automated distribution system over 25 years. In order to achieve this end state, HOL will need to install sensors and automated systems out onto the distribution grid each and every year which has indeed been the case.

Therefore with the future investments in distribution sensors and automated devices, HOL requires lower cost, high bandwidth connections across its service territory.

#### 4.1.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | With an advanced communications network connecting office locations and substations across its service territory, HOL will be able to add new connections for a very limited additional cost. Therefore, as more and more devices are connected, the communications network will become more and more cost efficient. These additional sensors and devices are an unavoidable reality for a modern distribution utility. |
| **Customer** | With a comprehensive communications network across the service territory, HOL will be able to deploy advanced sensors and distribution automation equipment. These devices will have a direct and measurable effect on the duration of outages experienced by customers (SAIDI).<br>Furthermore, by collecting more and more data from substation and field devices, there will be a significant improvement in the prioritization of maintenance activities. This evidence based maintenance will lead to significant reductions in the frequency of asset failures over the longer term. Therefore, customers will see an associated reduction in asset failure based outages thereby reducing the outage frequency (SAIFI) |
| **Safety** | In designing a complete, reliable communications network with redundant paths built in, HOL will eliminate its dependence on third part networks which can fail at inopportune moments. Therefore, a more reliable network will allow for higher reliability in the SCADA connections thereby improving the overall safety of system operations. |
| **Cyber-Security, Privacy** | With a private network HOL will no longer be dependent on third party carriers for the bulk of its network traffic. This will serve to reduce the overall exposure of the HOL SCADA system to cyber-attacks. |
| **Co-ordination, Interoperability** | The proposed network will make extensive use of standards based technology in order to ensure the long term availability of replacement parts. Furthermore, by creating a common network for all HOL traffic there will be a significant improvement in the internal co-ordination of communications systems deployment and usage. |

| | |
|---|---|
| **Economic Development** | Given the size and scope of this investment, it is likely that the construction phase will require the support of third party firms in the Ottawa area. These design and construction contracts will provide direct economic benefits to both the high tech community as well as the construction firms within the capital region. |
| **Environment** | The communications network proposed in this project is an enabling technology. By connecting the sensors and devices across the distribution system, HOL will be in a better position to operate the grid in a more efficient and environmentally friendly way. |

**Table 104 - Project Benefits**

### 4.1.4 Prioritization

#### 4.1.4.1 *Consequences of Deferral*

While this communications network is not critical to providing electricity to HOL's customers, it will aid in the transformation of HOL's business. This transformation will result in a significant improvement in the capabilities of this utility to collect, analyze, and act on data collected from the field. These actions will have a direct and significant benefit to both HOL's customers and its shareholder. The former will see improved outage statistics while the latter will see improved financial performance garnered from a reduction in the cost growth associated with communications expenses. Therefore, any delay in this project will delay the realization of the associated benefits to HOL's stakeholders.

#### 4.1.4.2 *Priority*

The overall priority of this project is medium. Due to the fact that the communications systems are not central to the distribution of electricity to HOL customers, this investment cannot be rated as a high priority. However, due to the benefits that will be garnered from the connectivity and the associated cost growth of 3rd party connections, this project cannot be listed as a low priority.

### 4.1.5 Execution Path

#### 4.1.5.1 *Implementation Plan*

As discussed in section 3.2 above, this project will be executed in three distinct phases. The first phase will be the initial design and the conversion of the current fibre network to a high-speed network. The second phase will involve enhancement to the capacity of the network in terms of geographical coverage. This expansion will be in the form of new fibre optical cabling as well as the deployment of radio systems into the field. Finally, the third phase will see construction of fibre optic connections to replace the connections that are currently leased from a third party network provider.

#### 4.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

The largest risk to completion of this project is the overall cost of implementing the network. While it appears to be a significant expenditure, the overall cost of owning this network will be far lower than the associated service costs from third parties.

#### 4.1.5.3 *Timing Factors*

Due to the fact that this is a long term investment, there is little risk that schedule pressure will be an issue. HOL requires a replacement to the leased fibre optic network before the end of the year 2024. While it is advisable that the full network be implemented as soon as possible, there is a significant amount of time remaining for execution.

#### 4.1.5.4 *Cost Factors*

Given any project of this magnitude, the overall cost of implementation is a factor. Due to the fact that the network proposed in this project will cost in excess of $17 million dollars to fully implement, it has been broken down into much smaller investments. While it would be ideal to implement this network as fast as possible, it is recognized that this would prove infeasible. Therefore to mitigate the risk of cancellation, the project will be delivered in smaller investments over the next 10 years thereby positioning HOL to be independent of a costly lease at the end of its current contract.

#### 4.1.5.5 *Other Factors*

N/A

### 4.1.6 Renewable Energy Generation (if applicable)

N/A

### 4.1.7 Leave-To-Construct (if applicable)

N/A

### 4.1.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Telecommunications Master Plan |
| **Capital Cost:** | Approximately $17M |
| **O&M:** | TBD |
| **Start Date:** | January 1 2014 |
| **In-Service Date:** | December 31 2024 |
| **Investment Category:** | System Service |
| **Main Driver:** | Long-Term Economic Viability of Communications Infrastructure |
| **Secondary Driver(s):** | Accommodate Ever Increasing Demands for Device Connectivity |
| **Customer/Load Attachment** | 305,000 |

**Project Scope**

This project encompasses the entire network communications infrastructure of HOL. This includes corporate data and voice traffic between offices as well as SCADA traffic between facilities, substations, and field devices.

**Work Plan**

This project will be executed over a 10 year time frame starting from 2014 and ending in the year 2024. The work will be broken out into three distinct phases of work, phase one will see the transition of the existing system to a high-speed network. Phase two will feature expansion of the communications infrastructure to include more field devices and substations. Finally the third phase will feature replacement of the leased fibre infrastructure.

**Customer Impact**

A comprehensive and advanced communications infrastructure will allow HOL to improve both its ability to react to customer outages as well as its ability pro-actively maintain its assets, thereby preventing outages from occurring. This improvement will come from HOLs ability to collect more data from assets in the field, and its ability to interactively communicate with intelligent devices on the distribution system.

# 5 SCADA Upgrades

## 5.1 SCADA Upgrade Project

### 5.1.1 Project/Program Summary

The Supervisory Control and Data Acquisition (SCADA) System replacement project is necessary to bring both the hardware and software components up to date. Installed in the fall of 2006, the current system uses an out of date operating system, end of life hardware, and is no longer regularly maintained by the vendor. It is therefore necessary to install new hardware and software that utilizes a modern architecture and is designed for both maximum security and reliability.

### 5.1.2 Project/Program Description

#### 5.1.2.1 *Current Issues*

The current SCADA system was installed in the fall of 2006 and has been operational for over 8 years. This operational period is well beyond the typical 5-year lifespan of information technology hardware. Over the past year, there have been several hardware failures within the server equipment which clearly indicate that the assets are approaching the end of their useful life and should be replaced immediately.

In addition, the software used in the HOL SCADA system is running on an operating system that is no longer being supported by the vendor and (according to our SCADA vendor) cannot be migrated to a new operating system. It is the intention of this project to bring the HOL SCADA system back onto a solution where regular maintenance of the software, operating systems, and hardware is once again possible.

The SCADA system at HOL provides real-time situational awareness of the state of the distribution system and assets to the control room. Equally important is the fact that the SCADA system provides the control room with the ability to operate devices remotely without the need to dispatch field staff. This remote operation is extremely important in cases of public or employee safety where a device needs to be opened with little or no advanced warning.

As a result of the above mentioned dependencies, the HOL SCADA system cannot be allowed to fail. Without the ability to supervise and control the distribution system, there would be a significant impact on the ability to detect and mitigate outages and, as a result, the customers would be severely impacted (particularly the SAIDI measure of outage duration).

While the current system does have redundancy across multiple servers in two locations by design, the similar age and software dependencies of all systems serves to erode any reliability gained.

#### 5.1.2.2 *Program/Project Scope*

This project will involve the purchase and installation of an entirely new SCADA system for the HOL control room. Due to the fact that the current system is no longer on an upgrade path with the vendor (i.e. there are no patches or service packs available) a new installation will be required. This replacement project presents an opportunity to architect a new system that takes into account matters of functionality, reliability and cyber-security.

Therefore, this project will be focused on acquiring new hardware including: database servers (9), engineering servers (3), interface servers (13), workstations (25), networking equipment, firewalls (8), and communications equipment. More importantly this project will have a significant software purchase including: the Supervisory Control and Data Acquisition system, advanced distribution management systems, intrusion detection systems, and firewall software.

These systems will be located across several HOL locations including the Merivale Road and Albion Road offices as well as either the Bank Street or Maple Grove Road facilities. The project will not include any of the remote terminal units in the field or substations unless absolutely necessary.

#### 5.1.2.3 *Main and Secondary Drivers*

The primary driver for this project is to ensure the continued operation and reliability of the HOL SCADA system. This will be achieved by replacing the computer and networking equipment with newer hardware and acquiring the software from a trusted and proven vendor.

The secondary objectives of this project are to enhance the functionality and reliability of the SCADA system moving forward. Under this functionality and reliability goals are the following:

- Improving Cyber Security: The current system does not have any specific intrusion detection measures or third party tools for monitoring traffic within the SCADA network.
- Enhancing Functionality: The current SCADA system does not have any advanced distribution management system functionality. These new functions serve to provide operators with analysis and in some cases can help to automatically restore customers.
- Improving reliability: While the current system has redundant hardware in two physical locations, it would be beneficial to expand this hardware to cover a third location. This third site would be used as both a disaster recovery location as well as a quality assurance (development) environment for testing any changes or new technologies. With this third location available the overall reliability of the system will be improved as new patches and other improvements can be tested without affecting the production environment.

#### 5.1.2.4 *Performance Targets and Objectives*

The following represents the targets and objectives for the SCADA replacement project.

1) The primary objective of the SCADA replacement project is to have a new SCADA system deployed at HOL by the end of 2017. This new system must be:
   a) Capable of aggregating data from all of the current sensors and devices
   b) Capable of controlling all of the current remotely operated devices
   c) Capable of distributing information to engineering systems and related control systems
2) The second objective is to improve upon the reliability of the current system with:
   a) New enterprise class server hardware capable of running 24x7 for several years
   b) New networking equipment capable of routing SCADA traffic with high reliability
   c) Deployed systems configured for high reliability (dual power sources etc.)
   d) Regular maintenance and patching from the system vendor
3) The first upgrade objective is to improve the cyber-security posture of the HOL SCADA system

   a) Advanced Firewalls and network security equipment capable of securing SCADA traffic
   b) Enhanced user roles and management to prevent unauthorized access
   c) Detailed auditing capability for capturing all SCADA connected assets and users
4) The second upgrade objective is to include a third physical location in the network topology
   a) This will provide a disaster recovery location that could save the system database
   b) This will also allow for an environment for the purposes of testing and training
   c) It will aid in the transition to new facilities sometime over the next 5 years
5) The third upgrade objective is to enhance the features available to the control room staff
   a) Adding Distribution Management System (DMS) features can improve outage response
   b) Adding system drawing and pin-board features can reduce the number of additional tools needed within the control room

### 5.1.3 Project/Program Justification

#### 5.1.3.1 *Alternatives Evaluation*

##### 5.1.3.1.1 Alternatives Considered

Unfortunately, due to the age of the current SCADA system and the consequences of failure, the 'do nothing' alternative is not a valid option. Like any modern utility, HOL is dependent on the information collected from, and the control provided by the SCADA system. Operating without a reliable SCADA system over the long term would represent an untenable situation.

Alternative 1 is to perform a full replacement of both the hardware and software of the SCADA system. Given the age of the software and the operating systems used in the HOL SCADA system, it makes the most sense to perform a full replacement while the hardware is also being upgraded. This project should include expansion of the system and enhancement to the features in order to have the most impact on reliability, security and performance.

Therefore, there is essentially only one other alternative to the proposed replacement project which involves replacing only the hardware of the currently installed system. To do this, HOL would still require the purchase of new servers and networking equipment as the current equipment is near end of life. In order to keep the current SCADA software running, a set of virtual machines would need to be created from the existing systems and ported over to the new hardware. While the underlying operating system running on the servers would be new, both the operating system and the SCADA software running on the virtual machines would not be new. Although the primary objective of ensuring the continued operation of the SCADA system would be met, the secondary objectives of increasing functionality, reliability, and cyber security would either not be met or only partially met.

##### 5.1.3.1.2 Evaluation Criteria

The following criteria will be used to evaluate the alternatives for the SCADA replacement project:

1) Mitigate Risk of System Failure: The proposed solution should address the current risk of hardware failure.

2) Improved System Reliability: The chosen solution should serve to improve the ability to recover from a major disaster.
3) Improved Cyber Security: The chosen solution should contain features that improve the defense in depth as well as the ability to audit the system hardware, network traffic, and users.
4) Cost: The selected alternative should serve to minimize the future replacement costs of the SCADA system.

##### 5.1.3.1.3 Preferred Alternative

The preferred project alternative is to perform a full replacement of the SCADA hardware and software, with the enhancements described in alternative 1 above. This option is preferred over all others as it accomplishes all of the primary and secondary goals, but more importantly it is the option with the least amount of future risk. By upgrading the system with additional features for cyber security as well as a third redundant location, the risk posture of the HOL SCADA system would be dramatically reduced. This reduced risk posture more than compensates for the delta cost for adding these features to the new system. Additionally, installing new hardware during the acquisition of new software will allow for an easier transition to the new system while reducing disruption to the existing system.

Among the benefits of deploying a new system is the ability to engage ongoing support from the system vendor. Due to the fact that the current system is no longer on the vendor's development path it is not getting regular maintenance patches.  With a properly selected replacement system (i.e. one with a clear development future) the future upgrades can come in the form of regular maintenance as opposed to infrequent major upgrade projects such as this one. This type of process is currently being used to maintain the HOL Outage Management System (OMS) which has resulted in both regular system improvements and predictable maintenance costs.

#### 5.1.3.2 *Project/Program Timing & Expenditure*

This upgrade is coming at the very end of the typical life cycle of a SCADA system; therefore there is no comparable project for which costs can be directly compared over the recent past. However, by building a modern and fully featured system, HOL will be mitigating the costs and potential impacts of either a cyber-event or a disaster event.

The currently installed SCADA system at HOL has the following hardware: database servers (6), engineering servers (1), interface servers (3), workstations (17), networking equipment, firewalls (3), and communications equipment. The proposed system has 2 additional database servers (8), one additional engineering server (2), 10 additional interface servers (13), 8 additional workstations (25), additional networking equipment, 5 additional firewalls (8), and additional communications equipment.

The following chart illustrates the expected capital expenditure over the course of the SCADA replacement project. It is expected that the bulk of the spending is on vendor equipment and services from 2016 to 2018 while costs in 2015 are primarily for consulting and design services.

| Historical ($M) | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| N/A | N/A | N/A | N/A | N/A | 0.3 | 1.0 | 1.0 | 0.5 | 0 |

Table 105 - Project Expenditures

### 5.1.3.3 *Benefits*

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | A new SCADA system will provide direct benefits on system operation efficiency as it is used to collect data and provide a real time picture of the distribution system. Therefore any improvements will result in greater situational awareness and enhanced capabilities for the control room staff. Furthermore, by increasing the capabilities and intelligence available in the control room, decisions will be made faster and result in more effective use of field resources. |
| **Customer** | As mentioned above, the enhanced situational awareness and advanced functionality provided to the control room staff from a new SCADA system will result in improved response times which will serve to reduce outage durations (SAIDI). Furthermore, added functionality of a new SCADA system can provide information to support day-to-day system operations and help to offload at risk assets and reduce the number of preventable outages (thereby improving SAIFI).<br><br>While it is infeasible to quantify these impacts, features such as a Distribution Management System (DMS) and Power Flow analysis are designed to aid the system operators in the performance of their duties. |
| **Safety** | As described in an earlier section, the SCADA system is an integral part of protecting employees during planned and emergency work. Therefore this replacement project serves to improve the overall safety of staff by fully mitigating the risk of failure of the current system. |
| **Cyber-Security, Privacy** | As stated in the upgrade objectives above, one of the key elements specified in the new system will be tools and hardware dedicated to the defense of the SCADA system. These security features will be procured in accordance with industry best practices. With the improved security posture, HOL will be in a better position to protect the critical electrical infrastructure within the Ottawa area. |
| **Co-ordination, Interoperability** | The new SCADA system will employ industry standard technologies and best practices. A solution will be selected that allows for continued coordination and communications (over Inter-Control Centre Communications Protocol or ICCP) with both Hydro One and with the Independent Electricity System Operator.<br><br>The new SCADA system will also be selected based partially on the ability to collect data from a variety of new sensors and technology that has been deployed throughout the HOL distribution system since the last SCADA solution was installed. |
| **Economic Development** | Due to the distinct nature of SCADA systems and the particular skills required to install them, it would be unwise to restrict purchasing to one geographic area at this time. While there are SCADA vendors and service providers within the province of Ontario, they should be evaluated for their ability to address the project objectives first, before addressing the economic development objectives. |
| **Environment** | A modern and fully featured SCADA system will help HOL's operations utilize |

| | |
|---|---|
| | assets in the field more effectively (with features such as volt-var control) which will help reduce losses. Furthermore, a reliable SCADA system will allow HOL to readily detect issues with failing assets and to easily remove them from service (with features such as power flow analysis) and prevent catastrophic failures which can lead to environmental spills (e.g. transformer oil leakage). |

**Table 106 - Project Benefits**

### 5.1.4 Prioritization

#### 5.1.4.1 *Consequences of Deferral*

As discussed above, the SCADA system that is currently installed at HOL is at the end of its useful life and is no longer receiving regular updates from the vendor. Therefore a replacement system is required in the short term. Should this replacement project be deferred, the risk of hardware failure will become unacceptably high. Furthermore, due to the fact that the Operating Systems and SCADA software are no longer receiving regular updates, the risk of new vulnerabilities will not be fully mitigated as they would be with a new system. As a result, deferral of this project would be an inappropriate risk to the safe and reliable operation of the HOL distribution system.

#### 5.1.4.2 *Priority*

As a result of the consequences of deferral discussed above, this project is considered a very high priority when compared to most other projects (in this and other categories). Without an updated SCADA system in place, HOL operations could be significantly affected by a failure in the current system. To recover from such an unplanned failure would result in significant additional expenses for emergency work over and above those planned in this project.

### 5.1.5 Execution Path

#### 5.1.5.1 *Implementation Plan*

This project will be completed in several phases over the next 4 years starting in 2015.

- Phase 1: Beginning in early 2015, HOL will engage the services of a consulting firm with experience in helping distribution companies select and install new SCADA systems. At the completion of this phase, it is expected that a detailed set of specifications would be used to select a SCADA vendor for the replacement system.
- Phase 2: During the course of 2016-17, the successful vendor will install the hardware and software for the new SCADA system and will complete the transition of the existing database to the new system. This will include the bulk of the server and workstation hardware for the control room. This end of phase will have the HOL control room fully trained and transitioned to the new system.
- Phase 3: The final phase occurring in 2017-18 will involve transitioning the SCADA system to the new facilities and to create and install the disaster recovery location.

#### 5.1.5.2 *Risks to Completion and Risk Mitigation Strategies*

There are risks to any project of this size and complexity including documentation issues, project mismanagement, poor resourcing etc. Recognizing that HOL is unable to commit the number of resources with the required skills to mitigate those risks, an outside firm will be contracted to manage the replacement project. This project management service will serve to reduce the level of risk that HOL is exposed to by leveraging experienced professionals for the duration of the project.

Of course, this additional relationship between HOL and the consulting firm, comes with some level of risk. Therefore, a risk to the successful completion of this project is a failure on the part of the project management firm selected. To mitigate this risk, only a small group of firms with previous experience in SCADA deployments are being invited to bid on the contract. Furthermore, part of the criteria in selecting the successful bidder will be a thorough review of the staff and involvement in previous projects.

#### 5.1.5.3 *Timing Factors*

There are several factors which could affect the timing of this project including:

- Early failure of existing SCADA system: It is possible that the existing system fails in such a way that requires immediate replacement. This would necessitate a significant advancement of the schedule.
- Vendor and support availability: This risk has been mitigated by starting the project a full three years before the target completion date.
- Additional time required to integrate with existing HOL systems: This risk has been mitigated by engaging a consultant to help define the requirements of the new system early on in the project.

#### 5.1.5.4 *Cost Factors*

With any project involving IT hardware and software, there are risks that additional features, licenses, or modules will be required that could serve to inflate the cost of the overall project. Furthermore, while every effort has been made to ensure that adequate funding has been earmarked for this project, it is possible that there will be additional funds required to ensure the smooth transition from the old system and that all of the data is preserved in the new system. This risk has been partially mitigated by bringing in an outside firm to aid in the selection of the new system vendor.

#### 5.1.5.5 *Other Factors*

N/A

### 5.1.6 Renewable Energy Generation (if applicable)

N/A

### 5.1.7 Leave-To-Construct (if applicable)

N/A

### 5.1.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | SCADA Replacement Project |
| **Capital Cost:** | $2.8 M Est. |
| **O&M:** | $50k/yr Est |
| **Start Date:** | January 2015 |
| **In-Service Date:** | January 2018 |
| **Investment Category:** | System Service |
| **Main Driver:** | Current Assets at End of Life |
| **Secondary Driver(s):** | Improving Cyber-Security<br>Improving Overall Reliability<br>Improving the Tool Set |
| **Customer/Load Attachment** | 305,000 |

**Project Scope**

This project will encompass the selection, design, installation, and commissioning of an entirely new SCADA system at HOL. The project will begin with a requirements definition phase beginning in 2015 and end with user training and the transition to the new system in 2017/18.

**Work Plan**

This project will occur in the basic phases:

- Phase 1: With outside support, requirements will be defined and a new system selected
- Phase 2: System installation, training n and commissioning
- Phase 3: Reliability Enhancement and transition to new facilities.

**Customer Impact**

With the new SCADA system customers will see enhanced system reliability and improved outage performance. The system reliability will be improved through hardening of the SCADA system itself from failure or cyber-attacks. The improved outage performance will come from the advanced features which will help the HOL system office respond faster and more effectively to outage events.

# General Plant

# 1 Facilities Implementation Plan

## 1.1 Project/Program Summary

Hydro Ottawa's Facilities Implementation Plan is the result of a determination by executive management team and Board of Directors to procure new facilities intended to:

a) consolidate operations and administrative staff;
b) to move its operational centers out of high traffic residential districts to land parcels or sites with easy access to major highways within the Ottawa area;
c) to replace the aging buildings; and
d) to upgrade the operational centers in order to provide better response to customers.

This is a once in a 50 year generation investment that has already been deferred by Hydro Ottawa for 15 years.

## 1.2 Project/Program Description

During the 2016-2020 Custom IR period Hydro Ottawa will construct facilities on two parcels of land, namely an Eastern Operations & Administrative Campus and a Southern Operations & Warehouse. The facilities will be built on two parcels of land already purchased by Hydro Ottawa in the eastern and southern regions of the City of Ottawa. The Eastern Operations & Administration Campus land parcel was purchased in April 2013 and is located at the corner of Hunt Club and Hawthorne beside the 417 highway. The Southern Operations land parcel was purchased December, 2012 and is located at the corner of Moodie & Fallowfield drives near the 416 highway. Construction is expected to begin in 2016 with the eastern and southern facilities build being treated as two separate and distinct projects.

## 1.3 Project/Program Justification

The need for new facilities was identified 15 years ago when Hydro Ottawa amalgamated from five former municipal utilities, namely Ottawa Hydro, Gloucester Hydro, Nepean Hydro, Kanata Hydro and Goulbourn Hydro. Due to the short timeframe given for amalgamation and the magnitude of capital required Hydro Ottawa opted to temporarily keep its existing facilities. Since then, the need for new facilities has been revisited internally an in consultation with real estate experts a number of times. The current facilities are beyond their useful lives.

## 1.4 Main and Secondary Drivers

| Driver | | Explanation |
|---|---|---|
| **Primary** | **Asset End of Life** | Like other LDCs in Ontario, Hydro Ottawa's investment in new facilities is a once in a generation investment. This generational investment was identified 15 years ago to consolidate administrative functions, to better locate the operation centres, to modernize the work environment and to provide for future growth. Buildings such as the Albion Road facility of Hydro Ottawa are 60 years old and were designed and built in an era to meet a very different need from what is currently and prospectively serves. Hydro Ottawa's facilities are at capacity, |

| | | |
|---|---|---|
| | | are poorly located and in need of repair. |
| **Secondary** | **Public Safety** | Due to commercial and residential growth in the areas surrounding Hydro Ottawa facilities, truck and employee traffic now pose safety risks to the general public. At the Albion Road facility for example, school children board and debark from school buses just outside the Hydro Ottawa facility. Wide turning trucks must navigate heavily populated residential streets posing significant risk to public safety. |
| **Secondary** | **Operational Efficiency** | Hydro Ottawa's move to new facilities is further motivated by the need to align its administrative and operational staff in a manner allowing better cultural and organizational synergies. Consolidating administrative, technical and operational staff will permit greater operating efficiencies by increasing opportunities for collaboration and cross-functional teamwork. In addition to providing a greater foundation for productive collaboration, the new facilities are being located close to major traffic arteries in the City of Ottawa are expected to significantly reduce travel time to work locations by all work crews resulting in better customer service and response times. |
| **Secondary** | **Health & Safety (employees)** | Hydro Ottawa existing facilities are being extended beyond their useful lives but are unable to meet future capacity requirements without major renovations or requiring new construction/leasing off-site facilities. The current facilities have several deficiencies many of which present health and safety concerns for Hydro Ottawa's staff, crews and customers and/or require substantial investment to replace or repair. Examples of major investments that would be required include bringing the buildings up to code to meet the Accessibility for Ontarians with Disabilities Act (hereinafter "AODA Act"), or investments necessary to upgrade the building envelope (roof, windows, flooring, HVAC system) to facilitate a more favourable work environment. Examples of safety concerns include numerous and increasing incidents of theft and crime in the areas surrounding the Albion head office including a recent incident of an intruder found in the garage. Other examples include uneven pavement and flooring causing risks for slips or trips. |

**Table 107 - Facilities Implementation Plan Drivers**

## 1.5 Alternatives Considered

### 1.5.1 Alternatives Evaluation

In Exhibit B1, Tab 2, Schedule 4 filed by Hydro Ottawa in 2012 in support of its cost of service rate case (EB-2011-0054), it described in detail beginning in section 4.3 the numerous options considered by Hydro Ottawa in consultation with its expert consultants for deriving the optimal facilities arrangement. Some of the options considered include:

a) retaining and retrofitting Hydro Ottawa's existing facilities;

b) consolidating all administrative staff at the Albion Road location;
c) consolidating all Administration staff at the Merivale location; and
d) constructing new facilities.

In Section 4.4 of Exhibit B1, Tab 2, Schedule 4 provided its analysis of the alternatives as well as its conclusion that Option 4, namely to construct new facilities, was the superior economic option resulting in long term value to ratepayers.

The evidence filed by Hydro Ottawa in Exhibit B1, Tab 2, and Schedule 4 was thoroughly explored in interrogatories exchanged with the stakeholders including Board Staff, VECC, SEC and Energy Probe. The capital expenditures proposed in Hydro Ottawa's 2012 Cost of Service Application were addressed in the context of the settlement agreement. Hydro Ottawa's proposal to construct new facilities and its proposal to set aside an initial $4.0 million to purchase land was reviewed and in its settlement agreement. Consequently, Hydro Ottawa does not propose to review the alternatives of staying in its existing facilities versus building new facilities as this issue was addressed in the context of Hydro Ottawa's 2012 Cost of Service application as reviewed pursuant to the proceeding initiated under EB-2011-0054.

## 1.6 Project/Program Timing

Below is a table that sets out the activities associated with the realization of Hydro Ottawa's Facilities Implementation Plan and the approximate timelines within which each of these activities is currently scheduled to take place.

| Activity | Estimated Timeline |
|---|---|
| **Dibblee Land Purchase** | Closed December 2012 |
| **Hunt Club Land Purchase** | Closed April, 2013 |
| **Issue Request for Qualification** | May 2013 |
| **Engage Fairness Commissioner** | May - October 2013 |
| **Review request for Qualification responses and Shortlisting of Design Build Proponents** | December 2013 - May 2014 |
| **Issue & Review Design Build RFP** | Q2 2015 |
| **RFP Evaluation and Award** | Q32015 |
| **East Operations and Administrative Campus** | |
| **Design** | Q3-Q4 2015 |
| **Site Plan Approval and Permitting** | Q4 2015 – Q2 2016 |
| **Construction** | Q3 2016- 2018 |
| **Move In** | 2018 |
| **South Operations, Warehouse** | |
| **Design** | Q3-Q4 2015 |
| **Site Plan Approval and Permitting** | Q4 2015 –Q2 2016 |
| **Construction** | Q3 2016 - 2017 |
| **Move In** | 2017 |

**Table 108 - Facilities Implementation Plan Timelines**

## 1.7 Project/Program Expenditure

As discussed in section 3.4.3 of B-5(A) HOL's Distribution System Plan, the historical spend (2011-2015) is attributed to monies spent to procure the land upon which Hydro Ottawa will construct its new facilities. Forecasted spend (2016-2020) represents monies that Hydro Ottawa estimates it will need to facilitate the construction of the new facilities. The table below sets out the historical and forecasted spend on the land and building for each of the two projects.

| Facility | | 2011 Act | 2012 Act | 2013 Act | 2014 Q2 | 2015 Bud | 2016 Bud | 2017 Bud | 2018 Bud | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | $'000 | | | | | | | | |
| **East Ops / Admin Campus** | Land | - | 250 | 12,445 | 21 | - | - | - | - | 12,716 |
| | Building | 234 | 492 | 287 | 432 | 3,835 | 19,642 | 25,818 | 6,073 | 56,813 |
| **South Ops** | Land | - | 6,704 | 94 | - | - | - | - | - | 6,798 |
| | Building | 68 | 140 | 83 | - | 1,098 | 5,620 | 9011 | - | 16,020 |
| **Total** | | 302 | 7,586 | 12,909 | 453 | 4,933 | 25,262 | 34,829 | 6,073 | 92,347 |

**Table 109 - Facilities Implementation Plan Expenditures**

## 1.8 Prioritization

### 1.8.1 Consequences of Deferral

Hydro Ottawa has deferred the current projects by 15 years. The consequences of further deferral are escalating repair and replacement costs as well as health and safety costs. Further deferring Hydro Ottawa's facilities implementation plan would have cascading impacts on inflationary values of construction materials and costs necessary to construct the facilities. In addition to inflationary costs, Hydro Ottawa would also incur costs associated with replacing key elements of the building envelop such as the roofs, windows and HVAC systems. This does not include the costs to upgrade each of Hydro Ottawa's facilities to comply with the AODA. Like many other investments project deferral introduces significant risks and associated costs of risk.

## 1.9 Execution Path

### 1.9.1 Implementation Plan

#### 1.9.1.1 *Land Purchase (historical implementation)*

The land parcels upon which the two projects will be built were purchased in 2012 and 2013. The purchase of these land parcels followed a lengthy search and evaluation of approximately forty candidate listings. The search was complicated by restrictions on land use imposed by National Capital Commission and the unavailability of vacant lands due to protected status. Bidding for the two properties was done on a "no-name" anonymous basis to avoid attracting a price premium.

In total Hydro Ottawa purchased approximately 41 acres at an average price of $460K per acre totalling $19 million. Ultimately market availability and alignment with Hydro Ottawa's stated criteria[1] dictated the parcels purchased.

#### 1.9.1.2 *Building Construction (historical and prospective implementation)*

Following the appointment of PPI Consulting Limited (hereinafter PPI) as Fairness Commissioner in the fall of 2013, Cresa Partners[2], Hydro Ottawa and PPI prepared a Request for Qualification ("RFQ") to prequalify design-build contractors for the design and construction of Hydro Ottawa's new Administrative Building and Operations Centers. The RFQ was divided into two projects, the first covering the Administrative Building and the second covering the East and South Operations Centers. Respondents to the RFQ were given the option to respond to and prequalify for one or both projects. For each project as many as five respondents could pre-qualify for the design-build RFP.

The RFQ was posted on MERX December 24, 2013 and closed on February 28, 2014. Upon closing eight Statements of Qualification ("SOQ") were received for the Administrative Building and ten for the Operations Centers.

Hydro Ottawa expects to issue an RFP in Q2 2015 to the five design-build proponents who pre-qualified for the Head Office and Training Center and the five design-build proponents that pre-qualified to build the two Operations Centers.

Hydro Ottawa again hired the services of PPI to oversee the RFP process and documentation to ensure its fairness and transparency.

#### 1.9.1.3 *Estimated Square Footage/Employee and Workstation Estimates*

In designing the space requirements for the new building and operations centers, Hydro Ottawa estimates that the Administrative Campus will provide for 166,000 square feet of space which works out to be approximately 332 gross square feet per employee. Hydro Ottawa notes that this is well below the International Facility Management Association ("IFMA"[3])'s average of 396 gross square feet per occupant as well as the IFMA average of 425 gross square feet per occupant for utilities. Hydro Ottawa further notes that its estimated gross square foot per employee is also well below Enersource's move in, five year and ten year forecast gross square footage per employee allotment and below Powerstream's. See Table 110.

[1] Hydro Ottawa's criteria were a) to be near a major artery for ease of access to highways; b) be central and accessible for employees and visitors; c) to be located beside public transit or proposed light rail transit system and d) have suitable zoning within an industrial area.

[2] Cressa Partners Corporate Real Estate Advisors

[3] (see website: http://www.ifma.org/publications/books-reports/research---benchmarks-iv ).

| | Hydro Ottawa (proposed) | Enersource | Powerstream |
|---|---|---|---|
| **Total Space (Admin building only)** | 155,000[4] | 79,000 | 92,000 |
| **# of Employees (@ move in)** | 511 | 150 | 270 |
| **Gross Square foot per employee** | 303 | 526 | 341 |

**Table 110 - Gross Square Footage per Employee**

In assessing comparable space allocations for employees, Hydro Ottawa commissioned a study of comparable office and workstation standards. Table 111 sets out the results of its findings. It was determined that Hydro Ottawa's current office and workstation space allocations are consistent with or lower than the space allocations of other utilities within Ontario. As such, Hydro Ottawa determined that it would retain the existing office and workstation space allocations for current and future staff.

| **Comparable Office and Workstation Standards (SF)** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **CEO** | **EMT** | **DIR** | **MGR** | **WS1** | **WS2** | **WS3** | **WS4** |
| **Comp 1** | 300 | 200-225 | | 150 | 80 | 64 | 48 | 15 |
| **Comp 2** | n/a | 200 | | 125 | 72 | 61 | 42-55 | 12 |
| **HOL Current** | n/a | 225 | 150 | 150 | 80 | 64 | 48 | n/a |
| **HOL Proposed** | 300 | 225 | 150 | 150 | 80 | 64 | 48 | 15 |

**Table 111 - Space Allocations per Employee**

### 1.9.1.4 *Sale of Existing Facilities*

Part of the implementation of Hydro Ottawa's facilities plan entails the sale of Hydro Ottawa's vacated facilities. To gauge the relative value of Hydro Ottawa's existing facilities, Hydro Ottawa engaged the services of Altus Group Limited to estimate the approximate market value of the Albion, Merivale and Bank Street facilities. In estimating the market value for each of the three facilities that Hydro Ottawa intends to sell, Altus advises that the valuations will be positively or negatively impacted by current zoning designations and the ability to change said designations. Decisions on zoning will not be known until Hydro Ottawa is closer to the sale date.

Other factors that could impact the market value are the need that a purchaser may have to demolish the buildings or any need to undertake any supplemental remediation in order to repurpose the sites.

[4] Space Design allows for 30% growth in number of employees to accommodate at the facility.

## 1.10 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Facilities Implementation Plan |
| **Capital Cost:** | $66.3M |
| **O&M:** | $0 |
| **Start Date:** | January 2015 |
| **In-Service Date:** | Date to be confirmed |
| **Investment Category:** | General Plant |
| **Main Driver:** | Current Assets at End of Life |
| **Secondary Driver(s):** | Public Safety<br>Operational Efficiency<br>Health & Safety |
| **Customer/Load Attachment** | N/A |

**Project Scope**

During the 2016-2020 Custom IR period Hydro Ottawa will construct three new facilities on two sites, namely an Eastern Operations & Administrative Campus and a Southern Operations & Warehouse. The facilities will be built on two parcels of land already purchased by Hydro Ottawa in the eastern and southern regions of the City of Ottawa.

**Work Plan**

This project will occur in the basic phases:

- Phase 1: Land parcels purchase
- Phase 2: Construction of three facilities
- Phase 3: Move from existing facilities to new facilities
- Phase 4: Sale of existing facilities

**Customer Impact**

N/A

# 2 CC&B Enhancements

## 2.1 Project/Project Summary

Operational Efficiency: Ensure efficient and effective operations of the Customer Care & Billing (CC&B) application which is used to produce all customer bills by ensuring that the application remains fully supported by IBM and Oracle.

## 2.2 Project/Program Description

### 2.2.1 Current Issues

Hydro Ottawa's customer information system environment was implemented in March 2014 with a Customer Care and Billing (CC&B) v2.3.1 component and the premier support for this component ends in June of 2016. To ensure this critical application remains fully supported by Oracle and IBM, an upgrade to either version 2.4 or 2.5 (considered a minor lift) would be performed in 2016 with a preliminary estimate of $2.5M. In 2019, we plan on performing a significant lift to what we believe will be the next major version of CC&B (version 3.0) with a preliminary estimate of $6M.

### 2.2.2 Program/Project Scope

- To perform an upgrade of a key component, CC&B, including enhancement & interfaces, of Hydro Ottawa's customer information system environment which consists of CC&B, OIM/OVD, interfaces including ODI & Globalscape, In-tool-lect Dashboard, BI Publisher and Hypertension SQR, from v2.3.1 to v2.x (minor lift) and from version 2.x to version 3.0 (significant lift).
- To confirm all components of the Hydro Ottawa customer information system environment work with these upgraded components (i.e. CC&B, enhancements and interfaces)

### 2.2.3 Main and Secondary Drivers

- Provide a solid supported system as the foundational platform that will position Hydro Ottawa to better leverage our other technologies and provide enhanced services to our customers
- To remain in Premier Support for the CC&B application which is industry standard and to be compliant with the maintenance contract for the CC&B system with IBM covering 2014 to 2022 inclusive ($21M) which specifies that HOL must keep current with upgrades throughout the duration of the contract.
- Additional functionality in CC&B v2.x & v3.0 which would imply that less future enhancements would be required as they would be included as part of base CC&B.
- To strengthen HOL's position with Oracle and with our regulators by being on the same version as other large distribution companies in Ontario (i.e., Toronto Hydro-currently on v2.2, Enersource -currently on v2.2 and Powerstream- will be going live with v2.4).

### 2.2.4 Performance Targets and Objectives

Performing upgrades to Hydro Ottawa's core customer information system would meet the following objectives:

- Ensure that the Oracle CC&B product, which is a key component of our meter to cash system remains in premier or extended support which is required by our managed service provider IBM to deliver on our contracted service level agreements.

## 2.3 Project/Program Justification

### 2.3.1 Alternatives Evaluation

#### 2.3.1.1 *Alternatives Considered*

**Alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019**

This alternative is to perform an upgrade to CC&B v2.x in 2016 (considered a minor lift) and v3.0 (considered a significant lift) in 2019 to allow HOL to remain on a fully supported platform.

**Alternative 2: No upgrade in 2016 and upgrade to version 3.0 in 2019**

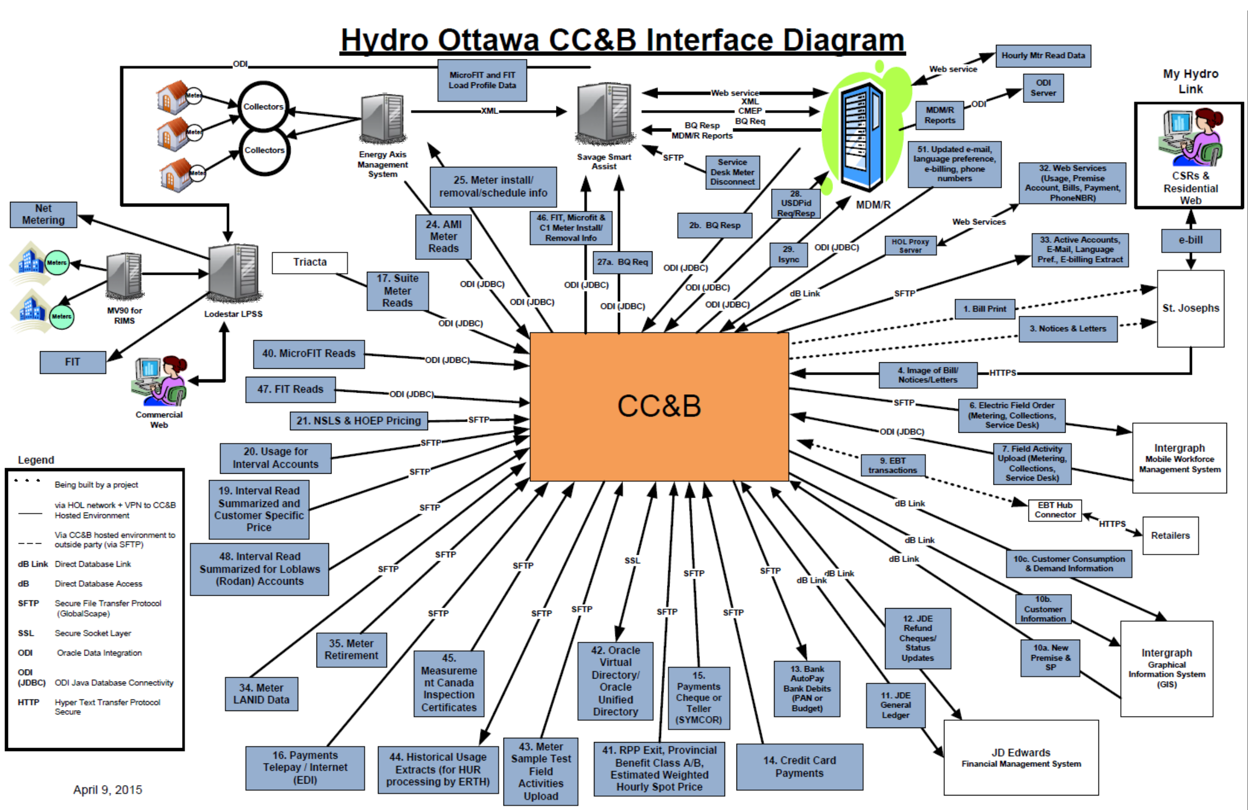
This alternative is to remain on CC&B v2.3.1 and only perform an upgrade to CC&B v3.0 in 2019. By having no upgrade in 2016 consuming resources, this would allow the tuning of CC&B v2.3.1 in the years of 2016, 2017 & 2018.

**Alternative 3: Do not perform any upgrades**

This alternative would be to remain on CC&B v2.3.1 and not perform any upgrades (between the years of 2015- 2020).

Figure 102 demonstrates the number of interfaces to/from CC&B that would need to be considered as part of the analysis for each upgrade.

**Figure 102 - CC&B Interfaces**



#### 2.3.1.2 *Evaluation Criteria*

Evaluation criteria: Below are the criteria's used to evaluate the alternatives for the CC&B path as well as the points used to rank these criteria's.

1. **Capital costs:** outweighing upgrading to a later version of CC&B versus capital costs avoided to build new functionality to make up for features not available should the upgrades not occur
   a. Ranking: 10 points = lowest, 20 points = medium, 30 points = highest
2. **Impact on OM&A costs:** due to additional licensing costs tied to Oracle support (premier vs extended vs sustaining) for CC&B and increased managed services cost with IBM.
   a. Ranking: 10 points = highest, 20 points = medium, 30 points = lowest
3. **Risk profile:** due to not being on a fully supported platform. This will impact the managed services with IBM as they will not have access to all security patches, fixes to the database, operating system and or servers. Therefore, should a critical issue occur, or a new regulatory change is imposed on HOL, we would be left exposed if we did not have access to premier or extended support.
   a. Ranking: 10 points = lowest, 20 points = medium, 30 points = highest

**<u>Detailed assessment</u>:**

**Alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019**

The alternative is to perform an upgrade to CC&B v2.x in 2016 and v3.0 in 2019:

- Capital Costs (Ranking: 10 points):
  - o Capital investments will continue to be required to maintain regulatory compliance in years 2017, 2018 & 2020
- No increased OM&A (Ranking: 30 points)
  - o Hydro Ottawa would remain in premier support, included in 22% of Oracle support fees
  - o No additional fees for IBM managed services and Oracle licensing costs
- Risk profile is low as we will have access to all patching and will be fully supported (Ranking: 30 points)

| Costs | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|
| **Capital** | $2.5M | $500K | $500K | $6M | $500 | $11.7M |
| **Increased OM&A** | $0 | $0 | $0 | $0 | $0 | $0 |

**Table 112 - CC&B Alternative 1 Costs**

**Alternative 2: No upgrade in 2016 and upgrade to version 3.0 in 2019**

The alternative is to remain on CC&B v2.3.1 and perform an upgrade to CC&B v3.0 in 2019:

- Capital Costs (Ranking: 20 points):
  - o An additional $25K per year (2016, 2017 & 2018) for capital costs will be required to enhance CC&B due to not acquiring the new features with a later version of CC&B (version 2.x)
- Increased OM&A (Ranking: 20 points):
  - o Increase in Oracle support from 22% per year to 37% per year (~$100K/year) due to being on extended support.

  - Potential increases to the monthly fees paid to IBM for managed services on an increasing scale based on being on extended (i.e., hosting and application support- a rough estimate of what this additional cost could be $240K/year which is approximately 10% increase to monthly fees). Then on sustaining support a rough estimate of what this additional cost could be $480K/year which is approximately 20% increase to monthly fees.
- Risk profile is medium based on the fact that for a year and half (Ranking: 20 points):
  - We will be on sustaining support from July 2018 to Dec 2019 as extended support for version 2.3.1 runs out in June 2018 which leaves HOL exposed to not be able to meet new regulations.
  - IBM will not be able to apply all security patches and fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.
  - It should be noted that Oracle still needs to confirm the feasibility of upgrading from CC&B v2.3.1 directly to CC&B version 3.0

| Costs | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|
| **Capital** | $525K | $525K | $525K | $6M | $500K | $8.075M |
| **Increased OM&A** | $170K | $340K | $410K | $480K | $0 | $1.4M |

**Table 113 - CC&B Alternative 2 Costs**

**Alternative 3: Do not perform any upgrades**

This alternative would be to remain on CC&B v2.3.1 and not perform any upgrades (between the years of 2015- 2020):

- Capital Costs(Ranking: 30 points):
  - An additional $25K per year (up to June 2018) for capital costs will be required to enhance CC&B due to not acquiring the new features with a later version of CC&B (version 2.x). From June 2018 to 2020, an additional $50K per year to cover capital costs for features not acquired in major version of CC&B 3.0.
- Increased OM&A (Ranking: 10 points):
  - Increase in Oracle support from 22% per year to 37% per year (~$100K/year) due to being on extended support.
  - Potential increases to the monthly fees paid to IBM for managed services on an increasing scale based on being on extended (i.e., hosting and application support- a rough estimate of what this additional cost could be $240K/year which is approximately 10% increase to monthly fees). Then on sustaining support a rough estimate of what this additional cost could be $480K/year which is approximately 20% increase to monthly fees.
- Risk profile is high based on the fact that for 2 and a half years (Ranking: 10 points):
  - We will be on sustaining support from July 2018 to 2020 as extended support for version 2.3.1 runs out in June 2018, which leaves HOL exposed to not be able to meet new regulations.
  - IBM will not be able to apply all security patches and fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.

| Costs | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|
| **Capital** | $525K | $525K | $538K | $550K | $550K | $2.688M |
| **Increased OM&A** | $170K | $340K | $410K | $480K | $480 | $1.880M |

**Table 114 - CC&B Alternative 3 Costs**

#### 2.3.1.3 *Preferred Alternative*

Based on the above analysis, Hydro Ottawa recommends alternative 1: Upgrade to version 2.x in 2016 and v3.0 in 2019. Although the capital investments are the highest of all alternatives ($11.7M), we would be avoiding the increased OM&A costs of $1.4M (Alternative 2) and $1.88M (Alternative 3). Of all of the alternatives, alternative 1 is the least risky as it would allow HOL to remain on a fully supported platform with access to all security patching, fixes to the database, operating system and or servers without any increase to OM&A costs.

A points system was used to rank the alternatives against the evaluation criteria outlines above. The chart below demonstrates the outcome of how each alternative ranked:

| Criteria | Alternative 1 | Alternative 2 | Alternative 3 |
|---|---|---|---|
| **Capital Costs** | 10 | 20 | 30 |
| **OM&A Costs** | 30 | 20 | 10 |
| **Risk Profile** | 30 | 20 | 10 |
| **Total** | **70** | **60** | **50** |

**Table 115 - CC&B Alternative Evaluation**

### 2.3.2 Project/Program Timing & Expenditure

| Historical ($M) | | | | | Future ($M) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | | | | | 1.70 | 2.50 | 0.50 | 0.50 | 6.06 | 0.50 |

**Table 116 - Project Expenditures**

### 2.3.3 Benefits

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | • Ensuring efficient and effective operations of the CC&B application which is used to produce all customer bills by ensuring that the application remains fully supported by IBM and Oracle.<br>• Keeping CC&B fully upgraded to the latest versions would save the organization in increased OM&A ($1.4M with alternative 2) and ($1.880M with alternative 3).<br>• An upgraded CC&B system will be capable of meeting more of our future regulatory and business requirements through configuration changes, instead of developing code. |
| **Customer** | • Will allow HOL to fully automate customer moves without the manual involvement of our resources.<br>• Is the foundational platform that will position Hydro Ottawa to better leverage our other technologies and services such as our award-winning Outage Communications system and MyHydroLink (our account management web portal).<br>• Will enable us to strengthen our relationships with landlord customers |

| | |
|---|---|
| | through automated landlord agreements. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | Performing these upgrades to CC&B would allow for IBM to continue to have access to all security patches as HOL would continue to be supported via premier or extended support. |
| **Co-ordination, Interoperability** | Increased cooperation/sharing of best practices among Ontario LDCs who are also on CC&B (Toronto Hydro, Enersource & Powerstream) on business critical systems leading to cost savings and improvements in customer service. |
| **Economic Development** | N/A |
| **Environment** | N/A |

**Table 117 - Project Benefits**

## 2.4 Prioritization

### 2.4.1 Consequence of Deferral

If the decision was to defer the CC&B upgrades, the consequences / risks of deferring these projects would be the following:

- Increased in OM&A costs for both licensing and managed services costs for IBM OM&A ($1.4M with alternative 2) and ($1.880M with alternative 3).
- IBM would not have access to the latest security patches, fixes to the database, operating system and or servers as they will be limited by the interoperability of CC&B v2.3.1 with these components of the solution stack.
- HOL would not be able to leverage additional functionality easily to further automate processes that would benefit our customers.
- HOL would be on sustaining support for several years, which leaves HOL exposed to not be able to meet new regulations.
- Collaborating with other local distributors in the Ontario market (Toronto Hydro, Powerstream & Enersource) would be less feasible if we are all operating under different CC&B versions.

### 2.4.2 Priority

**High**

- With these upgrades it is expected that some future enhancements will not be required as they are now base functionality in the newer versions of the application

## 2.5 Execution Path

### 2.5.1 Implementation Plan

### 2.5.2 Risks to Completion and Risk Mitigation Strategies

| Risk | Mitigation Strategy |
|---|---|
| Resource constraint potentially required for other projects | • Prioritize projects<br>• Combine CC&B enhancements within the upgrade to free up resources |
| CC&B version 3.0 would be considered “bleeding | • Detailed analysis of functionality offered in |

| | |
|---|---|
| edge" | version 3.0 to make an informed decision of whether to proceed with CC&B version 3.0 or to a different version |

**Table 118 - Risks & Mitigation Strategy**

### 2.5.3 Timing Factors

- Premier Support of CC&B v2.3.1 ending in June 2016 and Extended Support in June 2018
- Premier Support of CC&B v2.4 ending November 2017 and Extended Support in November 2020
- Release date of CC&B v2.5 June/July 2015 – support timelines not currently available
- Release date of CC&B v3.0 and maintenance support is tied to it is not currently available

### 2.5.4 Cost Factors

- Preliminary estimates were provided by our managed services contractor IBM for these upgrades, these estimates could change once the detailed analysis of these projects have been performed
- Duration of the upgrade projects extending longer than original estimates
- Potential for increased scope

## 2.6 Project Details and Justification

| | |
|---|---|
| **Project Name:** | CC&B Upgrade from v2.3.1 to v2.x |
| **Capital Cost:** | $2.5M |
| **O&M:** | N/A |
| **Start Date:** | January 2016 |
| **In-Service Date:** | September 2016 |
| **Investment Category:** | General Plant |
| **Main Driver:** | • Provide a solid supported system as the foundational platform that will position Hydro Ottawa to better leverage our other technologies and provide enhanced services to our customers<br>• To remain in premier support for the CC&B application which is industry standard and to honour the maintenance contract for the CC&B system with IBM covering 2014 to 2022 inclusive ($21M) which outlines that HOL must keep current with upgrades throughout the duration of the contract.<br>• Additional functionality in CC&B v2.x & v3.0 which would mean that we do not need some future enhancements – as they would be included as part of base CC&B. |
| **Secondary Driver(s):** | To strengthen HOL's position with Oracle and with our regulators by being on the same version as other large distribution companies in Ontario (i.e., Toronto Hydro-currently on v2.2, Enersource -currently on v2.2 and Powerstream- will be going live with v2.4). |
| **Customer/Load Attachment** | N/A |

**Project Scope**

Analysis, design and build of this technical upgrade of CC&B customizations, interfaces and reports (35 interfaces (see diagram below), 50 customizations, 100 reports)

- Functional testing, integration testing
- User acceptance testing
- Organizational Change Management
- Training
- CC&B Functional configuration
- Coordinate and manage participation of third parties

**Work Plan**

1. Assign a dedication project team (HOL and contractors)
2. Assess upgrade requirements
3. Design Upgrade changes
4. Build/Develop Upgrade changes
5. System Functional Testing
6. System Integration Testing
7. Training
8. User Acceptance & Regression Testing
9. Deploy into production
10. Stabilization period

**Customer Impact**

| |
|---|
| The impact to Hydro Ottawa's customers would be that we could achieve further efficiencies in the future that would benefit our customer, for example:<br>• It will allow us to fully automate customer moves without the manual involvement of our resources.<br>• Will be the foundational platform that will position Hydro Ottawa to better leverage our other technologies and services such as our award-winning Outage Communications system and MyHydroLink (our account management web portal).<br>• Will enable us to strengthen our relationships with landlord customers through automated landlord agreements. |

| | |
|---|---|
| **Project Name:** | CC&B Upgrade from version 2.x to v3.0 |
| **Capital Cost:** | $6M |
| **O&M:** | N/A |
| **Start Date:** | January 2019 |
| **In-Service Date:** | December 2019 |
| **Investment Category:** | General Plant |
| **Main Driver:** | Same as above |
| **Secondary Driver(s):** | Same as above |
| **Customer/Load Attachment** | N/A |
| **Project Scope** | |
| Same as above.<br>However seeing as this upgrade is a significant lift to the application (moving from version 2.x to 3.0), this usually entails architectural changes which then equates to more work:<br>• Review all existing enhancement interfaces created to work with v2.x to ensure that they are still required with CC&B v3.0. Some may require re-work due to the changes between versions.<br>• Regression testing phase would be extended due to the potential for more architectural changes to the application. | |
| **Work Plan** | |
| Same as above | |
| **Customer Impact** | |
| Same as above | |

# 3 Outage Communications System

## 3.1 Project/Project Summary

Hydro Ottawa's current Outage Communications System (OCS) needs to be replaced with a state-of-the art and scalable mobile solution, designed to be a specifically compatible foundation for all current and future Customer Experience Management initiatives. While the existing solution was delivered to resolve a broken outage communications process, Hydro Ottawa is now embarking on a proactive mission to deliver outage communications at the next level. Hydro Ottawa's vision of "2-way, proactive, personalized, and premise-based Outage Communications" is totally consistent with industry thought leaders.

## 3.2 Project/Program Description

### 3.2.1 Current Issues

Customers are demanding proactive two-way communications with relevant, timely and accurate outage information being provided not only via the call centre and Interactive Voice Recognition (IVR) but also through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

The existing APEX point based outage system is made up of a number of subsystems that all play specific roles in arriving at the point of creating information, or notifying customers, with respect to outages. Factoring in APEX application history and current vulnerabilities, Outage Communications risk profile, and reliability, supportability, and scalability needs, we have reached the conclusion that the current APEX OCS application is not a suitable foundation upon which to build the future vision.

### 3.2.2 Program/Project Scope

In keeping with our strong commitment to improving customer service, we intend to provide a rich customer experience with 2-way, proactive, personalized, premise-based outage communications. In doing so, the following objectives must be met:

**Reporting Personalization:** Allowing the customer to report an outage utilizing the channel that they prefer. Typically this will include the traditional outage line, augmented by mobile, web, and text.

**Notification Personalization:** Allowing the customer to specify preferences that determine how and when they receive outage alerts, updates, and restoration information.

**Message Personalization:** Provides the intelligence for the overall solution. It determines the messaging to go out for a particular outage, the customers it should be delivered to, and via which channel, as dictated by the customer's stated preferences.

Customer Administration: A robust customer administration capability is a core requirement in allowing Hydro Ottawa to scale from administering a few hundred key customers to our base of over 318,952 customers.

#### 3.2.3 Main and Secondary Drivers

The main driver for this project is the ability to meet evolving customer needs as identified above.

#### 3.2.4 Performance Targets and Objectives

A new OCS solution must be architected and designed in the context of Hydro Ottawa's reality. IVR, Web, OMS, CC&B, MHL, and Mobile are all key contributors to the business and full compatibility with those systems is a pre-requisite for any replacement.

**Customer Value:** Hydro Ottawa has a customer-centric view to the future. As of December 31, 2014, there were 122,300 MyHydroLink accounts. Hydro Ottawa will establish a multi-channel communication strategy that reached customers across a variety of communication channels.

**Organizational Effectiveness:** The custom solution will be developed using current application development standards. Hydro Ottawa will not be locked in to a proprietary toolset. Skilled resources should be common and permit risk avoidance/mitigation in the need of hiring or future partner development.

**Corporate Citizenship:** The development of a replacement Outage Communications System will enable Hydro Ottawa to communication with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible.

**Financial Strength:** Proactive communication has resulted in the reduction in the cost per customer contact as well as decreased the number of calls to our Outage Reporting call centre during outages. As a specific example, redirecting customers to using the Outage Web Maps reduced telephone call volumes to the Call Centre by 67,926 over 2013/14 at a savings of almost $900k.

### 3.3 Project/Program Justification

#### 3.3.1 Alternatives Evaluation

##### 3.3.1.1 *Alternatives Considered*

Commercial-Off-The-Shelf (COTS), Hybrid, and Custom solutions were all deemed to be approaches that could meet the needs of Hydro Ottawa.

In the initial high level pricing estimate, COTS was most expensive, followed by Hybrid, then Custom as the least expensive. In the latest estimates, Outage Maps have been excluded, making the Hybrid approach redundant. In terms of magnitude, the custom solution costs 40% of the cost for the COTS solution.

##### 3.3.1.2 *Evaluation Criteria*

Business decisions will drive the solution evaluation, with the following mandatory requirements:

- Reduce operational burdens while extending customer interaction capabilities. This is critical, as any new Outage Communication process should create less work for Operations, not more.

- Manage customer preferences efficiently while allowing a high level of personalization. The customers' wishes must be integral to any Customer Experience Management initiative.
- The Messaging Engine must be able to support all known channels. Although business decisions must drive which channels will be supported and when, the engine must be designed in such a way as to be capable of supporting all channels. No development work should be required should the company choose to add channels at a later date.

#### 3.3.1.3 *Preferred Alternative*

The recommendation to proceed with a custom solution significantly reduces the total cost of ownership over the 5 Year Total Cost of Ownership assessment, realizing a cost savings of approximately $1,234,000 over the five year period.

### 3.3.2 Project/Program Timing & Expenditure

| Historical ($k) | | | | | | | Future ($k) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| - | - | - | - | - | - | - | 910 | - | - | - |

**Table 119 - Project Expenditures**

### 3.3.3 Benefits

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | Proactive communication has resulted in the reduction in the cost per customer contact as well as decreased the number of calls to our Outage Reporting call centre during outages. As a specific example, redirecting customers to using the Outage Web Maps reduced telephone call volumes to the Call Centre by 67,926 over 2013/14 at a savings of almost $900K. |
| **Customer** | Hydro Ottawa has a customer-centric view to the future. As of December 31, 2014, there were 122,300 MyHydroLink accounts. Hydro Ottawa will establish a multi-channel communication strategy that reaches customers across a variety of communication channels.<br>The development of a replacement Outage Communications System will enable Hydro Ottawa's to communicate with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible. |
| **Safety** | N/A |
| **Cyber-Security, Privacy** | HOL will ensure all applicable laws and standards are met throughout. |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | N/A |
| **Environment** | N/A |

**Table 120 - Project Benefits**

## 3.4 Prioritization

### 3.4.1 Consequence of Deferral

To maintain customer satisfaction and reach the broadest number of customers possible, and to respond to widespread internet use and mobile phone ownership, utilities need to establish a multi-channel communication strategy that reaches customers across a variety of communication channels. As the internet becomes the new communication standard, utilities will need to adapt to continue meeting customers' expectations for responsiveness, accuracy, and personalization. Customers will be frustrated by websites that are not formatted for mobile phone access or communication that doesn't include text messages.

With the increase in the frequency and duration of outages caused by extreme weather events across North America, customers are expecting utilities to keep them continually updated on the status of outages; especially the estimated restoration time. In fact, customers are requiring utilities to keep them informed via two-way communications using the IVR, call centre, social media, utility websites and modern communications devices (e.g. tablets, smartphones) and applications (apps).

Hydro Ottawa has a customer-centric view to the future. Outage communications, planned or unplanned, are key customer interactions. An increasing number of utility companies are now launching proactive communication channels – that is, channels (usually voice messaging, text or email) through which they can "push" alerts to customers. These allow the utility to contact the customer many times with updates during an event, informing them when their estimated restoration time changes or when crews have determined the cause of their outage.

Failure to provide the power outage information accurately and in a timely manner will result in customer complaints, create unwanted media attention, and negatively impact customer satisfaction.

### 3.4.2 Priority

High – the project will allow HOL to meet customer expectations.

## 3.5 Execution Path

### 3.5.1 Implementation Plan

This project will be initiated and completed in 2017.

### 3.5.2 Risks to Completion and Risk Mitigation Strategies

As with any planned project, the limited availability of skilled resources with competing priorities may impact the timely implementation of an Outage Communications System. With executive support, stakeholder engagement, and careful planning and attention to schedules, this risk can be managed effectively.

## 3.6 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Outage Communications Systems |
| **Capital Cost:** | $910 |
| **O&M:** | $412 (2016-2020) |
| **Start Date:** | 2017 |
| **In-Service Date:** | 2017 |
| **Investment Category:** | General Plant |
| **Main Driver:** | Customer Service |
| **Secondary Driver(s):** | Communication efficiency |
| **Customer/Load Attachment** | N/A |
| **Project Scope** | |
| **Reporting Personalization:** Allowing the customer to report an outage utilizing the channel that they prefer. Typically this will include the traditional outage line, augmented by mobile, web, and text.<br>**Notification Personalization:** Allowing the customer to specify preferences that determine how and when they receive outage alerts, updates, and restoration information.<br>**Message Personalization:** Provides the intelligence for the overall solution. It determines the messaging to go out for a particular outage, the customers it should be delivered to, and via which channel, as dictated by the customer's stated preferences.<br>**Customer Administration:** A robust customer administration capability is a core requirement in allowing Hydro Ottawa to scale from administering a few hundred key customers to our base of over 318,952 customers. | |
| **Work Plan** | |
| Implementation 2017 | |
| **Customer Impact** | |
| The development of a replacement Outage Communications System will enable Hydro Ottawa's to communicate with our customers using the methods that they want to be communicated with. Hydro Ottawa will continue to offer a customer-centric view, raising the bar on customer satisfaction even further, and reaching the broadest number of customers possible. | |

# 4 JDE Application Upgrade

## 4.1 Project/Project Summary

An effective Enterprise Resource Planning (ERP) solution is a critical component to Hydro Ottawa's ongoing business operations. In 2003, J.D. Edwards (JDE) EnterpriseOne Xe was implemented. Since that time, investments were made to provide enhancements and stay relatively current on related technology components to enable ongoing business requirements and mitigate risk. The current ERP solution is JDE EnterpriseOne v9.0. After a decade of using the JDE solution as Hydro Ottawa's ERP, there was cause to pause and consider multiple factors impacting future ERP decisions. Assessment by Hydro Ottawa's Executive Management, IM&IT support and input from key impacted Stakeholder groups of a variety of consideration criteria, concluded that a full upgrade within the JDE product line should be pursued with adherence to Out of the Box (OOTB) product wherever possible to leverage best practices. Since Hydro Ottawa is currently operating on JDE version 9 (v9.0) for which only Sustaining Support will be available from the vendor after Sept. 2016, time is of the essence to proceed with the project.

**Figure 103 - JDE EntrepriseOne Releases**

Oracle's JD Edwards EnterpriseOne Releases

| Release | GA Date | Premier Support Ends | Extended Support Ends | Sustaining Support Ends |
|---|---|---|---|---|
| Xe | Sep 2000 | Dec 2013 | Not Available | Indefinite |
| 8 | Jun 2002 | Dec 2013 | Not Available | Indefinite |
| 8.9 | Sep 2003 | Sep 2008 | Not Available | Indefinite |
| 8.10 | Jun 2004 | Jun 2009 | Not Available | Indefinite |
| 8.11 | Dec 2004 | Dec 2009 | Dec 2012 | Indefinite |
| 8.11 CRM Mobile Sales(both i-Series and non i-Series) | Dec 2004 | Dec 2009 | Dec 2010 | Indefinite |
| 8.12 | Apr 2006 | Apr 2011 | Apr 2014 | Indefinite |
| 8.12 CRM Mobile Sales(both i-Series and non i-Series) | Apr 2006 | Apr 2011 | Dec 2010 | Indefinite |
| 9.0 | Sep 2008 | Sep 2013 | Sep 2016 | Indefinite |
| 9.0.2 | Nov 2010 | Nov 2015 | Nov 2018 | Indefinite |
| 9.1 | Mar 2012 | Mar 2017 | Mar 2020 | Indefinite |

Source: http://www.oracle.com/us/support/library/lifetime-support-applications-069216.pdf (Note: Our current status context has been highlighted for ease of reference)

## 4.2 Project/Program Description

### 4.2.1 Current Issues

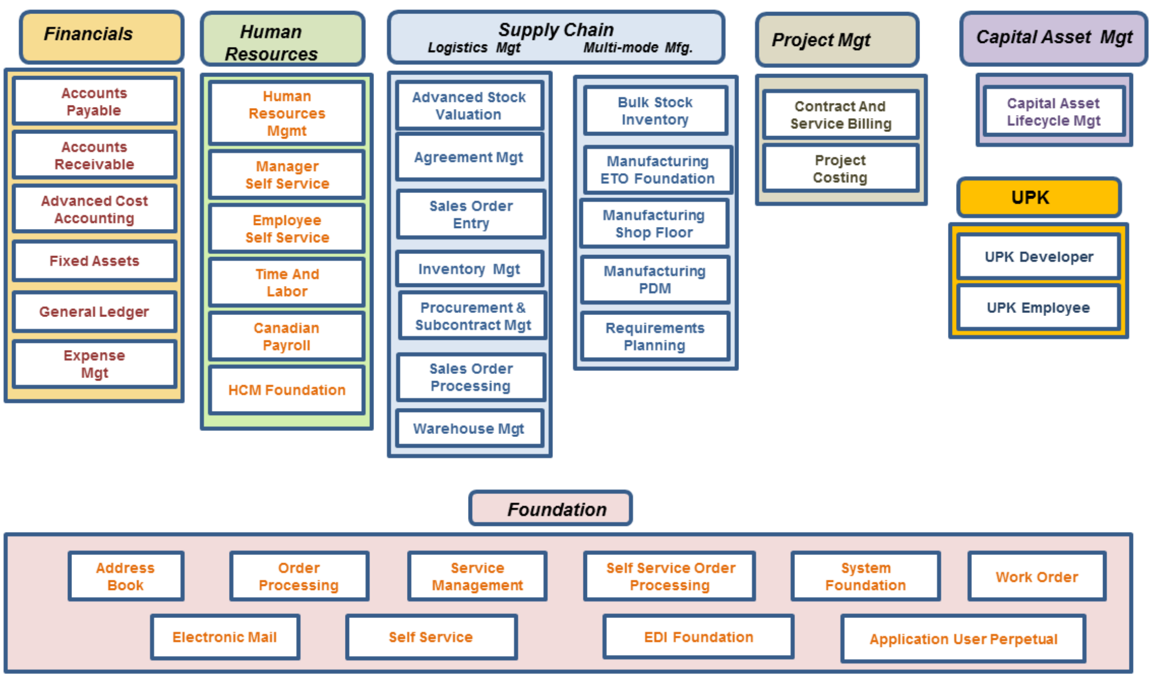
Since its implementation, JDE has proven to be a consistently dependable solution for core operational outcomes like financial accounting, accounts payable and receivable, budget management, procurement administration, inventory management, and payroll. However, the ERP solution did have some adaptability shortcomings to address specific, evolving business needs and/or business processes. These resulted in the extraction of business outcomes like Fleet Management from the ERP footprint and customizations to the JDE solution which can cause ongoing support complexities and/or challenges.

Ensuring full vendor support for ERP as a critical business solution is aligned with prudent stewardship. Since JDE v9.0 will lapse into Sustaining Support soon, a project is necessary to mitigate the risk.

### 4.2.2 Program/Project Scope

As shown in Figure 104, the JDE solution encompasses multiple modules to provide a comprehensive solution enabling vital business capabilities such as financial accounting, Accounts Payable and Receivable, budget management, procurement administration, inventory management, human resource management, payroll etc.

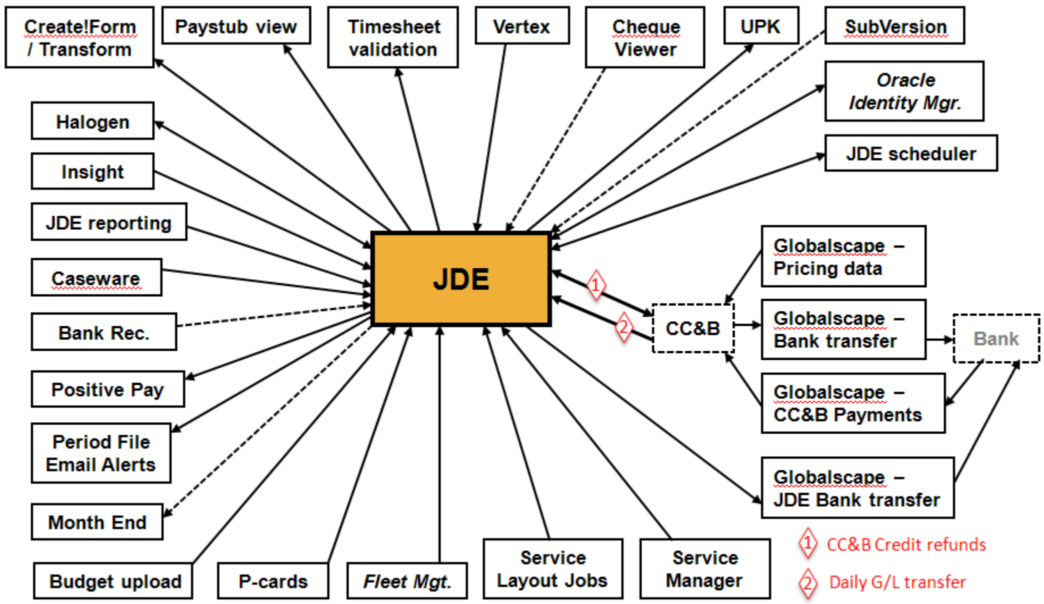
**Figure 104 - JDE Solution Modules**




Ongoing operational support is achieved by a small Enterprise Solutions team in the Systems Management group within IM & IT in collaboration with functional Stakeholder Subject Matter Experts (SME's) as part of a matrix support model. In addition, vendor engagements are leveraged when necessary to augment skills, complete development and/or provide additional capacity for support. Adherence to the future OOTB product vision will enhance the opportunities for external assistance. Infrastructure, hardware and database support services are currently provided by resources within Hydro Ottawa's CIO Division.

JDE is a highly integrated solution as evidenced by interfaces with both internal systems as well as external systems, as shown in Figure 105.

Figure 105 - JDE Interfaces




Various functional areas at Hydro Ottawa rely on JDE to achieve their operational mandates in an expedient, cost-effective manner. Stakeholder desires to maximize business efficiency and/or effectiveness, or address emerging legal or business requirements can lead to requests for further integration and/or JDE changes.

### 4.2.3 Main and Secondary Drivers

The main driver for this project is to ensure efficient, effective ERP business outcomes are sustained for HOL's ongoing business operations in a manner that mitigates immediate and longer term risk. In addition, the identified project is directly aligned with key guiding principles in HOL's approved IM&IT Strategy (excerpt below).

- HO's business strategies and corporate priorities will be the primary driver of the IM&IT initiatives.
- Where feasible, HO will leverage existing systems and services prior to investing in new solutions and will leverage its IT Investments in Oracle, Intergraph, and Microsoft by adhering to a "Best of Brand" strategy.
- Commercial-off-the-Shelf (COTS) solutions will be implemented with limited customization, in preference to custom-developed business applications, to reduce risks and costs, and to facilitate software supportability and upgrade paths.
- Standard architectural framework will be established to improve integration, facilitate access to key data, re-engineer business processes to improve outcomes, productivity and efficiency.

## 4.3 Project/Program Justification

### 4.3.1 Alternatives Evaluation

Alternatives considered for the future ERP strategy include:

1. Remain operating on current ERP solution (JDE v9.0 with customizations) and accept the inherent risks of not retaining the maximum support from the vendor
2. Upgrade/re-implement a newer OOTB version of JDE with a strategy to divest of customizations and fully leverage the products' best practices, support
3. Upgrade to a newer version of JDE with a mandate to port forward current customizations
4. Evaluate available Tier 1 ERP solutions for the best alignment to HOL's identified fit/form/function requirements
5. Evaluate potential Tier 2 ERP solutions for the best alignment to HOL's identified fit/form/function requirements against a heightened risk profile for ERP outcomes.

#### 4.3.1.1 *Alternatives Considered*

#### 4.3.1.2 *Evaluation Criteria*

After a decade of using the JDE solution as HOL's ERP, there was cause to pause and consider multiple factors impacting future ERP decisions from immediate, short and long term perspectives. Evaluation criteria considerations included:

- Anticipated business requirements to define essential scope;
- Functionality features and adaptability capabilities in the out-of-the-box (OOTB) product version;
- Degree and complexity of integration needs;
- Industry trends for ERP solutions;
- Vendor commitment towards future investments in the product line;
- Business operational risks of change;
- Alignment with technology strategy and ongoing stewardship; and
- Cost effectiveness of options

#### 4.3.1.3 *Preferred Alternative*

Assessments by HOL's Executive Management, IM&IT support and input from key impacted stakeholder groups to date, have concluded that the preferred alternative would be a full application upgrade within JDE product line should be pursued with adherence to a strategy to divest of current customizations in favour of the OOTB product wherever possible. The outlined budget and project path details are reflective of this intention, but are subject to change based on evolving information.

### 4.3.2 Project/Program Timing & Expenditure

The projected overall costs are $6.5M and will take 1 year to complete. Recommended project timeline will target a Q3 2016 transition.

| Historical ($M) | | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| - | - | - | - | - | 1.5 | 5.0 | - | - | - | - |

**Table 121 - Project Expenditures**

#### 4.3.3 Benefits

Operating on a current OOTB ERP solution within the JDE product line will align with desire to mitigate critical business outcome risks caused by the transition, leverage in-house knowledge of the JDE solution and related investments such as Insight reporting, improve overall system operational efficiency and provide new opportunities for cost-effective support and/or development assistance from vendors when needed.

### 4.4 Prioritization

#### 4.4.1 Consequence of Deferral

Deferral of this project will negatively impact the risk for critical ERP business outcomes once the maximum level of product support from the vendor will lapse in 2016.

#### 4.4.2 Priority

This project is considered to be a High priority based on risk to critical ERP business outcomes.

### 4.5 Execution Path

#### 4.5.1 Implementation Plan

The JDE upgrade/re-implementation plan will follow best practices for change and project management. The plan's approach will also align with Oracle's Unified Method (OUM) for JD Edwards implementations which prescribes five distinct phases (Inception, Elaboration, Construction, Transition and Production). Based on the mandate of achieving OOTB installation, a preliminary phase will be needed to assess current customizations against standard offerings to identify business processes and/or outcome impacts. Outcomes of this preliminary phase will help to define specifics of project scope.

#### 4.5.2 Risks to Completion and Risk Mitigation Strategies

Risks to completion include resource availability of key subject matter experts, strains to desired business outcomes caused by adherence to OOTB approach, potential extended timeline and/or scope creep. These risks will be mitigated through involvement of HOL's Executive Management Team in the Steering Committee to reinforce expectations, independent project management oversight, strict scope containment through change management process that restricts approvals to essential items only, and internal resource reassignments for full-time dedicated participation in the project along with empowerment to make decisions.

#### 4.5.3 Timing Factors

To avoid the risk of not having maximum vendor product support for our critical ERP solution, the recommended project timeline will target a Q3 2016 transition.

#### 4.5.4 Cost Factors

Final cost of the project will be affected by negotiated contracts with vendors.

## 4.6 Project Details and Justification

| | |
|---|---|
| **Project Name:** | JDE Application Upgrade |
| **Capital Cost:** | $6.5M |
| **O&M:** | No change from existing program |
| **Start Date:** | 2015 |
| **In-Service Date:** | Q3 2016 |
| **Investment Category:** | General Plant |
| **Main Driver:** | Business operations efficiency |
| **Secondary Driver(s):** | N/A |
| **Customer/Load Attachment** | N/A |
| **Project Scope** | |
| Upgrade/re-implement a newer OOTB version of JDE with a strategy to divest of customizations and fully leverage the products' best practices, support | |
| **Work Plan** | |
| The plan's approach will also align with Oracle's Unified Method (OUM) for JD Edwards implementations which prescribes five distinct phases (Inception, Elaboration, Construction, Transition and Production). Based on the mandate of achieving OOTB installation, a preliminary phase will be needed to assess current customizations against standard offerings to identify business processes and/or outcome impacts. Outcomes of this preliminary phase will help to define specifics of project scope. | |
| **Customer Impact** | |
| Provide HOL with a more effective framework to address evolving business needs and customer expectations in a more timely and efficient manner by utilizing an OOTB approach and not having to build custom applications. | |

# 5 Fleet Replacement

## 5.1 Project/Program Summary

Hydro Ottawa Limited ("Hydro Ottawa") requires a fleet of specialized vehicles to complete many daily activities. Hydro Ottawa maintains approximately 270 vehicles and other related equipment. Vehicles are an essential component in providing efficient and reliable service to customers through the quick restoration of power, the efficient construction and maintenance of the distribution system and the safety of employees.

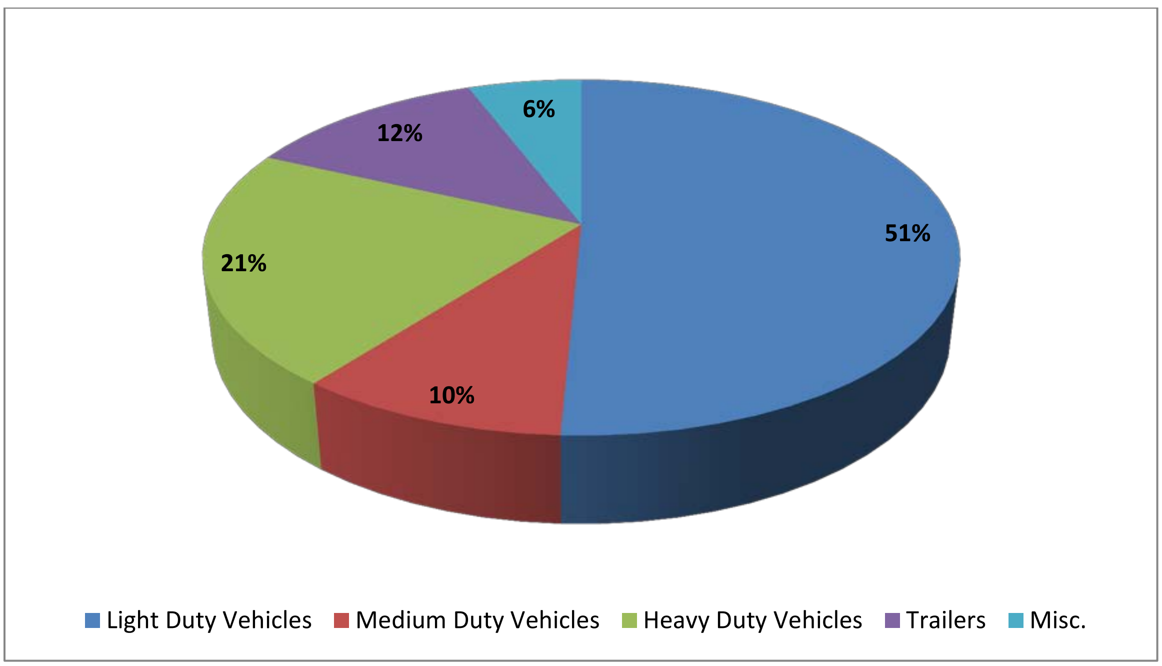
Hydro Ottawa maintains a multiple year capital plan to effectively manage its fleet assets. This plan is an essential tool for both long and short term planning and budgeting. This document outlines the 2016-2020 Fleet capital replacement plans.

## 5.2 Project/Program Description

### 5.2.1 Current Composition of Fleet

Figure 106 below shows the current composition of Hydro Ottawa fleet grouped by major category of asset.

**Figure 106 - Composition of Fleet**




### 5.2.2 Program/Project Scope

Hydro Ottawa's Fleet replacement plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Factors taken into consideration in establishing the replacement date of individual vehicles include:

- Vehicle age

- Mileage
- Engine hours
- Power take off hours
- Operating and maintenance costs
- Overall general condition of the vehicle

As the result of these evaluations, vehicles may be retained longer due to being in better than average condition and while others may be replaced earlier due to being in poorer condition.

Preventative scheduled maintenance on the entire Fleet is conducted regularly. Schedules are implemented per the manufacturers' recommendations, unless Fleet determines the condition of equipment is extreme or the equipment is lightly operated.

Hydro Ottawa operates a repair centre to maintain a large majority of our fleet internally. We strive to minimize potential risks involved by subcontracting our aerial units to unqualified vendors. Hydro Ottawa provides extensive training to our technicians in order to achieve the qualifications necessary to sign off on inspection documents. These documents are signed by our technicians stating that the aerial units are safe to operate in proximity of high voltage power lines.

Hydro Ottawa regularly inspects the aerial equipment on a 4-month basis, as well as monitors mileage and engine hours, which may trigger an earlier inspection. On light duty equipment, Hydro Ottawa performs regular scheduled maintenance every six months or 6,000 km.

## 5.3 Main and Secondary Drivers

The main driver of this program is System Capital Investment Support: providing safe, reliable and efficient vehicles and equipment that meet operational requirements.

## 5.4 Performance Targets and Objectives

The objectives of Hydro Ottawa's Fleet replacement plan are:

- Provision of safe, reliable and efficient vehicles and equipment to meet the operational requirements;
- Compliance with legislation and regulations, as well as accepted industry norms and practices,
- Cost effectiveness;
- Optimization of size of fleet;
- Standardization of equipment specifications; and
- Environmental considerations such as fuel economy and exhaust emissions.

## 5.5 Project/Program Justification

Hydro Ottawa applies the following metrics in determining fleet asset life cycle replacement projections (see Table 121).

| Unit Type | Years | Kilometres | Engine Hours | Power Take Off (PTO) Hours |
|---|---|---|---|---|
| **Automobile** | 10 | 150,000 | 4,000 | |
| **Vans – Compact** | 7 | 150,000 | 5,000 | |
| **Vans - Cargo** | 8 | 150,000 | 6,000 | |
| **Vans – Step / Cube** | 10 | 150,000 | 8,000 | |
| **Trucks – Pickup (Compact)** | 7 | 100,000 | 5,000 | |
| **Trucks – Pickup (Conventional)** | 8 | 150,000 | 6,000 | |
| **Trucks – Dump** | 10 | 125,000 | 6,000 | |
| **Trucks – Stake** | 10 | 150,000 | 8,000 | |
| **Trucks – Knuckle Boom** | 15 | 200,000 | 10,000 | 5,000 |
| **Trucks – Buckets** | 12 | 200,000 | 10,000 | 5,000 |
| **Trucks – Line / RBD** | 12 | 200,000 | 10,000 | 5,000 |
| **Forklifts** | 15 | | 10,000 | |
| **Trailers** | 12 | | | |
| In addition to the above quantitative metrics, the overall general condition of the vehicle is also assessed leading to some vehicles replaced in advance of reaching these metrics while others are retained for a longer period. | | | | |

**Table 122 - Fleet Replacement Metrics**

Note that the plan does not provide for any growth to the current size of the fleet but rather just the replacement of aging vehicles.

Hydro Ottawa uses a passive GPS tracking system to collect data any time while a vehicle is running. The data is stored onboard the GPS until such time the vehicle returns to a home base and shuts off. At this time, the data is downloaded to Hydro Ottawa's internal system and the data is calculated. This data includes routes, idling time, kilometer traveled, excessive accelerating/braking, speeding, and unacceptable operation.

### 5.5.1 Project/Program Timing & Expenditure

In the first few years following amalgamation in 2000 (2000 – 2004) insufficient capital was spent on fleet replacement however between 2005 and 2009 an accelerated replacement plan was implemented. Replacement spending is now required annually to maintain the fleet. Table 122 shows the vehicle purchase history from 2012 to 2013 and the budgeted vehicle purchases from 2014 to 2020. In 2013, a large group of vehicles were due to be replaced, causing the capital expenditures to be higher than normal in that year. Again in 2020, a higher than normal amount of vehicles are due for replacement as shown in the table below.

In order to increase fleet efficiencies, Hydro Ottawa purchased a fleet management software system, FleetWave, in 2014. With this fleet software, Hydro Ottawa was able to streamline processes. FleetWave is a web-based enterprise fleet management software solution. It utilises the very latest technologies to provide comprehensive fleet management for Hydro Ottawa fleet operation:

- Asset Tracking and Management including Capital Replacement Planning
- Preventative Maintenance Scheduling
- Workshop Management (Workflow Planning, Scheduling, Job Assignment);
- Work Order Management;
- Warranty, Recalls & Campaigns;
- Operating Cost Management (Fuel, Licences, Permits, etc.);
- Inventory Management (parts supply system);
- Motor Pool Management;
- Risk Management (MVA, Safety, MOT Compliance, Records, etc.); and
- Technician Records and Training Plan.

| Historical ($M) | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|
| **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| **2.02** | 2.54 | 3.06 | 1.44 | 1.54 | 1.45 | 1.21 | 1.45 | 1.48 |

**Table 123 - Project Expenditures**

### 5.5.2 Benefits

| Benefits | Description |
|---|---|
| **System Operation Efficiency and Cost-effectiveness** | Fleet replacement is required to support the day to day business activities and sustain operations by minimizing down-time and minimizing the total vehicle life cycle costs. |
| **Customer** | Newer vehicles are required to maintain and sustain operations and ensure appropriate response times to customers, older vehicles require more repairs resulting in increased downtime. |
| **Safety** | Newer vehicles are needed to maintain safe work practices, new safety features in newer models also improve workplace safety |
| **Cyber-Security, Privacy** | N/A |
| **Co-ordination, Interoperability** | N/A |
| **Economic Development** | N/A |
| **Environment** | New vehicles are more fuel efficient than older units, improvements in emission standards and engine design also result in a reduction of green house gas emissions. |

**Table 124 - Project Benefits**

## 5.6 Prioritization

### 5.6.1 Consequence of Deferral

If this program is deferred the crews will not have the vehicles and equipment that they require in order to complete daily activities to meet customer expectations in a safe, reliable and efficient manner.

## 5.7 Execution Path

### 5.7.1 Implementation Plan

HOL uses the criteria identified in sections 5.2.2 and 5.5 to prioritize and stage the work.

## 5.8 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Fleet Replacement |
| **Capital Cost:** | $7.47M (2016-2020) |
| **O&M:** | N/A |
| **Start Date:** | Ongoing |
| **In-Service Date:** | N/A |
| **Investment Category:** | General Plant |
| **Main Driver:** | System Capital Investment Support |
| **Secondary Driver(s):** | N/A |
| **Customer/Load Attachment** | N/A |

**Project Scope**

Hydro Ottawa's Fleet replacement plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Factors taken into consideration in establishing the replacement date of individual vehicles include:

- Vehicle age
- Mileage
- Engine hours
- Power take off hours
- Operating and maintenance costs
- Overall general condition of the vehicle

As the result of these evaluations, vehicles may be retained longer due to being in better than average condition and while others may be replaced earlier due to being in poorer condition.

**Work Plan**

Preventative scheduled maintenance on the entire Fleet is conducted regularly. Schedules are implemented per the manufacturers' recommendations, unless Fleet determines the condition of equipment is extreme or the equipment is lightly operated.

Hydro Ottawa operates a repair centre to maintain a large majority of our fleet internally. We strive to minimize potential risks involved by subcontracting our aerial units to unqualified vendors. Hydro Ottawa provides extensive training to our technicians in order to achieve the qualifications necessary to sign off on inspection documents. These documents are signed by our technicians stating that the aerial units are safe to operate in proximity of high voltage power lines.

Hydro Ottawa regularly inspects the aerial equipment on a 4-month basis, as well as monitors mileage and engine hours, which may trigger an earlier inspection. On light duty equipment, Hydro Ottawa performs regular scheduled maintenance every six months or 6,000 km.

**Customer Impact**

Newer vehicles are required to maintain and sustain operations and ensure appropriate response times to customers, older vehicles require more repairs resulting in increased downtime.

# 6 Enterprise Architecture Program

## 6.1 Project/Project Summary

The HOL vision is that information is accessible, when and where it is needed to support customer interaction, decision making, ongoing business operations, regulatory compliance and business sustainability. As and where ever possible cost effectiveness will be sought to ensure all information technology and information management measures are managed appropriately. A guiding principle, to achieve the vision, is that a standard architectural framework is to be established to improve integration, facilitate access to key data, re-engineer business processes to improve outcomes, productivity and efficiency, and implement master data management.

The ***Enterprise Architecture Program – Enterprise Service Bus*** project was launched in 2014 to establish a Service Oriented Architecture (SOA) methodology for managing, measuring, executing, and optimizing processes within HOL to help better achieve business outcomes and enable realization of the above visions. A key component of the SOA methodology is the deployment of an Enterprise Service Bus (ESB) to establish and prioritize a standard architectural framework for all system and solution work across HOL that leverages industry best practices and enables real-time integration of business applications.

HOL's strategy is to put the customer at the centre of everything HOL does, to that end this project will be a major enabler/contributor to that strategy and the associated critical areas of performance as addressed in Table 124 below.

| HOL Corporate Objectives | Details |
|---|---|
| Customer Value | ESB/SOA Enables:<br>• Leveraging of existing IT investments (e.g., Contact Centre 6) to provide consistent inbound and outbound communications for customers across media (phone, website, text, etc.)<br>• Providing customers with real-time access to data as well as providing them with self-service that flows automatically to the various business applications (e.g., today the move-in/move-out web form that customers fill out on the website is actually processed manually through HOL<br>• Automating processes/workflows to provide more timely response to customer requests (e.g., Orlando Utility can achieve a service re-connect request in 3 min. from time request is entered on website to when electricity is reconnected, used to be days) |
| Organizational Effectiveness | ESB/SOA Enables:<br>• Access to real-time data for more timely decision making<br>• Automating processes/workflows to increase productivity, reduce staff labour, and complete tasks more quickly, thereby reducing OM&A<br>• Wrapping of legacy/existing applications with Web Services in order to provide better service to internal users, provide new services more quickly than waiting for an application refresh<br>• Applications developed using Service Oriented Architecture (SOA) principles to perform faster, thus increasing productivity and timeliness (Studies have SOA applications to perform up to 30% faster) |
| Financial Strength | ESB/SOA Enables: |

| | |
|---|---|
| | • Delivery of new services/functionality at lower costs and more quickly<br>• Access to real-time data for faster financial decision making<br>• Providing internal users with new services/functionality by leveraging investments in existing applications and wrapping with Web Services which can defer/or reduce application refresh/rip & replace, thereby reducing costs and risks |
| Corporate Citizenship | n/a |

**Table 125 - ESB/SOA as an Enabler to HOL's Strategy**

Industry has realized significant business benefits from aligning on the Service Oriented Architecture (SOA) methodology and deploying an Enterprise Service Bus (ESB) platform for application integration. Some of the business benefits of SOA/ESB, from recent studies, are shown in Table 125. It is expected that HOL can realize many of these benefits from this project.

| Data Point | Source |
|---|---|
| • 30% improvement in application performance using SOA/ESB<br>• 100% system uptime.<br>• Replaced >30 point-to-point integration links with a flexible, standardized business platform | HydroOne – Case Study (Oracle)<br>http://www.oracle.com/jp/hydro-one-business-benefit-brief-335567-ja.pdf |
| • 36% faster implementation and integration of new applications using SOA/ESB<br>• 50% reduction in time spent on supporting and maintaining the system using SOA/ESB | Tucson Electric Power Company – Case Study (Oracle)<br>http://www.oracle.com/us/corporate/press/015318_EN.doc |
| • 35% of IT activity in a typical enterprise is dedicated to application integration – includes development, maintenance and operational cost. | Gartner<br>http://www.serenecorp.com/v3/pdf/Serene_DS_EAI.pdf |
| • 60% of the implementation cost of an ERP package is spent on integration. | METAgROUP<br>http://www.serenecorp.com/v3/pdf/Serene_DS_EAI.pdf |
| • 13% to 35% lower cost can be achieved with SOA software development as compared to non-SOA development | Return on Investment for Composite Applications<br>and Service Oriented Architectures<br>Enterprise Applications Consulting<br>http://www.eaconsult.com/articles/SOA_ROI_EACReport.pdf |
| • Integration development cycle time cut by 50% compared to proprietary integration broker<br>• Integration development in less than 4 weeks compared to estimated 3 to 4 months using PLSQL-based point-to-point integration<br>• Non-expert internal IT resource up to speed in 8 days, ready to maintain 22 core BPEL processes | Heald College "From EAI to SOA by Accident – Case Study (Oracle)<br>http://smartintegration.com.au/Resources/reading/SOA%20Value%20Patterns.pdf |
| • Core process automation in six months compared to a typical two-year-long IT project<br>• Avoided a "rip and replace" project estimated at $100M over four years with less than $1M in SOA development | ING Lease/ING Group "From Two Years to Six Months – Case Study (Oracle)<br>http://smartintegration.com.au/Resources/reading/SOA%20Value%20Patterns.pdf |

**Table 126 - Realized Benefits of SOA/ESB by Industry**

## 6.2 Project/Program Description

### 6.2.1 Current Issues

With a significant portion of the company's business tied to information systems and technology, tighter alignment and a more integrated environment is needed to achieve standardization of technology, broader use of functionality across business lines with better grouping of specific purpose services, improved user-interfaces and significantly reduced development of point-to-point integrations and associated on-going support.

Current projections are that, during the period 2015 to 2020, potentially 20 or more new applications will be deployed which will result in a significant increase in application-to-application integration. Based on current methods used in Hydro Ottawa today, this growth will drive up operating and support costs further and increase data flow complexity. This is an unsustainable trend that has led other industries, including those within the utility sector, to deploy enterprise-wide Enterprise Service Bus architecture, as a best practice.

Preparation of the Smart Grid data environment in terms of greater integration between systems is needed to more fully realize the benefits of the Smart Grid.

There is a significant amount of replicated data stored across HOL in application specific databases (staging tables and staging folders) and user specific databases which indicates a master data management strategy is needed for better protection of data, and reduction of database and storage costs. Real-time access to data, will enable stricter management of master data, establishment of authoritative sources of data, ensure access to most current data and reduce data storage costs.

No uniform and standard structured approach is used to transfer data between HOL and external businesses (service providers, partners, banks, IESO, etc.) for Business-to-Business communications.

Processes are typically isolated at the application level (application-centric) and there is little use of automated business processes/workflows and real-time monitoring of process data flows. Inconsistencies are experienced in the transfer of data between Operational Technologies systems and the HOL business systems.

The time to market for offering new services (customer or internally facing) is slow due to the reliance on the application vendor's feature release roadmap or the need to customize the application (which leads to on-going support challenges and higher costs). The investments in some existing applications are not fully leveraged for offering new services.

HOL IT environment was not well positioned to leveraging public cloud services or for integrating them in to existing processes.

### 6.2.2 Program/Project Scope

The project involves adopting a "service-centric" model for providing new internal and external services based on Service Oriented Architecture (SOA) methodology, use of web services for creating new services and the deployment of an Enterprise Service Bus (ESB).

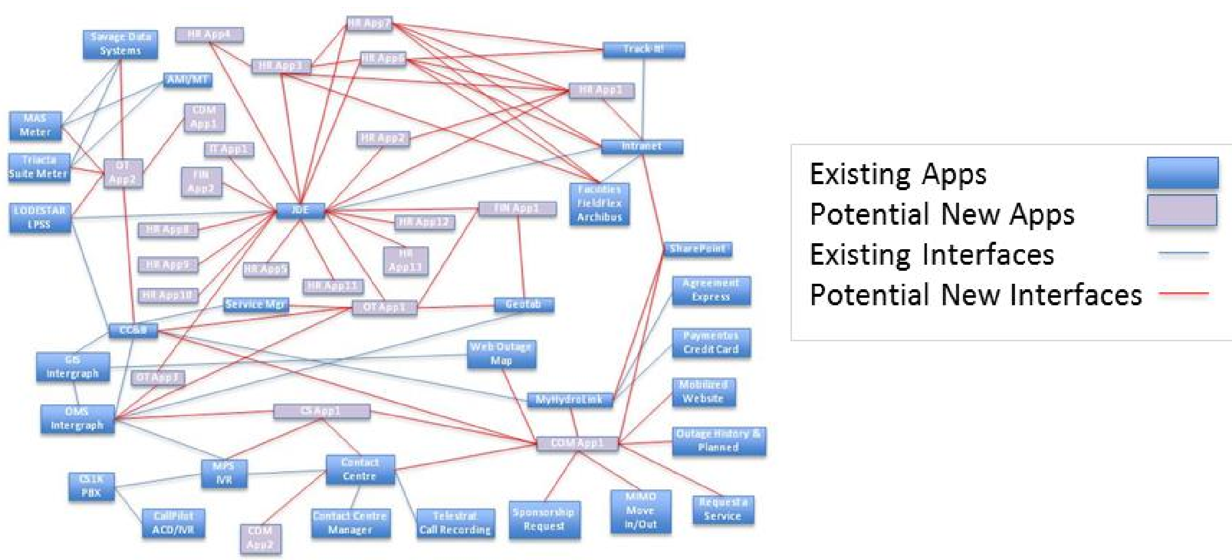
There are three major phases to the project which began in 2014:

- Architecture Planning and Design: ESB Solution Design; Governance; Application Integration Roadmap; and Operational Pre-Planning – *completed in 2014*
- ESB Platform Deployment: Deployment of the ESB platform in the following environments: Development Workstation; Test/Quality Assurance; and Production with high availability (HA) – *targeted for completion in 2015*
- Application Integration and Service Orchestration: Integration of initial foundational applications and subsequent new applications, with a view to automating key processes through service orchestration – *targeted to begin in 2015*

This project is using the industry leading Oracle Enterprise Service Bus technology that has been implemented by many Utilities and other enterprises in North America, as well as globally. HOL is benefitting from the maturity of this technology, over the past ten years and wide deployment.

### 6.2.3 Main and Secondary Drivers

**Figure 107 - Illustration of the Projected Growth in Applications & Interworking**




The main drivers for the project:

- Stability and standardization of data interworking across HOL applications / systems
- Fully realize the benefits of Smart Grid with greater integration of applications in Operations Technologies and with business applications
- Stronger and more consistent controls on application interworking
- Scalable and cost-effective approach to application integration (to address growth illustrated in Figure 107 and the potential 350% increase in point to point integrations)
- Centralized security controls for applications on the ESB and data traversing the ESB
- Real-time flow of data across Hydro Ottawa for improved decision making and improved employee productivity
- Automating processes through service orchestration to reduce costs, increase reliability, and increased employee productivity

- Centralized application and management of security to all data traversing the ESB

Secondary drivers for the project:

- Master data management with significant reduction and avoidance of data replication
- Leverage and extend current investments and de-risk rollout of new services
- Faster and lower cost approach to delivering new services for customers and improving internal operations
- Avoid the need to “rip & replace” some legacy applications, by wrapping legacy applications with web services to enhance user access to information
- Easy integration of public cloud services to on premise applications, as well as integrate public cloud services in to existing processes

Reduction in number of secondary databases as well as reduction in the myriad of personal databases.

### 6.2.4 Performance Targets and Objectives

The performance targets and objectives are:

- Automate key processes, through service orchestration, to reduce cost of processes, increase reliability, and reduce completion time of processes
- Reduce the number of new point to point integrations and the associated costs of maintaining integrations
- Reduce the amount of replicated data, through real-time access to data, that will be realized by reduction in databases and storage
- Enable faster integration for new applications
- Potentially reduce further the number of existing point to point integrations

## 6.3 Project/Program Justification

### 6.3.1 Alternatives Considered

The only alternative is to continue to experience the “current issues” and projected increase in the point to point integrations growing exponentially to the point of being unsustainable in size, variety and purpose and on-going maintenance and support, as illustrated in Figure 107.

#### 6.3.1.1 *Preferred Alternative*

This project is a shift in the way applications will be integrated, and data shared between applications.

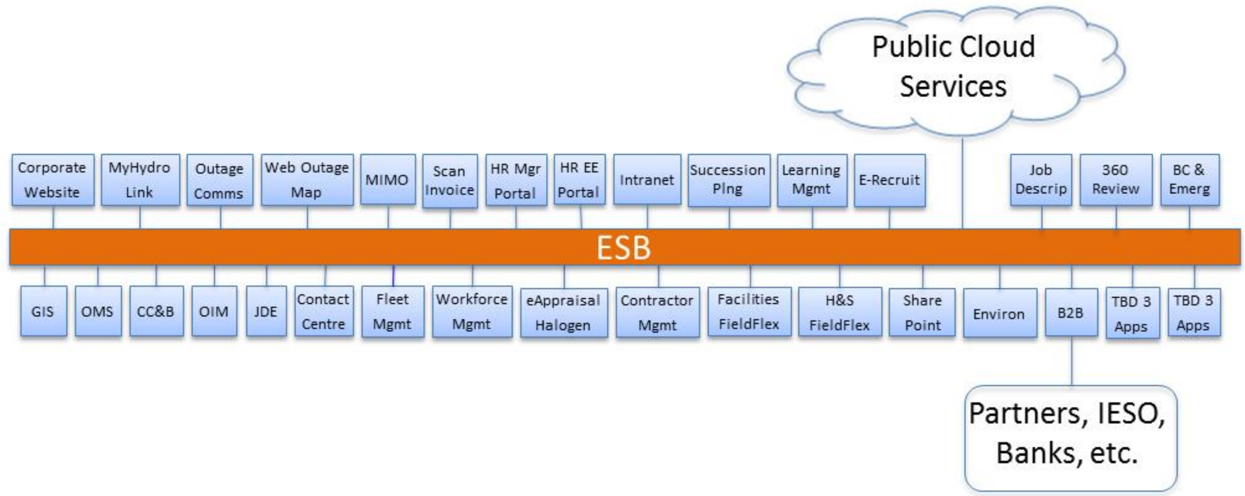
### 6.3.2 Project/Program Timing & Expenditure

This business case for 2016 to 2020 is focused on Phase 3 “Application Integrations”

- Architecture Planning and Design (2014)
- ESB Platform Deployment (2015)
- Application Integration and Service Orchestration (2015 to 2020)

A view of the 2020 “To Be State”, consisting of projected application integrations to the ESB is shown in Figure 108.

**Figure 108 - Illustration of the Projected Integration of Applications to ESB**




**2014**

The upfront Architecture Planning and Design work done in 2014, in terms of: Business Case; Analysis; Research; ESB Solution Design; Governance; Application Integration Roadmap; and Operational Pre-Planning, has set the foundation for the work outlined in this project and will be used to issue the associated RFPs for the consulting work. The HOL investment in the detailed Architecture Planning and Design work has contributed significantly to minimizing risk and unexpected expenses.

**2015**

In 2015, there will be the deployment of the ESB platform in the following environments: Development Workstation; Test/Quality Assurance; and Production with high availability (HA). As well starting in 2015 and continuing in 2016 will be the integration of initial foundational applications.

**2016 to 2020**

The work done in 2014 to 2016 will lay the foundation for all application integration work, as well as process automation, through to 2020 and beyond. It will comprise and embrace all existing integrations (where eligible) and all net new acquisitions, services (including Public Cloud), and solutions.

HOL minimized and will control costs in this project by:

- Securing high discounts on the software licensing and thus reducing the annual software maintenance expenses
- Deploying integrated system/server platform (Oracle Database Appliance) for hosting the ESB software, as well as other future applications and databases, that improves: reliability through built-in redundancy; reduces on-going support efforts and costs through simplified patching procedures and centralized monitoring and management; and flexible software license management

| Historical ($k) | | | | Future ($k) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| | | | | 783 | 797 | 787 | 364 | 290 | 295 | 300 |

**Table 127 - Project Expenditures**

### 6.3.3 Benefits

**Near-Term Benefits**

The expected near-term benefits of SOA/ESB to HOL are:

- Reduce number of links needed to integrate new applications.
- Reduce current data flow issues, especially for OMS to CC&B and Corporate website, by improving integration of disparate applications.
- Build new applications, such as Outage Communications and Employee Self-Service Portal by leveraging existing enterprise assets and making them accessible for reuse outside their original purpose.
- Expose web services of Contact Centre to build communications functionality in new applications.
- Using existing services /reusable software to build new application reduces the risk of delayed IT projects and thus increasing the likelihood of timely new product and service introductions.
- Enable OT to harness full capability of Intergraph OMS, will apply to other purchased apps.

**Longer Term Benefits**

The expected longer term benefits of SOA/ESB to HOL are:

- Enable Hydro Ottawa to adapt quickly in response to changes in the industry, regulatory, marketplace, by quickly deploying new services.
- Use of the Security Services of ESB/SOA, enables quick application of any security changes once, in one location and used throughout the enterprise, to comply with CIP, NSERC, etc.
- Extending life of current investments and exposing functionality as services (re-useable) for other applications
- Any component can be connected, ejected, or modified without impacting the performance of others.
- Increase efficiency in working with partners for saving costs, off-loading non-core functions.

| Benefits | Description |
|---|---|
| System Operation Efficiency and Cost Effectiveness | • Stability and standardization of data interworking across HOL applications / systems<br>• Fully realize the benefits of Smart Grid with greater integration of applications in Operations Technologies and with business applications<br>• Stronger and more consistent controls on application interworking<br>• Scalable and cost-effective approach to application integration<br>• Centralized security controls for applications on the ESB and data traversing the ESB<br>• Real-time flow of data across Hydro Ottawa for improved decision making and improved employee productivity<br>• Automating processes through service orchestration to reduce costs, increase reliability, and increased employee productivity<br>• Master data management with significant reduction and avoidance of data |

| | |
|---|---|
| | replication<br>• Centralized application and management of security to all data traversing the ESB |
| Customer | • Faster response to customer enquiries will be realized through real-time access to data and automated services<br>• Potential automation of Outage Communications and enabling solutions such as mobile workforce management, and will provide more reliable service and enhance the level of service<br>• Increased reliability of external and internal services through well managed and monitored data flows and automated processes |
| Safety | • Health and safety processes could be automated to provide real-time access to information and to ensure consistent processes |
| Cyber-Security, Privacy | • Centralized security controls will be applied at the ESB level thus providing consistent and enhanced security for all data traversing the ESB<br>• Changes to security controls can be quickly applied centrally via the ESB |
| Co-ordination, Interoperability | • Utilities and enterprises across North America are standardizing on Service Oriented Architecture (SOA) methodologies for interoperability<br>• ESB enables the leveraging of publicly available web services to create new services<br>• The SOA technologies purchased from Oracle and used for the Enterprise Service Bus include B2B (Business to Business) application for standardized data transfer with 3rd parties, including IESO, Banks, etc.<br>• The deployment of an ESB will enable HOL to easily integrate to services provided through Public Cloud providers. |
| Economic Development | n/a |
| Environment | Reduction in point to point environment (footprint), code, and change management at individual interface layer. |

**Table 128 - Project Benefits**

## 6.4 Prioritization

### 6.4.1 Consequence of Deferral

Deferral of this project would result in HOL continuing to incur the costs and operational issues identified under “current issues”, and with a projection of approximately 30 new applications being deployed in the next 5 years, the impact of the current issues and exponential growth of point to point integrations will continue to increase.

This is a multi-year project and deferral of the project at this time would strand the current investments with no operational benefit, while at the same time having to pay the annual maintenance on the software licenses (over $110K per year).

### 6.4.2 Priority

This project is rated as a High priority project relative to the other IT projects. The execution of this project with Service Oriented Architecture (SOA), web services, and Enterprise Service Bus (ESB) will fundamentally change how applications are integrated, new services/functionality is implemented, processes are automated, and public cloud services are leveraged. This project will enable HOL to achieve its goals of reducing costs, increasing productivity, delivering new services, and providing access to information anywhere, anytime (as stated in IMIT Strategy).

## 6.5 Execution Path

### 6.5.1 Implementation Plan

The implementation plan is as follows:

- Phase 1 – Architecture planning and design
- Phase 2 – Build and deploy ESB platform, and establish the operational model
- Phase 3
    - Integrate foundational applications via ESB
    - Automate major processes through service orchestration
    - Integrate new applications

### 6.5.2 Risks to Completion and Risk Mitigation Strategies

Delay in rolling out potential to allow current practices to build more point to point integrations.

### 6.5.3 Timing Factors

Phase 1 has been completed, Phase 2 is underway in 2015 and work has begun for Phase 3 in 2015.

A factor that may affect the timing of the project completion is the availability of skilled resources to operate and manage the ESB. Vendor expertise has been identified to address and de-risk any potential deficiency/need.

### 6.5.4 Cost Factors

The total staffing effort to operate and manage the ESB once in operation and the need for external expertise to resolve operational issues have been estimated and may end up being lower or higher than the estimates.

## 6.6 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Enterprise Architecture Program – Enterprise Service Bus |
| **Capital Cost:** | 2,036,416 |
| **O&M:** | n/a |
| **Start Date:** | 2014-09-26 |
| **In-Service Date:** | 2020-12-31 |
| **Investment Category:** | General Plant |
| **Main Driver:** | System Operation Efficiency and Cost Effectiveness |
| **Secondary Driver(s):** | Enabling master data management and reducing database and storage costs |
| **Customer/Load Attachment** | n/a |

**Project Scope**

The scope of the project from 2016 to 2020 will be focused on integrating applications via the Enterprise Service Bus and automating major processes using SOA service orchestration. The integration will mainly involve integrating new applications to existing applications.

**Work Plan**

The work plan for 2016 to 2020 is to continue the integration and service orchestration work begun in 2015. In particular, this will involve supporting the Field Service Management project planned to begin in 2015 and that will be leveraging SOA and service orchestration.

**Customer Impact**

- Faster response to customer enquiries will be realized through real-time access to data and automated services
- Potential future automation of Outage Communications will provide more reliable service and will enhance the level of service
- Increased reliability of external and internal services through well managed and monitored data flows and automated processes

# 7 Mobile Workforce Management

## 7.1 Project/Project Summary

Hydro Ottawa has a large mobile workforce that is responsible for a wide range of work from simple disconnect, reconnects or meter changes to the more complex and longer duration pole changes and cable replacements. To date we have been using a combination of Excel spreadsheets, in-house developed databases, and our Intergraph In-Service system for scheduling and dispatching work. This is accomplished in a decentralized model with several different groups dispatching mainly to their own resources. Although this has been relatively effective, the organization needs to invest in a Mobile Workforce Management (MWM) tool to drive productivity to the next level.

## 7.2 Project/Program Description

### 7.2.1 Current Issues

Effective mobile workforce management is critical to our ongoing corporate success, especially as it relates to Customer Service, Productivity, Operating Costs, and System Reliability. A comprehensive review of the systems currently in use for managing field service workloads confirmed that there are significant opportunities to drive improvements across many facets of our field operations.

We currently use a combination of tools to schedule and dispatch work. Medium and long term work is managed using spreadsheets which are useful, but very manual and labour intensive to manage and maintain. We also have a home grown solution called Service Manager that assists with managing the checklists and information for service connections and other work managed by the Service Desk. We are able to send service layout requests out to field staff and it includes some calendar functionality for booking Service Truck appointments. From a mobile perspective we are using the Outage Management System (OMS) as a basic dispatch system. Flat files of work orders are received from systems like Service Manager and Customer Care & Billing (CC&B). Staff from various groups then needs to access OMS to dispatch this work to internal and contract resources. There is no schedule or optimizer available in OMS to ensure that the right jobs are allocated to the right resource based on all the other work and variables to take into account for that day.

Furthermore, we do not have ready access to data and information to track, monitor, report and manage the day to day performance of field staff. Many of the tools we have reviewed have strong performance management capabilities to provide Supervisors and Managers access to timely, relevant and accurate data. Supervisors will have access to reports that will summarize activity from the prior day while allowing them to drill down into specific areas of concern quickly and easily.

Hydro Ottawa operations teams have done well with their current disparate systems, however new tools are required to drive improvements being demanded around service delivery and cost reduction/containment. The current system is resulting in tangible expenditures that could and should be avoided. The current process has some limitations that impact Hydro Ottawa's continued ability to effectively dispatch work, and generate more "on the job" time.

These limitations include:

- All jobs available to dispatch are not held in one system, complicating the job of optimizing the dispatch of work;
- Forecasting and profiling are separate from dispatching systems;
- Significant amounts of manual dispatching is required;
- Sub-optimal routing of crews against jobs;
- Significant limitations in real time control of planned work, and new work, emergent or otherwise; and
- A lack of performance management capabilities to understand current and future work dynamics.

In summary:

- HOL must focus on increasing the productivity across the organization;
- The Field Service teams are doing well managing with their current tool set;
- The current systems and processes result in less than optimal dispatching of work leading directly to latent capacity in field service teams;
- Sub-optimal routing for jobs is contributing to excess fuel costs, truck rolls, and kilometers being driven;
- Lack of a unified dispatching system and processes has resulted in a steady backlog of work potentially impacting reliability, bad debt expense, etc.;
- There is a need for improved real time analysis to support intraday decision making; and
- Performance management capabilities along with compliance on capturing key job metrics is an absolute must to allow for better decision making.

### 7.2.2 Program/Project Scope

To purchase and implement an industry leading Mobile Workforce Management tool to enhance scheduling and dispatch at Hydro Ottawa.

### 7.2.3 Main and Secondary Drivers

The main driver for this project is business operations efficiency. Workforce Management systems enable an organization to centralize all of the scheduling and dispatch functions for all field resources, improve overall visibility of workload and resource availability and ensure consistent application of scheduling policies to all types of work. With features such as schedule optimization and route planning, it improves field resource productivity, reduces mileage and overtime costs, and increases the ability to meet customer commitments. It also reduces the time spent on scheduling allowing the dispatcher to focus on handling exceptions or emergencies like trouble calls or outages.

The result is a consolidated view of both immediate and long term jobs and a vehicle to consistently make smart decisions about prioritization, crew scheduling, and fast response to emergencies and outages. Through more effective planning, scheduling and dispatch the company will ensure that the right resource, with the right skills is at the right location, with the right tools, parts and equipment to complete the work at the lowest cost while meeting customer needs.

### 7.2.4 Performance Targets and Objectives

The objective of the project is to purchase and implement an industry leading MWM tool to enhance scheduling and dispatch at Hydro Ottawa. These tools provide the ability to optimize work load versus resources in real time while balancing priorities that will enable the following:

**Improve Productivity** – Less than optimal dispatching and routing of work using Hydro Ottawa's current systems and tools is leading to latent capacity in the field service teams, and presents a real opportunity to increase daily job completion rates. Another area of opportunity is that of administration tasks, more specifically, time capture. Timesheets are completed by all field service personnel daily, and timesheets are a significant time drain when viewed over the course of a full year. Our review of the capabilities of newer systems indicated the ability to automate time capture for field service staff.

A portion of this improved productivity could be used to complete tasks currently being contracted out to third party resources including things like infrared scans and asset inspections. There will be an increase in the need for quality asset condition information to populate the new Asset Investment Planning tool that was recently implemented. We have several skilled resources that can complete these inspections with little to no training.

**Cut Operating costs –** Implementing unified dispatching in concert with route optimization capabilities typically has been shown to reduce kilometers driven and fuel consumption anywhere from 15%, to as much as 40%. In reducing kilometers driven and the related travel time, additional work can be completed within a typical daily operating window. This when combined with the afore mentioned productivity gains will have the additional benefit of having less work needed off core shifts, and is expected to result in a 10% reduction in overtime costs.

**Exploit Unfulfilled Opportunity Costs –** Most every field services discipline is maintaining a backlog of work that they are expected to deal with, on top of the ongoing daily workload. Often these backlog items are important from the perspective of avoiding future outages and certainly can have a detrimental impact on SAIFI and SAIDI if gone unattended. In the case of collections, these back logged work orders could have a negative impact on bad debt expense. Utilizing a unified dispatch technology with intelligent dispatching will ensure that these back logged work orders are scheduled and dispatched to appropriate resources based on priority, severity and resource availability. The new system will make it easier to take advantage of available time at the beginning of a shift and in between customer appointments for completing backlog items, testing, inspection, or maintenance activities to ensure they are completed in a more timely fashion.

**Increase performance against service levels and enhance customer satisfaction –** MWM tools have the capability to tailor dispatching rules to prioritize work based on a variety of factors including those represented by proximity to missing a customer appointment or service level agreement target. Meeting customer commitments and service level agreements will lead to enhanced customer satisfaction.

**Execute better decisions with Performance Management –** Even as we exploit what MWM tools have to offer there is a continuing need to analyze business trends, costs per job, and a variety of other key metrics to stay in control of the complex business of field service delivery. Several of the MWM tools provide sophisticated performance management capabilities needed to assist decision makers, while reducing the need for time spent aggregating date. These modules will also assist with the tracking and monitoring of the metrics and key performance indicators contained in the OEB's performance based Renewed Regulatory Framework.

## 7.3 Project/Program Justification

### 7.3.1 Alternatives Evaluation

#### 7.3.1.1 *Alternatives Considered*

An analysis was done to understand our current system and the requirements of any possible replacement. A significant amount of research was done to both identify and complete a high level evaluation of the wide array of solutions and systems that are available on the market. We focussed our initial efforts on a review of the capabilities of solutions offered by the following vendors: IFS360, ClickSoft, Viryanet, and Oracle. This initial assessment included product demos and discussions with other utilities across the industry to better understand the capabilities and benefits associated with implementing these types of tools.

The status quo was considered as an option. Although we do have some electronic dispatching of work orders, we do not have an "intelligent" schedule with supporting algorithms to optimize dispatching, trip routing, etc. Because the tasks and work orders reside in several different systems, it can be difficult for supervisors and dispatchers to make the "best" decisions on resource utilization, or to provide additional work to crews on short notice should unexpected capacity be made available. Furthermore, we currently do not provide Supervisors or Managers with timely, accurate data that they can use to measure, monitor and manage the performance of their staff.

Based on the evaluation of the options and review of the quantitative and qualitative benefits, the decision was made to move ahead with the initiative.

#### 7.3.1.2 *Evaluation Criteria*

After our initial assessment, Hydro Ottawa reduced the list of potential solutions to two vendors, ClickSoft and Oracle, based on their consistent ranking in the top, right quadrant of Gartner's system assessments. Hydro Ottawa then developed a set of business and technical requirements to assist in the evaluation and selection of the options. The business requirements looked specifically at the actual functionality and options of the systems to ensure that it would meet the majority of our documented needs. The technical requirements were focussed on the nuts and bolts of the systems including how they would fit into our current architecture and hardware arrays. Overall cost of the solution was also a key consideration in the decision making process.

#### 7.3.1.3 *Preferred Alternative*

Based on the evaluation, both of the systems met the vast majority of the business requirements. The Oracle solution scored better in the technical requirements section largely due to the fact that we have many Oracle products and databases already installed which should make integration into our current systems more straight forward. The overall cost for the Oracle solution also benefited from our existing architecture.

Based on the results of the evaluation the decision was made to select the Oracle Mobile Workforce Management system.

### 7.3.2 Project/Program Timing & Expenditure

The capital cost for implementation of this project is $1,950k. There will be incremental operating costs that include an additional resource in IT to support the new application as well as an annual maintenance agreement for the vendor that covers system patches, updates and ongoing technical support. The costs of an IT resource is approximately $120k and the annual maintenance cost is approximately $150k.

| Historical ($M) | | | | | | Future ($M) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| - | - | - | - | - | 1.95 | - | - | - | - | - |

**Table 129 - Project Expenditures**

### 7.3.3 Benefits

A summary of the financial benefits is included below:

- As a result of increased productivity we anticipate reducing headcount through attrition by two resources over the next two years, a savings of approximately $180k annually.
- We also anticipate a 15% increase in productivity from resources on the service trucks by better utilizing their idle time. This amounts to a benefit of approximately $140k annually.
- We also anticipate a 10% savings in OT due to increased productivity. This translates into approximately $55k annually
- We will reduce our reliance on external parties to assist with collections activities and anticipate annual savings of approximately $50k
- We will reduce our reliance on external parties to assist with certain asset inspections as well by better leveraging the capacity of our skilled resources on a daily basis. By using internal staff to complete infrared scans, manhole inspections and other asset testing we anticipate avoided costs of approximately $300k annually.
- We anticipate a 15% savings in fuel costs as a result of optimized routing or $42k annually

The combination of increased productivity, reduced operating costs, and exploiting opportunity costs offset by increased operating costs for maintenance agreements and IT resources results in approximately $2,920k in savings over 6 years with a payback period of 48 months.

The project will also drive many qualitative or unquantified benefits:

- Enhanced performance in meeting customer appointments and service level agreements
- Greater access for Call Centre resources to book customer appointments at the time the accept the customer call
- Real time information regarding field work status available to Call Centre resources for responding to customer inquiries
- Potential positive impact on bad debt expense with improvements in collection field activities
- Increased capacity to complete additional asset inspections required to populate the new Asset Investment Tool being implemented

## 7.4 Prioritization

### 7.4.1 Consequence of Deferral

A decision to defer the project would lead to a delay in achieving the quantitative and qualitative benefits defined in the business case.

### 7.4.2 Priority

This project has a high priority due to the quantitative and qualitative benefits. The solution will have a positive impact on business operations efficiency, customer satisfaction and system reliability.

## 7.5 Execution Path

### 7.5.1 Implementation Plan

The project will be implemented in phases as follows:

**Phase 1**

- Initial installation and configuration
- Integration with CC&B
- Groups: Residential Connections, Damage Prevention and Collections
- Users/Work Orders: 13 staff; 80,000 work orders in 2014

**Phase 2**

- Integration with Service Manager
- Groups: Metering, Service Layout, Plant Inspections, Forestry
- Users/Work Orders: 34 staff; 18,976 work orders in 2014

**Phase 3**

- Integration with OMS
- Groups: 24x7, Reliability, Service Truck, Construction
- Users/Work Orders: 125 staff; 10,762 work orders in 2014

### 7.5.2 Risks to Completion and Risk Mitigation Strategies

The major risks that will be closely monitored during the project are:

| Risk Description | Impact Statement (Budget, Schedule, Scope, Quality) | Mitigation Strategy |
|---|---|---|
| There is a risk that there will be resistance to the adoption of a "drip feed" method of dispatch | If significant resistance is encountered there could be a delay realizing the benefits expected from the new system. | Consult Field Technicians throughout the design and development of the application to ensure solution meets basic user needs.<br><br>Proactively communicate to Field Technicians via Managers and Supervisors.<br><br>Provide Supervisors sufficient reporting |

| | | |
|---|---|---|
| | | capabilities to speak to staff concerns. |
| Internal HOL staff may not have the correct skill set to configure and test the new tool without support from the supplier. | An over reliance on internal staff may result in delays to the completion of the project. | Ensure the professional services contract includes sufficient assistance from the supplier to ensure a successful implementation.<br><br>Add contingency to the project budget to cover an extension of Oracle Professional Service time. |
| CC&B resource constraint | The CC&B team who will be participating in the workshops and configuring the system will not have any resources available until the beginning of April | Delay configuration workshops until this resource can join. |

**Table 130 - Risks and Mitigation Strategy**

### 7.5.3 Timing Factors

We do not anticipate many constraints from a timing perspective. We are sensitive to limiting the amount of configuration and testing completed during the busy construction season due to availability of resources.

### 7.5.4 Cost Factors

No material variances are expected in the execution of the project.

## 7.6 Project Details and Justification

| | |
|---|---|
| **Project Name:** | Mobile Workforce Management Software |
| **Capital Cost:** | 1,950,000 |
| **O&M:** | $150,000 (annual maintenance agreement) |
| **Start Date:** | February 2015 |
| **In-Service Date:** | November 2015 |
| **Investment Category:** | General Plant |
| **Main Driver:** | Business Operations Efficiency |
| **Secondary Driver(s):** | Customer Satisfaction<br>System Reliability |
| **Customer/Load Attachment** | N/A |
| **Project Scope** | |
| The scope of this project is to select and implement a mobile workforce management system for short and long cycle work. | |
| **Work Plan** | |
| Project Start February 2015<br>Project Planning Complete April 2015<br>Project Execution May – November 2015<br>Project Implementation November 2015 | |
| **Customer Impact** | |
| • Enhanced customer satisfaction by meeting service levels and appointments<br>• Enhanced reliability by eliminating backlog of work orders and ensuring priority work is completed in a timely fashion<br>• Real time view into field work status by call centre staff should lead to increased first call resolution for related customer inquiries | |


# 2014 Annual Planning Report

Executive Summary

# Contents



# The Plan

The Asset Management Plan covers a period of twenty years from the fiscal year beginning January 2014 until the year ending December 2033.

The objectives of the plan are to report on the performance of the distribution system and to identify the risks and challenges that will adversely affect the ability to deliver on Hydro Ottawa Limited's (HOL) strategic objectives; Financial Strength, Customer Value, Organizational Effectiveness, and Corporate Citizenship.

Addressed in the plan are the financial, technical, and management elements needed for making sound innovative or best practice asset management decisions.

A fundamental requirement for the successful development and management of a distribution system is effective system planning. The plan is the documented output of HOL distribution system planning and provides short and long range planning direction for distribution system development, reliability improvements, asset inspection and replacement programs, as well as increases to overall system capacity.

The Plan has been broken down into four major categories of study: Capacity, Reliability, Assets and Maintenance.

HOL's system capacity is lagging behind the load growth – currently 15% of substations are above their specified planning rating. Over the next 20 years an investment of approximately $230 Million will be necessary to ensure that sufficient and reliable supply is maintained throughout the city to support the 1050 MVA of forecasted load growth over this period.

Hydro Ottawa's reliability performance in 2013 did not meet our expected targets. Interruption categories such as defective equipment and adverse weather, or storm related have been progressively trending worse and have exceeded the previous 3-year averages. Improvement will be needed in asset management processes in order to prioritize end of life asset replacements. Maintenance, inspection and testing of existing assets will continue to be essential to ensure equipment operates as expected and identify failures before they occur. In addition, consideration of new ways of operating to reduce system susceptibility to storm damage and foreign interference is vital.

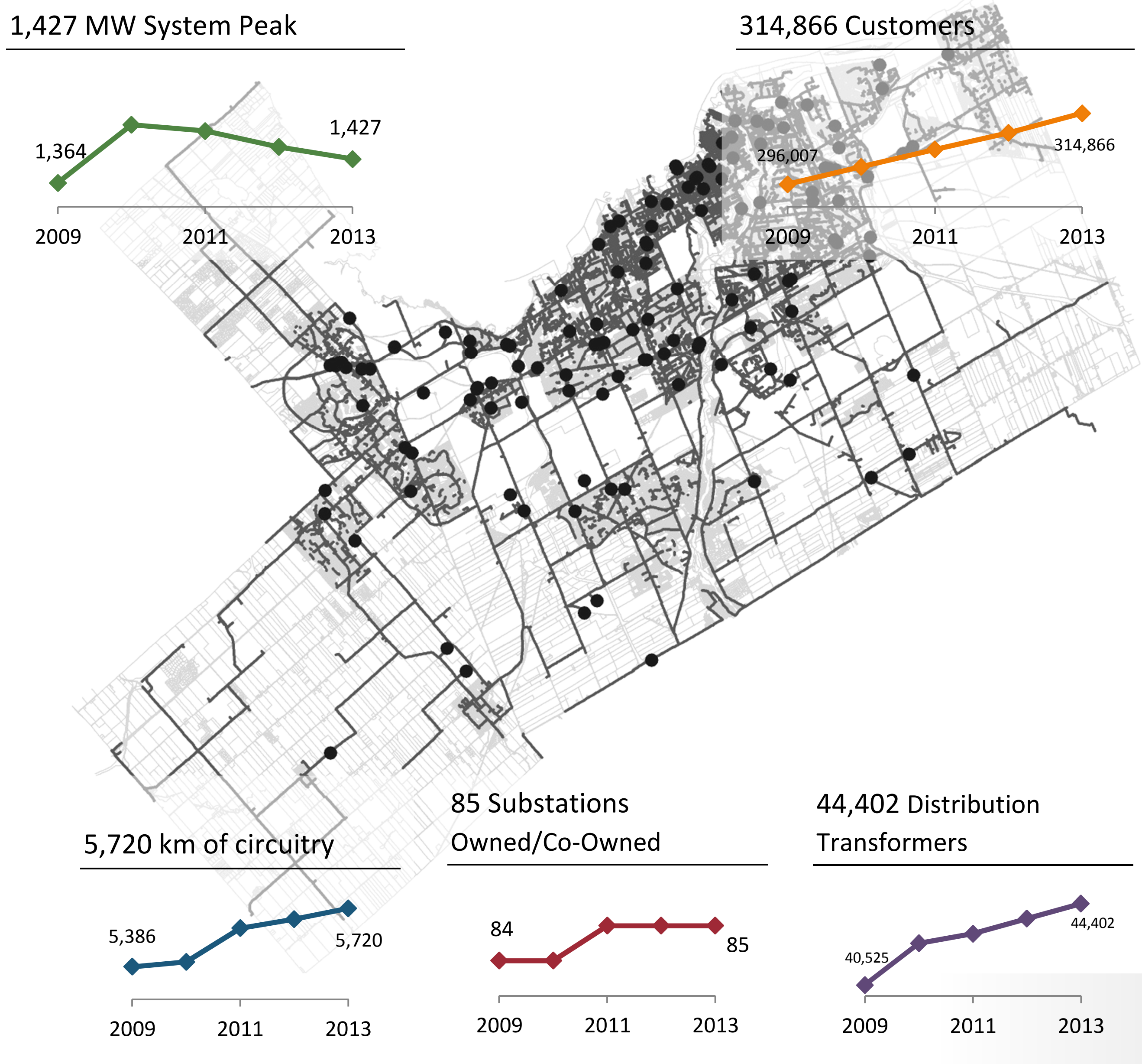
Large segments of the system were constructed in the 1960s, 70s and 80s – as most assets have a lifespan on the order of 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end-of-life. System wide forecasts indicate that at the current investment levels, asset failure rates will continue to rise having a direct impact on service reliability and labour resources. At current investment levels it is anticipated that labour associated with distribution system plant failure alone will increase to 296% of current levels by 2033, equivalent to 39% of the current labour resources.

The plan identifies projects and resource requirements to allow HOL to keep pace with the City's growth and aging infrastructure while maintaining high standards of system reliability and operability.

HydroOttawa

# Performance & Statistics

# The System at a Glance…




Although Hydro Ottawa's service area has remained constant, the distribution system continues to expand and evolve. In 2013, Kilborn UP was decommissioned after completing a system voltage conversion in the area. As well, a new substation in the south end of Kanata, Terry Fox MTS, was energized.

System Load has remained relatively constant over the last 5 years. The system wide actual summer peak has grown at an average rate of 1.2% annually since 2009, while winter actual peak has increased at an average annual rate of 0.3% over the same period.

### TABLE 1 - SYSTEM SUPPLY STATISTICS

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Service Area ($km^2$) | 1,104 | 1,104 | 1,104 | 1,104 | 1,104 |
| Total Metered Customers | 296,007 | 300,664 | 305,059 | 309,543 | 314,866 |
| Total Un-Metered Supply Points | 55,791 | 57,619 | 58,281 | 59,019 | 58,973 |
| Total # of Substations Used by HOL | 92 | 92 | 93 | 93 | 93 |
| HOL Owned/Co-owned | 84[1] | 84 | 85[2] | 85[3] | 85[4] |
| Used & not owned/co-owned | 8 | 8 | 8 | 8 | 8 |

Notes:

[1, 5] Cyrville MTS Energized (2 transmission transformers)

[2,6] Janet King DS 28kV Energized (1 sub-transmission transformer)

[3, 7] Ellwood MTS Energized (2 transmission transformers) & Uplands DS Decommissioned (1 transmission transformer)

[4,8,9] Kilborn UP Decommissioned (2 sub-transmission transformers) & Terry Fox MTS Energized (2 transmission transformers)

### TABLE 2 - SYSTEM ASSET STATISTICS

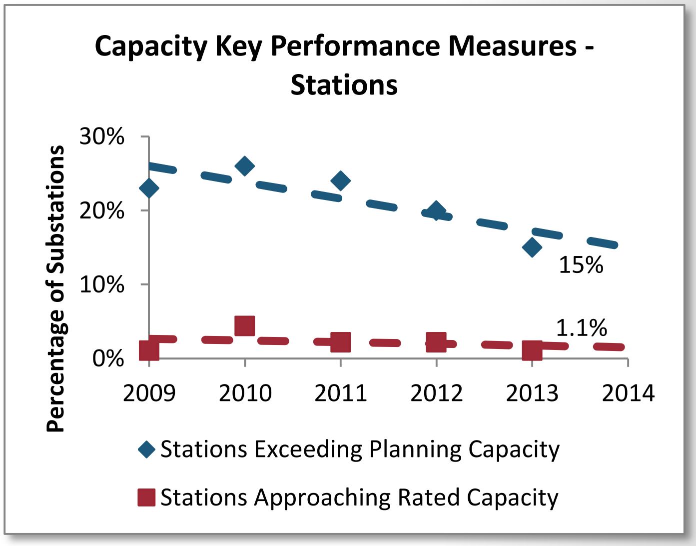
| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Total Circuit Length (km) | 5,386 | 5,414 | 5,606 | 5,658 | 5,720 |
| O/H Circuit | 2,709 | 2,693 | 2,916 | 2,923 | 2,926 |
| U/G Circuit | 2,677 | 2,721 | 2,690 | 2,735 | 2,794 |
| Total Number of Poles | 48,699 | 48,574 | 48,380 | 48,298 | 47,978 |
| Distribution Transformers | 40,525 | 42,516 | 42,970 | 43,689 | 44,402 |
| O/H | 17,393 | 17,228 | 16,801 | 16,617 | 16,424 |
| U/G & Vaults | 17,475 | 17,228 | 18,376 | 18,785 | 19,189 |
| Stores + Missing Serial Number | 5,657 | 7,470 | 7,793 | 8,287 | 8,789 |
| Substation Transformers | 166 | 170 | 170 | 167 | 169 |
| Transmission | 25 | 27 | 27 | 26 | 28 |
| Sub-Transmission | 141 | 143 | 143 | 141 | 141 |
| Total Number of U/G chambers | 3,006 | 3,082 | 3,268 | 3,167 | 3,399 |

# System Capacity

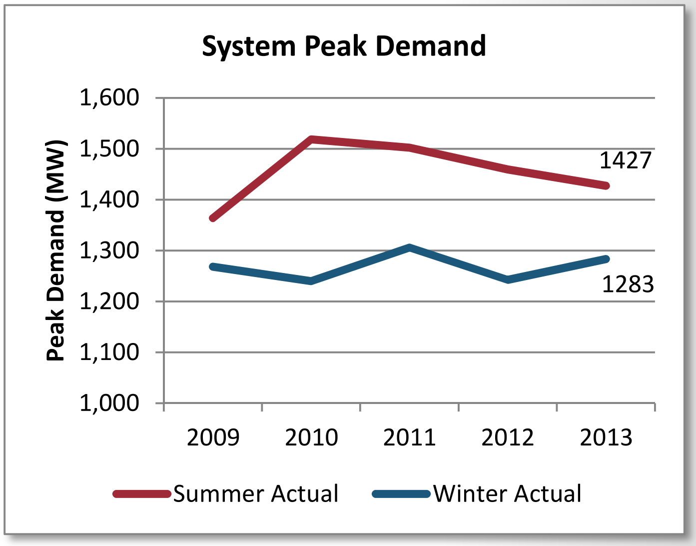
System capacity is currently trailing load growth in the city; this has resulted in 15% of the stations which HOL owns operating above their planning rating. This planning rating is set to ensure adequate capacity is reserved for reliable operation during system contingency.

In 2013, only one station was loaded above it's equipment ratings at system peak: Richmond North DS.

*Fifteen Percent of the stations which HOL owns are operating above their planning rating.*




Work to increase capacity at Richmond South DS is scheduled to begin in 2015 and will allow for better load balancing between Richmond North and South to alleviate the overload condition. There is a positive trend being shown in the data: as capacity projects progress the system is seeing less stress since 2009.




Losses remained within the acceptable range of between 2% to 4%. Hydro Ottawa continues to work to reduce system losses through the updating and replacement of equipment, as well as system planning.

Feeders exceeding their planning ratings are within target, but careful review and planning is being undertaken to ensure adequate backup is maintained to allow for secure and reliable power for Hydro Ottawa Limited's Customers.

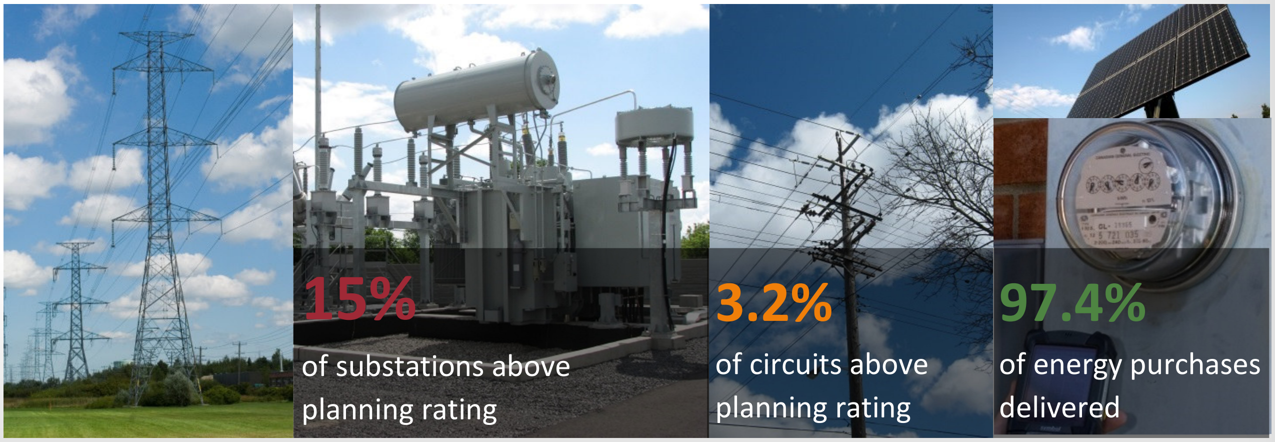


**TABLE 3 - CAPACITY KEY PERFORMANCE MEASURES**

| Measure | Target | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| **Stations Exceeding Planning Capacity** | ≤ 5% | 23% (21) | 26% (23) | 24% (22) | 20% (18) | 15% (14) |
| **Feeders Exceeding Planning Capacity** | ≤ 10% | - | 3.5% (28) | 3.4% (27) | 3.3% (26) | 3.2% (23) |
| **Stations Approaching Rated Capacity** | zero | 1.1% (1) | 4.4% (4) | 2.2% (2) | 2.2% (2) | 1.1% (1) |
| **Feeders Approaching Rated Capacity** | zero | - | 0.4% (3) | 0.5% (4) | 0.5% (4) | 0.3% (2) |
| **System losses** | ≤ 4% | 2.88% | 3.12% | 3.13% | 3.60% | 2.63% |

**TABLE 4 - SYSTEM DEMAND & ENERGY STATISTICS**

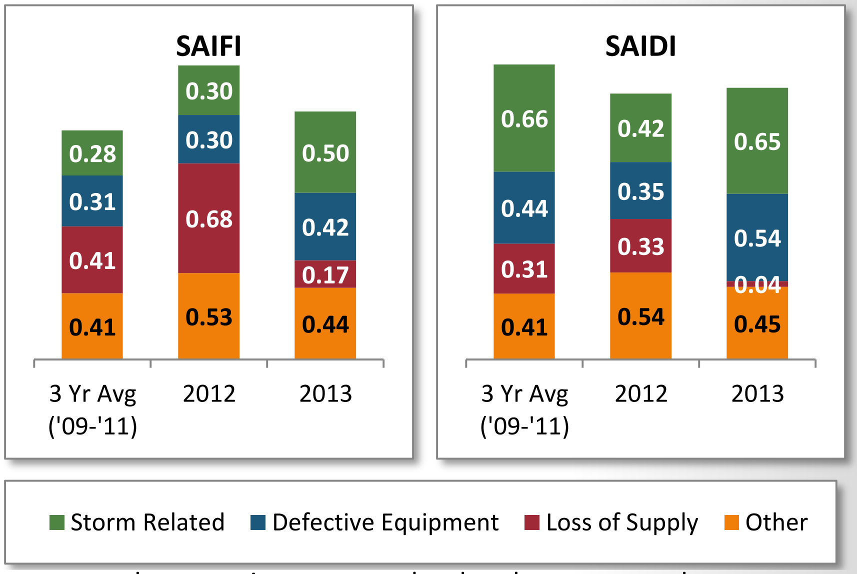
| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Peak Load-Summer (MW)** | 1,364 | 1,518 | 1,502 | 1,459 | 1,427 |
| **Peak Load-Winter (MW)** | 1,268 | 1,239 | 1,306 | 1,242 | 1,283 |
| **Total Energy Supplied to HOL Customers (Sold, GWh)** | 7,560 | 7,595 | 7,608 | 7,570 | 7,519 |
| **Total Energy Purchased from Bulk System (Purchased, GWh)** | 7,785 | 7,840 | 7,851 | 7,856 | 7,722 |
| **Capacity Utilization** | 70% | 76% | 75% | 73% | 69% |
| **Load Factor** | 63% | 57% | 58% | 59% | 60% |
| **Total Distributed Generation Connected (MW)** | 29 | 30 | 31 | 55 | 58 |

# System Reliability

Hydro Ottawa's reliability performance in 2013 did not meet our expected targets. Interruption categories such as defective equipment and adverse weather, or storm related have been progressively trending worse and have exceeded the previous 3-year averages.

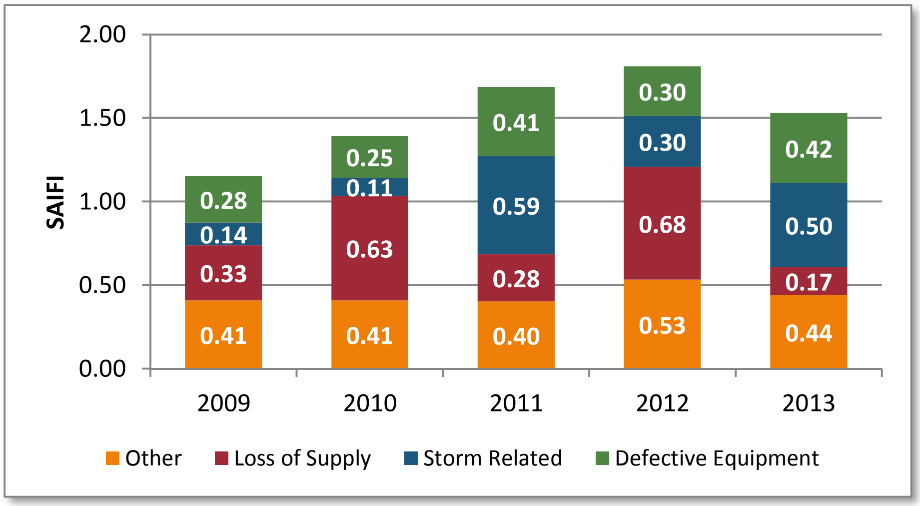
*In 2013, on average, a customer experienced 1.5 interruptions with an average duration of 1.7 hours.*

Overall, since 2009 system SAIFI has been steadily increasing, due to the increase of storms with severe wind and rain as well as an increase in equipment failures. Moving forward, it is critical that investment levels for equipment replacement increase in order to storm harden the system and to get ahead of the curve of aging equipment.




While the two primary causes of system interruption in 2012, Adverse Weather and Loss of Supply, are outside of direct HOL control, the ability to respond to such challenges is not. As a result of the experiences in 2011 and 2012 Hydro Ottawa is planning and has undertaken initiatives to improve future performance. These include updates to the emergency response organization and procedures, review of vegetation management planning, as well as ongoing commitment to asset replacement and automation; to storm harden the system, reduce restoration time and customer impact.

**HISTORICAL SAIFI BY PRIMARY CAUSE**




**HISTORICAL SAIDI BY PRIMARY CAUSE**

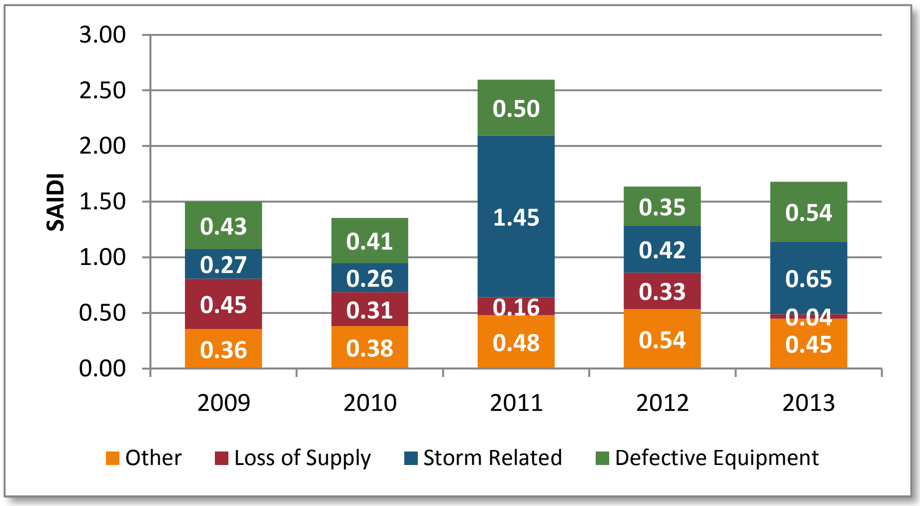


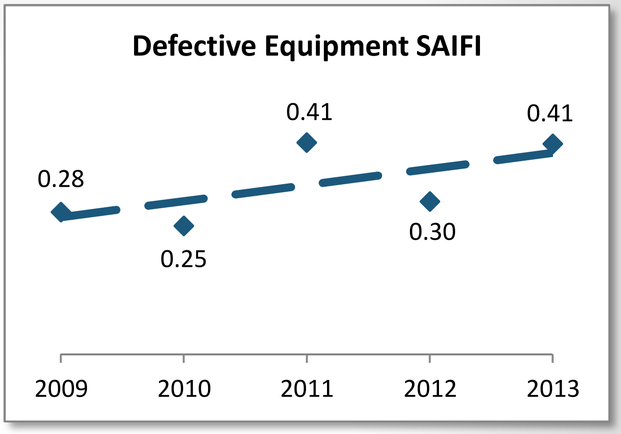

**TABLE 5 - SYSTEM RELIABILITY PERFORMANCE**

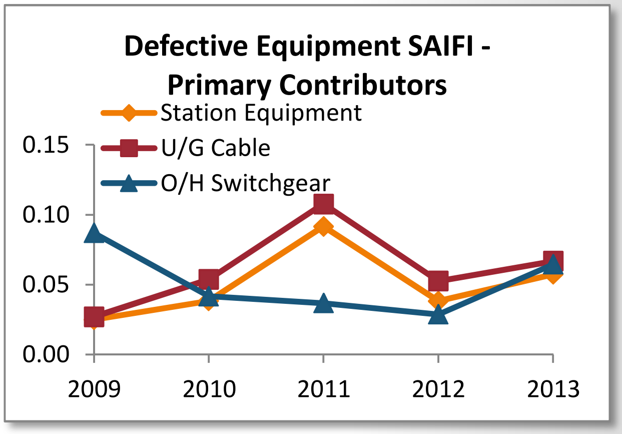
| | ERM Target | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| 3 Yr Avg. SAIFI including LoS | < 1 | 1.13 | 1.19 | 1.41 | 1.63 | 1.67 |
| 3 Yr Avg. SAIFI excluding LoS | N/A | 0.72 | 0.78 | 1 | 1.10 | 1.30 |
| 3 Yr Avg. SAIDI including LoS | < 1.5 | 1.29 | 1.28 | 1.82 | 1.86 | 1.96 |
| 3 Yr Avg. SAIDI excluding LoS | N/A | 0.98 | 1.01 | 1.52 | 1.60 | 1.79 |
| 3 Yr Avg. CAIDI | < 1.5 | 1.15 | 1.08 | 1.29 | 1.14 | 1.17 |
| $FEMI_{10}$ excluding LoS & Unplanned Outages | ≤ 12 | 9 | 7 | 12 | 13 | 13 |

# System Assets

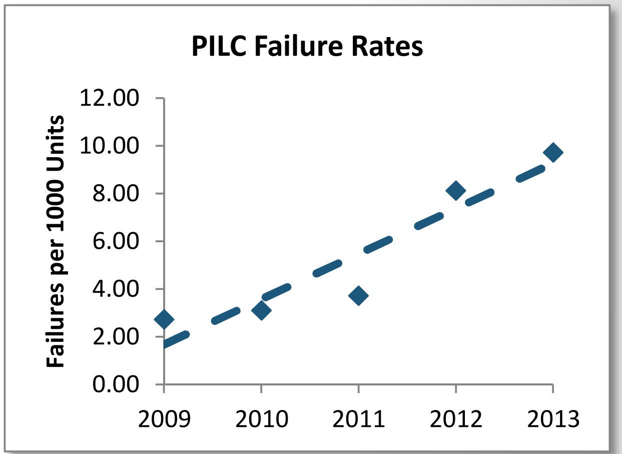
Hydro Ottawa's Assets are the physical objects which transform, monitor and ultimately transfer electricity to the customer. This equipment not only fulfills the essential role of distributing electricity, but also acts as the barrier and protection that allows this potentially hazardous product to be transported through public spaces safely and reliably.

*The frequency of customer interruptions due to defective equipment has increased by 48% since 2009.*




Over the last 5 years, there has been an increasing trend in customer interruptions due to defective equipment. The main contributors to this trend in 2013 were O/H Switchgear, U/G Cable and Station Equipment. Increased or more targeted asset replacement is required to manage these assets such that they do not adversely impact the system. At the current investment rate, defective equipment SAIFI is projected to maintain an upward trend.




Asset failure rates provide indication of the adequacy of proactive replacement programs to manage asset failures. Failures to distribution Poles, PILC cable and both U/G and O/H transformers are indicating an increasing trend, with PILC cable showing the steepest increase. These increases signify the need to ramp-up replacement rates.

#### Table 6 – Asset Failures

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Poles** | 46 | 29 | 74 | 41 | 76 |
| **Distribution Transformers (UG)** | 63 | 51 | 80 | 116 | 96 |
| **Distribution Transformers (OH)** | 49 | 52 | 71 | 84 | 61 |
| **U/G Cable – PILC** | 975 | 1110 | 1332 | 2912 | 3487 |
| **U/G Cable – XLPE** | 485 | 408 | 373 | 97 | 191 |
| **Station Transformers** | 5 | 0 | 2 | 0 | 6 |

*Note that a failed PILC cable requires repair from device to device accounting for the large number of meters replaced.

#### Table 7 - Defective Equipment Contribution to System SAIFI

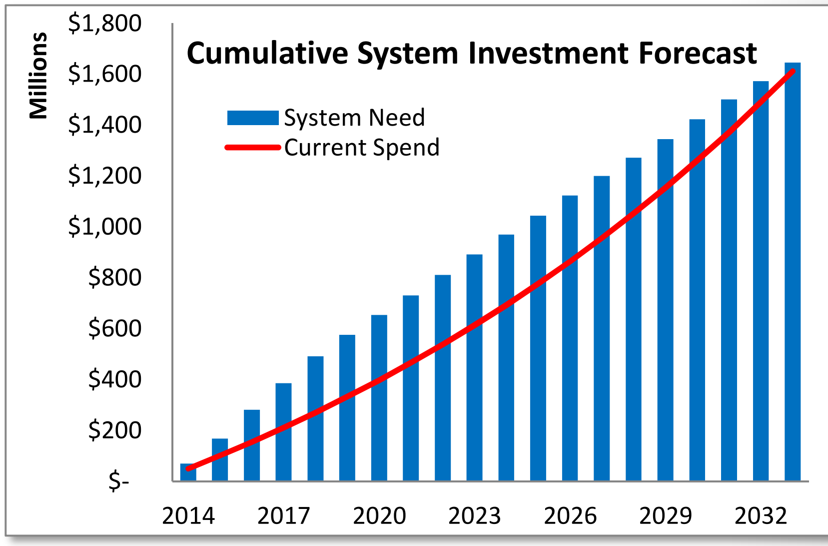
#### (customer interruptions per 100 customers served)

| | Target | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| **U/G Cable - Polymer** | TBD | 2 | 5 | 10 | 4 | 2 |
| **Insulator** | TBD | 3 | 2 | 7 | 0.3 | 0.1 |
| **Station Switchgear** | TBD | 1 | 2 | 5 | 0 | 3 |
| **O/H Switchgear** | TBD | 9 | 4 | 4 | 3 | 6 |
| **U/G Cable Attachment** | TBD | 1 | 2 | 3 | 2 | 5 |
| **Station Transformer** | TBD | 1.4 | 1.2 | 1.2 | 2 | 0 |
| **U/G Switchgear** | TBD | 0 | 1 | 1 | 7 | 0.1 |
| **U/G Cable - PILC** | TBD | 0.2 | 0.7 | 0.6 | 0.6 | 1.5 |
| **O/H XFRM** | TBD | 0 | 0 | 0 | 1 | 2 |
| **Pole** | TBD | 1 | 0 | 0 | 1 | 4 |
| **U/G XFRM** | TBD | 2 | 1 | 0 | 3 | 3 |
| **Other** | TBD | 7 | 6 | 9 | 6 | 5 |
| **Total** | **TBD** | **28** | **25** | **41** | **30** | **32** |

# Outlook

# System Outlook

The goal of the Annual Planning Report is to identify the system needs. System needs are based on the work required to manage asset failures, system capacity and system operability – in a manner which will maintain and improve worker and public safety and system reliability over the next 20 years and beyond.




System forecasts indicate that the annual system investment is currently lagging the need. This is reflected in system performance measures – 15% of substations are above their planning rating and defective equipment customer interruption has risen steadily over the last 5 years.

Annual system investments increases of 5% are needed until 2033 to meet the cumulative system needs. Without increased investment, it is expected that asset failures will continue to rise – not only impacting system reliability, but also having a significant impact on labour resources. It is estimated that at the current rate by 2033, 39% of available labour hours will be spent on distribution asset failure repairs.

*Annual system investments increases of 5% are needed until 2033 to meet the cumulative system needs.*

Currently, system capacity is lagging load growth in the city, the plan has identified the need to upgrade 13 existing substations, build 2 new substations and invest in 3 transmission upgrades over the next 10 years. If current investment levels are maintained, these required capacity investments may have to be deferred beyond the need date affecting system operability and ultimately system reliability. Furthermore, these required investments may necessitate further deferral of asset replacements.

While the identified increase in funding may not be immediately achievable, progress towards this goal is essential in maintaining system performance.

# Capacity

Hydro Ottawa's system capacity is lagging behind the load growth – currently 15% of substations are above their specified planning rating. Over the next 20 years ongoing and significant investment will be necessary to ensure that sufficient and reliable supply is maintained throughout the city to support the MVA of forecasted load growth over this period.

Overall, the city of Ottawa is seeing continued growth, primarily focused in four regions: the downtown core, Nepean & Riverside South, South Kanata & Stittsville and Orleans. This growth is being seen through the development of new mixed retail/residential communities as well as intensification of existing communities and the Light Rail Transit developments. Moving forward, significant investment in capacity for the system, at both the station and distribution level, will be required to catch up to and maintain pace with the demand. The sidebar indicates the required station capacity investments over the next 20 years. In addition, there are a number of required distribution expansions which will be required to bring power from the substations to the customer site.

*1050 MVA of load growth is forecasted over the next 20 years – 66% of the current summer peak demand.*

There are several upgrades of transmission interties within the city which will be necessary over the next 20 years to maintain adequate and reliable supply from the bulk system. Hydro Ottawa is currently involved in a joint planning study with Hydro One Networks Inc. (HONI), the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA) evaluating the transmission capacity and infrastructure requirements in the Ottawa region. Preliminary findings indicate required upgrades to the transmission system in all four regions of the city: west to Terry Fox MTS, south to Fallowfield DS or a new station, east to supply a new HONI station, Orleans TS, and to the downtown core to support load growth across the central 13kV substations.

**2014**
- Hinchey TH - 57 MVA
- Limebank MS - 40 MVA
- Startop MS - 5 MVA
- Terry Fox MTS - 100 MVA
- Borden Farm DS - 8 MVA
- Orleans TS (HONI) - 16 MVA

**2016**
- Lisgar- 53 MVA
- Leitrim MS - 5 MVA
- Richmond South DS - 67 MVA
- Overbrook TO - 55.6 MVA

**2017**
- Merivale MS - 12 MVA

**2018**
- Uplands DS - 40 MVA
- Bayshore T1- 5 MVA

**2019**
- King Edward TK - 56 MVA
- Bridlewood MS - 50 MVA
- New South 28 kV - 100 MVA

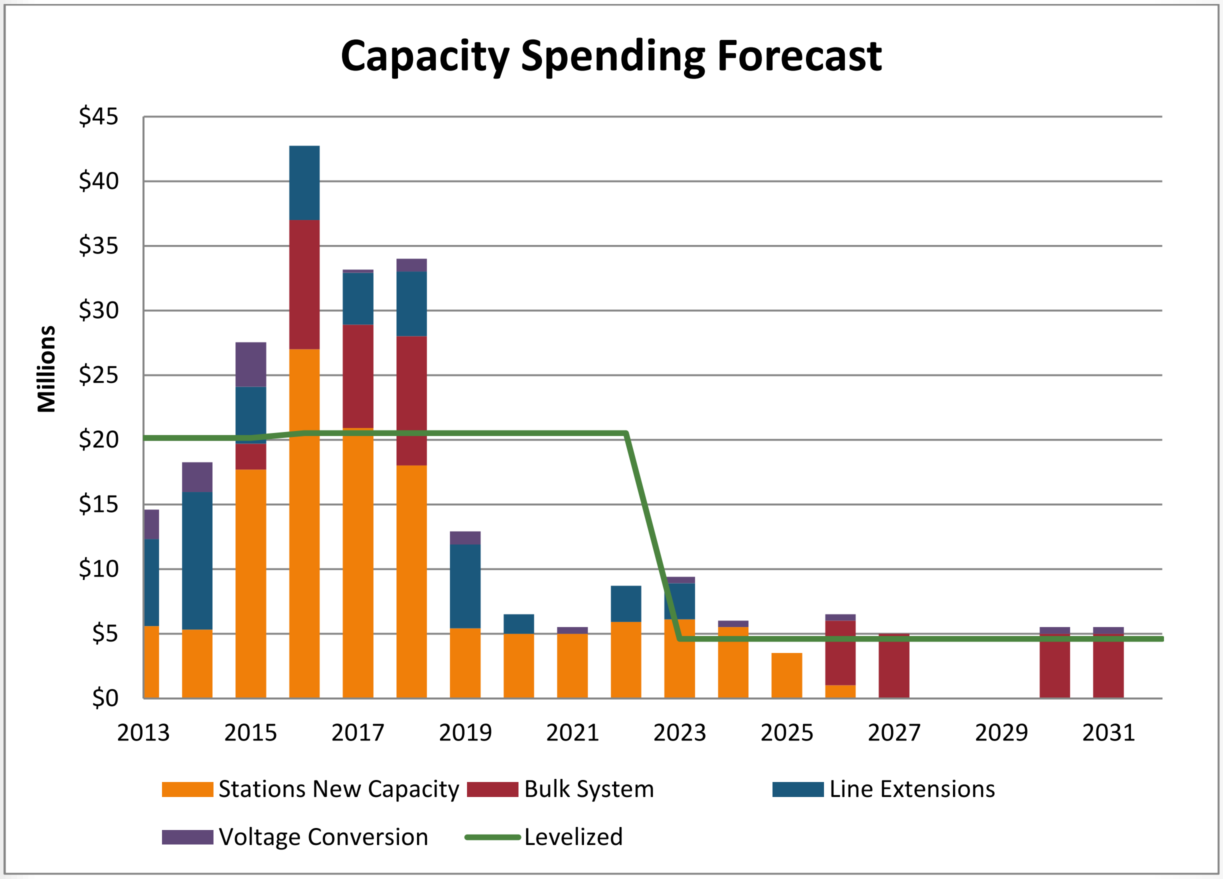
**2021**
- Limebank MS - 46 MVA
- Bells Corners DS - 4 MVA

**2022**
- Marchwood MS - 33 MVA

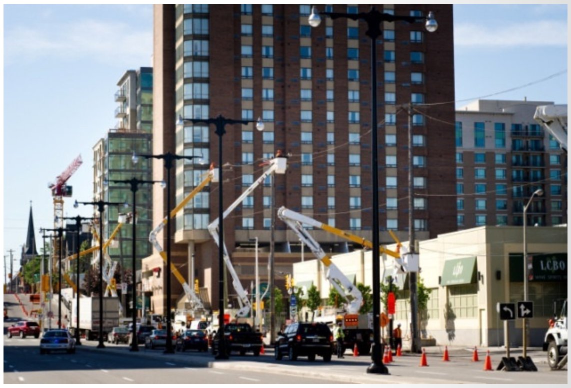
**2024**
- Russell TB - 67 MVA

**2026**
- QCH DS - 4 MVA

Failure to meet the capacity milestones has the potential to result in increased outage duration as a result of the operational challenges created by inadequate supply and operability. In addition, such capacity deficits may cause accelerated equipment deterioration due to overloading at system peak.




# Assets



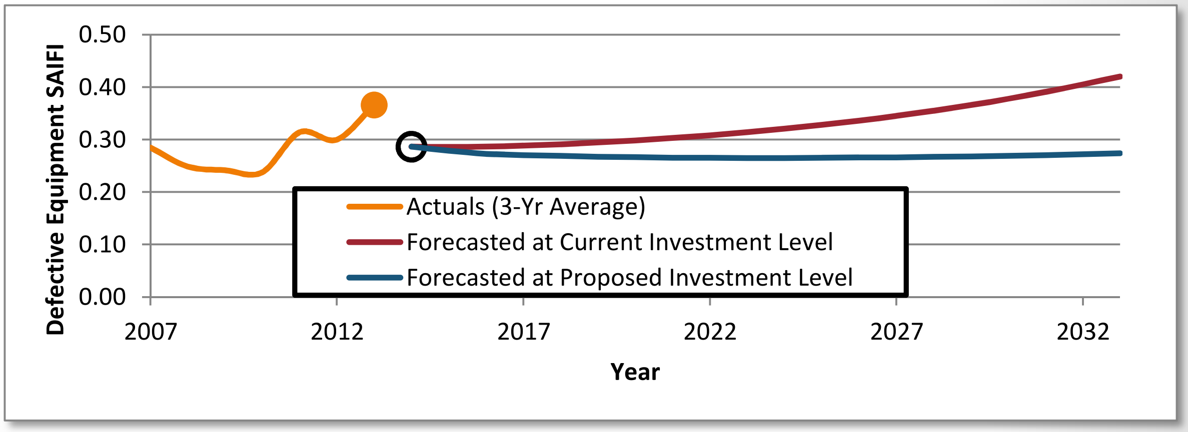

Large segments of Hydro Ottawa's system were constructed in the 1960s, 70s and 80s – as most assets have a lifespan on the order of 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end-of-life. The increased potential of failure posed by these aging assets will, without intervention, impact the organization's ability to guard worker and public safety, maintain system reliability and protect organizational strength in the future.

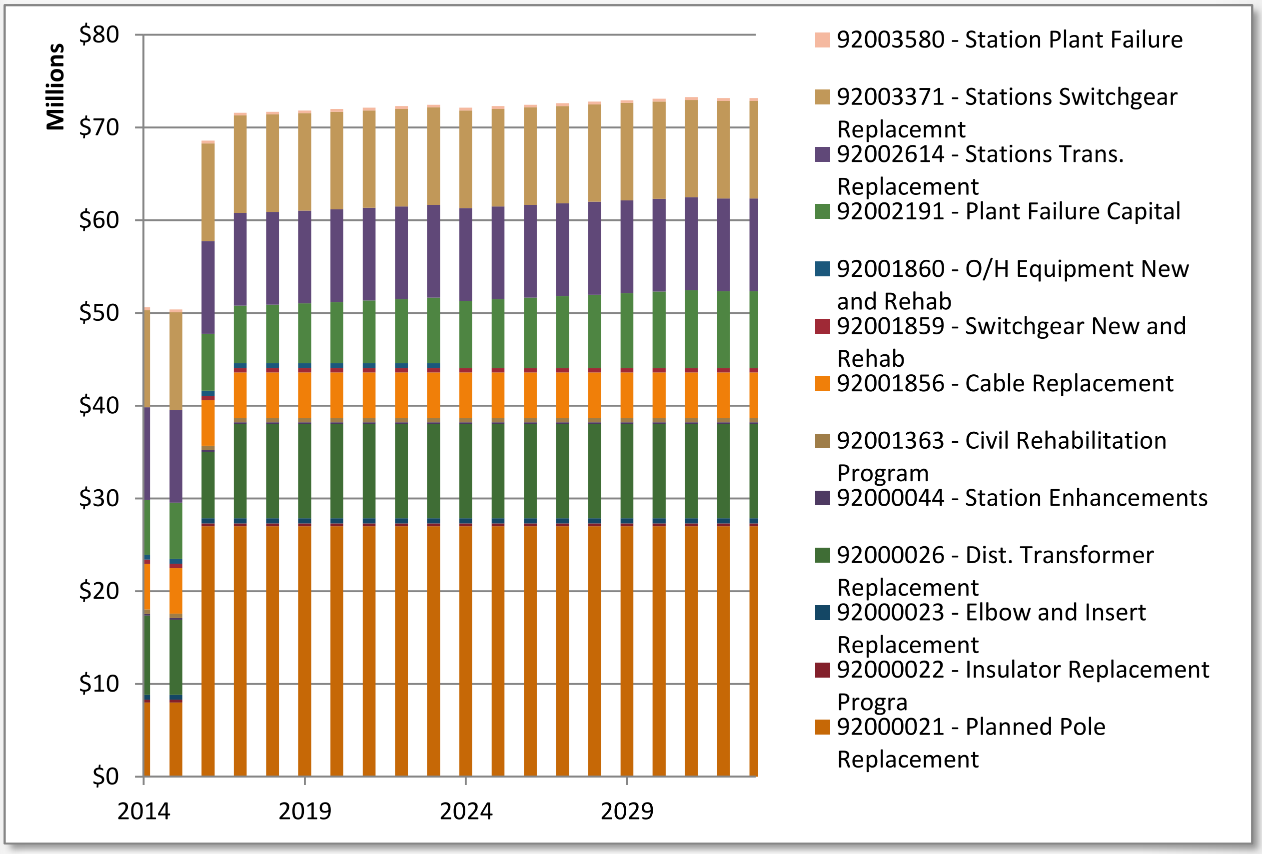
The current recommendation for the annual sustainment budget to replace equipment and manage failures is to be increased to $72 million in the next 10 years – roughly 4 times the current investment level.

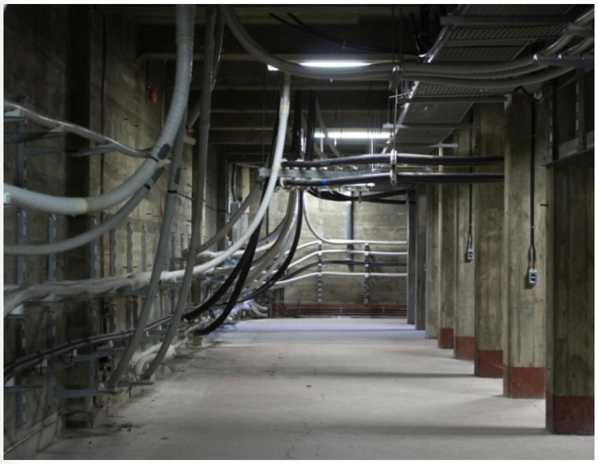
*Distribution plant failure will account for 36% of available labour-hours, by 2032, if the current annual replacement levels are not increased.*

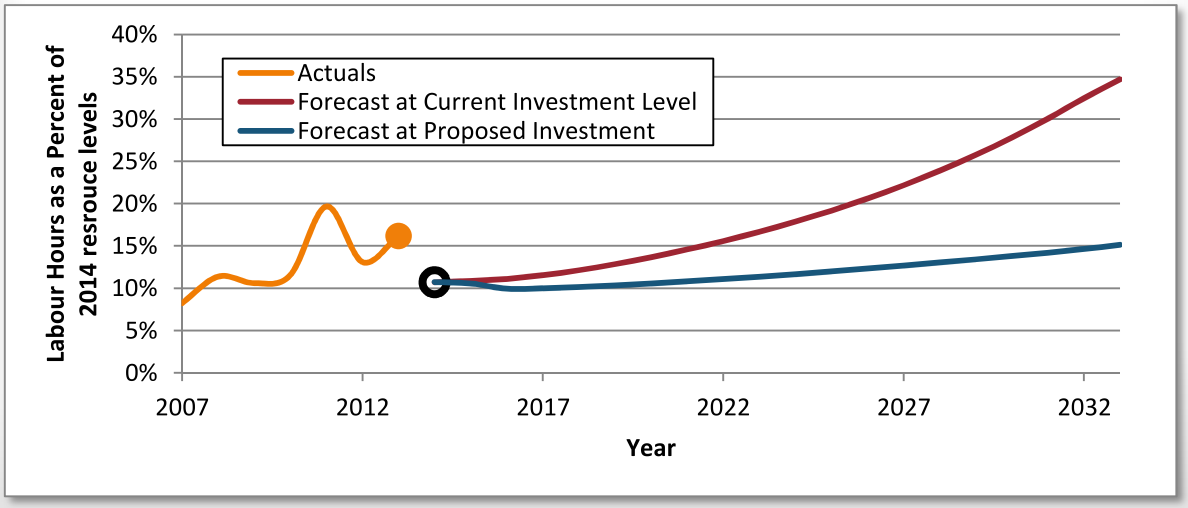
The financial impacts of the proposed investment increases are significant, yet, so too are the risks of simply maintaining the status quo. System wide forecasts indicate that at the current investment levels, asset failure rates will continue to rise having a direct impact on service reliability and labour resources. At current investment levels it is anticipated that Plant Failure labour associated with the distribution system alone will increase to 296% of current levels by 2033, equivalent to 39% of the current labour resources. This increase in labour will impact the ability to complete planned work. The increase in failed equipment will also result in a 54% increase in Defective Equipment SAIFI by 2032. Furthermore, the elevated density of assets in poor condition will increase the potential for unrecoverable events in the case of high climatic stress (i.e. heat waves or severe storms), significantly impacting system reliability and corporate image. The deferral of these increases will lead to a growing annual burden while achieving the same result.

While the identified increase in funding may not be immediately achievable, progress towards this goal is essential in maintaining system performance.




Millions
$80
$70
$60
$50
$40
$30
$20
$10
$0
2014
2019
2024
2029
92003580 - Station Plant Failure
92003371 - Stations Switchgear Replacemnt
92002614 - Stations Trans. Replacement
92002191 - Plant Failure Capital
92001860 - O/H Equipment New and Rehab
92001859 - Switchgear New and Rehab
92001856 - Cable Replacement
92001363 - Civil Rehabilitation Program
92000044 - Station Enhancements
92000026 - Dist. Transformer Replacement
92000023 - Elbow and Insert Replacement
92000022 - Insulator Replacement Progra
92000021 - Planned Pole Replacement




Labour Hours as a Percent of 2014 resrouce levels
40%
35%
30%
25%
20%
15%
10%
5%
0%
2007
2012
2017
2022
2027
2032
Year
Actuals
Forecast at Current Investment Level
Forecast at Proposed Investment

# Reliability

Hydro Ottawa's reliability performance in 2013 did not meet our expected targets.  Interruption categories such as defective equipment and adverse weather, or storm related have been progressively trending worse and have exceeded the previous 3-year averages. Improvement will be needed in asset management processes in order to prioritize end of life asset replacements.  Maintenance, inspection and testing of existing assets will continue to be essential to ensure equipment operates as expected and identify failures before they occur.  In addition, consideration of new ways of operating to reduce system susceptibility to storm damage and foreign interference is vital.

Fundamental in Hydro Ottawa's approach to system reliability is the implementation of grid technologies. Ongoing targeted installation of automated devices is planned for the foreseeable future to improve system reliability and operation. Currently, targeted programs are the East 44kV automation, which will deploy automatic restoration to this sub-transmission loop that supplies 3% of Hydro Ottawa's customers. In addition, automation plans are being deployed in the quickly growing South Nepean/Barrhaven area, as well as targeted annual installation to address the Worst Performing Feeders. Continued investment in the communication infrastructure will be essential to support current automation plans while maintaining the flexibility to integrate the technologies of tomorrow.


Hydro
Ottawa

# INFORMATION TECHNOLOGY STRATEGY

Hydro Ottawa Limited's Information Technology Strategy can be found in Attachment B-1(E).

# 2015-2020 IM&IT Strategy

## TABLE OF CONTENTS

# EXECUTIVE SUMMARY

The Hydro Ottawa IM&IT Strategy for the period 2015-2020 is a foundational component and key enabler of the corporate Strategic Direction. Hydro Ottawa's continuing IM&IT vision is that information is accessible, when and where it is needed; is managed as a corporate asset; is reliable, accurate, and secure. "Accessing Anything, Anytime, Anywhere" remains the core mission of the IM&IT Strategy.

To position HO for "Accessing Anything, Anytime, Anywhere", key change strategies are proposed in the IM&IT domains of Business Solutions, Enterprise Architecture, Information Management, IT Security, and Infrastructure.

Consultations with HO's Divisions provide business requirements for new applications and for upgrades and additional functionality for existing applications. The effectiveness of the current Enterprise Resource Plan (ERP) solution in meeting HO's evolving business needs will be considered with a view to potential upgrade or replacement. The Customer Care & Billing (CC&B) system will be augmented with additional functionality. Legacy applications will be rationalized to simplify ongoing support and maintenance requirements. Contracts review will apply continued diligence on maintenance and support services in seeking most cost-effective maintenance programs as well as to identify areas where consolidation of licenses and services will reduce technology overhead.

The accelerating rate of technological change means that the speed of delivery must increase. The IT organization must become agile in its ability to respond and service the business constituent. Business Intelligence tools will be investigated where they can leverage existing data points to increase customer understanding, utilization rates and potential energy savings. The proposed Services Oriented Architecture (SOA) is one strategy that could enhance HO's agility to respond and adapt to the changing business requirements. Investigating and leveraging Software as a Solution (SaaS), Infrastructure as a Service (IaaS) and Platform as a Service (PaaS) will, under the right conditions, successfully offset multiple infrastructure management and provisioning burdens, both one-time and reoccurring. Processes for delivery need to be revamped and where possible, map to a more agile, waterfall methodology.

The facility relocation will need to be considered as a requirement for a new LEED Certified[1] Data Centre emerges. As fit-up is required, it will need to take advantage of new generation of technologies, including network and database appliances, wireless communications, etc. Overall the technology footprint will be reduced and the support model simplified with fewer devices installed, and more advanced composite technologies requiring less configuration effort. Mobile computing capabilities will be leveraged.

IT Security will continue to be proactive in protecting HO's IM and IT assets and environments against attack from the ever-changing threat landscape.

In summary, the following IM&IT strategies will help to position HO to fulfil its corporate strategic objectives and deliver value across the entire customer experience, and the enterprise IM&IT vision of "Accessing Anything, Anytime, Anywhere":

- Cloud computing: Software as a Service[2] (SaaS)
- Security enhancement tools: continuous diagnostic monitoring, digital forensics
- Mobile workforce technologies and solutions
- Enterprise Resource Planning (ERP)
- Virtualization: servers, desktop, storage, applications, data centre
- Legacy applications modernization / renovation
- Business Intelligence (BI), Business Analytics (BA) applications, Big Data
- Disaster Recovery / Business Continuity
- Identity and access management,
- Networking: unified voice and data communications,
- Enhanced customer portals that deliver critical the information needed, and
- Multi-channel customer-service experience (through voice, data, email, chat and social media avenues).

[1] **LEED**, or Leadership in Energy & Environmental Design, is a green building **certification** program that recognizes best-in-class building strategies and practices.
[2] Software as a Service (SaaS) is a software distribution model in which applications are hosted by a vendor or service provider and made available to customers remotely as a Web-based service. SaaS is an increasingly prevalent delivery model as underlying technologies that support Web services and service-oriented architecture (SOA) mature. SaaS allows organizations to access business functionality at a cost typically less than the total cost of ownership of licensed applications. SaaS removes the need for organizations to handle the installation, set-up and often daily upkeep and maintenance.

# INTRODUCTION

The over-arching theme of the IM&IT Strategy is “Accessing Anything, Anytime, Anywhere”, which encapsulates HO’s IM&IT vision of information that is accessible, when and where it is needed to support decision-making, ongoing business operations, customer interactions, regulatory compliance, and business sustainability.

This IM&IT Strategy for the period 2015-2020 has been prepared in anticipation of the 2016 Rate Application; its purpose is to provide functional direction and support to Hydro Ottawa (HO), its business planning and associated IM&IT opportunities and requirements while respecting and adapting to the ever changing landscape for technology.

“Accessing Anything, Anytime, Anywhere” remains the core direction of the IM&IT Strategy Update with added focus on enabling customer experience, efficiency and productivity. Prudent IT investment choices drawn from well-defined business cases will support financial and IT decisions. Where it makes sense, consideration should be given to leveraging untapped functionality from existing investment. The need for a more agile and flexible technical infrastructure will draw upon all available options both within the existing investment as well as through cloud computing options. Significant savings and increased efficiencies can be achieved through more these more agile computing capabilities.

The key principles that will guide the acquisition, development and use of IM&IT resources are as follows.

- HO’s business strategies and corporate priorities are the primary drivers for IM&IT initiatives.
- An enterprise architectural perspective will inform network and operational technology decision-making to reduce point-to-point interfaces, establish authoritative data sources, and to provide real-time data availability.
- Where feasible, HO will leverage existing systems and services before investing in new technology solutions.
- HO will leverage its significant investment in Oracle, Intergraph, and Microsoft by adhering to a “Best of Brand” strategy, where feasible and cost-effective to do so.
- Commercial-Off-the-Shelf (COTS) solutions will be implemented with limited customization in preference to custom-developed business applications, to reduce risks and costs, and to facilitate software supportability and upgrade paths.

- Cloud applications providing software, infrastructure and platform as services (Saas, IaaS, PaaS) will be considered where business, cost, resource and support considerations warrant.
- IM&IT solutions will be implemented as part of a process to redesign business models and processes to improve outcomes, productivity and efficiency.
- Upfront, rigorous and cyclical IT investment planning will serve as the cornerstone to all IT initiatives and will include strong business case rationale which identifies Total-Cost-of-Ownership, including business requirements, technology & integration considerations, support and ongoing management requirements, identified prior to the approval of IM&IT investments by any part of the organization and integrated into the overall Hydro Ottawa IMIT technology plan.
- Alignment with IT Security program is essential for all proposed IM&IT solutions, including code development, solution acquisition and integration into HO's environment.

The IM&IT Division will maintain the stewardship responsibility to ensure that HO's information and technology assets are managed efficiently, securely and cost-effectively throughout their lifecycle.

## HYDRO OTTAWA BUSINESS CONTEXT

As the Local Distribution Company (LDC) for the Nation's Capital, HO is an essential service provider committed to the delivery of reliable, quality power in a secure and cost-efficient manner. The fundamental change in the behaviour of the electricity supply system, from a one-way flow of power from LDC to consumer, to two-way power flows necessitates much greater situational awareness and capability throughout the power system.

During December of 2013, Hydro Ottawa began the journey of looking at the current communications infrastructure, as well as current and future communications requirements centered on building a self-healing Smart Grid network infrastructure to better support operations and customers utilizing more
secure, reliable, and company-owned telecommunications infrastructure.

The resulting Telecommunications Strategy will introduce a company owned fibre optic based telecommunications system (ring) for the majority of Hydro Ottawa's substations and all of its corporate locations with microwave radio to outlying substations where fibre builds may be cost

prohibitive, particularly to those located in far reaching service areas. By having real-time information on conditions
at the edges of the distribution system, HO can ensure that the voltage is within mandated service standards while optimizing distribution system efficiency and identifying undersized or failing distribution equipment.

Advancing Smart Grid network infrastructure and telecommunications capabilities will in turn introduce associated infrastructure and communications needs from wide-area and field LAN sites as well as advance metering and SCADA systems. Beyond advancing communication protocols, tools to aggregate and analyze data and present information (e.g. Distribution Management System (DMS), Outage Management Systems (OMS), etc.) will be required and will need to be considered in the context of data management, authoritative sourcing and business intelligence.

HO continues to place primary focus on the customer, moving from a transactional service to a personal experience through better understanding of and response to growing customer demands and expectations with customer-enabled service offerings, personalized services, 24/7 accessibility, and a choice of channels for communication and interaction, including social media, and online self-service functionality. Multi-media, live/web-chat, pre-pay experiences and on-line surveys are only a few of the capabilities which must be enabled to appropriately engage and serve. Community partnerships, reputation and response to critical outages will require creative, capable internet and mobile solutions to enhance existing communication needs.

HO must be prepared to diversify and grow in all facets of its business, including generation, utility services, energy services, and distribution. HO is committed to environmental leadership in terms of renewable energy generation, energy consumption management, and the greening of its operations. This must occur within its IM&IT infrastructure and architectural framework, through server virtualization, outsourced managed services (printers) and ongoing reduction of technology “footprint” as can be achieved as well through the reduction of extensive customized applications and integrations to a more agile, plug-and-play capability.

HO must ensure that it has the organizational capacity and robust infrastructure to fulfill its business objectives and to meet the many challenges of a changing operational environment.

Efficient, lean operating capability, standardization and automation, formalized knowledge capture and transfer, and the ongoing preparation and support of the workforce with appropriate tools and technologies will be essential. Managing the Hydro Ottawa employee base with effective communication and self-serve solutions is crucial to effective and efficient performance. Hydro Ottawa must begin preparation for a more mobile workforce with technologies and solutions which enable needed information and business tools anywhere, anytime.

## IM&IT SITUATIONAL ANALYSIS

The transformation and connectivity to large stores of information (big data) as well as social, mobile, cloud and analytics evolutions are changing the way we will live, work and interact. The industry will see a number of significant changes in the coming years. Smart Meters and Network Sensor information will become part of the way utilities will need to share and manage consumption and energy management. Traditional networks will be transformed to interact with a variety of systems and services in offering flexible, transparent, situation-aware services. With this, a significant increase in data sources, information flows and uses.

In 2010 Hydro Ottawa began putting in place foundational frameworks and establishing programs related to: IM&IT Governance, IT Security, Information Management, IM&IT Planning, and IM&IT Project Management. Substantial progress has been made.

In 2014, a formal Enterprise Architecture position was introduced to facilitate the move to a more homogenous alignment of technologies, to standardize on integration and middle-ware and link, as appropriate, needed shared services and information. An architectural framework and standard operating architecture (SOA) have been established and will now, through an Enterprise Service Bus (ESB) approach, facilitate ease of integration, reduce the proliferation of point-to-point and enable the orchestration of new services.

Existing Enterprise Resource Plan (ERP) COTS solutions have been heavily customized to meet HO’s specific business needs, thereby adding further to the cost for point-to-point interfaces as well as the complexity of maintenance and support. There is considerable duplication of data through replicated databases. The absence of automated workflow processes coupled with hundreds of independent data sources results in data re-entry with its inherent error risks and productivity impacts. The ESB initiative will play a role in the reduction of legacy solutions and point-to-point integrations, but more importantly in availing true, authoritative sources of information to be shared throughout the enterprise thereby reducing unnecessary duplication significantly. Net new solutions are being designed with the expectation that they will be "plugged into" an environment which is SOA enabled with an Enterprise Service Bus infrastructure in place. In the case of OMS and GMS, there is existing functionality which will be enabled to support metering services (Last Gasp, Meter Ping). The proposed Field Service Management workforce application houses automated processes which can be easily leveraged (out of the box capability) once the ESB infrastructure in place. New product releases expect this level of sophistication and the IT infrastructure must be positioned accordingly. Investment in the infrastructure will be needed to facilitate, where it makes sense, wireless, mobile, desktop productivity and personal computing /Bring-Your-Own- Device (BYOD) strategies.

The coming years will be significant for IT, specifically in preparing and adjusting to existing and future technology needs. The infrastructure will be strengthened, MPLS and Dark Fibre will extend communication capabilities, "green" data centers will lighten the cost/footprint of doing business; cloud or hybrid cloud solutions will be leveraged for flexibility and capability. Business Intelligence tools will support decisions. Back office systems will be replaced and upgraded to ensure we optimize process, execute effectively, standardize the model, reduce risk and improve business system capabilities.

## IM&IT STRATEGIES 2014-2020

### Business Solutions

HO operates and maintains a number of critical enterprise applications, including the JD Edwards Enterprise Resource Plan (ERP), Customer Care & Billing (CC&B) system, Outage Management System (OMS), Geographic Information System (GIS), SharePoint, MS-Exchange, and the HydroOttawa.com internet site. These critical applications must be treated as vital corporate assets and managed accordingly.

In addition to these widely used enterprise applications, there is a portfolio of over 40 business applications of varying age and technology platforms that are used by groups and individuals throughout the organization. Hydro Ottawa's direction for improving services and productivity, and reducing costs is through greater integration of applications and a focus on process automation, which will be enabled by the deployment of an enterprise-wide service bus and alignment to Services Oriented Architecture services. HO currently has a mixed environment of on premise applications, outsourced application hosting and management, and cloud-based (SaaS) applications which is challenging for application integration and process automation. To leverage HO's extensive data assets, the introduction of Business Intelligence (BI) capabilities is desirable to support more effective strategic and tactical planning, operational insights and decision-making.

An Intranet Multi-Year Strategy was established in late fall to allow Hydro Ottawa to progress towards its corporate objective of Organizational Effectiveness and re-enforce the many positive aspects of its corporate Culture by embracing the strategic possibilities of Engagement, Collaboration, and Leadership on a new intranet.

The intranet strategic purpose is to improve organizational participation, contribute to the organizational effectiveness through cost savings and productivity gains by maximizing the use of intranet, promote cross-divisional collaboration/communication, celebrate and reinforce Hydro Ottawa's culture, and enact leadership through exemplary behaviors on the intranet.

Internal consultations at Hydro Ottawa indicate extensive business requirements for new applications and for upgrades and additional functionality for existing applications over the next six years. The Customer Care & Billing (CC&B) system will be upgraded with major new releases and new functionality for Customer Self-Serve (CSS). Legacy applications supporting the metering processes (i.e. Lodestar) will require rationalization. Upgrades and enhancements are anticipated to the Outage Management System (OMS), Outage Communications system, and to MyHydroLink; a replacement SCADA system is projected coincident with the relocation to new HO facilities. Within the business, Human Resources may require a number of new applications, potentially SaaS-based or outsourced, to provide functionality for Learning Management, Performance Management, Succession Planning, e-Recruitment / Talent Management, Workforce Analytics, Job Description Management, Contractor Management, Business Continuity and Emergency Preparedness, and e-Appraisal. Customer Service and Communications will look to the IM&IT vision and strategy for customer communications capability that provides a fully integrated, robust, multi-channel infrastructure that supports a broad mix of communications media including internet, voice, email, twitter, SMS text, instant messaging, web chat, fax and social media. This infrastructure will allow Hydro Ottawa customers to communicate with the company how and when they_want to communicate. Additionally, there is a growing need to examine and draw upon the many data sources available with a view to leveraging business intelligence on energy usage, consumption, and customer experience and service value.

In the near term, efforts will be devoted to stabilizing the existing ERP environments. Longer term consideration of the ERP strategy will be essential and should take into account essential data needed from these enterprise applications to supply many emerging solutions and services.

*Gartner predicted that mobile phones would overtake PCs as the most common web access device worldwide by 2013. With a large mobile workforce, and the growing prevalence of mobile devices, HO's business solutions must be web-based, designed to run on a myriad of devices, and be accessible anytime, anywhere.*

A corporate strategy for future business application planning and acquisition / development is needed to ensure that these investments can be efficiently and cost-effectively implemented and maintained in HO's technology environment. Longer term IM&IT planning must consider the timing and coordination of major IM&IT projects to ensure that the required business resources are available and that the organization is not unduly stressed.

## IM&IT Planning

All business sectors, groups and stakeholders must ensure advance, upfront identification of potential IT requirements, changes or additions to existing, new program needs or the potential retirement of existing function. This early notification step is paramount to the ongoing evolution of technology planning, tracking and management of IT investment as well as ensuring preparedness of the infrastructure in terms of enabling and supporting the business.

Interest in specific technologies or solutions will include thorough business case detail covering business need, potential solution considerations, customer/end user impact, one-time and reoccurring costs as well as infrastructure needs (be this hardware, licensing, maintenance, install, integration and support). The richness of planning detail is crucial and directly proportional to the results drawn from the IMIT organization.

## Information Management

IM provides the framework for how corporate information is to be captured, stored, shared, transmitted and disposed of or securely retained across HO. Sound IM practices throughout the organization are the foundation on which to build the capability to “Access Anything, Anytime, Anywhere”.

The March 2014 KPMG Audit of Information and Records Management rated the overall maturity of HO’s IM Program as bordering between Phase 2 “Reactive” and Phase 3 “Proactive” on the Gartner six-stage Electronic Information Management (EIM) maturity scale. This represents good progress from the previous KPMG Audit of HO’s Records Management practices in 2009 and serves now as the foundation from which to operate.

Attention will be needed on the classification, appropriate retention / storage and disposition of HO information and data, regardless of media (electronic or physical). The corporate move to new facilities in 2018 provides a significant opportunity to reduce the physical records footprint, working in accordance with records retention and disposition schedules to manage existing hardcopy and electronic transitory records.

Enterprise-wide SharePoint deployment will underpin enterprise search capabilities. More data than ever is collected in order to conduct business. Effective retention and disposition strategies for electronic information and data are required, as retention forever is not an option.

## IT Security

The IT security program will continue to align HO practices with industry standards through the progressive rollout of capabilities and methods, ongoing effort to detect and protect against possible intrusion, replacement of legacy controls, and support for the migration to a mobile-centric infrastructure.

Mobile and remote computing practices will require associated security and management controls to allow authorized devices to connect and work seamlessly within Hydro Ottawa trusted environments. The protection and management of the mobile worker’s access to enterprise information sources will be achieved through the use of standard mobile device management capabilities.

With the increasing use of Cloud Computing, the potential tracking and responsiveness of the organization against infiltration and compromise due to malicious activity will be paramount. The development of a Security Information & Event Management (SIEM) monitoring, interpretation and response strategy will need to be defined and draw on the good work already leveraged in the collection and aggregation of log file data. This needs to include SCADA and operating environments, particularly those leveraging analytical, historic physical security or asset management solutions.

The constant pressure to monitor external threats will remain the paramount security objective for all technology acquisitions, solutions, integrations, updates and access points.

Critical Infrastructure Protection will continue as a fundamental role of the Hydro Ottawa cyber program through the participation in industry and government programs for the energy sector and in the management of a corporate Cyber Security Incident Management plan as prescribed by Public Safety Canada and in the event response and mitigation measures be required.

## Infrastructure

The technical infrastructure is the foundation on which the rest of the IT and OT environments operate. Built up over time, HO's technology infrastructure encompasses a mix of hardware, systems software, cabling, communications technologies, protocols, practices and disciplines. As the construction of a new HO Operations Centre and an Administration Building advance, infrastructure technologies upgrades and shared common structures will be leveraged in establishing a new Data Centre.

The relocation offers an opportunity to review and potentially "leapfrog" a technology generation, while positioning HO with a technology infrastructure that is less costly to operate and support. There will be a smaller Data Centre technology footprint with reduced energy consumption, fewer devices to support and maintain, and reduced depreciation expenses. The move to technology appliances – already fully integrated and configured – will reduce labour costs to configure and stand up new hardware and software. The new Data Centre will have the potential to host more systems in-house, reducing costs for outsourced hosting / facilities management services.

By carefully managing significant technology life cycle replacement initiatives in the 18-24 months prior to relocation to the new HO Administration Building, and a similar period post-relocation, an increased funding envelope will be needed for the procurement and implementation of new technologies for the new facilities.

The way in which individuals work has increasingly become mobile. Streamlined use of telecommunications devices (i.e. Smart Phones and Notebooks) will alter the way IT infrastructure will provision and handle voice and data services. There will be efficiency and cost savings benefits to moving to individual tele-computing capabilities with greater emphasis on mobile device management within a virtualized (secured) work session which is available remotely. This mobility factor will create opportunities to collapse a variety of individual technologies as well as associated maintenance functions, allowing a greater range of computing freedom for the mobile worker (inside the office, at home, in the field, while travelling) while at the same time, bringing greater economy of support effort. BYOD, improved laptop, tablet and other mobile computing devices will be introduced. Collaboration tools to support remote/different location meetings and identify management solutions to manage access and permissions become standard methods by which the infrastructure will transform anywhere, anytime.

Legacy applications will be rationalized to simplify ongoing support and maintenance requirements. Contracts review will apply continued diligence on maintenance and support services in seeking most cost-effective maintenance programs as well as identify areas where consolidation of licenses and services will reduce technology overhead.

Infrastructure Management will continue to work closely with Distribution Operations and support the Smart Grid initiatives, including the multi-year plan to build a new communications network.

## MAKING IT HAPPEN

Considerable effort will be essential in terms of what needs to be done to transform HO's IM&IT environment to one in which "Accessing Anything, Anytime, Anywhere".

Recognizing that HO's business performance is dependent on complex technology systems, HO has demonstrated its commitment to invest in technology through the provision of Capital funding for major IM&IT and OT initiatives. While pressure continues to grow, the OM&A funding envelope will be maintained to operate within existing budgets. The implication of Total Cost of Ownership on all new IM&IT or OT initiatives will be evaluated in view of this budget pressure.

The accelerating rate of technological change means that the speed of delivery of solutions must increase. The IT organization must become agile in its ability to respond and service the business constituent. The proposed Services Oriented Architecture (SOA) is one strategy that could enhance HO's agility to respond and adapt to the changing business requirements. Investigating and leveraging Software as a Solution (Saas), Infrastructure as a Service (IaaS) and Platform as a Service (PaaS) will, under the right conditions successfully offset multiple infrastructure management and provisioning burdens, both one-time and reoccurring. Processes for delivery need to be revamped and where possible, map to a more agile, waterfall methodology.

"Getting it right because we can't afford to get it wrong ..." continues to be the watchword for HO as the Local Distribution Company for the Nation's Capital. HO needs to remain proactive when securing the IT infrastructure and assets, SCADA systems, and protecting sensitive information. HO must layer security and privacy into all systems, new and old, housed, hosted or in the cloud, to protect HO's technology assets, and HO's and its customers' information.

Investment in emerging wireless capabilities, tablet and laptop technologies as well as smart-phone and personal computing devices will be critical in facilitating mobility and productivity. The changing demographic of Hydro Ottawa employee must be considered and integrated.

## CRITICAL SUCCESS FACTORS

The following factors are regarded as critical for the successful implementation of the IM&IT Strategy Update 2014-2020:

1. An IM&IT funding model that considers the Total Cost of Ownership (TCO) of business solutions and technology investments, providing Capital funding for project implementation and working within commensurate OM&A for the ongoing operation, support and maintenance of the solution throughout its lifecycle.
2. An architecture-driven enterprise model of technologies, inter-connectivity, data flows, security and access to guide the evolution of HO's information and technology environments.
3. An effective enterprise technology planning and change management process including effective communications across the organization so that all HO employees are aware of the

technology direction of the company, project priorities, supporting policies and practices, and respective roles and responsibilities.

4. The availability of skilled IM&IT resources, including adequate bench strength to support and maintain as well as implement new IM&IT initiatives.

## EXPECTED OUTCOMES

Implementation of the IM&IT Strategy Update 2014-2020 should result in the following outcomes:

1. HO will have more agility to respond to changes in its business environment and corporate priorities as a result of the adoption of a Services Oriented Architecture.
2. Productivity improvements across HO will result from increased workflow processing, mobile applications, real-time data, and enterprise search capabilities.
3. HO's business continuity and the reliability of distribution operations will be strengthened. Leveraging new technologies in conjunction with the relocation to new HO facilities will reduce the computing footprint and facilitate the move to a paperless environment.

A summary of the potential benefits of the proposed IM&IT initiatives follows:

| IM&IT Strategies / Potential Benefits | Productivity | Efficiency | Cost Savings | "Greening" | Security | Customer Experience | Compliance |
|---|---|---|---|---|---|---|---|
| Service Oriented Architecture | ✓ | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Enterprise Service Bus | ✓ | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Reduction of Point-to-Point Interfaces | ✓ | ✓ | ✓ | | | | |
| Process Re-engineering | ✓ | ✓ | ✓ | | | ✓ | |
| Paper Records Reduction (new facility) | | ✓ | ✓ | ✓ | | | ✓ |
| Electronic Information Management | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ |
| Enterprise Search | ✓ | ✓ | | | | | |
| Master Data Management | | ✓ | | | | | ✓ |
| Information Security Classification | | ✓ | | | ✓ | ✓ | ✓ |
| Information Classification & Retention | | ✓ | ✓ | | | | ✓ |
| Attack Surface Reduction | | | | | ✓ | | |
| Security Information & Event Monitoring | | | | | ✓ | | |
| Data Loss Prevention | | ✓ | | | ✓ | ✓ | ✓ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Virtualization | ✓ | ✓ | ✓ | ✓ | | | |
| Mobile Device Management | ✓ | ✓ | ✓ | | | | |
| Disaster Recovery | ✓ | | | | ✓ | | |
| Asset Management | ✓ | | ✓ | | | | |
| Next Generation Technology | ✓ | | ✓ | | | | |
| ERP Strategy | | ✓ | ✓ | | | | |
| Legacy Applications Rationalization | ✓ | ✓ | ✓ | | | | |
| Mobile / Cloud Computing | | ✓ | | ✓ | ✓ | | |
| Business Intelligence | ✓ | ✓ | | | | ✓ | |
| Business Solutions | ✓ | ✓ | ✓ | | | | |

# CIS TRANSITION PROJECT

## 1.0 INTRODUCTION

On 6 March, 2014, Hydro Ottawa seamlessly replaced its legacy Customer Information System (PeopleSoft® Customer Information System version 8.8) with Oracle's Customer Care and Billing (CC&B) version 2.3.1 system – a project which had been in the making since 2009, when Oracle announced CC&B was its flagship product and that PS CIS would be sunset. Hydro Ottawa achieved this objective well within industry standards and less than the benchmark of $85 US per customer; according to Gartner benchmark data on CIS implementations (refer to figure 1).

**Figure 1 – Gartner Benchmark Data for CIS & Billing System Implementations[1]**

| Company Size* | Number of Customers | Total Cost Per Customer^ |
|---|---|---|
| Small | < 500,000 | $85 |
| Medium | 500,000 - 1.5 million | $65 |
| Large | > 1.5 million | $42 |
| **High/low values (all)** | | **$27.50 / $174** |

*Based on market research of 100 CIS and billing system implementations in the US for energy utilities
^US dollar amounts were not converted as during the Hydro Ottawa CIS Transition Project CDN $ was at par with US $

One year post go-live, Hydro Ottawa is extremely satisfied with the CC&B system as it continues to produce timely and accurate monthly bills for our customers in an efficient manner, positions Hydro Ottawa very well to maintain compliance with emerging OEB regulations, to deploy new customer self-serve options and to implement other initiatives to help customers reduce their electricity usage as indicated in Exhibit D-1-06 Customer Service Strategy. It should be noted that with the implementation of the CC&B system,

[1] Information from 13 March 2015 interview with Zarko Sumic, VP Distinguished Analyst of Gartner

Hydro Ottawa transitioned all its residential and small commercial customer from bi-monthly to monthly billing, a year in advance of the OEB amendment to the Distribution System code on the 15 April 2015 mandating monthly billing for all customer classes by the 31 December 2016.

The following sections describe why a new CIS was required, explain the sensible approach taken for the replacement, describe the fair and equitable vendor selection process and provide a high level over-view of the efficient and effective execution of the project.

**Why Was a New CIS Required?**

The Customer Information System (CIS) is a critical business system for Hydro Ottawa as this comprehensive system provides the capability required to meet the core business mandate of producing timely and accurate bills for more than 320,000 customers in our service area. In addition, various functional areas rely on the CIS to achieve their operational mandates in an expedient, cost-effective manner. Hydro Ottawa's existing CIS, PeopleSoft® CIS version 8.8 (PS CIS) was successfully implemented on the 7 September 2004. A change to the risk profile occurred in June 2009 pertaining to available support for this mission-critical business application. Oracle, the product vendor, no longer offered premier support for this particular product version and would only assist in maintaining the current version through sustaining support (refer to Figure 2 for the key features of each level of support) . Having a mission-critical business application which produces bills for our customers on sustaining support provides an increased risk of failure as time progresses and is not aligned with Hydro Ottawa's practice of remaining in premier support. In addition, Oracle announced the Customer Care & Billing (CC&B) would be its flagship product and that it was phasing out the PS CIS.

**Figure 2 – Oracle Lifetime Support[2]**

LIFETIME SUPPORT EXCLUSIVE BENEFITS

| Key Feature | Premier Support | Extended Support | Sustaining Support |
|---|---|---|---|
| Major Product and Technology Releases | ● | ● | ● |
| Technical Support | ● | ● | ● |
| Access to Support Portal | ● | ● | ● |
| Updates and Fixes | ● | ● | Pre-existing |
| Security Alerts | ● | ● | Pre-existing |
| Critical Patch Updates | ● | ● | |
| Tax, Legal, and Regulatory Updates | ● | ● | |
| Upgrade Scripts | ● | ● | Pre-existing |
| Certification with Existing third-party Products/versions | ● | ● | |
| Certification with most new third-party products/versions | ● | | |
| Certification with most new Oracle products | ● | ● | |

Between 2007 and 2012 Hydro Ottawa modified its existing CIS to implement billing using data from smart meters, time of use billing and integration with the MDM/R as well as the Ontario Energy Board's new rules regarding customer service practices. However, in 2010 Hydro Ottawa recognized that delaying the replacement of the existing CIS could not wait any longer – as the ability of the current system to accommodate all these changes had been maximized and the risk of PS CIS failing was increasing with every year of being on sustaining support. In addition, through the preliminary work done by the CIS transition project – which was struck in October 2010 with the appointment of executive project sponsors, a project manager and the assignment of people to the project – it became apparent that the implementation of a new CIS would take approximately 18 to 36 months to execute[3].

[2] Information obtained from Oracle's website, www.oralce.com
[3] Information gathered during the draft of the request for proposal process conducted by Hydro Ottawa in July 2011.

**Approach Taken for the Replacement**

As described in the Hydro Ottawa's 2011 EDR application, from 2008 to 2011 Hydro Ottawa conducted a due diligence review of available options to consider and found that the industry standard anticipated the cost of a replacement to the PS CIS sister product CC&B to be less than the cost of implementing another CIS product such as SAP, Harris or Customer/1. The cost-effective and prudent decision was taken to replace Oracle's PeopleSoft CIS version 8.8 with Oracle's current product, CC&B version 2.3.1, in order to minimize product licensing costs as well as overall CIS transition project costs including data migration, enhancement and integration, reports development and training costs.

In 2011 Hydro Ottawa acquired Oracle's CC&B application software and in order to reduce development costs related to the implementation of CC&B at Hydro Ottawa, secured Oracle to upgrade to CC&B v2.3.1 the Custom Components for the Ontario Marketplace (CCOM). The custom components, which implemented the OEB regulations in effect as of December 2013, were created originally for two other Ontario local distribution companies (i.e., Toronto Hydro and Enersource). Even though the custom components were specifically developed within the context of the other systems in operation at those LDCs and those LDCs specific business processes, using these components as a starting point allowed Hydro Ottawa to focus on implementing new regulations, adopting our business processes to the base CC&B product and ensuring that the business efficiencies gained in the Hydro Ottawa's existing PS CIS were met by CC&B v2.3.1.

With the CC&B v2.3.1 software and the Custom Components for the Ontario Marketplace acquired, Hydro Ottawa turned to the task of finding a company to implement our new CIS via system integration services and to have the same company provide hosting services and managed services to run our new CC&B system once the CIS transition project was complete. It was determined that this was the most prudent approach to take to ensure that the vendor had a vested interest in performing the system integration services to the highest quality as the vendor would continue to be accountable for the operation of CC&B post go-live.

**Request for Proposal for System Integrator and 10 year Hosting & Application Managed Services**

Hydro Ottawa used a request for proposal (RFP) process to obtain the best market price for the system integration services (services required to implement the new CC&B) and the ongoing hosting services and managed services (services which provide the computing environment on which CC&B runs, technical, functional and operational support, completion of nightly batch operations, defect fixes and new functionality development) of Hydro Ottawa's new CIS. In addition, Hydro Ottawa decided that the proposal would request a 10 year, long term partnership with the vendor – as this would enable Hydro Ottawa to get a better price rather than a short duration partnership, as the upfront cost of setting up a hosted environment as per Hydro Ottawa's specifications and training support staff to provide managed services would be deferred over a longer period resulting in lower yearly maintenance costs.

During the request for proposal stage of the CIS transition project, Hydro Ottawa was actively involved in discussions with several other large Ontario LDCs to look for ways to work together on our respective CIS implementations in an effort to find cost savings for all LDC's involved. Taking into consideration the fact that some LDCs were on a different version of CC&B and the fact that the various LDCs CIS transition projects were not aligned, Hydro Ottawa determined that a joint request for proposal process with another Ontario LDC, was not attainable.

Hydro Ottawa hired a procurement advisory firm, PPI Consulting, an expert in the procurement of large IT systems, to ensure a comprehensive request for proposal was created, a fair process for procurement was followed and that an unbiased evaluation process was used to evaluate the proposals and determine the successful bidder.

As part of the process Hydro Ottawa sent out a draft of the request for proposal in July 2011 to four vendors, HP, IBM, CGI and Capgemini, to gain vendor insight into the quality of the request for proposal documentation. Specifically, Hydro Ottawa was interested to determine if the scope of work was clearly defined and if there was sufficient information for the vendors to provide a fixed price. The vendors provided valuable insight in responding the questions and during the subsequent interview sessions. The vendors indicated that an 18 to 36 month implementation was a more typical timeframe for a CIS implementation, when asked if a 12 month implementation timeframe was reasonable and achievable.

In October 2011 Hydro Ottawa sent out the complete request for proposal to four vendors, HP, IBM, CGI and Capgemini, who were invited to submit a proposal. After the responses to the RFP were received, a dedicated Hydro Ottawa team of managers and supervisors, assisted by PPI Consulting, carried out an evaluation of each of the proposals in early 2012. The proposals were evaluated using a weighted decision model on the written proposal, the vendor interview and the financial proposal.

To maintain complete objectivity, the financial proposals were held confidential from the Hydro Ottawa proposal evaluation team until the evaluation of the written proposal and the vendor interviews were complete. The financial proposal once evaluated showed that the cost of the system integration services, including all Hydro Ottawa costs, was in the range of $23M to $25M.

The exploration of all the available options up to the vendor selection process including contraction negotiation with the successful bidder IBM Canada took 19 months and had a capital expenditure of $1.5M.

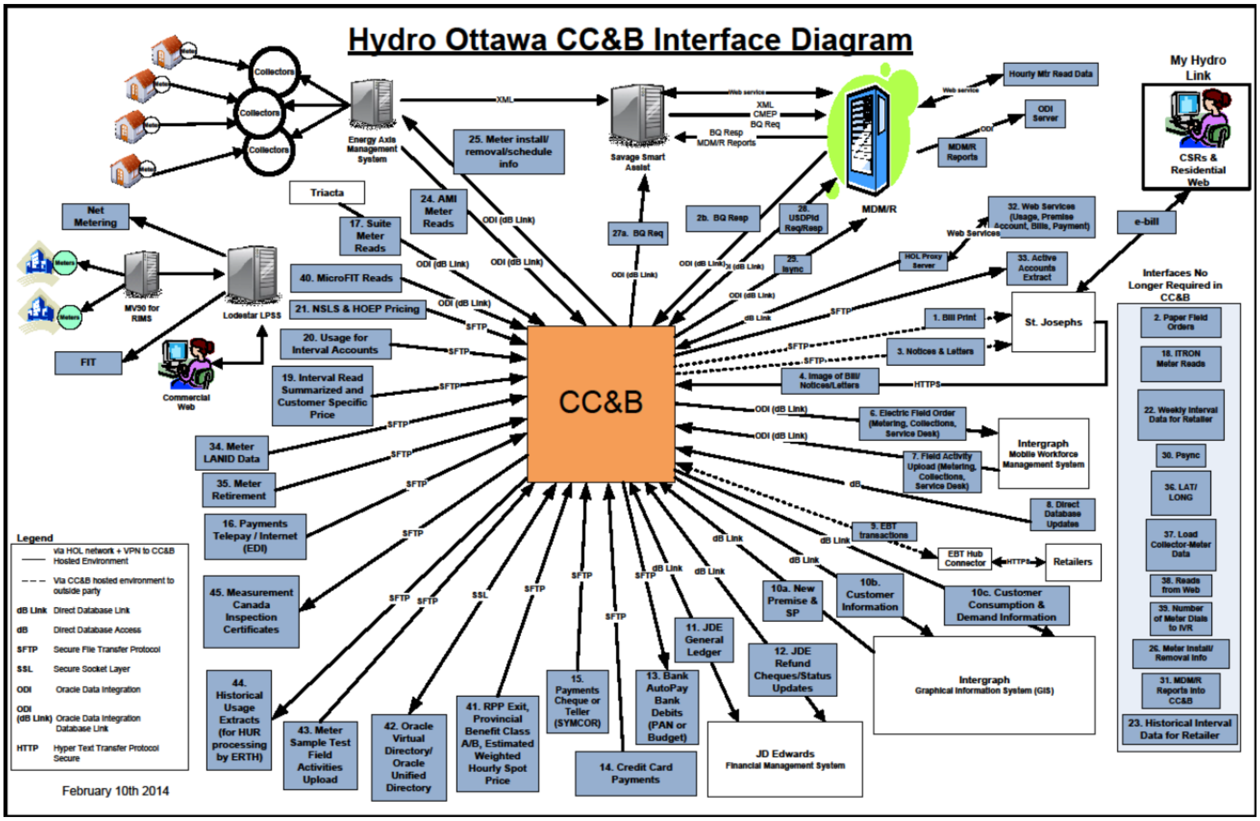
**Execution of CIS Transition Project**

The CIS transition project began on May 1st, 2012, once the contract with IBM Canada had been signed. The highly successful, 22 month project, involved a dedicated project team of key Hydro Ottawa and IBM Canada people (an average of 50 people and at the peak of the project more than 80 people) and many other technical and business contributors on an adhoc basis. The CIS transition project was delivered on time and according to a budget with a capital expenditure of $25.2M.

The CC&B solution delivered consisted of:

- 320,000 converted customer master records
- 2 years' worth of converted bills
- 100 custom reports
- 57 enhancements to CC&B
- A configured CC&B application, which integrated Custom Components for the Ontario Market place
- 35+ interfaces integrating with 10+ legacy systems (refer to Figure 3)
- computer based training for CC&B for Hydro Ottawa's 100+ staff
- disaster recovery, testing and reporting CC&B environments

**Figure 3 – Hydro Ottawa CC&B Interface Diagram**




The following items are of specific note, because they demonstrate Hydro Ottawa's ability to innovate, always keeping our customer in mind:

1. We did not change the customer account numbers with the new CC&B

Hydro Ottawa made the decision early on in the project to retain our customer's existing account numbers, service point numbers and premise numbers, even though Hydro Ottawa was initially told this was impossible and was rarely, if ever, achieved in other projects of a similar size and scope. We were able to achieve this feat through several careful adjustments to our data migration strategy and due to the fact we were transitioning to a sister product.  This decision served to minimize the impact of the new system on the systems of external parties such as our retail customers and the provincial MDM/R. Most importantly, it made the transition to our new system virtually invisible to our customers.

2. We transitioned customers from bi-monthly to monthly billing

Hydro Ottawa decided to transition all of our customer's accounts to monthly billing with the go-live of CC&B. In PS CIS, residential and small commercial customers were billed bi-monthly and our larger commercial customers were billed monthly. Through survey and focus group research, we knew our residential and small commercial customers preferred monthly billing because their electricity bills would then align with most of their other bills. This decision also saved in enhancement costs, because the new CC&B system is standardized for monthly billing.

3. We developed innovative self-serve training

Instead of in-class training, we developed computer-based training leveraging Oracle's User Productivity Kit (UPK). This was especially useful since our Call Centre operations are located in Saint John, New Brunswick, which is 1,100 kilometers from Ottawa, Ontario where Hydro Ottawa is headquartered and this decision minimized our travel costs for training. We deployed the training modules four months in advance of the go-live date so that our employees could be trained gradually, enabling them to learn and retain their new knowledge and skills more easily. This online training system also provided managers and supervisors with regular reports on the completion of the modules by each employee and their test training scores. In this way, targeted coaching could be provided to those requiring it.

4. We adapted our business processes to the base CC&B product instead of creating enhancements to make CC&B work to Hydro Ottawa's existing business processes. For example, we:

- Changed our equal payment plan amount review cycle to be twice yearly instead of daily to reflect the new system.
- Automated our account confirmation process when a new account holder is not known, eliminating multiple manual steps. Now, the account is setup automatically in the name "The Occupant", a notification is sent to the premise to have them contact us to let us know who is now responsible, and if no

responsibility for the account is accepted, then the account proceeds to suspension of service.

- Automated our payment plan (a.k.a., budget billing) reconciliation process, which used to be a manual daily process. Now, the CC&B schedules quarterly reviews and a semi-annual reconciliation.

Together, Hydro Ottawa and IBM Canada delivered an innovative CC&B solution which our key stakeholders are very satisfied with and which meets the objectives of:

- Delivering timely and accurate customer bills;
- Modernizing an aging and unsupported Customer Information System;
- Transforming billing cycle and processes from once every two months to monthly billing to meet customer expectations;
- Providing better functionality to more efficiently implement evolving business and regulatory requirements;
- Providing a platform for deploying new customer self-service options.

**Conclusion**

On 6 March 2014, Hydro Ottawa went live with Oracle's Customer Care and Billing (CC&B) version 2.3.1 system, the mission-critical business application which produces timely and accurate bills for Hydro Ottawa's customers. It was the result of a very successful 22 month CIS transition project lead by Hydro Ottawa and executed with our chosen vendor, IBM Canada. The CIS transition project was delivered on time, on budget and within industry standards. Most importantly, CC&B was seamlessly deployed to our customers.

With its' new Customer Information System Hydro Ottawa is well poised to maintain compliance with emerging OEB regulations, to more to more efficiently implement evolving business requirements to help customers further reduce their electricity usage, and to deploy new customer self-service options with a modern and fully supported system. As indicated in in Exhibit B-1-03 IT Strategy 2015-2020 Hydro Ottawa will continue to invest in a prudent manner in CC&B.

There was a great deal of information and experience sharing between Hydro Ottawa and other local distribution companies in Ontario before, during and after this project. Hydro Ottawa gained valuable insights through these discussions and the lessons Hydro Ottawa learned through this project are being shared with other LDCs who are transitioning to CC&B. This has strengthened Hydro Ottawa's cross-LDC relationships and we fully expect that our collaboration with other large Ontario LDCs who are using CC&B to grow in the future. We will continue to looking for ways to reduce overall costs of modifying CC&B in the future by leveraging these collaborations.

# ASSETS – PROPERTY PLANT AND EQUIPMENT CONTINUITY SCHEDULE

The tables in this exhibit provides Gross Assets continuity schedules by function for years from 2012 (last rebasing year) through to 2020 as presented in Hydro Ottawa Limited's ("Hydro Ottawa") Electricity Distribution Rate Application for 2016 (EB-2015-0004) based the Ontario Energy Boards minimum reporting groups. Exhibit D-3-1 provides continuity schedules for amortization and Appendix 2-B, Fixed Asset Continuity Schedules by Uniform System of Account ("USofA") for 2012 to 2013 Actuals and 2014 Forecast together with budgets for 2015 to 2020.

Hydro Ottawa's 2012 rate application was submitted under Modified International Financial Reporting Standards ("MIFRS") with a transition date of January 1, 2011 as directed by Ontario Energy Board (the "Board"). International Financial Reporting Standards ("IFRS") at that time did not contain standard governing rate-regulated activities. In May 2012, the International Accounting Standards Board ("IASB") decided to develop a project on Rate-regulated Activities. With this pending, the Canadian Accounting Standards Board allowed qualifying Rate Regulated entities to defer the adoption of IFRS to January 1, 2015. Hydro Ottawa Limited elected to take this deferral for financial reporting purposes while continuing to maintain MIFRS for regulatory purposes. The IASB has since issued interim standard *IFRS 14 - Regulatory Deferred Accounts* ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices.

Due to the divergence of financial accounting standards for regulatory reporting and financial reporting purposes, Hydro Ottawa was required to maintain two sets of records for a period of time. Hydro Ottawa has made a one-time adjustment to the 2014 opening Gross Asset Net book value reported under MIFRS to align the two sets of records to avoid future administrative burden of maintaining two sets as well as enhance operational efficiency and reduce the burden on Hydro Ottawa's IT systems. This results in a Net Book Value increase of $502k under MIFRS to be depreciated over the applicable remaining useful lives as well as $195k increase under MIFRS to the cost of

Construction in progress. For fiscal year 2011, Hydro Ottawa had recorded different amount of overheads applied to capital projects and different depreciation amount under MIFRS and CGAAP. The one-time adjustment for rate-making purposes will result in a minor increase to rate base. Hydro Ottawa expects that any rate impact arising from the rate base increase will be offset by savings realized from eliminating duplicate sets of records. The other adjustment was to clear the accumulated depreciation and contributed capital balances to nil as seen in Table 3, column B below. The adjustment can be seen in detail in 2015 Filing Requirements Chapter 2 Appendices (tab: App.2-BA_FA Cont 2014). With the adoption of IFRS and early adoption of IFRS 14 as the accounting basis for financial reporting purposes on January 1, 2015, Hydro Ottawa's regulatory and financial reporting records are now aligned from an accounting standards basis. All table figures in this exhibit are presented in dollars.

## Table 1: 2012 Fixed Assets

| | 2011 CIP (A) | 2011 Ending Balance (B) | 2012 Capital Expenditures (C) | 2012 CIP (D) | 2012 Disposals (E) | 2012 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 3,576,783 | 24,553,799 | 11,628,182 | 14,139,937 | 0 | 25,618,827 |
| TS Primary Above 50 | 14,544,602 | 55,223,256 | 7,592,761 | 14,060,864 | 0 | 63,299,755 |
| DS | 7,908,381 | 44,563,372 | 8,824,014 | 10,065,470 | 0 | 51,230,296 |
| Poles, Wires | 5,181,591 | 235,652,383 | 45,139,204 | 13,209,864 | (301,184) | 272,462,130 |
| Line Transformers | 1,713,616 | 45,853,921 | 10,646,715 | 2,633,883 | (204,591) | 55,375,779 |
| Services and Meters[1] | 643,739 | 97,432,759 | 6,622,396 | 491,858 | (35,554) | 104,171,482 |
| General Plant | 490 | 36,118,077 | 248,836 | 8,386 | 0 | 36,359,018 |
| Equipment | 1,062,699 | 15,332,946 | 3,652,381 | 1,277,112 | (5,545) | 18,765,370 |
| IT Assets | 3,684,878 | 28,000,238 | 14,296,060 | 13,742,512 | 0 | 32,238,664 |
| Other Distribution Assets | 101,607 | 9,602,369 | 1,654,013 | 1,375,071 | 0 | 9,982,919 |
| **Gross Assets** | **38,418,389** | **592,333,121** | **110,304,563** | **71,004,956** | **(546,874)** | **669,504,239** |
| Contributions and Grants | (5,484,667) | (21,049,858) | (23,539,871) | (6,833,595) | 0 | (43,240,801) |
| Amortization | 0 | (36,818,456) | (38,595,334) | 0 | 44,281 | (75,369,509) |
| **Total** | **32,933,722** | **534,464,807** | **48,169,358** | **64,171,361** | **(502,593)** | **550,893,929** |

[1] Stranded Meters have been included here.

## Table 2: 2013 Fixed Assets

| | 2012 CIP (A) | 2012 Ending Balance (B) | 2013 Capital Expenditures (C) | 2013 CIP (D) | 2013 Disposals (E) | 2013 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 14,139,937 | 25,618,827 | 13,965,050 | 279,187 | 0 | 53,444,628 |
| TS Primary Above 50 | 14,060,864 | 63,299,755 | 10,658,729 | 9,678,617 | 0 | 78,340,731 |
| DS | 10,065,470 | 51,230,296 | 10,441,901 | 8,175,357 | (819,212) | 62,743,098 |
| Poles, Wires | 13,209,864 | 272,462,130 | 55,417,921 | 18,442,036 | (1,450,262) | 321,197,617 |
| Line Transformers | 2,633,883 | 55,375,779 | 9,794,504 | 2,454,063 | (195,123) | 65,154,980 |
| Services and Meters[2] | 491,858 | 104,171,482 | 6,136,798 | 761,454 | (1,475,007) | 108,563,678 |
| General Plant | 8,386 | 36,359,018 | 236,223 | 49,143 | 0 | 36,554,484 |
| Equipment | 1,277,112 | 18,765,370 | 4,015,745 | 1,979,775 | (1,171) | 22,077,281 |
| IT Assets | 13,742,512 | 32,238,664 | 16,764,643 | 26,671,494 | 0 | 36,074,324 |
| Other Distribution Assets | 1,375,071 | 9,982,919 | 6,643,713 | 7,323,201 | 0 | 10,678,502 |
| **Gross Assets** | **71,004,956** | **669,504,239** | **134,075,229** | **75,814,327** | **(3,940,774)** | **794,829,323** |
| Contributions and Grants | (6,833,595) | (43,240,801) | (25,115,208) | (10,530,225) | | (64,659,379) |
| Amortization | 0 | (75,369,509) | (39,798,292) | 0 | 1,138,182 | (114,029,619) |
| **Total** | **64,171,361** | **550,893,929** | **69,161,728** | **65,284,102** | **(2,802,592)** | **616,140,325** |

[2] Stranded Meters have been included here.

## Table 3: 2014 Fixed Assets

| | 2013 CIP[3] (A) | 2013 Ending Balance[4] (B) | 2014 Capital Expenditures (C) | 2014 CIP (D) | 2014 Disposals (E) | 2014 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 279,187 | 51,869,022 | 1,885,295 | 694,548 | 0 | 53,338,956 |
| TS Primary Above 50 | 9,687,975 | 72,854,689 | 3,745,236 | 8,420,960 | (2,870) | 77,864,068 |
| DS | 8,189,580 | 54,066,400 | 14,715,828 | 14,596,902 | (138,213) | 62,236,694 |
| Poles, Wires | 18,472,443 | 252,125,738 | 61,706,774 | 26,153,771 | (1,173,116) | 304,978,068 |
| Line Transformers | 2,454,993 | 45,656,713 | 9,844,036 | 2,971,807 | (124,321) | 54,859,614 |
| Services and Meters | 739,788 | 75,121,923 | 6,022,160 | 634,008 | (154,156) | 81,095,707 |
| General Plant | 65,979 | 31,300,071 | 524,336 | 56,698 | (1,531) | 31,832,157 |
| Equipment | 1,977,593 | 15,099,294 | 1,934,910 | 359,156 | (51,686) | 18,600,955 |
| IT Assets | 26,818,276 | 10,397,474 | 12,765,875 | 2,076,697 | (91,791) | 47,813,136 |
| Other Distribution Assets | 7,324,079 | 8,151,484 | 16,925,227 | 15,999,272 | (4,483) | 16,397,035 |
| **Gross Assets** | **76,009,893** | **616,642,806** | **130,069,675** | **71,963,817** | **(1,742,167)** | **749,016,390** |
| Contributions and Grants | (10,530,225) | 0 | (22,405,563) | (12,792,224) | | (20,143,565) |
| Amortization | 0 | 0 | (36,517,006) | | 597,688 | (35,919,318) |
| **Total** | **65,479,667** | **616,642,806** | **71,147,106** | **59,171,593** | **(1,144,479)** | **692,953,507** |

[3] As described above CIP includes one-time increase to opening values of $195k
[4] As described above Property, plant and equipment includes one-time adjustment to opening cost of $502k, as well, opening Gross Asset values includes opening Amortization of $114,030k as required for the transition to IFRS

## Table 4: 2015 Fixed Assets

| | 2014 CIP (A) | 2014 Ending Balance (B) | 2015 Capital Expenditures (C) | 2015 CIP (D) | 2015 Disposals (E) | 2015 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 694,548 | 53,338,956 | 2,313,153 | 1,136,081 | 0 | 55,210,576 |
| TS Primary Above 50 | 8,420,960 | 77,864,068 | 1,646,063 | 911,635 | 0 | 87,019,457 |
| DS | 14,596,902 | 62,236,694 | 14,663,513 | 14,378,881 | (153,346) | 76,964,881 |
| Poles, Wires | 26,153,771 | 304,978,068 | 56,152,253 | 26,545,963 | (1,199,260) | 359,538,869 |
| Line Transformers | 2,971,807 | 54,859,614 | 12,439,831 | 2,937,729 | (211,886) | 67,121,637 |
| Services and Meters | 634,008 | 81,095,707 | 7,748,188 | 630,413 | (150,377) | 88,697,113 |
| General Plant | 56,698 | 31,832,157 | 492,174 | 56,620 | 0 | 32,324,409 |
| Equipment | 359,156 | 18,600,955 | 4,311,606 | 2,183,285 | (48,184) | 21,040,248 |
| IT Assets | 2,076,697 | 47,813,136 | 11,517,399 | 4,001,808 | 0 | 57,405,424 |
| Other Distribution Assets | 15,999,272 | 16,397,035 | 2,799,240 | 932,559 | 0 | 34,262,988 |
| **Gross Assets** | **71,963,817** | **749,016,390** | **114,083,420** | **53,714,972** | **(1,763,053)** | **879,585,602** |
| Contributions and Grants | (12,792,224) | (20,143,565) | (25,432,188) | (12,792,224) | | (45,575,753) |
| Amortization | 0 | (35,919,318) | (38,557,773) | | 1,013,053 | (73,464,038) |
| **Total** | **59,171,593** | **692,953,507** | **50,093,459** | **40,922,748** | **(750,000)** | **760,545,811** |

## Table 5: 2016 Fixed Assets

| | 2015 CIP (A) | 2015 Ending Balance (B) | 2016 Capital Expenditures (C) | 2016 CIP (D) | 2016 Disposals (E) | 2016 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 1,136,081 | 55,210,576 | 2,313,110 | 1,468,702 | 0 | 57,191,065 |
| TS Primary Above 50 | 911,635 | 87,019,457 | 1,634,612 | 2,044,213 | 0 | 87,521,491 |
| DS | 14,378,881 | 76,964,881 | 13,989,440 | 13,507,027 | (153,346) | 91,672,829 |
| Poles, Wires | 26,545,963 | 359,538,869 | 60,605,090 | 29,657,564 | (1,199,260) | 415,833,098 |
| Line Transformers | 2,937,729 | 67,121,637 | 10,588,683 | 2,937,667 | (211,886) | 77,498,496 |
| Services and Meters | 630,413 | 88,697,113 | 7,719,934 | 630,022 | (150,377) | 96,267,061 |
| General Plant | 56,620 | 32,324,409 | 1,249,580 | 56,506 | 0 | 33,574,103 |
| Equipment | 2,183,285 | 21,040,248 | 3,638,034 | 413,172 | (48,184) | 26,400,211 |
| IT Assets | 4,001,808 | 57,405,424 | 15,399,551 | 10,587,576 | 0 | 66,219,207 |
| Other Distribution Assets | 932,559 | 34,262,988 | 5,096,070 | 563,641 | 0 | 39,727,976 |
| **Gross Assets** | **53,714,972** | **879,585,602** | **122,234,104** | **61,866,088** | **(1,763,053)** | **991,905,537** |
| Contributions and Grants | (12,792,224) | (45,575,753) | (25,701,824) | (12,792,224) | | (71,277,577) |
| Amortization | 0 | (73,464,038) | (40,826,114) | | 1,013,053 | (113,277,099) |
| **Total** | **40,922,748** | **760,545,811** | **55,706,166** | **49,073,864** | **(750,000)** | **807,350,861** |

## Table 6: 2017 Fixed Assets

| | 2016 CIP (A) | 2016 Ending Balance (B) | 2017 Capital Expenditures (C) | 2017 CIP (D) | 2017 Disposals (E) | 2017 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 1,468,702 | 57,191,065 | 4,530,791 | 3,803,818 | 0 | 59,386,740 |
| TS Primary Above 50 | 2,044,213 | 87,521,491 | 9,831,305 | 8,605,201 | 0 | 90,791,808 |
| DS | 13,507,027 | 91,672,829 | 12,147,266 | 18,373,287 | (153,346) | 98,800,489 |
| Poles, Wires | 29,657,564 | 415,833,098 | 50,611,803 | 28,352,883 | (1,199,260) | 466,550,322 |
| Line Transformers | 2,937,667 | 77,498,496 | 11,309,359 | 2,978,335 | (211,886) | 88,555,301 |
| Services and Meters | 630,022 | 96,267,061 | 8,682,455 | 632,273 | (150,377) | 104,796,888 |
| General Plant | 56,506 | 33,574,103 | 434,236 | 56,430 | 0 | 34,008,415 |
| Equipment | 413,172 | 26,400,211 | 6,177,699 | 359,223 | (48,184) | 32,583,675 |
| IT Assets | 10,587,576 | 66,219,207 | 7,039,945 | 2,182,831 | 0 | 81,663,897 |
| Other Distribution Assets | 563,641 | 39,727,976 | 5,587,269 | 688,323 | 0 | 45,190,563 |
| **Gross Assets** | **61,866,088** | **991,905,537** | **116,352,128** | **66,032,602** | **(1,763,053)** | **1,102,328,098** |
| Contributions and Grants | (12,792,224) | (71,277,577) | (25,296,257) | (12,792,224) | | (96,573,834) |
| Amortization | 0 | (113,277,099) | (44,145,078) | | 1,013,053 | (156,409,124) |
| **Total** | **49,073,864** | **807,350,861** | **46,910,793** | **53,240,378** | **(750,000)** | **849,345,140** |

## Table 7: 2018 Fixed Assets

| | 2017 CIP (A) | 2017 Ending Balance (B) | 2018 Capital Expenditures (C) | 2018 CIP (D) | 2018 Disposals (E) | 2018 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 3,803,818 | 59,386,740 | 3,818,909 | 4,667,976 | 0 | 62,341,491 |
| TS Primary Above 50 | 8,605,201 | 90,791,808 | 6,978,261 | 13,502,607 | 0 | 92,872,663 |
| DS | 18,373,287 | 98,800,489 | 13,311,307 | 10,603,595 | (153,346) | 119,728,142 |
| Poles, Wires | 28,352,883 | 466,550,322 | 54,246,123 | 26,662,342 | (1,199,260) | 521,287,726 |
| Line Transformers | 2,978,335 | 88,555,301 | 11,767,301 | 3,000,508 | (211,886) | 100,088,543 |
| Services and Meters | 632,273 | 104,796,888 | 8,902,932 | 631,931 | (150,377) | 113,549,785 |
| General Plant | 56,430 | 34,008,415 | 123,299 | 56,423 | 0 | 34,131,721 |
| Equipment | 359,223 | 32,583,675 | 5,148,673 | 364,579 | (48,184) | 37,678,808 |
| IT Assets | 2,182,831 | 81,663,897 | 5,337,193 | 2,076,697 | 0 | 87,107,224 |
| Other Distribution Assets | 688,323 | 45,190,563 | 5,610,816 | 409,931 | 0 | 51,079,771 |
| **Gross Assets** | **66,032,602** | **1,102,328,098** | **115,244,814** | **61,976,587** | **(1,763,053)** | **1,219,865,874** |
| Contributions and Grants | (12,792,224) | (96,573,834) | (25,075,051) | (12,792,224) | | (121,648,885) |
| Amortization | 0 | (156,409,124) | (47,047,409) | | 1,013,053 | (202,443,480) |
| **Total** | **53,240,378** | **849,345,140** | **43,122,354** | **49,184,363** | **(750,000)** | **895,773,509** |

## Table 8: 2019 Fixed Assets

| | 2018 CIP (A) | 2018 Ending Balance (B) | 2019 Capital Expenditures (C) | 2019 CIP (D) | 2019 Disposals (E) | 2019 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 4,667,976 | 62,341,491 | 4,595,372 | 8,516,169 | 0 | 63,088,670 |
| TS Primary Above 50 | 13,502,607 | 92,872,663 | 9,332,947 | 22,539,204 | 0 | 93,169,013 |
| DS | 10,603,595 | 119,728,142 | 14,992,638 | 19,055,333 | (153,346) | 126,115,696 |
| Poles, Wires | 26,662,342 | 521,287,726 | 52,376,147 | 27,902,678 | (1,199,260) | 571,224,277 |
| Line Transformers | 3,000,508 | 100,088,543 | 11,519,979 | 3,062,596 | (211,886) | 111,334,548 |
| Services and Meters | 631,931 | 113,549,785 | 8,968,403 | 637,459 | (150,377) | 122,362,283 |
| General Plant | 56,423 | 34,131,721 | 248,568 | 56,464 | 0 | 34,380,248 |
| Equipment | 364,579 | 37,678,808 | 4,199,829 | 373,102 | (48,184) | 41,821,930 |
| IT Assets | 2,076,697 | 87,107,224 | 11,341,465 | 8,192,037 | 0 | 92,333,349 |
| Other Distribution Assets | 409,931 | 51,079,771 | 5,599,500 | 625,424 | 0 | 56,463,778 |
| **Gross Assets** | **61,976,587** | **1,219,865,874** | **123,174,848** | **90,960,464** | **(1,763,053)** | **1,312,293,792** |
| Contributions and Grants | (12,792,224) | (121,648,885) | (25,576,549) | (12,792,224) | | (147,225,434) |
| Amortization | 0 | (202,443,480) | (48,948,694) | | 1,013,053 | (250,379,121) |
| **Total** | **49,184,363** | **895,773,509** | **48,649,605** | **78,168,240** | **(750,000)** | **914,689,237** |

## Table 9: 2020 Fixed Assets

| | 2019 CIP (A) | 2019 Ending Balance (B) | 2020 Capital Expenditures (C) | 2020 CIP (D) | 2020 Disposals (E) | 2020 Ending Balance =A+B+C-D+E |
|---|---|---|---|---|---|---|
| Land and Buildings | 8,516,169 | 63,088,670 | 4,887,979 | 6,199,103 | 0 | 70,293,715 |
| TS Primary Above 50 | 22,539,204 | 93,169,013 | 10,017,547 | 13,145,810 | 0 | 112,579,954 |
| DS | 19,055,333 | 126,115,696 | 14,471,223 | 18,656,033 | (153,346) | 140,832,873 |
| Poles, Wires | 27,902,678 | 571,224,277 | 53,841,724 | 28,106,289 | (1,199,260) | 623,663,130 |
| Line Transformers | 3,062,596 | 111,334,548 | 11,821,423 | 3,031,585 | (211,886) | 122,975,096 |
| Services and Meters | 637,459 | 122,362,283 | 9,170,797 | 640,537 | (150,377) | 131,379,625 |
| General Plant | 56,464 | 34,380,248 | 177 | 56,509 | 0 | 34,380,380 |
| Equipment | 373,102 | 41,821,930 | 5,712,584 | 359,495 | (48,184) | 47,499,937 |
| IT Assets | 8,192,037 | 92,333,349 | 6,253,080 | 2,127,237 | 0 | 104,651,229 |
| Other Distribution Assets | 625,424 | 56,463,778 | 5,598,278 | 662,677 | 0 | 62,024,803 |
| **Gross Assets** | **90,960,464** | **1,312,293,792** | **121,774,812** | **72,985,273** | **(1,763,053)** | **1,450,280,742** |
| Contributions and Grants | (12,792,224) | (147,225,434) | (26,088,080) | (12,792,224) | | (173,313,514) |
| Amortization | 0 | (250,379,121) | (50,294,804) | | 1,013,053 | (299,660,872) |
| **Total** | **78,168,240** | **914,689,237** | **45,391,928** | **60,193,049** | **(750,000)** | **977,306,356** |

## VARIANCE ANALYSIS ON GROSS ASSETS

Table 10 below shows Hydro Ottawa's gross asset additions. Refer to Appendix 2-BA Fixed Asset Continuity Schedule, gross assets additions are the sum of additions and disposals before depreciation and capital contributions. Table 11 below shows the Gross Asset year-over-year variance. The variance analysis is provided below the tables.

**Table 10: Gross Asset Additions**

| $000s | 2012 Approved | 2012 Actual | 2013 Actual | 2014 Forecast | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test |
|---|---|---|---|---|---|---|---|---|---|---|
| Land and Buildings | 9,460 | 1,065 | 27,826 | 1,470 | 1,872 | 1,980 | 2,196 | 2,955 | 747 | 7,205 |
| TS Primary Above 50 | 662 | 8,076 | 15,041 | 5,009 | 9,155 | 502 | 3,270 | 2,081 | 296 | 19,411 |
| DS | 10,433 | 6,667 | 11,513 | 8,170 | 14,728 | 14,708 | 7,128 | 20,928 | 6,388 | 14,717 |
| Poles, Wires | 34,391 | 36,810 | 48,735 | 52,852 | 54,561 | 56,294 | 50,717 | 54,737 | 49,937 | 52,439 |
| Line Transformers | 8,110 | 9,522 | 9,779 | 9,203 | 12,262 | 10,377 | 11,057 | 11,533 | 11,246 | 11,641 |
| Services and Meters | 11,788 | 6,739 | 4,392 | 5,974 | 7,601 | 7,570 | 8,530 | 8,753 | 8,812 | 9,017 |
| General Plant | 713 | 241 | 195 | 532 | 492 | 1,250 | 434 | 123 | 249 | 0 |
| Equipment | 3,422 | 3,432 | 3,312 | 3,502 | 2,439 | 5,360 | 6,183 | 5,095 | 4,143 | 5,678 |
| IT Assets | 7,569 | 4,238 | 3,836 | 37,416 | 9,592 | 8,814 | 15,445 | 5,443 | 5,226 | 12,318 |
| Other Distribution Assets | 1,781 | 381 | 696 | 8,246 | 17,866 | 5,465 | 5,463 | 5,889 | 5,384 | 5,561 |
| **Gross Asset Additions** | **88,329** | **77,171** | **125,325** | **132,374** | **130,569** | **112,320** | **110,423** | **117,538** | **92,428** | **137,987** |

**Table 11: Gross Asset Year-over-Year Variance**

| $000s | 12-Approved | 13-12 | 14-13 | 15-14 | 16-15 | 17-16 | 18-17 | 19-18 | 20-19 |
|---|---|---|---|---|---|---|---|---|---|
| Land and Buildings | (8,395) | 26,761 | (26,356) | 402 | 109 | 215 | 759 | (2,208) | 6,458 |
| TS Primary Above 50 | 7,414 | 6,964 | (10,032) | 4,146 | (8,653) | 2,768 | (1,189) | (1,785) | 19,115 |
| DS | (3,766) | 4,846 | (3,343) | 6,558 | (20) | (7,580) | 13,800 | (14,540) | 8,330 |
| Poles, Wires | 2,419 | 11,926 | 4,117 | 1,708 | 1,733 | (5,577) | 4,020 | (4,801) | 2,502 |
| Line Transformers | 1,412 | 257 | (576) | 3,059 | (1,885) | 680 | 476 | (287) | 395 |
| Services and Meters | (5,049) | (2,347) | 1,582 | 1,628 | (31) | 960 | 223 | 60 | 205 |
| General Plant | (472) | (45) | 337 | (40) | 757 | (815) | (311) | 125 | (248) |
| Equipment | 10 | (121) | 190 | (1,062) | 2,921 | 824 | (1,088) | (952) | 1,535 |
| IT Assets | (3,331) | (403) | 33,580 | (27,823) | (779) | 6,631 | (10,001) | (217) | 7,092 |
| Other Distribution Assets | (1,400) | 315 | 7,550 | 9,620 | (12,401) | (2) | 427 | (505) | 177 |
| **Gross Asset Additions** | **(11,158)** | **48,154** | **7,048** | **(1,804)** | **(18,249)** | **(1,897)** | **7,115** | **(25,110)** | **45,559** |

**2012 Actual vs. 2012 Board Approved Budget:**

In comparing the 2012 Actuals with 2012 Board Approved budget, the decrease in gross assets of $11.2 is primarily due to the following programs:

- The purchase of land for the Facilities Implementation Plan was included in the 2012 Board Approved additions. The acquisition started in 2012, but was only completed in 2013.
- The project to construct a new 230kV to 27kV Terry Fox Substation, located in south Kanata, was started in 2009. The building costs were included in the 2012 Board Approved additions; however the actual costs incurred were in 2013.
- Demand capital especially services related were lower than approved in 2012. They are customer demand driven.

**2013 Actual vs. 2012 Actual:**

The total gross assets additions in 2013 of $125M are an increase of $48M compared with 2012 actuals. This is primarily due to the following programs:

- The purchase of land for two new facilities was started in 2012, but transaction closed in 2013 for a total of $19M.
- The Terry Fox substation was completed in 2013, for a total of $22M including building cost and station equipment.
- Poles and Wires increased from 2012 by $12M, half of it was in Demand capital (residential and new commercial). The other half is in Sustainment, mainly the Cable Replacement Program and the Woodroffe UW 4kV System Voltage Conversion project.

**2014 Forecast vs. 2013 Actual:**

The total gross assets additions forecasted in 2014 of $132M are an increase of $7M compared with 2013 actuals. This is primarily an increase in IT assets offset by a decrease in land and buildings:

- IT assets increased by $34M, the most notable one was CC&B (Customer Care and Billing) system upgrade. The project started in late 2010, went live in Q1 2014, for a total cost of $26M.
- Land and Buildings decreased due to the completion of Terry Fox substation and the land purchase for the Facilities Implementation Plan in 2013.

**Forecast 2015 Bridge Year vs. 2014 Forecast:**

Total forecast gross assets additions in 2015 of $130M are a decrease of $1.8M compared with 2014 Forecast. This is primarily due to the timing of project completion.

- IT assets decreased from 2014 due to CC&B completed.
- Increase in Distribution Stations including Stations Transformer Replacement

**Forecast 2016 Test Year vs. 2015 Bridge Year:**

Total forecast gross assets additions in 2016 of $112M are a decrease of $18M compared with 2015 Bridge Year. This is primarily due to a decrease in the following programs:

- Other distribution assets decreased by $12M primarily explained by the HONI CCRA (Hydro One Connection and Cost Recovery Agreement) payments in 2015 for the Hawthorne and Cyrville stations.
- TS Primary Above 50 decreased by $9M due to the timing of the stations completion. 2015 projected a few large stations completion while the 2016 plan is to focus on the Poles and Wires.

**Forecast 2017 Test Year vs. 2016 Test Year:**

Total forecast gross assets additions in 2017 of $110M are a decrease of $2M compared with 2016. This is primarily due to the changes in the following programs:

- DS (Station Equipment) decreased by $7M and Poles and Wires decreased by $5M
- IT Assets increased by $6M primarily the JDE application upgrade to be completed in 2017.

**Forecast 2018 Test Year vs. 2017 Test Year:**

Total forecast gross assets additions in 2018 of $117M are an increase of $7M compared with 2017. This is primarily due to the changes in the following programs:

- DS (Station Equipment) increased by $14M largely explained by an increase in transformer replacement
- IT Assets decreased by $10M due to the completion of JDE upgrade and SCADA replacement in 2017.

**Forecast 2019 Test Year vs. 2018 Test Year:**

Total forecast gross assets additions in 2019 of $92M are a decrease of $25M compared with 2018. The capital spending is steady, but the completion of some major projects forecasted in 2020, including the following:

- Large multi-year station projects are expected to be ongoing and are planned to be complete in 2020

**Forecast 2020 Test Year vs. 2019 Test Year:**

Total forecast gross assets additions in 2020 of $138M are an increase of $45M compared with 2019. Several major projects started in previous years to be completed in 2020.

- A number of large multi-year station projects are to be completed in 2020.
- CC&B enhancement of $6M

# WORKING CAPITAL REQUIREMENT

## 1.0 INTRODUCTION

This Exhibit provides a schedule of the Working Capital Requirement for the bridge year (2015) and the test years (2016 - 2020). For comparison purposes, the approved and actual Working Capital Requirement for the base year (2012) is also shown.

**Table 1 – Allowance for Working Capital[1]**

| | 2012 Approved $000 | 2012 Actual $000 | 2013 Actual $000 | 2014 Forecast $000 | 2015 Budget $000 |
|---|---|---|---|---|---|
| Power Supply Expenses | 685,303 | 709,935 | 768,079 | 763,312 | 851,135 |
| OM&A Expenses | 73,090 | 73,076 | 75,757 | 80,767 | 83,656 |
| Total Expenses for Working Capital | 758,393 | 783,011 | 843,836 | 844,079 | 934,791 |
| Working Capital % | 14.2 | 14.2 | 14.2 | 14.2 | 14.2 |
| | 107,692 | 111,188 | 119,825 | 119,859 | 132,740 |

| | 2016 Test $000 | 2017 Test $000 | 2018 Test $000 | 2019 Test $000 | 2020 Test $000 |
|---|---|---|---|---|---|
| Power Supply Expenses | 894,285 | 911,714 | 947,559 | 928,734 | 945,199 |
| OM&A Expenses | 87,106 | 89,932 | 92,850 | 95,863 | 98,974 |
| Total Expenses for Working Capital | 981,391 | 1,001,647 | 1,040,409 | 1,024,597 | 1,044,173 |
| Working Capital % | 14.2 | 14.2 | 14.2 | 14.2 | 14.2 |
| | 139,358 | 142,234 | 147,738 | 145,493 | 148,273 |

As part of Hydro Ottawa Limited's ("Hydro Ottawa") 2012 rate application, the Ontario Energy Board ("Board") approved a Working Capital Allowance percentage of 14.2. Hydro Ottawa submitted that it would implement monthly billing for all its customers in

[1] Totals may not match due to rounding

2013. As part of the decision and order the Board directed Hydro Ottawa to prepare a new lead-lag study for its next cost of service application.
In the first quarter of 2014 Hydro Ottawa implemented a new billing system. As part of this implementation Hydro Ottawa implemented monthly billing. Hydro Ottawa believes 12 months of stable monthly billing data is required to perform a new lead lag study. Hydro Ottawa is proposing to use data from July 2014 to June 2015 to complete its updated lead lag study. The new lead lag study will be submitted in September 2015 to be incorporated into final rates. Until the lead lag study is complete, Hydro Ottawa is using its 2012 Board approved rate of 14.2.

The Power Supply Expenses for 2016 to 2020 are calculated in the following manner:

The forecasted monthly purchased kWh and peak kW produced by the load forecasting model described in Exhibit C-1-1 were adjusted for the impact of Conservation and Demand Management activities. The monthly forecasted kWh purchases were multiplied by the monthly forecasted commodity price.

The commodity price for Regulated Price Plan customers (“RPP”) was calculated by using the Regulated Price Plan Price Report[2]. The RPP rate of $94.96/MWh was multiplied by a yearly residential factor derived from Ontario’s Long-Term Energy Plan[3] (“LTAP”) to arrive at a yearly RPP commodity rate for 2016 through 2020. Please see table 2.

**Table 2 - Estimated RPP Price 2016 to 2020 (kWh)**

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| 0.09496 | 0.09789 | 0.09965 | 0.10434 | 0.10375 | 0.10610 |

[2] Regulated Price Plan: Price Report November 1, 2014 to October 31, 2015, Ontario Energy Board, October 16, 2014
[3] Achieving Balance Ontario’s Long-Term Energy Plan, December 3013

The commodity price for non-Regulated Price Plan customers ("non-RPP") was calculated using the Ontario Wholesale Electricity Market Price Forecast[4]. The quarterly rates provided in 'Table ES-1: HOEP Forecast' were used to calculate a 2015 calendar average rate of $20.84/MWh. This rate was multiplied by a commercial factor derived from LTAP to arrive at a yearly rate for 2016 through 2020. Please see table 3.

**Table 3 - Estimated HOEP 2016 to 2020 (kWh)**

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---:|---:|---:|---:|---:|---:|
| 0.02084 | 0.02174 | 0.02265 | 0.02378 | 0.02310 | 0.02355 |

The Wholesale Market Charge is determined from the total kWh purchased multiply by the average rate from 2015 of $0.0057 for all years.

The forecasted kW monthly coincident peak is multiplied by historic percentages for each transmission charge to establish the kWs for those charges. The results are then multiplied by the 2015 rates for all years.

The Global Adjustment is calculated using the Regulated Price Plan Price Report[5]. The Global Adjustment rate of $74.88/MWh was multiplied it by the commercial factor derived from LTAP to arrive at a yearly Global Adjustment rate for 2016 through 2020. Please see table 4. This forecasted rate is multiplied by the Non Regulated Purchase Plan loss adjusted kWh.

**Table 4 - Estimated Global Adjustment 2016 to 2020 (kWh)**

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---:|---:|---:|---:|---:|---:|
| 0.07488 | 0.07814 | 0.08139 | 0.08546 | 0.08302 | 0.08465 |

[4] Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2014 through April 30, 2016, Navigant Consulting Ltd., October 8, 2014
[5] Regulated Price Plan: Price Report November 1, 2014 to October 31, 2015, Ontario Energy Board, October 16, 2014

From January 1, 2016 to October 31, 2018, the Smart Metering Entity charge of $0.788/ Residential and General Service <50kW customer is included in the calculation of the Cost of Power.

Power Supply Expenses was adjusted to reflect the Low Voltage Switchgear credit which Hydro Ottawa receives as a result of owning the low voltage switchgear at certain stations.

Spreadsheets showing the calculation of the Power Supply Expenses for 2016 through 2020 are provided as attachment B-3(A) COP 2016-2020.

# 2016 Cost of Power

**PURCHASED POWER**

**Power Purchases (kWh)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Load Forecast kWh | 735,715,000 | 662,726,000 | 659,347,000 | 579,137,000 | 582,395,000 | 628,554,000 | 686,324,000 | 654,575,000 | 580,591,000 | 599,838,000 | 623,961,000 | 685,332,000 | 7,678,495,000 |

**Power Purchased (kW)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Purchases - coincident peak (kW) | 1,228,000 | 1,174,000 | 1,103,000 | 948,000 | 1,211,000 | 1,310,000 | 1,375,000 | 1,305,000 | 1,093,000 | 962,000 | 1,089,000 | 1,194,000 | 13,992,000 |

**DEMAND CHARGES**

**kW Breakdown by Type**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coincident System Peak | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Transmission Network Charge IMO | 95.2% | 95.5% | 93.7% | 97.7% | 92.1% | 88.9% | 91.5% | 94.5% | 94.9% | 93.5% | 93.4% | 90.1% |
| Transmission Transformation Charge IMO | 80.9% | 82.4% | 80.0% | 82.4% | 77.2% | 75.6% | 76.4% | 77.0% | 78.6% | 78.8% | 76.4% | 76.8% |
| Transmission Line Charge IMO | 92.6% | 93.5% | 92.1% | 94.7% | 88.6% | 88.9% | 88.4% | 91.5% | 92.0% | 93.4% | 89.4% | 89.2% |
| Transmission Network Charge HONI | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| Transmission Transformation Charge HONI | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| Transmission Line Charge HONI | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% |

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Network Charge IMO | 1,168,853 | 1,121,670 | 1,033,670 | 925,900 | 1,115,107 | 1,165,070 | 1,258,029 | 1,233,213 | 1,037,521 | 899,538 | 1,017,083 | 1,076,022 | 13,051,675 |
| Transmission Transformation Charge IMO | 994,035 | 967,289 | 882,112 | 781,483 | 934,597 | 990,305 | 1,050,524 | 1,004,638 | 859,029 | 758,083 | 832,056 | 916,626 | 10,970,778 |
| Transmission Line Charge IMO | 1,136,940 | 1,098,119 | 1,016,059 | 897,807 | 1,073,462 | 1,163,938 | 1,215,967 | 1,193,539 | 1,005,264 | 898,249 | 973,896 | 1,064,975 | 12,738,213 |
| Transmission Network Charge HONI | 106,854 | 102,155 | 95,977 | 82,490 | 105,375 | 113,989 | 119,645 | 113,554 | 95,107 | 83,708 | 94,759 | 103,896 | 1,217,510 |
| Transmission Transformation Charge HONI | 73,431 | 70,202 | 65,957 | 56,688 | 72,415 | 78,335 | 82,222 | 78,036 | 65,359 | 57,525 | 65,119 | 71,398 | 836,686 |
| Transmission Line Charge HONI | 33,423 | 31,953 | 30,021 | 25,802 | 32,960 | 35,655 | 37,424 | 35,518 | 29,748 | 26,183 | 29,640 | 32,497 | 380,823 |

**RATES**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 | $0.0217 |
| Transmission Network Charge IMO | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 |
| Transmission Transformation Charge IMO | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 |
| Transmission Line Charge IMO | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 |
| Transmission Network Charge HONI | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 |
| Transmission Transformation Charge HONI | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 |
| Transmission Line Charge HONI | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 |
| Wholesale Market Charge | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 |
| Smart Metering Entity Charge | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 |

**Cost of Power**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge without rebates | $15,994,444.10 | $14,407,663.24 | $14,334,203.78 | $12,590,438.38 | $12,661,267.30 | $13,664,763.96 | $14,920,683.76 | $14,230,460.50 | $12,622,048.34 | $13,040,478.12 | $13,564,912.14 | $14,899,117.68 | $166,930,481 |
| rebates | $23,018,572.73 | $21,064,698.07 | $20,831,326.11 | $17,261,951.96 | $16,623,165.19 | $18,232,833.01 | $20,954,145.58 | $20,338,536.32 | $17,132,259.69 | $17,425,585.63 | $19,017,893.13 | $21,321,638.16 | $233,222,606 |
| Commodity Charge with rebates | $39,013,016.83 | $35,472,361.31 | $35,165,529.89 | $29,852,390.34 | $29,284,432.49 | $31,897,596.97 | $35,874,829.34 | $34,568,996.82 | $29,754,308.03 | $30,466,063.75 | $32,582,805.27 | $36,220,755.84 | $400,153,087 |
| Transmission Network Charge IMO | $4,465,019.91 | $4,284,777.66 | $3,948,618.47 | $3,536,936.19 | $4,259,707.75 | $4,450,566.75 | $4,805,669.75 | $4,710,874.30 | $3,963,331.57 | $3,436,236.01 | $3,885,257.94 | $4,110,402.39 | $49,857,399 |
| Transmission Transformation Charge IMO | $1,968,189.92 | $1,915,232.37 | $1,746,581.29 | $1,547,336.89 | $1,850,501.49 | $1,960,803.72 | $2,080,038.27 | $1,989,183.00 | $1,700,877.83 | $1,501,004.26 | $1,647,470.98 | $1,814,919.74 | $21,722,140 |
| Transmission Line Charge IMO | $932,290.62 | $900,457.19 | $833,168.21 | $736,201.46 | $880,238.45 | $954,429.04 | $997,092.91 | $978,701.58 | $824,316.62 | $736,564.12 | $798,594.68 | $873,279.70 | $10,445,335 |
| Transmission Network Charge HONI | $345,138.54 | $329,961.44 | $310,006.36 | $266,442.46 | $340,360.57 | $368,185.26 | $386,453.99 | $366,779.97 | $307,195.79 | $270,377.26 | $306,071.56 | $335,582.59 | $3,932,556 |
| Transmission Transformation Charge HONI | $118,958.72 | $113,727.64 | $106,849.73 | $91,834.59 | $117,311.90 | $126,902.22 | $133,198.90 | $126,417.86 | $105,881.01 | $93,190.79 | $105,493.53 | $115,665.08 | $1,355,432 |
| Transmission Line Charge HONI | $21,724.77 | $20,769.45 | $19,513.37 | $16,771.24 | $21,424.02 | $23,175.45 | $24,325.38 | $23,086.99 | $19,336.46 | $17,018.92 | $19,265.70 | $21,123.27 | $247,535 |
| Wholesale Market Charge | $4,355,432.80 | $3,923,337.92 | $3,903,334.24 | $3,428,491.04 | $3,447,778.40 | $3,721,039.68 | $4,063,038.08 | $3,875,084.00 | $3,437,098.72 | $3,551,040.96 | $3,693,849.12 | $4,057,165.44 | $45,456,690 |
| LV Charges | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $455,000 |
| Total | $51,257,689 | $46,998,542 | $46,071,518 | $39,514,321 | $40,239,672 | $43,540,616 | $48,402,563 | $46,677,041 | $40,150,263 | $40,109,413 | $43,076,725 | $47,586,811 | $533,625,173 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Switchgear Credit | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$3,067,809 |

**Cost of Power Summary**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity | $39,013,017 | $35,472,361 | $35,165,530 | $29,852,390 | $29,284,432 | $31,897,597 | $35,874,829 | $34,568,997 | $29,754,308 | $30,466,064 | $32,582,805 | $36,220,756 | $400,153,086.88 |
| Transmission Network | $4,810,158 | $4,614,739 | $4,258,625 | $3,803,379 | $4,600,068 | $4,818,752 | $5,192,124 | $5,077,654 | $4,270,527 | $3,706,613 | $4,191,329 | $4,445,985 | $53,789,954.48 |
| Transmission Connection | $2,785,513 | $2,694,536 | $2,450,462 | $2,136,493 | $2,613,825 | $2,809,660 | $2,979,005 | $2,861,739 | $2,394,761 | $2,092,127 | $2,315,174 | $2,569,337 | $30,702,632.34 |
| Wholesale Market | $4,355,433 | $3,923,338 | $3,903,334 | $3,428,491 | $3,447,778 | $3,721,040 | $4,063,038 | $3,875,084 | $3,437,099 | $3,551,041 | $3,693,849 | $4,057,165 | $45,456,690.40 |
| Smart Metering Entity Charge | $252,532 | $252,661 | $252,729 | $252,820 | $252,992 | $253,336 | $253,622 | $253,907 | $254,080 | $254,635 | $254,946 | $255,206 | $3,043,465.61 |
| LV Charges | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $455,000.00 |
| Total | $51,254,570 | $46,995,552 | $46,068,596 | $39,511,490 | $40,237,013 | $43,538,301 | $48,400,534 | $46,675,297 | $40,148,692 | $40,108,397 | $43,076,020 | $47,586,366 | $533,600,830 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Global Adjustment Total** | **$33,868,311** | **$30,170,852** | **$30,146,856** | **$27,542,105** | **$28,450,248** | **$30,405,383** | **$32,128,129** | **$30,279,375** | **$27,787,553** | **$28,990,526** | **$29,241,757** | **$31,673,562** | **$360,684,657** |
| Global Adjustment Class B Revenue 84% | $28,449,381 | $25,343,515 | $25,323,359 | $23,135,368 | $23,898,208 | $25,540,522 | $26,987,629 | $25,434,675 | $23,341,545 | $24,352,042 | $24,563,076 | $26,605,792 | $302,975,112 |
| Global Adjustment Class A Revenue 16% | $5,418,930 | $4,827,336 | $4,823,497 | $4,406,737 | $4,552,040 | $4,864,861 | $5,140,501 | $4,844,700 | $4,446,009 | $4,638,484 | $4,678,681 | $5,067,770 | $57,709,545 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **TOTAL COST of POWER EXPENSE** | $85,122,881 | $77,166,404 | $76,215,452 | $67,053,595 | $68,687,261 | $73,943,684 | $80,528,663 | $76,954,673 | $67,936,246 | $69,098,923 | $72,317,777 | $79,259,928 | $894,285,487 |

# 2017 Cost of Power

**PURCHASED POWER**

**Power Purchases (kWh)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Load Forecast kWh | 730,307,000 | 644,477,000 | 654,573,000 | 574,918,000 | 578,714,000 | 624,924,000 | 682,971,000 | 651,301,000 | 577,086,000 | 596,082,000 | 619,631,000 | 680,509,000 | 7,615,493,000 |

**Power Purchased (kW)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Purchases - coincident peak (kW) | 1,221,000 | 1,182,000 | 1,096,000 | 943,000 | 1,203,000 | 1,302,000 | 1,367,000 | 1,298,000 | 1,087,000 | 958,000 | 1,083,000 | 1,187,000 | 13,927,000 |

**DEMAND CHARGES**

**kW Breakdown by Type**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coincident System Peak | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Transmission Network Charge IMO | 95.2% | 95.5% | 93.7% | 97.7% | 92.1% | 88.9% | 91.5% | 94.5% | 94.9% | 93.5% | 93.4% | 90.1% |
| Transmission Transformation Charge IMO | 80.9% | 82.4% | 80.0% | 82.4% | 77.2% | 75.6% | 76.4% | 77.0% | 78.6% | 78.8% | 76.4% | 76.8% |
| Transmission Line Charge IMO | 92.6% | 93.5% | 92.1% | 94.7% | 88.6% | 88.9% | 88.4% | 91.5% | 92.0% | 93.4% | 89.4% | 89.2% |
| Transmission Network Charge HONI | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| Transmission Transformation Charge HONI | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| Transmission Line Charge HONI | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% |

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Network Charge IMO | 1,162,191 | 1,129,313 | 1,027,110 | 921,016 | 1,107,740 | 1,157,955 | 1,250,709 | 1,226,598 | 1,031,826 | 895,798 | 1,011,479 | 1,069,713 | 12,991,449 |
| Transmission Transformation Charge IMO | 988,369 | 973,880 | 876,514 | 777,362 | 928,423 | 984,257 | 1,044,412 | 999,249 | 854,314 | 754,931 | 827,472 | 911,252 | 10,920,434 |
| Transmission Line Charge IMO | 1,130,459 | 1,105,601 | 1,009,611 | 893,071 | 1,066,370 | 1,156,830 | 1,208,892 | 1,187,136 | 999,746 | 894,514 | 968,530 | 1,058,732 | 12,679,492 |
| Transmission Network Charge HONI | 106,245 | 102,851 | 95,368 | 82,055 | 104,679 | 113,293 | 118,949 | 112,945 | 94,585 | 83,360 | 94,237 | 103,286 | 1,211,854 |
| Transmission Transformation Charge HONI | 73,013 | 70,681 | 65,538 | 56,389 | 71,936 | 77,856 | 81,743 | 77,617 | 65,000 | 57,286 | 64,761 | 70,980 | 832,800 |
| Transmission Line Charge HONI | 33,232 | 32,171 | 29,830 | 25,666 | 32,742 | 35,437 | 37,206 | 35,328 | 29,585 | 26,074 | 29,476 | 32,307 | 379,054 |

**RATES**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 | $0.0227 |
| Transmission Network Charge IMO | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 |
| Transmission Transformation Charge IMO | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 |
| Transmission Line Charge IMO | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 |
| Transmission Network Charge HONI | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 |
| Transmission Transformation Charge HONI | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 |
| Transmission Line Charge HONI | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 |
| Wholesale Market Charge | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 |
| Smart Metering Entity Charge | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 |

**Cost of Power**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge without rebates | $16,541,453.55 | $14,597,404.05 | $14,826,078.45 | $13,021,892.70 | $13,107,872.10 | $14,154,528.60 | $15,469,293.15 | $14,751,967.65 | $13,070,997.90 | $13,501,257.30 | $14,034,642.15 | $15,413,528.85 | $172,490,916 |
| rebates | $23,033,720.99 | $20,893,673.55 | $20,865,449.07 | $17,289,899.61 | $16,660,741.74 | $18,309,996.46 | $21,087,275.05 | $20,465,452.46 | $17,198,879.81 | $17,466,565.30 | $19,051,213.03 | $21,344,320.96 | $233,667,188 |
| Commodity Charge with rebates | $39,575,174.54 | $35,491,077.60 | $35,691,527.52 | $30,311,792.31 | $29,768,613.84 | $32,464,525.06 | $36,556,568.20 | $35,217,420.11 | $30,269,877.71 | $30,967,822.60 | $33,085,855.18 | $36,757,849.81 | $406,158,104 |
| Transmission Network Charge IMO | $4,439,567.84 | $4,313,975.46 | $3,923,559.24 | $3,518,281.47 | $4,231,567.65 | $4,423,387.72 | $4,777,709.49 | $4,685,605.24 | $3,941,574.95 | $3,421,948.12 | $3,863,851.56 | $4,086,304.55 | $49,627,333 |
| Transmission Transformation Charge IMO | $1,956,970.60 | $1,928,283.36 | $1,735,496.91 | $1,539,175.83 | $1,838,276.87 | $1,948,829.34 | $2,067,936.23 | $1,978,513.06 | $1,691,540.89 | $1,494,763.08 | $1,638,394.00 | $1,804,279.51 | $21,622,460 |
| Transmission Line Charge IMO | $926,976.26 | $906,593.18 | $827,880.65 | $732,318.54 | $874,423.50 | $948,600.46 | $991,291.65 | $973,451.84 | $819,791.55 | $733,501.48 | $794,194.71 | $868,159.97 | $10,397,184 |
| Transmission Network Charge HONI | $343,171.14 | $332,209.90 | $308,038.96 | $265,037.17 | $338,112.11 | $365,936.80 | $384,205.53 | $364,812.57 | $305,509.44 | $269,253.03 | $304,385.21 | $333,615.19 | $3,914,287 |
| Transmission Transformation Charge HONI | $118,280.62 | $114,502.62 | $106,171.63 | $91,350.23 | $116,536.93 | $126,127.25 | $132,423.92 | $125,739.76 | $105,299.78 | $92,803.30 | $104,912.30 | $114,986.98 | $1,349,135 |
| Transmission Line Charge HONI | $21,600.93 | $20,910.98 | $19,389.54 | $16,682.79 | $21,282.49 | $23,033.92 | $24,183.85 | $22,963.16 | $19,230.32 | $16,948.15 | $19,159.55 | $20,999.43 | $246,385 |
| Wholesale Market Charge | $4,323,417.44 | $3,815,303.84 | $3,875,072.16 | $3,403,514.56 | $3,425,986.88 | $3,699,550.08 | $4,043,188.32 | $3,855,701.92 | $3,416,349.12 | $3,528,805.44 | $3,668,215.52 | $4,028,613.28 | $45,083,719 |
| LV Charges | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $455,000 |
| Total | $51,743,076 | $46,960,774 | $46,525,053 | $39,916,070 | $40,652,717 | $44,037,907 | $49,015,424 | $47,262,124 | $40,607,090 | $40,563,762 | $43,516,885 | $48,052,725 | $538,853,607 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Switchgear Credit | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$3,067,809 |

**Cost of Power Summary**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity | $39,575,175 | $35,491,078 | $35,691,528 | $30,311,792 | $29,768,614 | $32,464,525 | $36,556,568 | $35,217,420 | $30,269,878 | $30,967,823 | $33,085,855 | $36,757,850 | $406,158,104.49 |
| Transmission Network | $4,782,739 | $4,646,185 | $4,231,598 | $3,783,319 | $4,569,680 | $4,789,325 | $5,161,915 | $5,050,418 | $4,247,084 | $3,691,201 | $4,168,237 | $4,419,920 | $53,541,620.35 |
| Transmission Connection | $2,768,178 | $2,714,639 | $2,433,288 | $2,123,877 | $2,594,869 | $2,790,940 | $2,960,185 | $2,845,017 | $2,380,212 | $2,082,365 | $2,301,010 | $2,552,775 | $30,547,354.88 |
| Wholesale Market | $4,323,417 | $3,815,304 | $3,875,072 | $3,403,515 | $3,425,987 | $3,699,550 | $4,043,188 | $3,855,702 | $3,416,349 | $3,528,805 | $3,668,216 | $4,028,613 | $45,083,718.56 |
| Smart Metering Entity Charge | $255,675 | $255,819 | $255,909 | $256,020 | $256,200 | $256,531 | $256,812 | $257,091 | $257,273 | $257,789 | $258,090 | $258,351 | $3,081,559.10 |
| LV Charges | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $455,000.00 |
| Total | $51,743,101 | $46,960,942 | $46,525,311 | $39,916,438 | $40,653,266 | $44,038,788 | $49,016,585 | $47,263,565 | $40,608,713 | $40,565,900 | $43,519,324 | $48,055,425 | $538,867,357 |
| **Global Adjustment Total** | **$35,092,896** | **$30,370,680** | **$31,222,387** | **$28,518,855** | **$29,490,717** | **$31,508,688** | **$33,298,734** | **$31,378,540** | **$28,790,619** | **$30,053,303** | **$30,295,327** | **$32,826,323** | **$372,847,069** |
| Global Adjustment Class B Revenue 84% | $29,478,033 | $25,511,371 | $26,226,805 | $23,955,838 | $24,772,202 | $26,467,298 | $27,970,936 | $26,357,974 | $24,184,120 | $25,244,774 | $25,448,075 | $27,574,111 | $313,191,538 |
| Global Adjustment Class A Revenue 16% | $5,614,863 | $4,859,309 | $4,995,582 | $4,563,017 | $4,718,515 | $5,041,390 | $5,327,797 | $5,020,566 | $4,606,499 | $4,808,528 | $4,847,252 | $5,252,212 | $59,655,531 |
| **TOTAL COST of POWER EXPENSE** | $86,835,997 | $77,331,621 | $77,747,698 | $68,435,294 | $70,143,983 | $75,547,476 | $82,315,319 | $78,642,105 | $69,399,332 | $70,619,202 | $73,814,651 | $80,881,748 | $911,714,427 |

# 2018 Cost of Power

**PURCHASED POWER**

**Power Purchases (kWh)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Load Forecast kWh | 727,896,000 | 641,836,000 | 652,705,000 | 573,279,000 | 577,609,000 | 624,138,000 | 682,805,000 | 651,102,000 | 576,400,000 | 595,407,000 | 618,700,000 | 679,544,000 | 7,601,421,000 |

**Power Purchased (kW)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Purchases - coincident peak (kW) | 1,218,000 | 1,179,000 | 1,095,000 | 942,000 | 1,199,000 | 1,300,000 | 1,367,000 | 1,298,000 | 1,086,000 | 958,000 | 1,082,000 | 1,187,000 | 13,911,000 |

**DEMAND CHARGES**

**kW Breakdown by Type**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coincident System Peak | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Transmission Network Charge IMO | 95.2% | 95.5% | 93.7% | 97.7% | 92.1% | 88.9% | 91.5% | 94.5% | 94.9% | 93.5% | 93.4% | 90.1% |
| Transmission Transformation Charge IMO | 80.9% | 82.4% | 80.0% | 82.4% | 77.2% | 75.6% | 76.4% | 77.0% | 78.6% | 78.8% | 76.4% | 76.8% |
| Transmission Line Charge IMO | 92.6% | 93.5% | 92.1% | 94.7% | 88.6% | 88.9% | 88.4% | 91.5% | 92.0% | 93.4% | 89.4% | 89.2% |
| Transmission Network Charge HONI | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| Transmission Transformation Charge HONI | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| Transmission Line Charge HONI | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% |

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Network Charge IMO | 1,159,335 | 1,126,447 | 1,026,173 | 920,039 | 1,104,057 | 1,156,176 | 1,250,709 | 1,226,598 | 1,030,877 | 895,798 | 1,010,546 | 1,069,713 | 12,976,468 |
| Transmission Transformation Charge IMO | 985,941 | 971,409 | 875,714 | 776,537 | 925,336 | 982,745 | 1,044,412 | 999,249 | 853,528 | 754,931 | 826,708 | 911,252 | 10,907,761 |
| Transmission Line Charge IMO | 1,127,681 | 1,102,795 | 1,008,689 | 892,124 | 1,062,824 | 1,155,053 | 1,208,892 | 1,187,136 | 998,826 | 894,514 | 967,636 | 1,058,732 | 12,664,904 |
| Transmission Network Charge HONI | 105,984 | 102,590 | 95,281 | 81,968 | 104,331 | 113,119 | 118,949 | 112,945 | 94,498 | 83,360 | 94,150 | 103,286 | 1,210,461 |
| Transmission Transformation Charge HONI | 72,833 | 70,501 | 65,478 | 56,329 | 71,697 | 77,737 | 81,743 | 77,617 | 64,940 | 57,286 | 64,701 | 70,980 | 831,843 |
| Transmission Line Charge HONI | 33,151 | 32,089 | 29,803 | 25,639 | 32,633 | 35,382 | 37,206 | 35,328 | 29,558 | 26,074 | 29,449 | 32,307 | 378,619 |

**RATES**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 | $0.0238 |
| Transmission Network Charge IMO | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 |
| Transmission Transformation Charge IMO | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 |
| Transmission Line Charge IMO | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 |
| Transmission Network Charge HONI | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 |
| Transmission Transformation Charge HONI | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 |
| Transmission Line Charge HONI | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 |
| Wholesale Market Charge | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 |
| Smart Metering Entity Charge | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.788 | $0.000 | $0.000 |

**Cost of Power**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge without rebates | $17,309,366.88 | $15,262,860.08 | $15,521,324.90 | $13,632,574.62 | $13,735,542.02 | $14,842,001.64 | $16,237,102.90 | $15,483,205.56 | $13,706,792.00 | $14,158,778.46 | $14,712,686.00 | $16,159,556.32 | $180,761,791 |
| rebates | $24,059,600.53 | $21,827,274.38 | $21,809,013.69 | $18,074,934.76 | $17,429,870.00 | $19,194,854.65 | $22,140,081.68 | $21,476,388.03 | $18,014,101.26 | $18,278,490.49 | $19,933,298.75 | $22,326,260.01 | $244,564,168 |
| Commodity Charge with rebates | $41,368,967.41 | $37,090,134.46 | $37,330,338.59 | $31,707,509.38 | $31,165,412.02 | $34,036,856.29 | $38,377,184.58 | $36,959,593.59 | $31,720,893.26 | $32,437,268.95 | $34,645,984.75 | $38,485,816.33 | $425,325,960 |
| Transmission Network Charge IMO | $4,428,659.81 | $4,303,026.29 | $3,919,979.35 | $3,514,550.52 | $4,217,497.60 | $4,416,592.96 | $4,777,709.49 | $4,685,605.24 | $3,937,948.84 | $3,421,948.12 | $3,860,283.83 | $4,086,304.55 | $49,570,107 |
| Transmission Transformation Charge IMO | $1,952,162.31 | $1,923,389.24 | $1,733,913.43 | $1,537,543.62 | $1,832,164.56 | $1,945,835.75 | $2,067,936.23 | $1,978,513.06 | $1,689,984.74 | $1,494,763.08 | $1,636,881.17 | $1,804,279.51 | $21,597,367 |
| Transmission Line Charge IMO | $924,698.68 | $904,292.18 | $827,125.28 | $731,541.96 | $871,516.02 | $947,143.32 | $991,291.65 | $973,451.84 | $819,037.38 | $733,501.48 | $793,461.38 | $868,159.97 | $10,385,221 |
| Transmission Network Charge HONI | $342,327.97 | $331,366.73 | $307,757.90 | $264,756.11 | $336,987.88 | $365,374.68 | $384,205.53 | $364,812.57 | $305,228.39 | $269,253.03 | $304,104.16 | $333,615.19 | $3,909,790 |
| Transmission Transformation Charge HONI | $117,990.01 | $114,212.00 | $106,074.76 | $91,253.35 | $116,149.44 | $125,933.50 | $132,423.92 | $125,739.76 | $105,202.91 | $92,803.30 | $104,815.42 | $114,986.98 | $1,347,585 |
| Transmission Line Charge HONI | $21,547.86 | $20,857.90 | $19,371.85 | $16,665.09 | $21,211.73 | $22,998.54 | $24,183.85 | $22,963.16 | $19,212.62 | $16,948.15 | $19,141.86 | $20,999.43 | $246,102 |
| Wholesale Market Charge | $4,309,144.32 | $3,799,669.12 | $3,864,013.60 | $3,393,811.68 | $3,419,445.28 | $3,694,896.96 | $4,042,205.60 | $3,854,523.84 | $3,412,288.00 | $3,524,809.44 | $3,662,704.00 | $4,022,900.48 | $45,000,412 |
| LV Charges | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $455,000 |
| Total | $53,503,415 | $48,524,865 | $48,146,491 | $41,295,548 | $42,018,301 | $45,593,549 | $50,835,058 | $49,003,120 | $42,047,713 | $42,029,212 | $45,065,293 | $49,774,979 | $557,837,544 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Switchgear Credit | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$3,067,809 |

**Cost of Power Summary**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity | $41,368,967 | $37,090,134 | $37,330,339 | $31,707,509 | $31,165,412 | $34,036,856 | $38,377,185 | $36,959,594 | $31,720,893 | $32,437,269 | $34,645,985 | $38,485,816 | $425,325,959.61 |
| Transmission Network | $4,770,988 | $4,634,393 | $4,227,737 | $3,779,307 | $4,554,485 | $4,781,968 | $5,161,915 | $5,050,418 | $4,243,177 | $3,691,201 | $4,164,388 | $4,419,920 | $53,479,896.75 |
| Transmission Connection | $2,760,748 | $2,707,101 | $2,430,835 | $2,121,353 | $2,585,391 | $2,786,260 | $2,960,185 | $2,845,017 | $2,377,787 | $2,082,365 | $2,298,649 | $2,552,775 | $30,508,466.23 |
| Wholesale Market | $4,309,144 | $3,799,669 | $3,864,014 | $3,393,812 | $3,419,445 | $3,694,897 | $4,042,206 | $3,854,524 | $3,412,288 | $3,524,809 | $3,662,704 | $4,022,900 | $45,000,412.32 |
| Smart Metering Entity Charge | $258,791 | $258,949 | $259,060 | $259,190 | $259,378 | $259,700 | $259,977 | $260,254 | $260,445 | $260,927 | $0 | $0 | $2,596,668.82 |
| LV Charges | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $455,000.00 |
| Total | $53,506,555 | $48,528,162 | $48,149,900 | $41,299,087 | $42,022,029 | $45,597,598 | $50,839,384 | $49,007,723 | $42,052,507 | $42,034,488 | $44,809,642 | $49,519,328 | $557,366,404 |
| **Global Adjustment Total** | **$36,683,359** | **$31,698,279** | **$32,646,802** | **$29,820,231** | **$30,872,456** | **$32,976,732** | **$34,867,253** | **$32,862,308** | **$30,150,150** | **$31,494,247** | **$31,729,684** | **$34,390,868** | **$390,192,370** |
| Global Adjustment Class B Revenue 84% | $30,814,022 | $26,626,554 | $27,423,313 | $25,048,994 | $25,932,863 | $27,700,455 | $29,288,492 | $27,604,339 | $25,326,126 | $26,455,168 | $26,652,935 | $28,888,329 | $327,761,591 |
| Global Adjustment Class A Revenue 16% | $5,869,337 | $5,071,725 | $5,223,488 | $4,771,237 | $4,939,593 | $5,276,277 | $5,578,760 | $5,257,969 | $4,824,024 | $5,039,080 | $5,076,750 | $5,502,539 | $62,430,779 |
| **TOTAL COST of POWER EXPENSE** | $90,189,915 | $80,226,441 | $80,796,702 | $71,119,318 | $72,894,484 | $78,574,329 | $85,706,636 | $81,870,031 | $72,202,657 | $73,528,735 | $76,539,327 | $83,910,197 | $947,558,773 |

# 2019 Cost of Power

**PURCHASED POWER**

**Power Purchases (kWh)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Load Forecast kWh | 727,774,000 | 641,153,000 | 652,535,000 | 572,937,000 | 577,531,000 | 624,283,000 | 683,487,000 | 651,533,000 | 576,105,000 | 595,051,000 | 618,075,000 | 679,007,000 | 7,599,471,000 |

**Power Purchased (kW)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Purchases - coincident peak (kW) | 1,219,000 | 1,179,000 | 1,095,000 | 943,000 | 1,198,000 | 1,300,000 | 1,368,000 | 1,298,000 | 1,086,000 | 959,000 | 1,082,000 | 1,186,000 | 13,913,000 |

**DEMAND CHARGES**

**kW Breakdown by Type**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coincident System Peak | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Transmission Network Charge IMO | 95.2% | 95.5% | 93.7% | 97.7% | 92.1% | 88.9% | 91.5% | 94.5% | 94.9% | 93.5% | 93.4% | 90.1% |
| Transmission Transformation Charge IMO | 80.9% | 82.4% | 80.0% | 82.4% | 77.2% | 75.6% | 76.4% | 77.0% | 78.6% | 78.8% | 76.4% | 76.8% |
| Transmission Line Charge IMO | 92.6% | 93.5% | 92.1% | 94.7% | 88.6% | 88.9% | 88.4% | 91.5% | 92.0% | 93.4% | 89.4% | 89.2% |
| Transmission Network Charge HONI | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| Transmission Transformation Charge HONI | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| Transmission Line Charge HONI | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% |

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Network Charge IMO | 1,160,287 | 1,126,447 | 1,026,173 | 921,016 | 1,103,136 | 1,156,176 | 1,251,624 | 1,226,598 | 1,030,877 | 896,733 | 1,010,546 | 1,068,812 | 12,978,424 |
| Transmission Transformation Charge IMO | 986,750 | 971,409 | 875,714 | 777,362 | 924,564 | 982,745 | 1,045,176 | 999,249 | 853,528 | 755,719 | 826,708 | 910,485 | 10,909,407 |
| Transmission Line Charge IMO | 1,128,607 | 1,102,795 | 1,008,689 | 893,071 | 1,061,938 | 1,155,053 | 1,209,777 | 1,187,136 | 998,826 | 895,448 | 967,636 | 1,057,840 | 12,666,816 |
| Transmission Network Charge HONI | 106,071 | 102,590 | 95,281 | 82,055 | 104,244 | 113,119 | 119,036 | 112,945 | 94,498 | 83,447 | 94,150 | 103,199 | 1,210,635 |
| Transmission Transformation Charge HONI | 72,893 | 70,501 | 65,478 | 56,389 | 71,637 | 77,737 | 81,803 | 77,617 | 64,940 | 57,346 | 64,701 | 70,920 | 831,962 |
| Transmission Line Charge HONI | 33,178 | 32,089 | 29,803 | 25,666 | 32,606 | 35,382 | 37,233 | 35,328 | 29,558 | 26,101 | 29,449 | 32,280 | 378,673 |

**RATES**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 | $0.0231 |
| Transmission Network Charge IMO | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 |
| Transmission Transformation Charge IMO | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 |
| Transmission Line Charge IMO | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 |
| Transmission Network Charge HONI | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 |
| Transmission Transformation Charge HONI | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 |
| Transmission Line Charge HONI | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 |
| Wholesale Market Charge | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 |
| Smart Metering Entity Charge | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 |

**Cost of Power**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge without rebates | $16,811,579.40 | $14,810,634.30 | $15,073,558.50 | $13,234,844.70 | $13,340,966.10 | $14,420,937.30 | $15,788,549.70 | $15,050,412.30 | $13,308,025.50 | $13,745,678.10 | $14,277,532.50 | $15,685,061.70 | $175,547,780 |
| rebates | $24,104,250.27 | $21,866,175.13 | $21,848,920.98 | $18,104,350.05 | $17,460,710.40 | $19,261,766.34 | $22,245,669.07 | $21,563,331.59 | $18,050,007.68 | $18,299,125.66 | $19,954,802.46 | $22,351,004.35 | $245,110,114 |
| Commodity Charge with rebates | $40,915,829.67 | $36,676,809.43 | $36,922,479.48 | $31,339,194.75 | $30,801,676.50 | $33,682,703.64 | $38,034,218.77 | $36,613,743.89 | $31,358,033.18 | $32,044,803.76 | $34,232,334.96 | $38,036,066.05 | $420,657,894 |
| Transmission Network Charge IMO | $4,432,295.82 | $4,303,026.29 | $3,919,979.35 | $3,518,281.47 | $4,213,980.08 | $4,416,592.96 | $4,781,204.52 | $4,685,605.24 | $3,937,948.84 | $3,425,520.09 | $3,860,283.83 | $4,082,862.00 | $49,577,581 |
| Transmission Transformation Charge IMO | $1,953,765.07 | $1,923,389.24 | $1,733,913.43 | $1,539,175.83 | $1,830,636.48 | $1,945,835.75 | $2,069,448.98 | $1,978,513.06 | $1,689,984.74 | $1,496,323.37 | $1,636,881.17 | $1,802,759.48 | $21,600,627 |
| Transmission Line Charge IMO | $925,457.87 | $904,292.18 | $827,125.28 | $732,318.54 | $870,789.15 | $947,143.32 | $992,016.80 | $973,451.84 | $819,037.38 | $734,267.14 | $793,461.38 | $867,428.58 | $10,386,789 |
| Transmission Network Charge HONI | $342,609.03 | $331,366.73 | $307,757.90 | $265,037.17 | $336,706.82 | $365,374.68 | $384,486.59 | $364,812.57 | $305,228.39 | $269,534.09 | $304,104.16 | $333,334.13 | $3,910,352 |
| Transmission Transformation Charge HONI | $118,086.88 | $114,212.00 | $106,074.76 | $91,350.23 | $116,052.57 | $125,933.50 | $132,520.79 | $125,739.76 | $105,202.91 | $92,900.18 | $104,815.42 | $114,890.10 | $1,347,779 |
| Transmission Line Charge HONI | $21,565.55 | $20,857.90 | $19,371.85 | $16,682.79 | $21,194.04 | $22,998.54 | $24,201.54 | $22,963.16 | $19,212.62 | $16,965.84 | $19,141.86 | $20,981.74 | $246,137 |
| Wholesale Market Charge | $4,308,422.08 | $3,795,625.76 | $3,863,007.20 | $3,391,787.04 | $3,418,983.52 | $3,695,755.36 | $4,046,243.04 | $3,857,075.36 | $3,410,541.60 | $3,522,701.92 | $3,659,004.00 | $4,019,721.44 | $44,988,868 |
| LV Charges | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $455,000 |
| Total | $53,055,949 | $48,107,496 | $47,737,626 | $40,931,744 | $41,647,936 | $45,240,254 | $50,502,258 | $48,659,822 | $41,683,106 | $41,640,933 | $44,647,943 | $49,315,960 | $553,171,028 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Switchgear Credit | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$3,067,809 |

**Cost of Power Summary**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity | $40,915,830 | $36,676,809 | $36,922,479 | $31,339,195 | $30,801,676 | $33,682,704 | $38,034,219 | $36,613,744 | $31,358,033 | $32,044,804 | $34,232,335 | $38,036,066 | $420,657,894.09 |
| Transmission Network | $4,774,905 | $4,634,393 | $4,227,737 | $3,783,319 | $4,550,687 | $4,781,968 | $5,165,691 | $5,050,418 | $4,243,177 | $3,695,054 | $4,164,388 | $4,416,196 | $53,487,932.76 |
| Transmission Connection | $2,763,225 | $2,707,101 | $2,430,835 | $2,123,877 | $2,583,021 | $2,786,260 | $2,962,537 | $2,845,017 | $2,377,787 | $2,084,806 | $2,298,649 | $2,550,409 | $30,513,523.60 |
| Wholesale Market | $4,308,422 | $3,795,626 | $3,863,007 | $3,391,787 | $3,418,984 | $3,695,755 | $4,046,243 | $3,857,075 | $3,410,542 | $3,522,702 | $3,659,004 | $4,019,721 | $44,988,868.32 |
| Smart Metering Entity Charge | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.00 |
| LV Charges | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $455,000.00 |
| Total | $52,800,298 | $47,851,845 | $47,481,975 | $40,676,094 | $41,392,285 | $44,984,604 | $50,246,607 | $48,404,171 | $41,427,456 | $41,385,282 | $44,392,293 | $49,060,309 | $550,103,219 |
| | | | | | | | | | | | | | |
| **Global Adjustment Total** | **$35,609,279** | **$30,723,325** | **$31,686,041** | **$28,932,859** | **$29,974,600** | **$32,002,207** | **$33,847,093** | **$31,896,713** | **$29,250,736** | **$30,566,766** | **$30,774,258** | **$33,366,492** | **$378,630,369** |
| Global Adjustment Class B Revenue 84% | $29,911,794 | $25,807,593 | $26,616,274 | $24,303,602 | $25,178,664 | $26,881,854 | $28,431,558 | $26,793,239 | $24,570,619 | $25,676,083 | $25,850,377 | $28,027,853 | $318,049,510 |
| Global Adjustment Class A Revenue 16% | $5,697,485 | $4,915,732 | $5,069,767 | $4,629,258 | $4,795,936 | $5,120,353 | $5,415,535 | $5,103,474 | $4,680,118 | $4,890,683 | $4,923,881 | $5,338,639 | $60,580,859 |
| | | | | | | | | | | | | | |
| **TOTAL COST of POWER EXPENSE** | $88,409,577 | $78,575,170 | $79,168,016 | $69,608,953 | $71,366,885 | $76,986,811 | $84,093,700 | $80,300,884 | $70,678,192 | $71,952,048 | $75,166,551 | $82,426,802 | $928,733,588 |

# 2020 Cost of Power

**PURCHASED POWER**

**Power Purchases (kWh)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Load Forecast kWh | 726,496,000 | 652,834,000 | 651,265,000 | 571,531,000 | 576,394,000 | 623,536,000 | 683,354,000 | 651,147,000 | 574,967,000 | 593,847,000 | 616,712,000 | 677,787,000 | 7,599,870,000 |

**Power Purchased (kW)**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Purchases - coincident peak (kW) | 1,217,000 | 1,162,000 | 1,094,000 | 941,000 | 1,195,000 | 1,298,000 | 1,368,000 | 1,297,000 | 1,084,000 | 958,000 | 1,080,000 | 1,185,000 | 13,879,000 |

**DEMAND CHARGES**

**kW Breakdown by Type**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coincident System Peak | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Transmission Network Charge IMO | 95.2% | 95.5% | 93.7% | 97.7% | 92.1% | 88.9% | 91.5% | 94.5% | 94.9% | 93.5% | 93.4% | 90.1% |
| Transmission Transformation Charge IMO | 80.9% | 82.4% | 80.0% | 82.4% | 77.2% | 75.6% | 76.4% | 77.0% | 78.6% | 78.8% | 76.4% | 76.8% |
| Transmission Line Charge IMO | 92.6% | 93.5% | 92.1% | 94.7% | 88.6% | 88.9% | 88.4% | 91.5% | 92.0% | 93.4% | 89.4% | 89.2% |
| Transmission Network Charge HONI | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% | 8.7% |
| Transmission Transformation Charge HONI | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| Transmission Line Charge HONI | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% | 2.7% |

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Network Charge IMO | 1,158,383 | 1,110,204 | 1,025,235 | 919,063 | 1,100,374 | 1,154,397 | 1,251,624 | 1,225,653 | 1,028,978 | 895,798 | 1,008,678 | 1,067,911 | 12,946,299 |
| Transmission Transformation Charge IMO | 985,131 | 957,402 | 874,914 | 775,713 | 922,249 | 981,233 | 1,045,176 | 998,479 | 851,956 | 754,931 | 825,180 | 909,717 | 10,882,081 |
| Transmission Line Charge IMO | 1,126,755 | 1,086,894 | 1,007,768 | 891,177 | 1,059,279 | 1,153,276 | 1,209,777 | 1,186,222 | 996,987 | 894,514 | 965,847 | 1,056,948 | 12,635,444 |
| Transmission Network Charge HONI | 105,897 | 101,111 | 95,194 | 81,881 | 103,983 | 112,945 | 119,036 | 112,858 | 94,324 | 83,360 | 93,976 | 103,112 | 1,207,677 |
| Transmission Transformation Charge HONI | 72,774 | 69,485 | 65,418 | 56,269 | 71,458 | 77,617 | 81,803 | 77,557 | 64,820 | 57,286 | 64,581 | 70,860 | 829,929 |
| Transmission Line Charge HONI | 33,123 | 31,626 | 29,776 | 25,611 | 32,525 | 35,328 | 37,233 | 35,301 | 29,503 | 26,074 | 29,395 | 32,252 | 377,748 |

**RATES**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 | $0.0236 |
| Transmission Network Charge IMO | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 | $3.82 |
| Transmission Transformation Charge IMO | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 | $1.98 |
| Transmission Line Charge IMO | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 | $0.82 |
| Transmission Network Charge HONI | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 | $3.23 |
| Transmission Transformation Charge HONI | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 | $1.62 |
| Transmission Line Charge HONI | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 | $0.65 |
| Wholesale Market Charge | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 | $0.00592 |
| Smart Metering Entity Charge | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 | $0.000 |

**Cost of Power**

| | JAN | FEB | MAR | APR | MAY | JUN | JULY | AUG | SEPT | OCT | NOV | DEC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity Charge without rebates | $17,108,980.80 | $15,374,240.70 | $15,337,290.75 | $13,459,555.05 | $13,574,078.70 | $14,684,272.80 | $16,092,986.70 | $15,334,511.85 | $13,540,472.85 | $13,985,096.85 | $14,523,567.60 | $15,961,883.85 | $178,976,939 |
| rebates | $24,622,306.66 | $22,535,272.16 | $22,319,857.60 | $18,483,476.88 | $17,828,783.52 | $19,713,778.15 | $22,807,554.79 | $22,091,682.54 | $18,445,681.34 | $18,682,988.30 | $20,377,375.58 | $22,830,728.17 | $250,739,486 |
| Commodity Charge with rebates | $41,731,287.46 | $37,909,512.86 | $37,657,148.35 | $31,943,031.93 | $31,402,862.22 | $34,398,050.95 | $38,900,541.49 | $37,426,194.39 | $31,986,154.19 | $32,668,085.15 | $34,900,943.18 | $38,792,612.02 | $429,716,424 |
| Transmission Network Charge IMO | $4,425,023.80 | $4,240,980.95 | $3,916,399.46 | $3,510,819.58 | $4,203,427.55 | $4,409,798.20 | $4,781,204.52 | $4,681,995.38 | $3,930,696.63 | $3,421,948.12 | $3,853,148.37 | $4,079,419.46 | $49,454,862 |
| Transmission Transformation Charge IMO | $1,950,559.55 | $1,895,655.89 | $1,732,329.94 | $1,535,911.41 | $1,826,052.25 | $1,942,842.16 | $2,069,448.98 | $1,976,988.78 | $1,686,872.43 | $1,494,763.08 | $1,633,855.51 | $1,801,239.44 | $21,546,519 |
| Transmission Line Charge IMO | $923,939.49 | $891,253.19 | $826,369.92 | $730,765.37 | $868,608.54 | $945,686.18 | $992,016.80 | $972,701.87 | $817,529.02 | $733,501.48 | $791,994.72 | $866,697.19 | $10,361,064 |
| Transmission Network Charge HONI | $342,046.91 | $326,588.75 | $307,476.85 | $264,475.06 | $335,863.65 | $364,812.57 | $384,486.59 | $364,531.51 | $304,666.27 | $269,253.03 | $303,542.04 | $333,053.07 | $3,900,796 |
| Transmission Transformation Charge HONI | $117,893.13 | $112,565.18 | $105,977.89 | $91,156.48 | $115,761.95 | $125,739.76 | $132,520.79 | $125,642.89 | $105,009.17 | $92,803.30 | $104,621.68 | $114,793.23 | $1,344,485 |
| Transmission Line Charge HONI | $21,530.17 | $20,557.15 | $19,354.15 | $16,647.40 | $21,140.96 | $22,963.16 | $24,201.54 | $22,945.46 | $19,177.24 | $16,948.15 | $19,106.48 | $20,964.05 | $245,536 |
| Wholesale Market Charge | $4,300,856.32 | $3,864,777.28 | $3,855,488.80 | $3,383,463.52 | $3,412,252.48 | $3,691,333.12 | $4,045,455.68 | $3,854,790.24 | $3,403,804.64 | $3,515,574.24 | $3,650,935.04 | $4,012,499.04 | $44,991,230 |
| LV Charges | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $37,916.67 | $455,000 |
| Total | $53,851,054 | $49,299,808 | $48,458,462 | $41,514,187 | $42,223,886 | $45,939,143 | $51,367,793 | $49,463,707 | $42,291,826 | $42,250,793 | $45,296,064 | $50,059,194 | $562,015,918 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Switchgear Credit | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$255,650.75 | -$3,067,809 |

**Cost of Power Summary**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity | $41,731,287 | $37,909,513 | $37,657,148 | $31,943,032 | $31,402,862 | $34,398,051 | $38,900,541 | $37,426,194 | $31,986,154 | $32,668,085 | $34,900,943 | $38,792,612 | $429,716,424.18 |
| Transmission Network | $4,767,071 | $4,567,570 | $4,223,876 | $3,775,295 | $4,539,291 | $4,774,611 | $5,165,691 | $5,046,527 | $4,235,363 | $3,691,201 | $4,156,690 | $4,412,473 | $53,355,658.33 |
| Transmission Connection | $2,758,272 | $2,664,381 | $2,428,381 | $2,118,830 | $2,575,913 | $2,781,580 | $2,962,537 | $2,842,628 | $2,372,937 | $2,082,365 | $2,293,928 | $2,548,043 | $30,429,795.60 |
| Wholesale Market | $4,300,856 | $3,864,777 | $3,855,489 | $3,383,464 | $3,412,252 | $3,691,333 | $4,045,456 | $3,854,790 | $3,403,805 | $3,515,574 | $3,650,935 | $4,012,499 | $44,991,230.40 |
| Smart Metering Entity Charge | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0.00 |
| LV Charges | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $37,917 | $455,000.00 |
| Total | $53,595,403 | $49,044,157 | $48,202,811 | $41,258,537 | $41,968,236 | $45,683,492 | $51,112,142 | $49,208,056 | $42,036,176 | $41,995,142 | $45,040,413 | $49,803,543 | $558,948,109 |
| **Global Adjustment Total** | **$36,251,692** | **$32,157,722** | **$32,246,121** | **$29,430,623** | **$30,511,428** | **$32,569,447** | **$34,461,855** | **$32,469,831** | **$29,759,102** | **$31,113,838** | **$31,312,069** | **$33,966,665** | **$386,250,393** |
| Global Adjustment Class B Revenue 84% | $30,451,421 | $27,012,486 | $27,086,742 | $24,721,723 | $25,629,599 | $27,358,336 | $28,947,958 | $27,274,658 | $24,997,645 | $26,135,624 | $26,302,138 | $28,531,999 | $324,450,330 |
| Global Adjustment Class A Revenue 16% | $5,800,271 | $5,145,235 | $5,159,379 | $4,708,900 | $4,881,828 | $5,211,112 | $5,513,897 | $5,195,173 | $4,761,456 | $4,978,214 | $5,009,931 | $5,434,666 | $61,800,063 |
| **TOTAL COST of POWER EXPENSE** | $89,847,094 | $81,201,879 | $80,448,932 | $70,689,160 | $72,479,663 | $78,252,939 | $85,573,998 | $81,677,888 | $71,795,277 | $73,108,981 | $76,352,482 | $83,770,208 | $945,198,501 |

## PROPOSED TREATMENT FOR RECOVERY OF STRANDED METERS

As part of Hydro Ottawa Limited's ("Hydro Ottawa") 2012 rate application it proposed to include the remaining balance of its stranded meters in its 2012 rate base, amortizing the balance over the period ending December 31, 2013. As part of the settlement agreement this approach to dispose of the balance of Stranded Meters was accepted. The remaining balance to be recovered was $5,974k, $2,987k for each year 2012 and 2013.

Hydro Ottawa's forecasted amount of residual net Stranded Meters, to the end of 2011, was not materially different from the actuals recorded ($72k forecasted, $68k actual). Hydro Ottawa is not seeking to true-up the difference. Therefore, Hydro Ottawa has not completed Appendix 2-S as these amounts were already dealt with in its 2012 rate application. For financial purposes, by the end of 2011, the net stranded meters costs were recorded in Uniform System of Accounts ("USofA") 1555 sub account stranded meters.

The approach taken to include the remaining balance of stranded meters in depreciation resulted in the continuation of the stranded meter recovery in 2014 and 2015, $2,987k per year. As a result, by the end of 2015 Hydro Ottawa will recover an additional $5,974k.

Hydro Ottawa proposes to return the over collection related to Stranded Meters to rate payers. Please see section I-8-1, Disposition of deferral and variance accounts, for Hydro Ottawa's proposed treatment to return the balance sitting in USofA account 1555 sub account stranded meters.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
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# Appendix 2-S
## Stranded Meter Treatment

**Not Applicable - Please Refer to Exhibit B-4-1**

| Year | Notes | Gross Asset Value | Accumulated Amortization | Contributed Capital (Net of Amortization) | Net Asset | Proceeds on Disposition | Residual Net Book Value |
|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D ) = (A) - (B) - (C) | (E) | (F) = (D) - (E) |
| 2006 | | | | | $ - | | $ - |
| 2007 | | | | | $ - | | $ - |
| 2008 | | | | | $ - | | $ - |
| 2009 | | | | | $ - | | $ - |
| 2010 | | | | | $ - | | $ - |
| 2011 | | | | | $ - | | $ - |
| 2012 | | | | | $ - | | $ - |
| 2013 | | | | | $ - | | $ - |
| 2014 | (1) | | | | $ - | | $ - |

# CAPITAL EXPENDITURES OVERVIEW

In accordance with the OEB's Chapter 2 and Chapter 5 Filing Requirements, Hydro Ottawa Limited ("HOL") has filed a consolidated Distribution System Plan ("DSP") as Appendix B, Tab 1, Schedule 2. The Capital Expenditure plan in Section 3 of the DSP as well as the Material Investments Plan (Attachment B-1(A)) both detail the system investment decisions which are made through the asset management and capital expenditure planning process. The DSP (B-1-2) further details investments by investment categories, HOL Capital Program and Budget Program for the historic years of 2011 through 2015 and the forecast years of 2016 through 2020.

See Appendices 2-AA and 2-AB for an overview of HOL's Capital Projects and Capital Expenditures Summary. For comprehensive explanatory notes and variance analyses of HOL's capital expenditures, refer to section 3.4 of the DSP (B-1-2).

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | B |
| **Tab:** | 5 |
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| **Date:** | ORIGINAL |

# Appendix 2-AA
# Capital Projects Table

| Projects | 2011 | 2012 | 2013 | 2014 | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| **Reporting Basis** | **CGAAP** | **MIFRS** | **MIFRS** | **MIFRS** | **MIFRS** | **MIFRS** |
| **SYSTEM ACCESS** | | | | | | |
| **Plant Relocation** | 7,743 | 5,942 | 10,005 | 9,437 | 7,814 | 7,620 |
| **Residential** | 7,247 | 6,278 | 6,573 | 5,985 | 6,720 | 6,889 |
| **Commercial** | 9,159 | 11,892 | 10,634 | 9,342 | 12,279 | 13,423 |
| **System Expansion** | 3,276 | 1,675 | 5,710 | 10,144 | 3,727 | 3,479 |
| **Stations Embedded Generation** | 190 | 1,181 | 64 | 277 | 376 | 377 |
| **Infill & Upgrade (App. G)** | 3,081 | 2,731 | 3,178 | 2,857 | 3,075 | 3,160 |
| **Damage to Plant** | 826 | 798 | 1,349 | 840 | 1,120 | 1,148 |
| **Metering** | 112 | 370 | 160 | 130 | 163 | 167 |
| **Sub-Total** | 31,635 | 30,868 | 37,675 | 39,010 | 35,275 | 36,263 |
| **SYSTEM RENEWAL** | | | | | | |
| **Stations Asset** | 5,097 | 8,475 | 9,154 | 14,493 | 17,200 | 16,338 |
| **Stations Refurbishment** | 2,046 | 1,067 | 906 | 825 | 679 | 597 |
| **Distribution Asset** | 20,502 | 19,698 | 18,992 | 21,263 | 21,756 | 23,683 |
| **Metering** | 122 | 385 | 488 | 416 | 412 | 415 |
| **Sub-Total** | 27,768 | 29,625 | 29,540 | 36,997 | 40,048 | 41,033 |
| **SYSTEM SERVICE** | | | | | | |
| **Station Capacity** | 19,170 | 11,838 | 13,198 | 6,223 | 2,187 | 5,676 |
| **Distribution Enhancements** | 6,226 | 8,375 | 10,319 | 14,961 | 15,176 | 11,290 |
| **Automation** | 1,320 | 1,150 | 400 | 569 | 3,444 | 5,269 |
| **Sub-Total** | 26,716 | 21,362 | 23,917 | 21,753 | 20,806 | 22,235 |
| **GENERAL PLANT** | | | | | | |
| **Buildings - Facilities** | 767 | 380 | 380 | 426 | 688 | 688 |
| **Customer Service** | 3,818 | 10,365 | 13,389 | 5,839 | 2,450 | 3,740 |
| **ERP System** | 950 | 933 | 478 | 329 | 1,547 | 5,043 |
| **Fleet Replacement** | 2,024 | 2,542 | 3,056 | 1,441 | 1,537 | 1,455 |
| **Info Serv & Tech New Initiatives** | 296 | 578 | 57 | 1,584 | 2,111 | 2,127 |
| **IT Life Cycle & Ongoing Enhanceme** | 1,122 | 2,440 | 3,076 | 2,821 | 1,970 | 1,424 |
| **Operations Initiatives** | 356 | 683 | 242 | 3,011 | 2,756 | 1,074 |
| **Tools Replacements** | 580 | 568 | 539 | 386 | 512 | 512 |
| **Hydro One Payments** | 0 | 1,116 | 6,358 | 2,453 | 2,347 | 4,575 |
| **Facilities Implementation Plan** | 302 | 7,586 | 12,909 | 453 | 4,933 | 25,262 |
| **Sub-Total** | 10,215 | 27,190 | 40,484 | 18,742 | 20,850 | 45,899 |
| **Miscellaneous** | | | | | | |
| **Total** | **96,333** | **109,046** | **131,615** | **116,503** | **116,979** | **145,429** |
| **Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*** | | | | | | |
| **Total** | **96,333** | **109,046** | **131,615** | **116,503** | **116,979** | **145,429** |

***Notes:***

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
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## Appendix 2-AB
## Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

**First year of Forecast Period:** *2016*

| CATEGORY | **Historical Period** (previous plan[1] & actual) | | | | | | | | | | | | | | | **Forecast Period** (planned) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | | | 2012 | | | 2013 | | | 2014 | | | 2015 | | | 2016 | 2017 | 2018 | 2019 | 2020 |
| | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual[2] | Var | | | | | |
| | *$ '000 000* | | % | *$ '000 000* | | % | *$ '000 000* | | % | *$ '000 000* | | % | *$ '000 000* | | % | *$ '000 000* | | | | |
| **System Access** | 30.2 | 31.6 | 4.6% | 34.5 | 30.9 | -10.4% | 36.9 | 37.7 | 2.2% | 40.7 | 39.0 | -4.2% | 35.3 | | -100.0% | 36.3 | 35.2 | 35.1 | 35.8 | 36.6 |
| **System Renewal** | 26.7 | 27.8 | 4.1% | 27.4 | 29.6 | 8.0% | 23.4 | 29.5 | 26.1% | 32.8 | 37.0 | 12.8% | 40.0 | | -100.0% | 41.0 | 31.8 | 36.5 | 36.0 | 35.7 |
| **System Service** | 25.5 | 26.7 | 4.7% | 21.5 | 21.4 | -0.5% | 25.1 | 23.9 | -4.8% | 23.1 | 21.8 | -5.6% | 20.8 | | -100.0% | 22.2 | 34.0 | 29.5 | 30.5 | 33.3 |
| **General Plant** | 20.6 | 10.2 | -50.5% | 35.9 | 27.2 | -24.2% | 43.6 | 40.5 | -7.1% | 22.8 | 18.7 | -18.0% | 20.9 | | -100.0% | 45.9 | 48.1 | 18.3 | 18.7 | 14.0 |
| **TOTAL EXPENDITURE** | 103.0 | 96.3 | -6.5% | 119.3 | 109.1 | -8.5% | 129.0 | 131.6 | 2.0% | 119.4 | 116.5 | -2.4% | 117.0 | - | -100.0% | 145.4 | 149.1 | 119.4 | 121.0 | 119.6 |
| **System O&M** | N/A | N/A | -- | N/A | $ 24.9 | -- | N/A | $ 25.2 | -- | N/A | $ 27.1 | -- | $ 29.5 | N/A | -- | $ 30.9 | N/A | N/A | N/A | N/A |

**Notes to the Table:**

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

### Explanatory Notes on Variances (complete only if applicable)

**Notes on shifts in forecast vs. historical budgets by category**

See section 3.4 of the DSP (B-1-2)

**Notes on year over year Plan vs. Actual variances for Total Expenditures**

See section 3.4 of the DSP (B-1-2)

**Notes on Plan vs. Actual variance trends for individual expenditure categories**

See section 3.4 of the DSP (B-1-2)

# CAPITALIZATION POLICY

Hydro Ottawa Limited's Capitalization Policy can be found in Attachment B-5(A) and more details are noted in Exhibit B-5-3.

**HYDRO OTTAWA CORPORATE POLICY**

| **Subject**: Capitalization | | |
|---|---|---|
| **Category**: Finance | | **Policy Number**: POL-Fi-013.00 |
| **Administrator:** Director, Finance | **Owner:** Chief Finance Officer | **Approver:** President and CEO |

1. **PURPOSE**
   The purpose of this policy is to define the criteria used with respect to the capitalization of Hydro Ottawa assets.

2. **SCOPE**
   This policy applies to Hydro Ottawa.

3. **DEFINITIONS**
   **Capital assets** include tangible and intangible assets, exclusive of goodwill
   **Commissioned,** in the context of this policy, is when a capital asset is placed into service or when the enhancement or betterment to an existing capital asset is complete
   **Directly Attributable Costs** are costs that bring the asset to the location and condition intended for use and include direct labour, inventory, outside services, non-stock materials and specific burdens
   **Enhancement or Betterment** is an expenditure that contributes towards improving an asset's productivity or output or useful life
   **Goodwill,** as defined by IAS 38, is the difference between the purchase price of an asset and the net amount of the acquired asset and assumed liability
   **Grouped Assets** are asset purchases that are pooled into a single capital asset category as, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a single entity for the purposes of depreciation
   **Hydro Ottawa** refers to Hydro Ottawa Holding Inc. and its affiliates
   **IAS** refers to International Accounting Standards
   **IAS 16** refers to the International Accounting Standard titled Property, Plant and Equipment
   **IAS 23** refers to the International Accounting Standard titled Borrowing Costs
   **IAS 38** refers to the International Accounting Standard titled Intangible Assets
   **IASB** refers to the International Accounting Standards Board
   **IFRS** refers to International Financial Reporting Standards
   **Intangible Assets,** as defined by IAS 38, are rights or non-physical resources, which provide a benefit or advantage to a business entity
   **OM&A** refers to operating, maintenance and administrative expenses
   **PP&E** refers to Property, Plant and Equipment or Tangible Assets
   **Readily Identifiable Assets** are discrete capital assets that are easily identifiable, so the asset can be individually recorded and depreciated
   **Tangible Assets,** as defined by IAS 16, include PP&E that are used on a continuing basis in the production or supply of goods and services and are not intended for sale in the ordinary course of business

4. **POLICY DIRECTIVES**
   a) Hydro Ottawa will capitalize assets based on the standards established by the IASB under IAS 16 and IAS 38.
   b) Capitalized assets are expected to provide future economic benefits for more than one year.

c) The amount capitalized is comprised of:
   i. The amount of consideration provided to acquire, construct or develop an asset;
   ii. Directly attributable costs necessary to commission the new asset; and
   iii. Borrowing costs, in accordance with IAS 23, to finance PP&E projects with a duration greater than six months and accumulated cost is in excess of $100,000.

d) The following cost allocation rates included in directly attributable costs are based on management's best estimates of the applicable cost allocation determinants:
   i. Direct Labour – The hourly rate recovers direct labour and benefits costs. It will be applied to all direct labour hours through timesheet reporting.
   ii. Vehicle and Equipment - Vehicle and equipment hourly rates capture the directly attributable costs associated with fleet usage. Individual rates will be developed for major vehicle classifications based on expected utilization. Charges will be accomplished through vehicles timesheet reporting.
   iii. Supervision Burden – The supervision burden rate recovers the directly attributable costs associated with the supervision of internal labour and outside services.
   iv. Engineering Burden – The engineering burden rate recovers the directly attributable engineering costs. It will be applied to Distribution Capital projects where applicable.
   v. Supply Chain Burden – The supply chain burden rate recovers the directly attributable procurement and warehouse costs.
   vi. These rates are reviewed and monitored on an annual basis. Material adjustments for over or under recoveries will also be recorded at the end of the fiscal year.

e) Subsequent enhancement or betterment costs which are incurred after the original asset is commissioned will be capitalized based on the same criteria as the initial capital investment.

f) The materiality value for capitalizing newly acquired readily identifiable assets or additions to existing assets will be $500.

g) The materiality value for capitalizing grouped assets will be $1,000.

h) Capital spares such as spare switchgear, transformers and meters, once commissioned will be accounted for as capital assets, prior to commissioning, these assets will be accounted for as inventory.

i) Depreciation of capital assets is based on the straight-line method in accordance with IAS 16 and 38. The useful lives of assets are reviewed annually.

j) Costs that are incurred to maintain the existing service potential of capital assets are considered repairs and will be expensed in the period in which they occur.

k) Customer contributions associated with PP&E projects will be treated as deferred revenue and amortized to income over the life of the assets to which they relate.

l) When assets are retired from service, the capital cost and accumulated depreciation will be removed from Hydro Ottawa's financial statements with any gain or loss (after salvage proceeds, if applicable) charged to OM&A in the period in which the decommissioning occurs.

## 5. RELATED POLICIES, PROCEDURES AND REFERENCE DOCUMENTS

Hydro Ottawa Code of Business Conduct

## 6 EXCLUSIONS

None

## 7 ADDITIONAL POLICY ELEMENTS

None

## 8 COMPLIANCE

Policy non-compliance must be promptly reported to the Policy Owner and may result in disciplinary action.

## 9 APPROVAL HISTORY

| Revision | Release Date | Initial Release | Policy Owner Sign-off: | Approved by: |
|---|---|---|---|---|
| .00 | January 2015 | Supersedes Policy FIN5-001-02 published on January 1, 2008 | Chief Financial Officer | President and CEO |
| **Revision** | **Revision Date** | **Description of Changes** | **Policy Owner Sign-off:** | **Approved by:** |
| | | | Chief Financial Officer | President and CEO |

| Scheduled Re-affirmation Date | Responsibility |
|---|---|
| **January 2018** | Chief Financial Officer |

## 10. POLICY EXCEPTIONS

Exceptions to the above directives and/or changes to this policy must receive written pre-authorization from the President and Chief Executive Officer. For clarification on any aspect of this policy contact the Director, Finance.

# CAPITALIZATION OF OVERHEAD

Prior to 2012, Hydro Ottawa capitalized costs including those that were administrative in nature (facilities, human resources, information technology, finance, regulatory and other corporate costs).

Effective January 1, 2012, Hydro Ottawa revised its capitalization methodology used to apply overhead costs to property, plant and equipment and intangible assets in accordance with IFRS IAS 16 which prohibits the capitalization of administration and other general overhead costs. The majority of the administrative burden was deemed to be disallowable except for some costs pertaining to the supply chain function. The engineering and supervision allocations were also analyzed to determine which amounts could no longer be capitalized. The amount of allocated costs was significantly reduced due to the fact that many of the costs that were capitalized prior to the revision of the policy are considered administrative or other general overhead, which are specifically disallowed or which cannot be considered directly attributable to a specific asset. The policy remains the same in the forecast year.

Hydro Ottawa applies overhead costs to capital through three separate burden rates: Supervision burden, Engineering burden and Supply Chain burden. The use of multiple burden rates allows overhead costs to be applied more precisely to the particular projects that are associated with the various types of overhead costs. Refer to Attachment B-5(A) for a copy of the capitalization policy.

As shown in Appendix 2-D, the overhead costs capitalized from 2012 to 2016 are steady and in the range of 25% to 27% including labour and fleet costs.

# Appendix 2-D
## Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

| OM&A Before Capitalization | 2012 Historical Year | 2013 Historical Year | 2014 Q2 Forecast Historical Year | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| Collections, Acct & Activities | $ 2,937,418 | $ 4,070,580 | $ 3,649,114 | $ 3,543,341 | $ 4,059,282 |
| Corporate Costs | $ 6,056,030 | $ 6,575,378 | $ 5,420,096 | $ 5,015,524 | $ 4,993,415 |
| Customer & Community Relations | $ 7,716,112 | $ 7,605,947 | $ 8,220,736 | $ 8,785,231 | $ 9,084,617 |
| Customer Billing | $ 9,176,802 | $ 9,736,344 | $ 10,664,787 | $ 10,432,583 | $ 10,511,497 |
| Distribution Operations | $ 33,380,038 | $ 34,860,050 | $ 37,834,129 | $ 39,785,778 | $ 40,824,588 |
| Engineering & Design | $ 10,863,198 | $ 11,693,463 | $ 12,451,538 | $ 12,975,442 | $ 13,677,111 |
| Facilities | $ 5,518,926 | $ 5,656,285 | $ 5,794,592 | $ 6,027,819 | $ 6,108,573 |
| Finance | $ 4,074,222 | $ 3,988,437 | $ 4,368,115 | $ 4,517,544 | $ 4,759,915 |
| Human Resources & Training | $ 3,395,830 | $ 3,675,121 | $ 4,010,176 | $ 4,051,662 | $ 4,180,257 |
| Information Mgt & Technology | $ 6,343,145 | $ 6,717,794 | $ 7,521,460 | $ 7,500,528 | $ 7,862,963 |
| Metering | $ 2,712,295 | $ 2,807,318 | $ 2,846,087 | $ 2,842,465 | $ 2,956,322 |
| Regulatory Affairs | $ 1,930,844 | $ 1,967,875 | $ 2,340,940 | $ 2,505,096 | $ 2,580,684 |
| Safety, Environment & Bus Cont | $ 1,853,905 | $ 2,334,564 | $ 2,116,845 | $ 1,952,732 | $ 2,006,305 |
| Supply Chain | $ 2,233,136 | $ 1,985,925 | $ 2,491,808 | $ 2,498,434 | $ 2,744,524 |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| **Total OM&A Before Capitalization (B)** | $ 98,191,900 | $ 103,675,081 | $ 109,730,424 | $ 112,434,180 | $ 116,350,054 |

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

| Capitalized OM&A | 2012 Historical Year | 2013 Historical Year | 2014 Q2 Forecast Historical Year | 2015 Bridge Year | 2016 Test Year | Directly Attributable? (Y/N) | Explanation for Change in Overhead Capitalized |
|---|---|---|---|---|---|---|---|
| Supply Chain | $ 1,127,115 | $ 1,305,256 | $ 1,301,156 | $ 1,244,923 | $ 1,452,331 | | |
| Supervision | $ 1,831,800 | $ 2,157,288 | $ 1,826,399 | $ 2,034,276 | $ 2,077,315 | | |
| Engineering | $ 1,996,465 | $ 2,815,805 | $ 2,843,934 | $ 2,904,091 | $ 2,997,522 | | |
| Fleet | $ 2,613,093 | $ 2,593,457 | $ 2,737,548 | $ 2,627,424 | $ 2,698,352 | | |
| Labour | $ 17,547,092 | $ 19,046,118 | $ 20,253,970 | $ 19,967,657 | $ 20,018,970 | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| **Total Capitalized OM&A (A)** | $ 25,115,566 | $ 27,917,925 | $ 28,963,007 | $ 28,778,371 | $ 29,244,490 | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **% of Capitalized OM&A (=A/B)** | 26% | 27% | 26% | 26% | 25% | | |

# SERVICE QUALITY AND RELIABILITY PERFORMANCE

## 1.0 SERVICE QUALITY INDICATORS

Hydro Ottawa reports service quality indicators, which consist of service quality and service reliability metrics, to the Board on an annual basis. As shown in Appendix 2-G, Hydro Ottawa's Service Quality Requirements remain steadily above the OEB Minimum Standard for the years 2009 – 2013.

## 2.0 SERVICE RELIABILITY INDICATORS

Hydro Ottawa continuously assesses the distribution system's service reliability. Where gaps are found, the appropriate actions are identified to address these issues. Service reliability is integral to all work undertaken as part of system planning and asset management. The Reliability Plan does not supersede the importance of good Asset Management and System Capacity planning in the management of system reliability. Rather, it provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

Overall, since 2009, Hydro Ottawa's system SAIDI and SAIFI has been steadily increasing, due to the increase of storms with severe wind and rain as well as an increase in equipment failures. Moving forward, it is critical that investment levels for equipment replacement increase in order to storm harden the system and to get ahead of the curve of aging equipment.

Fundamental in Hydro Ottawa's approach to system reliability is the implementation of grid technologies. Ongoing targeted installation of automated devices is planned for the foreseeable future to improve system reliability and operation. Currently, targeted programs are the East 44kV automation, which will deploy automatic restoration to this sub-transmission loop that supplies 3% (or over 9,000) of Hydro Ottawa's customers. In addition, automation plans are being deployed in the quickly growing South Nepean/Barrhaven area, as well as targeted annual installation to address the Worst

Performing Feeders. Continued investment in the communication infrastructure will be essential to support current automation plans while maintaining the flexibility to integrate the technologies of tomorrow.

Overall, from 2009 through 2013, the three primary contributors to SAIFI and SAIDI were: Loss of Supply, Defective Equipment and Adverse Weather. These three contributors account for 60% of the overall SAIFI score and 62% of the overall SAIDI score.

### 2.1 Loss of Supply

The reliability and redundancy of system supply is continuously evaluated as part of the Capacity Planning exercise. The system operators are aware of plans for these circumstances and are able to expedite restoration and reduce the impact of the loss of any one supply. As well, the installation of remotely operable devices are considered when evaluating restoration and isolation scenarios to reduce the number of customers affected by a loss of supply and to quickly be able to resupply the affected region. Other work has been completed in order to reduce the reliance on any one transmission circuit: a second supply was connected to Marchwood MS in 2014, providing added redundancy to the West region, Terry Fox MTS was energized in 2013, connected to the 230kV M32S adding additional support to an area previously solely supplied by the 115kV circuit S7M. Hydro Ottawa is also currently working with the Ontario Power Authority, the Independent Electricity System Operator and Hydro One in an Integrated Regional Planning Process which began in 2011 and is tasked with reviewing the supply adequacy in the Ottawa area.

### 2.2 Defective Equipment

Annually, the secondary cause of Defective Equipment related outages are analyzed as part of the Annual Planning Report. Hydro Ottawa's asset replacement and refurbishment strategies are described annually as part of the Annual Planning Report (see Attachment B-1(B)), as well as in the Distribution System Plan (exhibit B-1-2). The Asset Management Plan (included within Attachment B-1(B)) was created to provide strategic guidance on the replacement and investment forecasts, manage priorities and identify process gaps. The plan focuses on optimizing the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet reliability service targets and future demand. Each year, the aim is to improve the plan by taking advantage of new information and changing technology. These innovations help to maintain the ranking as one of the most reliable and efficient electricity networks in the province of Ontario.

Large segments of Hydro Ottawa's system were constructed in the 1960s, 70s and 80s. As most assets have a lifespan on the order of 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end-of-life. The increased potential of failure poised by these aging assets will, without intervention, impact the organization's ability to guard worker and public safety, maintain system reliability and protect organizational strength in the future.

### 2.3 Adverse Weather

Continued enhancements are being made to the system to improve the withstand capabilities during storms and to reduce the impact of individual outages. There are three initiatives/programs which address this need:

- *Pole Replacement* – The conditions of poles is evaluated on an ongoing basis. From the condition assessment, a review is conducted to determine the areas which are in the poorest condition so they can be targeted for planned replacement. By eliminating poles in poor condition and upgrading the attached hardware, the ability of the system to operate through adverse weather without interruption is improved.
- *Vegetation Management* – Updates to the vegetation management program currently underway are anticipated to reduce tree contacts during wind storms. Changes to the program which are being implemented include targeted tree trimming cycle and clearance distance from lines based on tree species and their rate of growth. These changes have been determined based on an extensive system review which

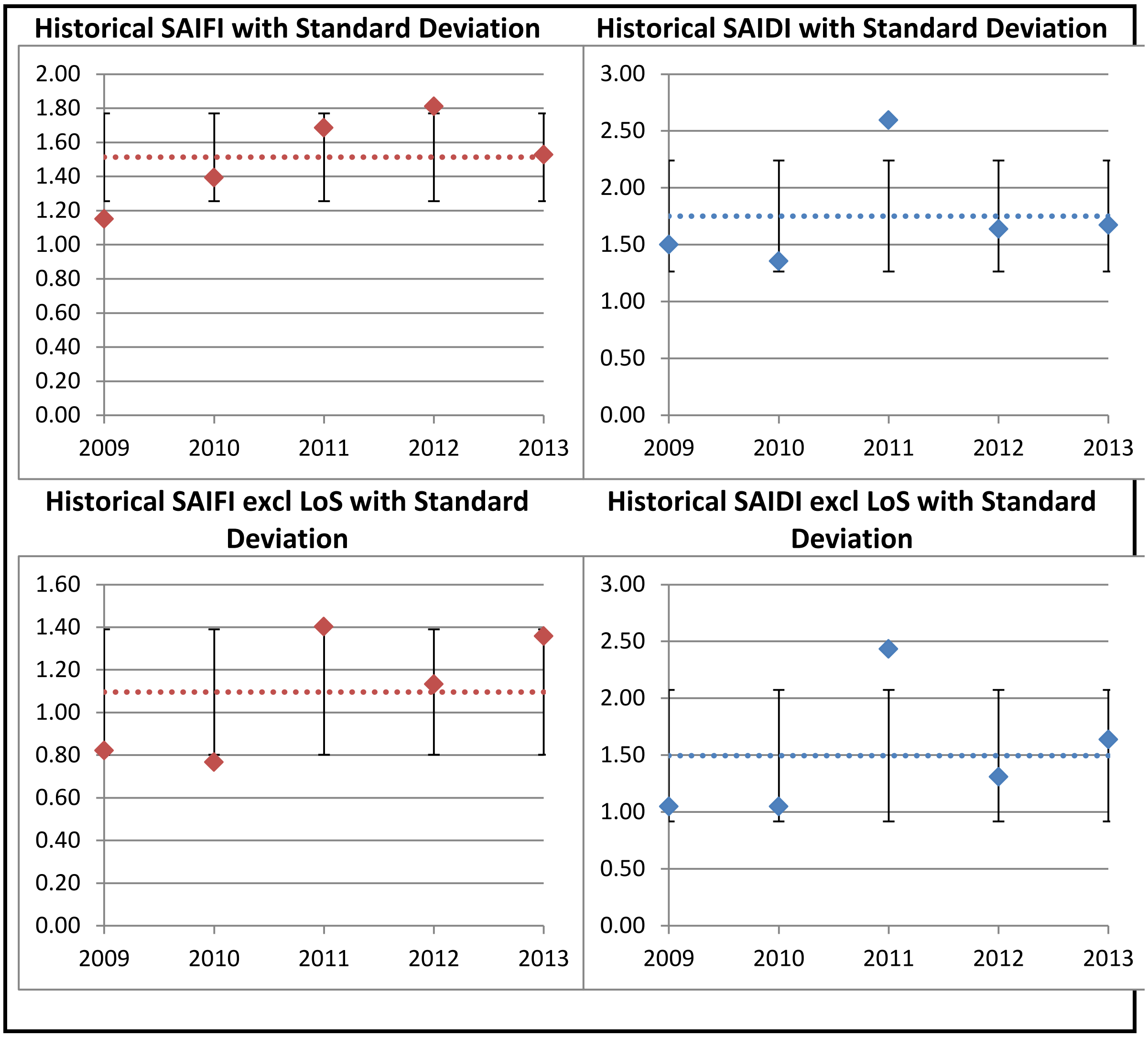
captured data on trees within proximity to all overhead spans within the service territory. Data collected included species so that growth rates could be considered for trim cycles and planned removal of Emerald Ash trees can be coordinated, as well as any locations with overhang. In addition, 'smart' tree removals are being considered. 'Smart' removals would target trees near overhead lines that either are near end of life and at risk of falling into the line or would require excess trimming (i.e. trimming would be required too frequently or would negatively impact the health of the tree) to maintain an appropriate clearance. Starting in 2014 and ending early 2015, HOL has hired contractors to remove all overhang across the system to eliminate the potential for branches falling onto the lines in the case of high winds or ice and snow loading.

- *System Protection* – Where appropriate, distribution reclosers are installed on the system. While these reclosers will not completely eliminate outages, they do sectionalize the distribution circuit, minimalizing the number of customer interruptions for a given fault. As well, where appropriate, a coordinate review is undertaken to ensure the appropriate size of fusing is in place and that the protection scheme operates as intended.

## 3.0 OUTLYING YEARS – SERVICE RELIABILITY INDICATORS

Comparing SAIFI and SAIDI performance by year to the 5-year averages, it can be seen that 2011 (SAIFI & SAIDI) and 2012 (SAIFI) show as outliers when you consider the standard deviation from the average:

**Table 1**




## 3.1 2011

System reliability in 2011 was defined by the storms experienced and HOL's response. Three major storms resulted in high levels of customer interruption and duration. Loss of service due to storms in 2011 was the equivalent to a 1.5 hour interruption to every Hydro Ottawa customer.

While the primary cause of system interruption in 2011, namely Adverse Weather, is outside the control of Hydro Ottawa, the ability to respond to such challenges is not. As a result of the experiences in 2011, in 2012 Hydro Ottawa undertook initiatives to improve future performance. These included updates to the emergency response organization and procedures, review of vegetation management planning, as well as ongoing commitment to asset replacement and automation; ultimately to storm harden the system and reduce restoration time. Further work is still being planned with the aim to storm harden the system, for example, the work planned to clear all tree overhang in 2014 and 2015 in described above.

The second leading cause of interruption in 2011 was Defective Equipment. Tree Contacts also had a measurable contribution to the SAIDI score in 2011. Collectively, Adverse Weather and Defective Equipment account for approximately 50% of the 2011 SAIFI and SAIDI scores.

**3.2 2012**

System reliability in 2012 continued to see degrading performance. Increasing interruption trends in Defective Equipment, Loss of Supply, Adverse Weather, and Foreign Interference were the main contributors to the performance of 2012.

Overall, since 2008 SAIDI has been steadily increasing, due to the increase of storms with severe wind and rain, but also due to the increase in scheduled work. Scheduled work causes SAIDI to increase due to outages planned in advance. Moving forward, it is anticipated that interruptions due to scheduled work will continue to grow based on the need described in the Annual Planning Report.

2012 fell outside the standard deviation for overall SAIFI due to the large contribution of Loss of Supply events. When looking at SAIFI excluding Loss of Supply, the 2012 performance falls within the standard deviation bands.

## 4.0 RELIABILITY COUNCIL AND SYSTEM ACTIVITY INVESTIGATION REPORTING CRITERIA

Hydro Ottawa works to continuously improve reliability measures. In response to reliability analysis and worst feeder performance reviews, in 2014 Hydro Ottawa initiated a cross-functional team known as the Reliability Council to discuss reliability concerns. The team is also tasked with identifying improvements and efficiencies that will improve overall reliability statistics. Issues and ideas related to storm response, system operability, circuit ties, tree trimming initiatives and intricacies of each voltage system in the service territory among other items are discussed and brought back to the team from all levels and areas of the organization.

The Asset Planning Group has also been engaged in producing System Activity Investigation Reports with the goal of providing clarity into issues with the configuration and operation of the distribution system. System Activity Investigation Reports provide insight into the root cause of an event, identifying issues with standard process and procedures, and provide recommendations to mitigate re-occurring events. The Asset Planning Group has developed a set of criteria to initiate System Activity Investigation Reports. These criteria will attempt to capture events that can lead to corrective actions to further better the system and operating procedures.

Any of the following criteria may initiate a System Activity Investigation Report:

- > 1000 Customers and > 1 Minute (unplanned)
- > 8 Hours and > 1 Customer
- Equipment/Protection mis-operation (HOL, HONI, or other)
- Incidents where equipment failure, protection mis-operation, or system operation have or are suspected to have caused or contributed to Health and Safety incidents (public or employee) or property damage
- Re-occurring incidents of supply quality falling outside tolerances for voltage, current, frequency and harmonic distortion as specified in ECG0008, that are suspected to have originated from the distribution system
- As circumstances require

These two initiatives, namely the Reliability Council and System Activity Investigation Reports, are but two of many internal initiatives which strive to complement Hydro Ottawa's already robust Distribution System planning, and ultimately optimize Hydro Ottawa's operational effectiveness and performance.

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# Appendix 2-G
# Service Reliability Indicators
# 2009 - 2013

| Index | Includes outages caused by loss of supply | | | | | Excludes outages caused by loss of supply | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2009 | 2010 | 2011 | 2012 | 2013 |
| SAIDI | 1.500 | 1.360 | 2.600 | 1.640 | 1.670 | 1.050 | 1.050 | 2.440 | 1.310 | 1.640 |
| SAIFI | 1.150 | 1.390 | 1.690 | 1.810 | 1.530 | 0.820 | 0.770 | 1.400 | 1.130 | 1.360 |

**5 Year Historical Average**

| | Includes outages caused by loss of supply | Excludes outages caused by loss of supply |
|---|---|---|
| SAIDI | 1.754 | 1.498 |
| SAIFI | 1.514 | 1.096 |

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

| Indicator | OEB Minimum Standard | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Low Voltage Connections | 90.0% | 98.7% | 100.0% | 100.0% | 100.0% | 100.0% |
| High Voltage Connections | 90.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Telephone Accessibility | 65.0% | 69.0% | 82.1% | 82.9% | 82.5% | 82.2% |
| Appointments Met | 90.0% | 99.3% | 100.0% | 97.3% | 97.4% | 97.4% |
| Written Response to Enquires | 80.0% | 99.8% | 99.9% | 99.9% | 100.0% | 99.3% |
| Emergency Urban Response | 80.0% | 95.3% | 97.0% | 81.6% | 98.5% | 97.6% |
| Emergency Rural Response | 80.0% | N/A | N/A | N/A | N/A | N/A |
| Telephone Call Abandon Rate | 10.0% | 5.8% | 2.6% | 2.7% | 1.8% | 1.9% |
| Appointment Scheduling | 90.0% | 100.0% | 100.0% | 100.0% | 99.8% | 100.0% |
| Rescheduling a Missed Appointment | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| Reconnection Performance Standard | 85.0% | N/A | N/A | 100.0% | 100.0% | 100.0% |

# LOAD FORECAST

Hydro Ottawa Limited ("Hydro Ottawa") engaged Itron to complete a 2015 to 2020 sales and energy forecast. Itron completed forecasts for total purchases sales and system demand and rate class sales, customers and connections, and billing demand. The forecast utilized actual data on sales, customer numbers and connections, and purchases until August 2014. Forecasts were provided both with and without the impact of future Conservation Demand Management ("CDM") targets.

A Purchases model was used with total sales allocated to the rate class sales forecast. For details regarding the forecast methodology, including CDM persistence and future targets, economic assumption, and data sources please see Itron's report as C-1(A).

Hydro Ottawa has completed Appendix 2-I, Load Forecast CDM Adjustment Workbook (2015) and Appendix 2-IA Summary and Variances of Actual and Forecast Data, and can be found as PDFs at the end of this exhibit.

While completing the Load Forecast, Hydro Ottawa was performing its analysis for its rate reclassification. Based on a detailed customer level analysis of the impact of the rate reclassification, Hydro Ottawa has adjusted the class level load forecast and customer numbers developed by Itron. The total kWh sales, kW demand, and customer and connection numbers equal that of Itron's, however the class level forecasts are different; the main reclassification being between General Service < 50 kW and General Service > 50 kW classifications. With new procedures implemented Hydro Ottawa is anticipating less movement between the General Service classes in the future.

Hydro Ottawa has also adjusted the forecast to include Sentinel Lights and Standby Demand as these were not forecasted separately by Itron.

Table 1 provides Hydro Ottawa's Sales forecast by MWh for 2016 through 2020.

**Table 1 – Hydro Ottawa 2016 through 2020 Forecasted Sales Forecast (MWh) by class[1]**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| RESIDENTIAL | 2,216,045 | 2,198,259 | 2,206,411 | 2,214,984 | 2,217,628 |
| GENERAL SERVICE <50KW | 726,360 | 716,896 | 709,791 | 704,193 | 699,744 |
| GENERAL SERVICE 50-1000KW Non Interval | 1,386,977 | 1,336,827 | 1,295,564 | 1,259,397 | 1,226,514 |
| GENERAL SERVICE 50-1000KW Interval | 1,207,946 | 1,214,762 | 1,226,094 | 1,240,552 | 1,256,773 |
| GENERAL SERVICE 1000-1500KW | 359,518 | 355,856 | 353,764 | 352,644 | 352,100 |
| GENERAL SERVICE 1500-5000 KW | 863,309 | 877,400 | 895,369 | 914,569 | 935,554 |
| LARGE USER | 620,218 | 619,253 | 618,467 | 617,036 | 615,195 |
| STREETLIGHTING | 43,552 | 43,653 | 43,765 | 43,876 | 44,015 |
| MU | 16,651 | 16,690 | 16,731 | 16,772 | 16,827 |
| SENTINEL LIGHTS | 48 | 48 | 48 | 48 | 48 |
| **TOTAL MWH SALES** | 7,440,624 | 7,379,644 | 7,366,004 | 7,364,071 | 7,364,398 |

Table 2 provides Hydro Ottawa's Demand forecast by kW for 2016 through 2020

[1] Forecat does not include Dry Core Transformer Charge

**Table 2 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) by class**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| GENERAL SERVICE 50-1000KW Non Interval | 3,533,354 | 3,406,354 | 3,301,064 | 3,208,582 | 3,123,291 |
| GENERAL SERVICE 50-1000KW Interval | 2,725,183 | 2,740,805 | 2,766,375 | 2,798,890 | 2,835,076 |
| GENERAL SERVICE 1000-1500KW | 769,442 | 761,481 | 756,911 | 754,458 | 753,212 |
| GENERAL SERVICE 1500-5000 KW | 1,847,365 | 1,877,691 | 1,916,044 | 1,957,009 | 2,001,525 |
| STANDBY | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 |
| LARGE USER | 1,121,449 | 1,119,726 | 1,118,300 | 1,115,702 | 1,112,342 |
| STREETLIGHTING | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 |
| SENTINEL LIGHTS | 216 | 216 | 216 | 216 | 216 |
| TOTAL | 10,124,953 | 10,034,217 | 9,986,854 | 9,962,801 | 9,953,606 |

Table 3 provides Hydro Ottawa's average number of customers and connections forecast for 2016 through 2020.

**Table 3 – Hydro Ottawa 2016 through 2020 Average Number of Customers and Connections by class**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| RESIDENTIAL | 297,343 | 301,258 | 305,144 | 308,990 | 312,786 |
| GENERAL SERVICE <50KW | 24,512 | 24,626 | 24,739 | 24,850 | 24,959 |
| GENERAL SERVICE 50-1000KW NONI | 2,481 | 2,481 | 2,481 | 2,481 | 2,481 |
| GENERAL SERVICE 50-1000KW INT | 758 | 785 | 813 | 841 | 869 |
| GENERAL SERVICE 1000-1500KW | 57 | 57 | 57 | 58 | 58 |
| GENERAL SERVICE 1500-5000 KW | 76 | 76 | 76 | 76 | 76 |
| STANDBY | 2 | 2 | 2 | 2 | 2 |
| LARGE USERS | 11 | 11 | 11 | 11 | 11 |
| **TOTAL CUSTOMERS** | 325,240 | 329,296 | 333,323 | 337,308 | 341,243 |

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| STREET LIGHTING | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 |
| SENTINEL LIGHTS | 55 | 51 | 47 | 43 | 39 |
| UNMETERED SCATTERED LOADS | 3,477 | 3,525 | 3,573 | 3,621 | 3,669 |
| **TOTAL CONNECTIONS** | 59,048 | 59,092 | 59,136 | 59,180 | 59,224 |

Table 4 provides Hydro Ottawa’s forecast kW for 2016 through 2020 for the transformer ownership credit.

**Table 4 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) for Transformer Ownership Credit**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| GENERAL SERVICE 50-1000KW NONI | (883,339) | (851,589) | (825,266) | (802,146) | (780,823) |
| GENERAL SERVICE 50-1000KW INT | (681,296) | (685,201) | (691,594) | (699,723) | (708,769) |
| GENERAL SERVICE 1000-1500KW | (192,361) | (190,370) | (189,228) | (188,615) | (188,303) |
| GENERAL SERVICE 1500-5000 KW | (461,841) | (469,423) | (479,011) | (489,252) | (500,381) |
| LARGE USER | (280,362) | (279,932) | (279,575) | (278,926) | (278,086) |
| **TOTAL CUSTOMERS** | (2,499,198) | (2,476,514) | (2,464,674) | (2,458,660) | (2,456,362) |

For class level revenue forecast please see Appendix 2-V, Revenue Reconciliation.

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# Appendix 2-I
## Load Forecast CDM Adjustment Work Form (2015)

The 2014 bridge year is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministirial directives of March 31, 2014. Thus, with 2015, there is a need to recognize the final year of the current 2011-2014 CDM program, as well as to estimate reasonable impacts each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2015 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

### 2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

Measured results for 2013 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014.

Based on these inputs, the residual kWh to achieve the 4 year CDM target icalculated for 2014 CDM under the assumption that the distributor will at least achieve the 2011-2014 CDM target that is currently a condition of the utility's Distribution Licence. If the distributor has met its cumulative kWh savings target by the end of 2013, the incremental savings for 2014 are assumed to be zero. Any further savings for 2014 CDM savings and any further compensation for meeting or exceeding the four-year (2011-2014) targets will be dealt with through the disposition of the 2011-2014 LRAMVA balance, which will occur in the next cost of service application filed after the final 2014 CDM Reports issued by the OPA in the fall of 2015.

| | | | | | |
|---|---|---|---|---|---|
| | | | **4 Year (2011-2014) kWh Target:** | | |
| | | | 374,700 | | |
| | **2011** | **2012** | **2013** | **2014** | **Total** |
| 2011 CDM Programs | 9.55% | 9.55% | 9.53% | 9.07% | 37.71% |
| 2012 CDM Programs | | 9.42% | 9.31% | 9.18% | 27.92% |
| 2013 CDM Programs | | | 12.01% | 11.05% | 23.06% |
| 2014 CDM Programs | | | | 11.32% | 11.32% |
| **Total in Year** | **9.55%** | **18.98%** | **30.85%** | **40.62%** | **100.00%** |
| | | | **kWh** | | |
| 2011 CDM Programs | 35,800.00 | 35,800.00 | 35,700.00 | 34,000.00 | 141,300.00 |
| 2012 CDM Programs | | 35,300.00 | 34,900.00 | 34,400.00 | 104,600.00 |
| 2013 CDM Programs | | | 45,000.00 | 41,400.00 | 86,400.00 |
| 2014 CDM Programs | | | | 42,400.00 | 42,400.00 |
| **Total in Year** | **35,800.00** | **71,100.00** | **115,600.00** | **152,200.00** | **374,700.00** |

## 2015-2020 CDM Program - 2015, first year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the OPA will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as established by the OPA.

| 6 Year (2015-2020) kWh Target: | | | | | | | |
|---|---|---|---|---|---|---|---|
| 395,000 | | | | | | | |
| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Total** |
| **%** | | | | | | | |
| 2015 CDM Programs | 10.00% | | | | | | 10.00% |
| 2016 CDM Programs | | 20.00% | | | | | 20.00% |
| 2017 CDM Programs | | | 20.00% | | | | 20.00% |
| 2018 CDM Programs | | | | 16.67% | | | 16.67% |
| 2019 CDM Programs | | | | | 16.67% | | 16.67% |
| 2020 CDM Programs | | | | | | 16.67% | 16.67% |
| **Total in Year** | **10.00%** | **20.00%** | **20.00%** | **16.67%** | **16.67%** | **16.67%** | **100.00%** |
| **kWh** | | | | | | | |
| 2015 CDM Programs | 39,500.00 | | | | | | 39,500.00 |
| 2016 CDM Programs | | 79,000.00 | | | | | 79,000.00 |
| 2017 CDM Programs | | | 79,000.00 | | | | 79,000.00 |
| 2018 CDM Programs | | | | 65,833.33 | | | 65,833.33 |
| 2019 CDM Programs | | | | | 65,833.33 | | 65,833.33 |
| 2020 CDM Programs | | | | | | 65,833.33 | 65,833.33 |
| **Total in Year** | **39,500.00** | **79,000.00** | **79,000.00** | **65,833.33** | **65,833.33** | **65,833.33** | **395,000.00** |

### *Determination of 2015 Load Forecast Adjustment*

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012 and 2013 CDM Final Reports, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

| Net-to-Gross Conversion | | | | |
|---|---|---|---|---|
| **Is CDM adjustment being done on a "net" or "gross" basis?** | | | | **net** |
| Persistence of Historical CDM programs to 2014 | **"Gross" kWh** | **"Net" kWh** | **Difference kWh** | **"Net-to-Gross" Conversion Factor ('g')** |
| 2006-2010 CDM programs | | | | |
| 2011 CDM program | **52,446,922** | **35,847,339** | | |
| 2012 CDM program | **48,896,698** | **35,093,510** | | |
| 2013 CDM program | **59,297,889** | **42,598,285** | | |
| **2006 to 2013 OPA CDM programs: Persistence to 2015** | 160,641,509 | 113,539,134 | 47,102,375 | 0.00% |

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment.  Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

**Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast**

| | 2011 | 2012 | 2013 | 2014 | 2015 | |
|---|---|---|---|---|---|---|
| **Weight Factor for each year's CDM program impact on 2014 load forecast** | **0** | **0** | **0** | **1** | **0.5** | Distributor can select "0", "0.5", or "1" from drop-down list |
| ***Default Value selection rationale.*** | *Full year persistence of 2011 CDM programs on 2015 load forecast.  Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.* | *Full year persistence of 2012 CDM programs on 2015 load forecast.  Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.* | *Default is 0, but one option is for full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.* | *Full year impact of persistence of 2014 programs on 2015 load forecast.  2014 CDM programs not in base forecast.* | *Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.* | |

## *2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast*

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2015 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

| | 2011 | 2012 | 2013 | 2014 | 2015 | Total for 2014 | Total for 2015 |
|---|---|---|---|---|---|---|---|
| | | | | kWh | | | |
| Amount used for CDM threshold for LRAMVA (2014) | 34,000.00 | 34,400.00 | 41,400.00 | 42,400.00 | | 152,200.00 | |
| 2012 CDM adjustment (per Board Decision in 2012 Cost of Service Application) (enter as negative) | - 8,000.00 | - 8,000.00 | - 8,000.00 | - 8,000.00 | | - 32,000.00 | |
| Amount used for CDM threshold for LRAMVA (2015) | | | | | 39,500.00 | | 39,500.00 |
| Manual Adjustment for 2015 Load Forecast (billed basis) | - | - | - | 42,400.00 | 19,750.00 | | 62,150.00 |
| Proposed Loss Factor (TLF) | 3.58% | Format: X.XX% | | | | | |
| Manual Adjustment for 2015 Load Forecast (system purchased basis) | - | - | - | 43,917.92 | 20,457.05 | | 64,374.97 |

*Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.*

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# 2014 Long-Term Electric Energy and Demand Forecast

## Hydro Ottawa

*Submitted to:*

Hydro Ottawa
Ottawa, Ontario

*Submitted by:*

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January, 2015

# Contents

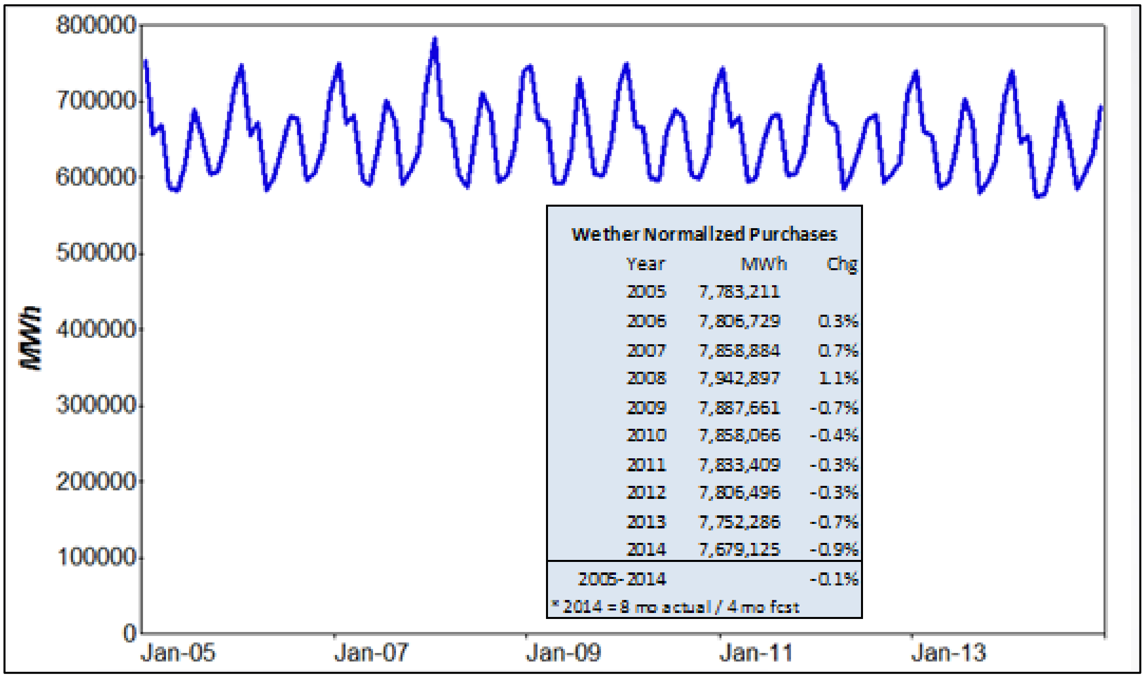
# 1 Overview

Itron, Inc. recently completed the 2015 to 2020 Hydro Ottawa sales and energy forecast. The forecast is based on actual sales, customer, and purchase data through August 2014. Forecasts are derived for total purchases, system demand and rate class sales, customer, and billing demand through 2020. This document presents an overview of the forecast methodology and results.

**Background**

Hydro Ottawa serves approximately 289,600 residential customers and 27,600 nonresidential customers. The residential customer class accounts for approximately 30% of system sales. In 2013, annual system purchases exceeded 7,722 GWh with a system peak demand of 1,427 MW. Over the last ten years, customer and economic growth has been relatively steady. Since 2005, regional population growth has averaged 1.4% while real GDP has averaged 1.5%; even during the recession GDP declined only 0.2% (2009). Since 2005, Hydro Ottawa has added over 40,000 new customers. While the population has been increasing and the economy expanding, system electricity purchases have been flat. Between 2005 and 2013, weather normalized purchases have actually declined from 7,783 GWh to an estimated 7,678 GWh by year-end 2014. Figure 1 shows annual weather normal purchases.

### Figure 1: Weather Normal System Purchases

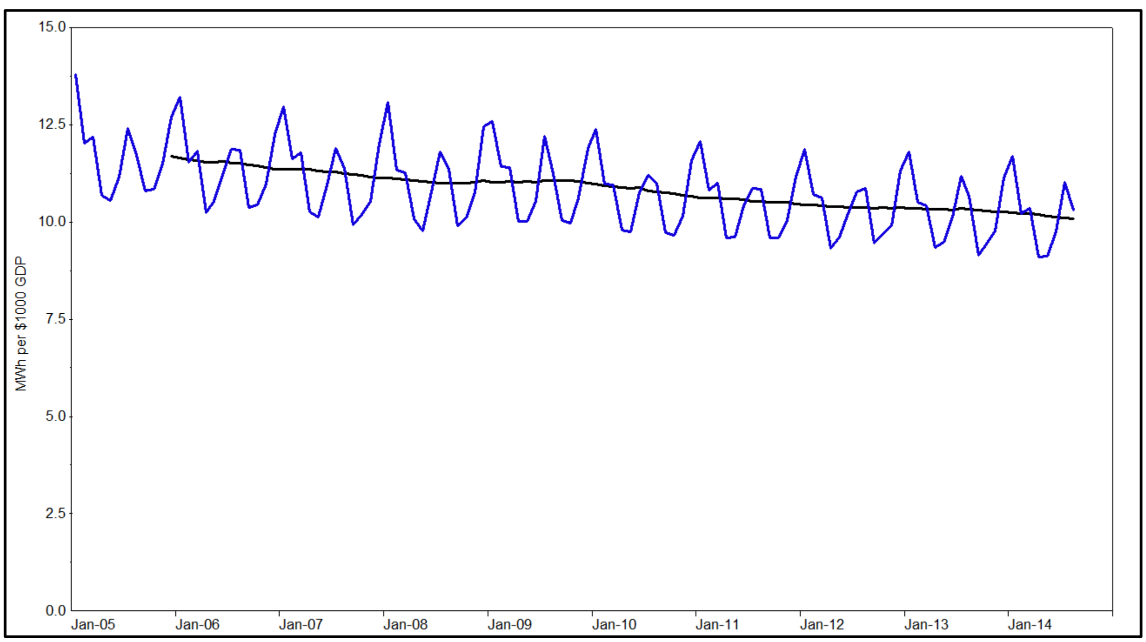



| Wether Normalized Purchases | | |
|---|---|---|
| Year | MWh | Chg |
| 2005 | 7,783,211 | |
| 2006 | 7,806,729 | 0.3% |
| 2007 | 7,858,884 | 0.7% |
| 2008 | 7,942,897 | 1.1% |
| 2009 | 7,887,661 | -0.7% |
| 2010 | 7,858,066 | -0.4% |
| 2011 | 7,833,409 | -0.3% |
| 2012 | 7,806,496 | -0.3% |
| 2013 | 7,752,286 | -0.7% |
| 2014 | 7,679,125 | -0.9% |
| 2005-2014 | | -0.1% |

* 2014 = 8 mo actual / 4 mo fcst

Flat energy purchases given relatively strong customer and economic growth implies strong electric efficiency improvements. This can be seen in Figure 2 which shows the ratio of Weather normal MWh to real GDP.

### Figure 2: MWh per Real GDP



The MWh input per dollar of output has been decreasing on average 1.9% per year. Another way of viewing this trend is to compare the energy consumption trend with GDP trend. This is depicted in Figure 3.

**Figure 3: Purchases vs. GDP (2000 = 1.0)**

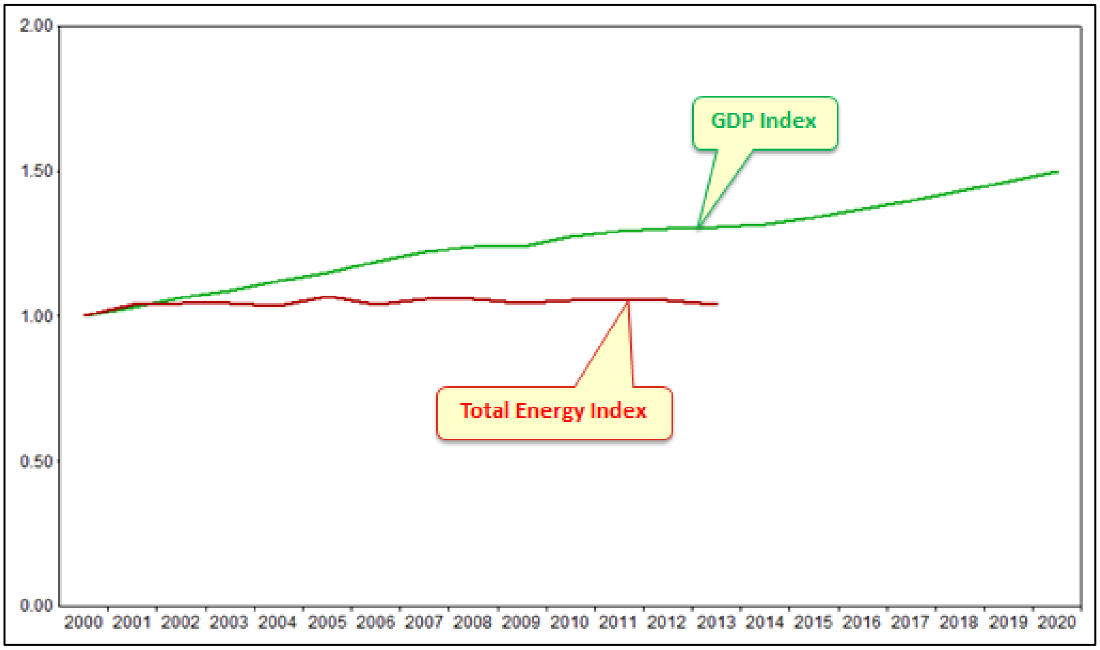


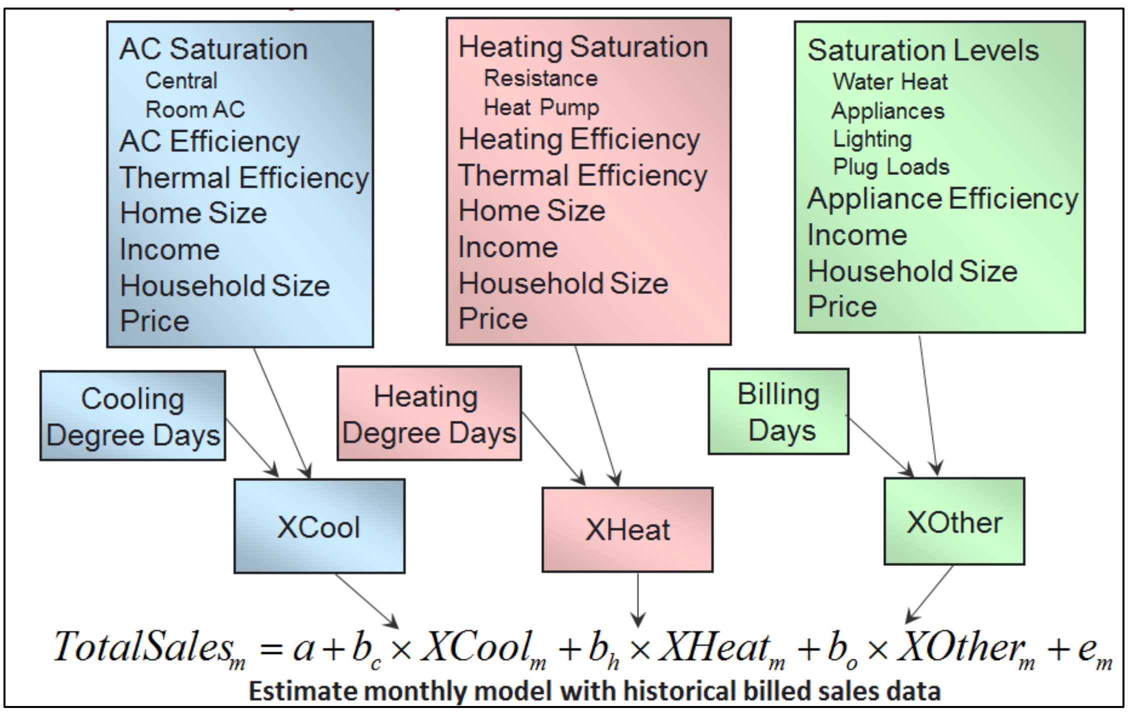

Figure 3 shows purchases and GDP indexed to 1.0 (2000). While GDP has been averaging 2.0% growth per year since 2000, purchases have effectively been flat. GDP is projected to continue to average 2.2% annual growth through 2020. As end-use energy efficiency is expected to continue to improve, we expect electricity required per dollar of GDP to continue to decline.

From the graph above, it's clear that that traditional energy forecast model that relates electric consumption to GDP or other economic driver will not work without accounting for efficiency improvements. A simple approach is to estimate a regression model that includes GDP and GDP interactive with a linear trend variable. The interactive variable allows the slope on GDP to change over time. While such a model will explain the historical purchase trend well, it assumes that the same trend observed over the last ten years will continue on through the next five years. The GDP/trend model ultimately results in too low of a forecast as we expect this trend to flatten out in the later years.

The objective then is to replace the trend variable with a more explicit variable of energy efficiency. This is done by using a Statistically Adjusted End-Use (SAE) modeling framework where end-use energy intensities are explicitly incorporated into the forecast model.

To capture the efficiency trend, forecasts for the residential and commercial rate classes are estimated using a Statistically Adjusted End-Use Models (SAE) modeling framework. This entails explicitly incorporating end-use intensity trends into the constructed monthly model variables that capture cooling requirements (XCool), heating requirements (XHeat), and all other uses (XOther). The variables are constructed as a combination of weather conditions, economic activity, price, and end-use intensity trends. End-use intensity trends are calculated on a kWh per household basis in the residential sector and a kWh per square foot in the commercial sector. Figure 4 shows the general residential modeling framework.

**Figure 4: SAE Model Framework**




The estimated model coefficients – $b_c$, $b_h$, and $b_o$ calibrate the estimated end-use loads (XCool, XHeat, and XOther) to actual billed customer usage. Projections of end-use intensity, economic conditions, price, and weather conditions executed through the estimated models drive projected monthly average use and sales. A similar specification is used for the commercial revenue classes where models for the largest revenue classes are estimated using total sales rather than average use.

For residential sector, end-use energy intensities are derived from historical and forecasted saturation and annual energy estimates or unit of energy consumption (UEC) from the recent Ontario Power Authority (OPA) end-use forecast for the province. End-use intensities for the commercial sector are based on the U.S. Energy Information Agency (EIA) forecast for the U.S. East North Central (ENC) Census Division. EIA develops end-use forecast for seven census regions in the U.S. each year as part of the Annual Energy Outlook (AEO).

Over the last ten years, end-use efficiency has been increasing faster than end-use saturation; as a result residential and commercial energy intensity has been declining. Improvements in end-use efficiency is the result of replacing existing appliances with more energy efficient appliances, new appliance efficiency standards, improving thermal shell efficiency, and CDM program activity. From a modeling perspective, it is impossible to explain historical sales trends and generate a reasonable long-term sales and energy forecast without explicitly capturing end-use efficiency improvements in the model structure. This is illustrated in Figure 3.

**Figure 5: Indexed System Energy and Model Drivers (2005 = 1.0)**

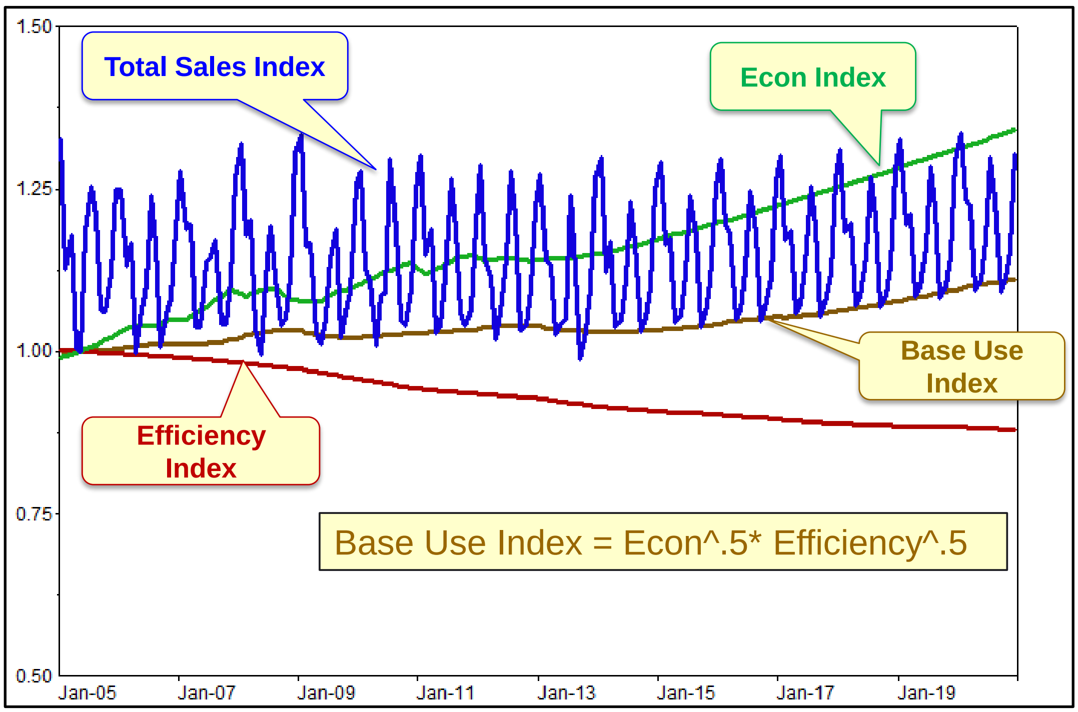



Figure 5 compares monthly system sales, against an economic index (weighted GDP and Population), an efficiency index (weighted residential and commercial energy intensity), and a combination of the economic and efficiency index (Base Use). The variables have been indexed to 1.0 in 2005. It is not until the economic variable is combined with energy intensity that we can adequately capture the historical energy trend and generate a plausible energy forecast.

When projected intensity improvements are combined with population and GDP, total sales are expected to average 0.7% annual growth before CDM adjustment and -0.1% with CDM adjustments. Table 1 shows historical and forecasted purchases; historical figures are weather normalized.

**Table 1: Hydro Ottawa 2015 Purchase Forecast**

| Year | Weather Normal Purchases (MWh) | Chg | CDM Adjusted | Chg |
|---|---|---|---|---|
| 2005 | 7,782,623 | | 7,782,623 | |
| 2006 | 7,806,222 | 0.3% | 7,806,222 | 0.3% |
| 2007 | 7,859,026 | 0.7% | 7,859,026 | 0.7% |
| 2008 | 7,943,364 | 1.1% | 7,943,364 | 1.1% |
| 2009 | 7,888,248 | -0.7% | 7,888,248 | -0.7% |
| 2010 | 7,857,253 | -0.4% | 7,857,253 | -0.4% |
| 2011 | 7,832,897 | -0.3% | 7,832,897 | -0.3% |
| 2012 | 7,805,660 | -0.3% | 7,805,660 | -0.3% |
| 2013 | 7,752,664 | -0.7% | 7,752,664 | -0.7% |
| 2014 | 7,678,337 | -1.0% | 7,670,470 | -1.1% |
| 2015 | 7,748,274 | 0.9% | 7,698,635 | 0.4% |
| 2016 | 7,789,387 | 0.5% | 7,678,495 | -0.3% |
| 2017 | 7,808,056 | 0.2% | 7,615,493 | -0.8% |
| 2018 | 7,868,846 | 0.8% | 7,601,419 | -0.2% |
| 2019 | 7,934,956 | 0.8% | 7,599,471 | 0.0% |
| 2020 | 8,003,412 | 0.9% | 7,599,868 | 0.0% |
| **2005 - 14** | | **-0.1%** | | **-0.2%** |
| **2014 - 20** | | **0.7%** | | **-0.2%** |

**Rate Class Build-Up vs. Total Purchase Forecast**

While the ideal approach is to build purchase requirements from the rate class sales level, in the end we allocated out the total sales forecast to the rate classes based on the rate class forecasts before CDM adjustments; CDM savings projections are then subtracted from the allocated rate class sales forecast. The rate class models were not strong enough statistically to totally rely on and generated too low of a sales forecast as the starting point for billed sales model is 2008 – right at the start of the recession. Billing data before 2008 was not usable for estimating statistically acceptable forecast models. Also, while the ideal approach is to estimate average use models for residential and small commercial revenue classes, we elected to develop total class sales forecast models as there was even more unexplained variation in the average use models.

The forecast is derived from monthly regression models estimated for both rate classes and total purchases. Rate class sales, and customer forecast models are estimated for the following rate classes.

- Residential
- GS (less than 50 kW)
- GS Non-Interval Metered (50kW to 1000 kW)
- GS Interval Metered (50 kW to 1000 kw)
- GS (1000 kW to 1500 kW)
- GS (1500 kW to 5000 kW)
- Large Users (5000 kW plus)
- Street Lighting
- MU
- DCL

SAE models are estimated for Residential, GS classes, and total purchases. While the rate class models adjusted R-squared are relatively low, the coefficients on the model variables heating (XHeat), cooling (XCool), and other use (XOther) have strong coefficients that are statistically significant. The end-use model variables which combine weather, economic and population growth, and improving end-use efficiency captures differences in sales growth across rate classes and generates a statistically strong forecast model at the total system level. Class sales model results are used to allocate total system sales forecast to rate classes allowing us to capture differences in class sales growth over time. Allocated class sales forecasts are then adjusted for CDM savings projections. Table 2 shows the unadjusted class sales forecast, while Table 3 shows the CDM adjusted forecast.

### Table 2: Unadjusted Class Sales Forecast (MWh)

| Year | Res | GS < 50kW | GS NI 50-1000kW | GS I 50-1000kW | GS 1000-1500kw | GS 1500-5000kw | Large Users | Street Lght | MU | DCL |
|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 2,209,986 | 706,581 | 1,489,888 | 1,135,002 | 338,244 | 860,536 | 615,653 | 44,419 | 16,392 | 3,387 |
| 2015 | 2,241,257 | 710,082 | 1,463,207 | 1,179,844 | 350,053 | 883,241 | 620,305 | 43,504 | 16,594 | 3,418 |
| 2016 | 2,232,769 | 711,334 | 1,450,111 | 1,215,423 | 355,011 | 902,777 | 620,219 | 43,550 | 16,650 | 3,429 |
| 2017 | 2,226,833 | 709,771 | 1,427,265 | 1,247,004 | 358,529 | 916,868 | 619,254 | 43,654 | 16,690 | 3,437 |
| 2018 | 2,245,849 | 709,908 | 1,410,826 | 1,281,251 | 363,006 | 934,838 | 618,467 | 43,765 | 16,732 | 3,446 |
| 2019 | 2,264,296 | 710,894 | 1,397,088 | 1,316,704 | 367,839 | 954,038 | 617,036 | 43,875 | 16,773 | 3,455 |
| 2020 | 2,276,815 | 713,027 | 1,386,525 | 1,354,052 | 373,224 | 975,022 | 615,194 | 44,015 | 16,826 | 3,465 |

## Table 3: CDM Adjusted Class Sales Forecast (MWh)

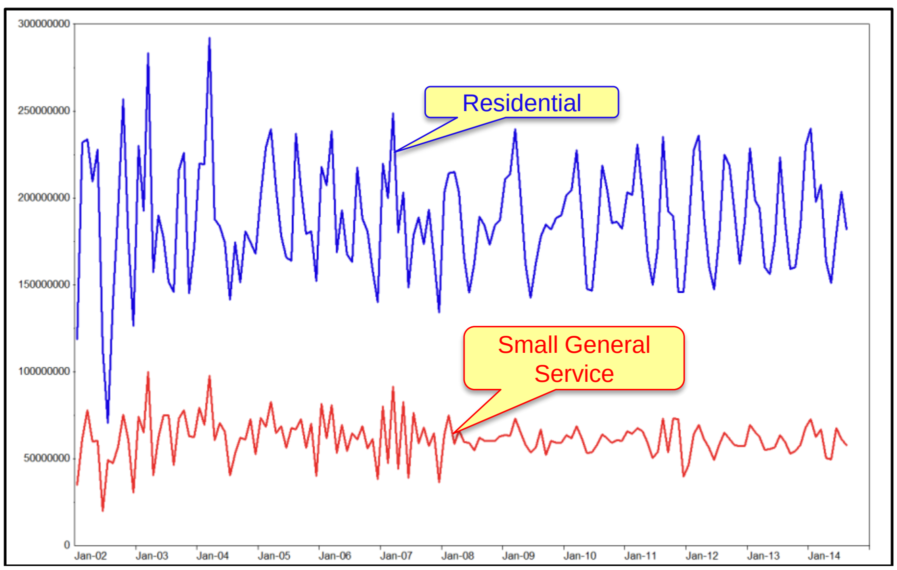
| Year | Res | GS < 50kW | GS NI 50-1000kW | GS I 50-1000kW | GS 1000-1500kw | GS 1500-5000kw | Large Users | Street Lght | MU | DCL |
|---|---|---|---|---|---|---|---|---|---|---|
| **2014** | 2,208,503 | 705,819 | 1,487,331 | 1,132,841 | 337,596 | 860,536 | 615,653 | 44,419 | 16,392 | 3,387 |
| **2015** | 2,233,420 | 705,280 | 1,446,533 | 1,165,427 | 345,766 | 883,241 | 620,305 | 43,504 | 16,594 | 3,418 |
| **2016** | 2,216,044 | 700,607 | 1,412,731 | 1,182,652 | 345,345 | 902,777 | 620,219 | 43,550 | 16,650 | 3,429 |
| **2017** | 2,198,259 | 691,144 | 1,362,581 | 1,189,466 | 341,685 | 916,868 | 619,254 | 43,654 | 16,690 | 3,437 |
| **2018** | 2,206,412 | 684,039 | 1,321,314 | 1,200,798 | 339,592 | 934,838 | 618,467 | 43,765 | 16,732 | 3,446 |
| **2019** | 2,214,984 | 678,442 | 1,285,150 | 1,215,257 | 338,471 | 954,038 | 617,036 | 43,875 | 16,773 | 3,455 |
| **2020** | 2,217,629 | 673,992 | 1,252,266 | 1,231,479 | 337,928 | 975,022 | 615,194 | 44,015 | 16,826 | 3,465 |

# 2 Forecast Data and Assumptions

## 2.1 Historical Class Sales and Energy Data

Unfortunately, historical billing data is extremely difficult to use in constructing class sales forecast. The primary reason is that reported monthly sales are not a measure of calendar month use but rather reflect consumption over the current and prior two months, and includes accounting adjustments for unbilled sales – an estimate of what has been delivered, but not yet billed. The end-result is a monthly data series that does not correlate well with current-month weather conditions (the primary short-term driver of sales), and includes large month-to-month accounting adjustments that can't be explained in a regression model. As an example, monthly sales data for residential and small general service is depicted in Figure 6.

**Figure 6: Residential and Small Commercial Billed Sales (kWh)**




As depicted in Figure 6 there are large swings in month to month usage that are not weather related – particularly before 2008. With little to explain some of this variation the models' adjusted R-squared are relatively low.

Model statistical fit can be improved by using the billing data beginning in 2008 and constructing monthly weather variables that are derived as a weighted average of the current and prior two-month weather conditions. The problem with this solution, however, is that the historical data set is then rather short (January 2008 to August 2014) and begins right at the start of the recession; the class sales models estimated with the shorter historical series have better model statistics, but result in forecasts that are likely too low. AMI data should eventually allow for much better rate class sales forecast models. While this will significantly improve forecast models in the future, a longer period of historical sales data is still needed to estimate the sales regression models.

## 2.2 Weather Data

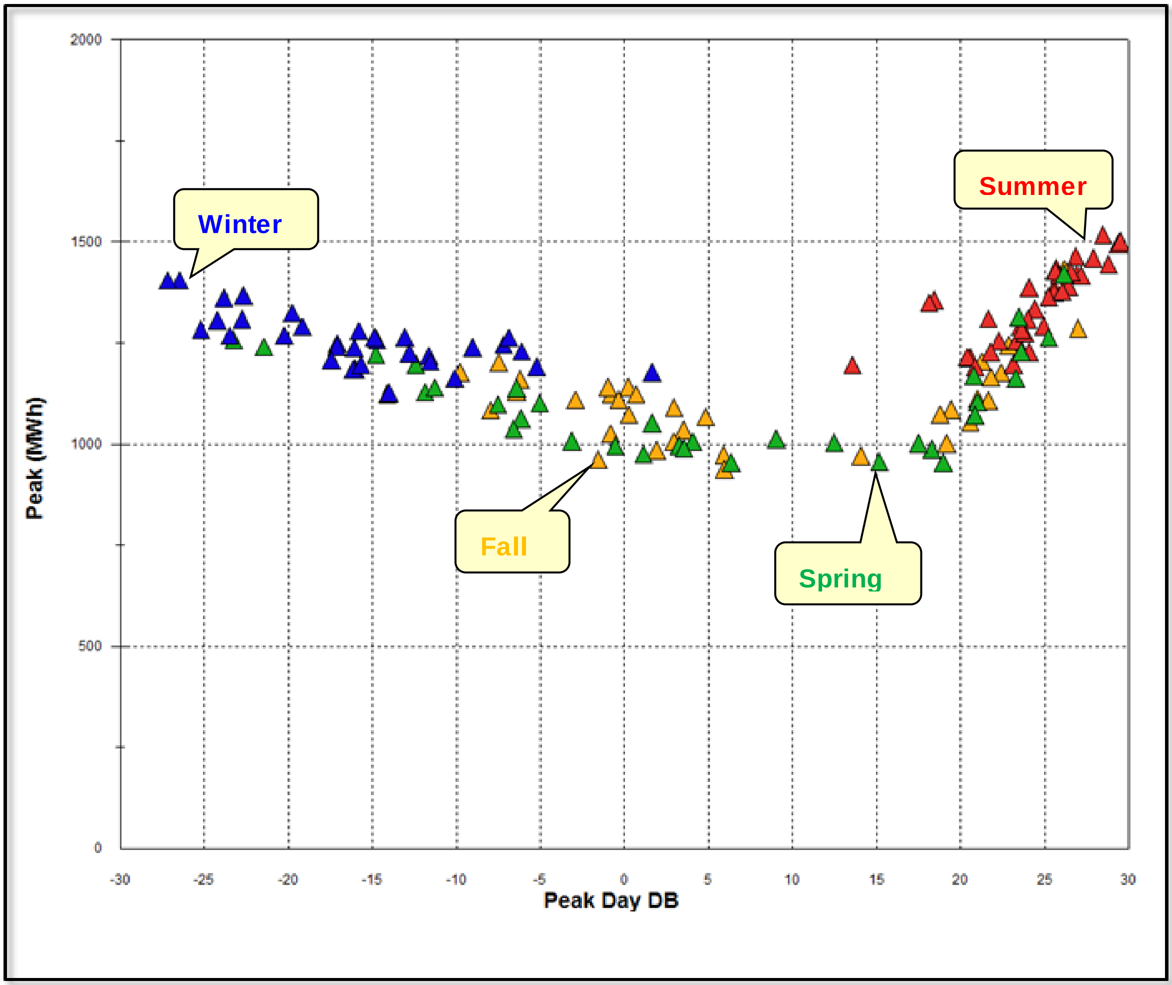
Actual and normal Heating Degree Days (HDD) and Cooling Degree Days (CDD) are calculated from daily average temperature and dew point data for Ottawa. Normal degree-days are calculated as an average of monthly degree-days over the past twenty years – 1994 through 2013. CDD and HDD are used in estimating and forecasting class sales and total purchases.

Given class billing data spans several calendar months, sales models are estimated using current as well as lag HDD and CDD variables. Residential sales are modeled using three-month weighted HDD and CDD as residential meters have historically been read every other month. Current and prior month HDD and CDD are used in constructing the weather variables for the nonresidential rate classes.

***Peak-Day Weather Variables***

Monthly peak-day HDD and TDD (temperature-humidity based degree-days) are used in forecasting peak demand. Peak-day degree-days are based on the average daily temperature and dew point that occurs on the day of the monthly peak. The appropriate breakpoints for the HDD and TDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 7.

**Figure 7: Monthly Peak Demand /Temperature Relationship**




From the scatter plot (and initial regression models) the "best" fit TDD variable is where TDD is defined with a THI base of 13 degrees and the best breakpoint for calculating the peak-day HDD variable is 10 degrees.

Normal peak-day HDD and TDD are derived as a twenty-year average using a *rank and average* approach. This approach entails first finding the highest HDD and TDD that occurred in each month over the last twenty years, and within each year ranking the degree-days from the highest to the lowest value so that there are 12 monthly ranked HDD and TDD in each year. The ranking across the years are then averaged effectively generating peak-weather TDD and HDD duration curves with 12 average values. The ranked-average TDD and HDD are assigned to specific months based on that peak-month TDD or HDD is most likely to occur. So for example, the highest TDD value is assigned to July, the next highest

August, the third highest June, and so forth. The highest HDD value is assigned to January, the next highest to February, the third highest to December, and so forth.

## 2.3 Economic Data

Purchases and class sales forecasts are based on the Conference Board's September 2014 economic forecast for the Ottawa and Gatineau area. The primary economic drivers are population, GDP, and real personal income (RPI). Table 4 shows the historical and forecasted economic drivers.

### Table 4: Ottawa Regional Economic Forecast

| Year | Population (000's) | Chg | GDP (Millions $) | Chg | RPI (Millions $) | Chg |
|---|---|---|---|---|---|---|
| 2003 | 1,140 | | 52,444 | | 36,688 | |
| 2004 | 1,150 | 0.9% | 53,924 | 2.8% | 37,661 | 2.7% |
| 2005 | 1,160 | 0.9% | 55,468 | 2.9% | 38,649 | 2.6% |
| 2006 | 1,172 | 1.0% | 57,253 | 3.2% | 40,263 | 4.2% |
| 2007 | 1,188 | 1.4% | 58,853 | 2.8% | 42,102 | 4.6% |
| 2008 | 1,207 | 1.6% | 59,880 | 1.7% | 43,203 | 2.6% |
| 2009 | 1,229 | 1.8% | 59,789 | -0.2% | 44,898 | 3.9% |
| 2010 | 1,251 | 1.8% | 61,473 | 2.8% | 45,221 | 0.7% |
| 2011 | 1,270 | 1.6% | 62,390 | 1.5% | 45,745 | 1.2% |
| 2012 | 1,289 | 1.5% | 62,759 | 0.6% | 46,941 | 2.6% |
| 2013 | 1,305 | 1.3% | 63,032 | 0.4% | 47,724 | 1.7% |
| 2014 | 1,319 | 1.0% | 63,484 | 0.7% | 48,712 | 2.1% |
| 2015 | 1,330 | 0.9% | 64,611 | 1.8% | 49,413 | 1.4% |
| 2016 | 1,343 | 1.0% | 66,029 | 2.2% | 50,509 | 2.2% |
| 2017 | 1,358 | 1.1% | 67,485 | 2.2% | 51,615 | 2.2% |
| 2018 | 1,373 | 1.1% | 69,037 | 2.3% | 52,791 | 2.3% |
| 2019 | 1,388 | 1.1% | 70,602 | 2.3% | 53,946 | 2.2% |
| 2020 | 1,402 | 1.0% | 72,165 | 2.2% | 55,080 | 2.1% |
| 2003-14 | | 1.35% | | 1.75% | | 2.63% |
| 2015-20 | | 1.03% | | 2.17% | | 2.07% |

## 2.4 Appliance Saturation and Efficiency Trends

End-use intensities are calculated from end-use saturation estimates (the share of homes that own a specific appliance) and measure of equipment efficiency. As saturation increases, energy intensity increases. As efficiency improves end-use intensity decreases. Declining customer average use is largely attributable to efficiency gains that have been stronger then increases in end-use saturations. Residential end-use intensity estimates are based on historical and projected end-use saturation and UEC (unit of energy consumption) from the Ontario Power Authority (OPA) recent long-term forecast for Ontario. UECs are used as a proxy for end-use stock average efficiency as efficiency data was not readily available. Residential lighting intensity is based on Energy Information Agency's (EIA) projection for the East North Central (ENC) Census Region; we felt that the OPA lighting intensity decline is too strong in the near-term.

Figure 8 shows the resulting major end-use intensities; Heating, Cooling, and All Other end uses. Figure 9 shows a detailed breakdown of the end-uses that make up All Other category.

**Figure 8: Major Residential End-Use Intensities (kWh per HH)**

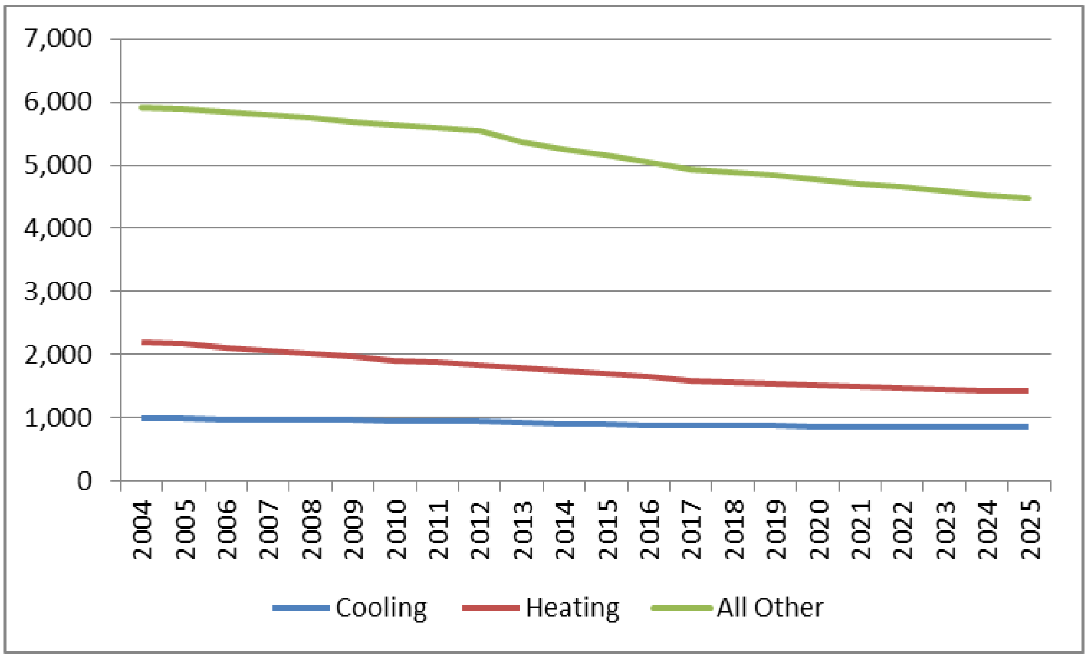
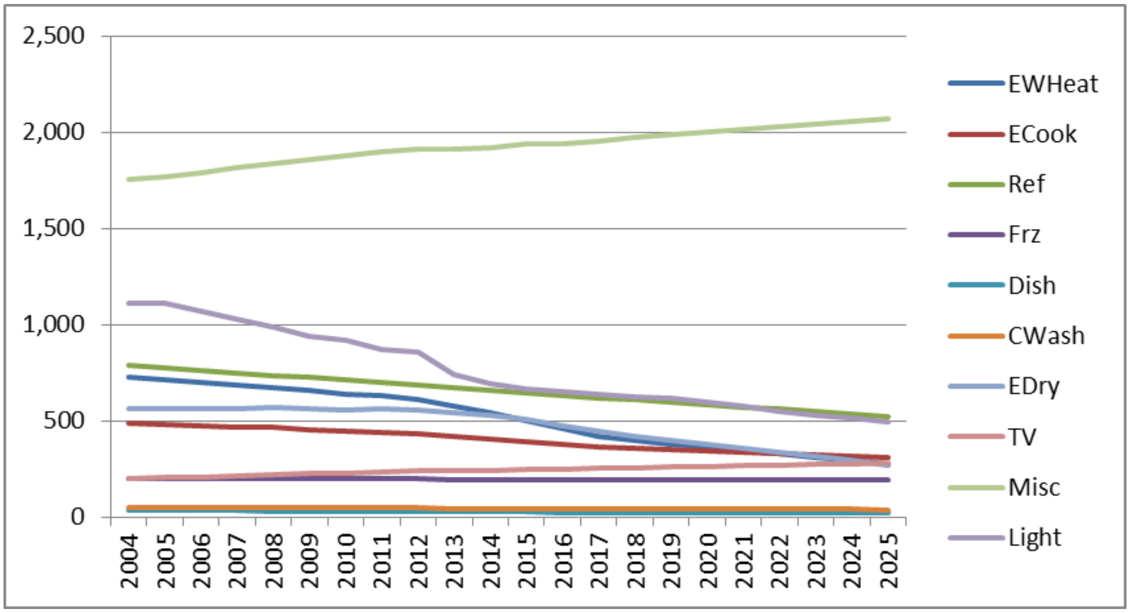


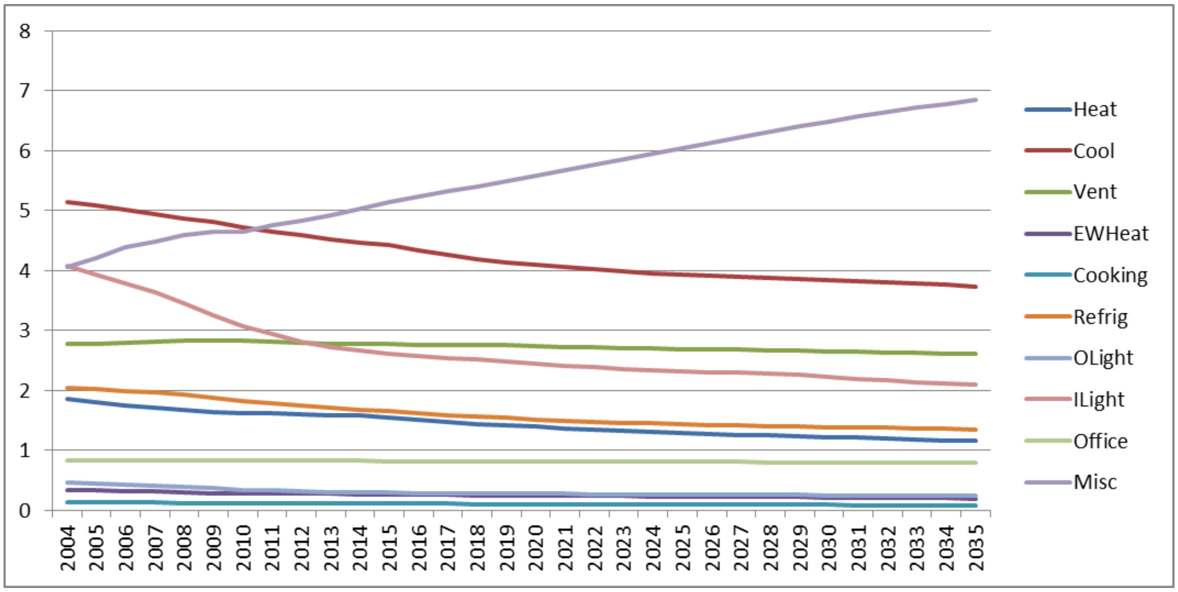
**Figure 9: Residential Non-Weather Sensitive End-Use Energy Intensities (kWh per HH)**




Electric heat is the largest residential end-use but has been declining and is expected to continue to decline as gas heat and more efficient heat pumps gain market share. Lighting intensity is expected to decline sharply over the next few years with the phase-in of new lighting standards; the new lighting standards effectively eliminate traditional incandescent light bulbs from the market with CFLs and LED lighting technologies gaining market share.

Commercial end-use intensities are derived from the Energy Information Agency (EIA) 2014 Annual Energy outlook for the East North Central Census Division. We assume that commercial end-use intensity trends in Ottawa are similar to that in the U.S. East-North Central Census Division. While Ottawa borders New York (in the Atlantic Census Division), the Atlantic Census Division is heavily influenced by New York City, New Jersey, and Pennsylvania. Figure 10 shows the commercial end-use intensity projections. Other than the miscellaneous end-use, commercial end-use energy intensities are either flat or declining. The strong growth in miscellaneous reflects increases in computer equipment, elevators, medical, and other equipment. Through 2020, commercial intensity is expected to decline 0.4% per year.

**Figure 10: Historical and Projected Commercial End-Use Intensities (kWh per square foot)**



# 3 Forecast Methodology

## 3.1 Class Sales Forecast

Changes in economic conditions, prices, weather conditions, and end-use energy intensity trends drives electricity use and demand through a set of monthly system and rate class sales forecast models. Models are estimated for the following rate classes:

- Residential
- GS50 (Less than 50 kW)
- GS1000NI (Non-Interval 50 kW – 1000 kW)
- GS1000I (Interval 50 kW – 1000 kW)
- GS1500 (1000 kW – 1500 kW)
- GS5000 (1500 KW – 5000 kW)
- Large Users (Over 5000 kW)
- Street Lighting
- MU
- DCL

.

### *3.1.1 Residential Model*

The residential monthly sales forecast captures economic growth as well improvements in energy efficiency through an SAE model specification. Residential sales are modeled as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

$$ResSales_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

Models are estimated using monthly billed sales data. As residential customer meters are read on a bi-monthly basis, usage in anyone month reflects not only current month weather conditions, but weather conditions in prior months. Both current and lag HDD and CDD are incorporated into the XHeat and XCool variables. For each rate class the optimal weighting of current and lagged month degree-days are determined by regressing usage on current and lagged HDD and CDD variables; the resulting coefficients are then used to construct weighted degree-day variables.

Model variables – *Xheat*, *XCool*, and *XOther* incorporate both economic activity and improvements in end-use efficiency. *XHeat* for month *m* is calculated as:

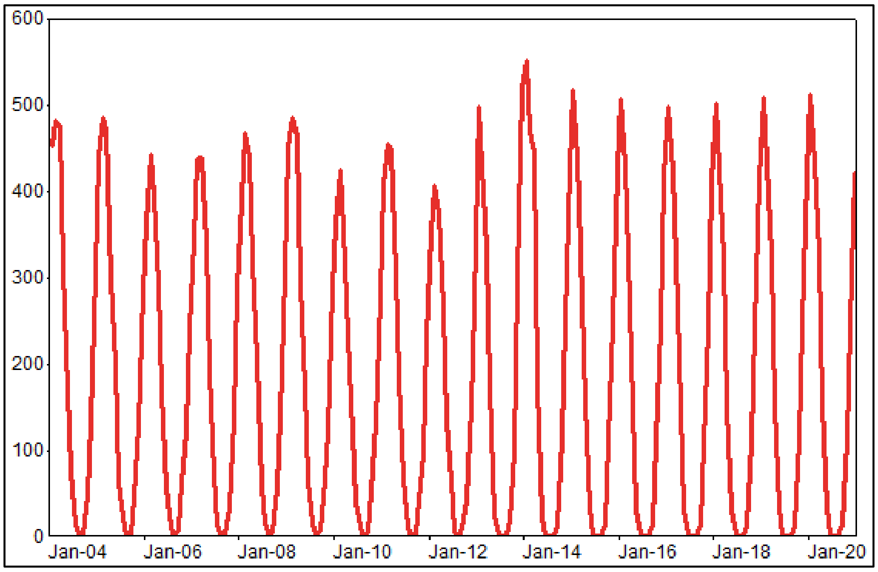
$$XHeat_m = HDD_m \text{ x } ResEcon_m \text{ x } HeatIntensity_a$$

Where

- $HDD_m$ = three-month weighted HDD (calendar-month HDD beginning in 2013)
- $ResEcon_m$ = weighted population and real personal income ($POP_m$^.5 x $RPI_m$^.5)
- $HeatIntensity_a$ = annual end-use heating intensity trend

Figure 11 shows the calculated XHeat variable

**Figure 11: Residential XHeat Variable**




*XCool* is derived in a similar manner:

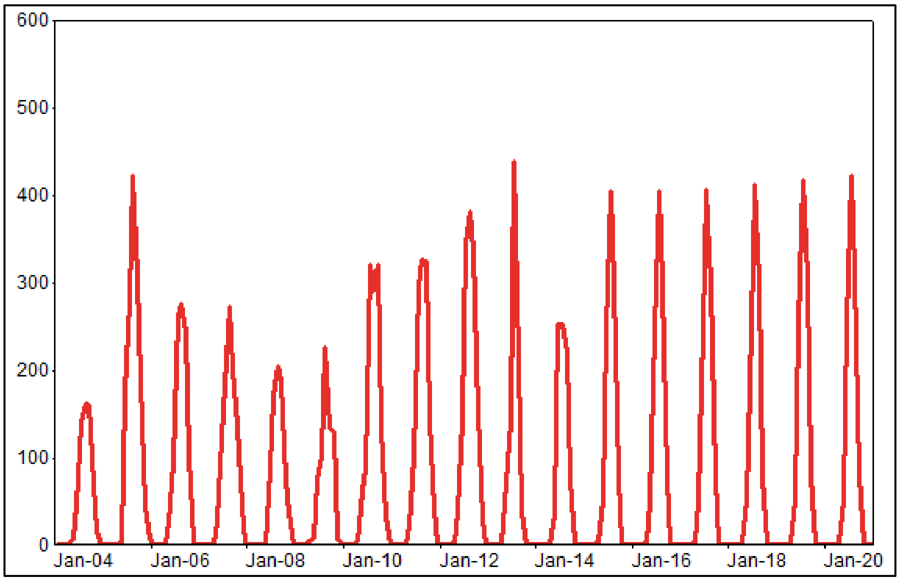
$XCool_m = CDD_m \times ResEcon_m \times CoolIntensity_a$

Where

- $CDD_m$ = three-month weighted CDD (calendar-month CDD beginning in 2013)
- $ResEcon_m$ = weighted population and real personal income ($POP_m$^.5 x $RPI_m$^.5)
- $CoolIntensity_a$ = annual end-use cooling intensity trend

Figure 12 shows the calculated XCool variable.

**Figure 12: Residential XCool Variable**




*XOther* captures non-weather sensitive end-use

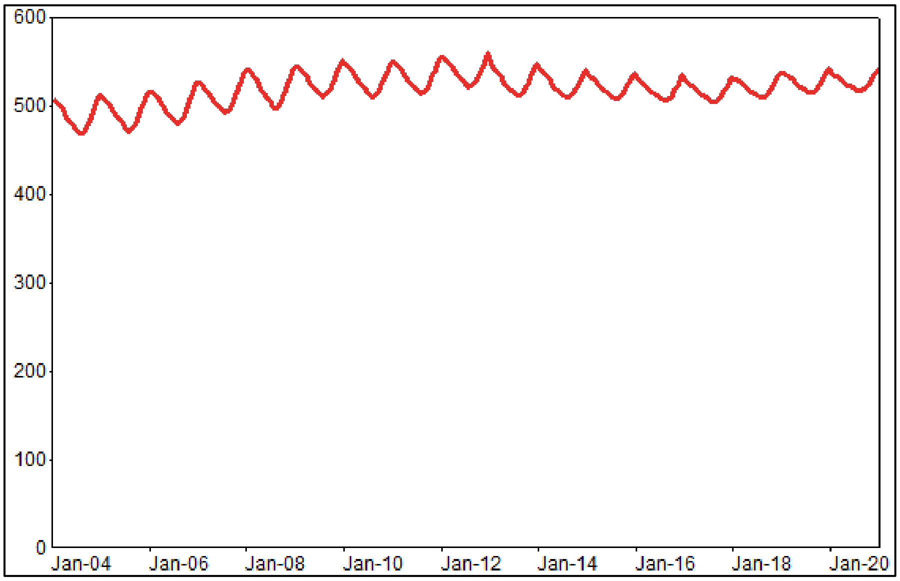
$$XOther_m = ResEcon_m \times OtherIntensity_a \times MonthlyMultiplier_m$$

Where

- $ResEcon_m$ = weighted population and real personal income ($POP_m$^.5 x $RPI_m$^.5)
- $OtherIntensity_a$ = annual non-weather sensitive end-use intensity trend
- $MoMultiply_m$ = monthly end-use usage fraction (fraction of annual usage)
-

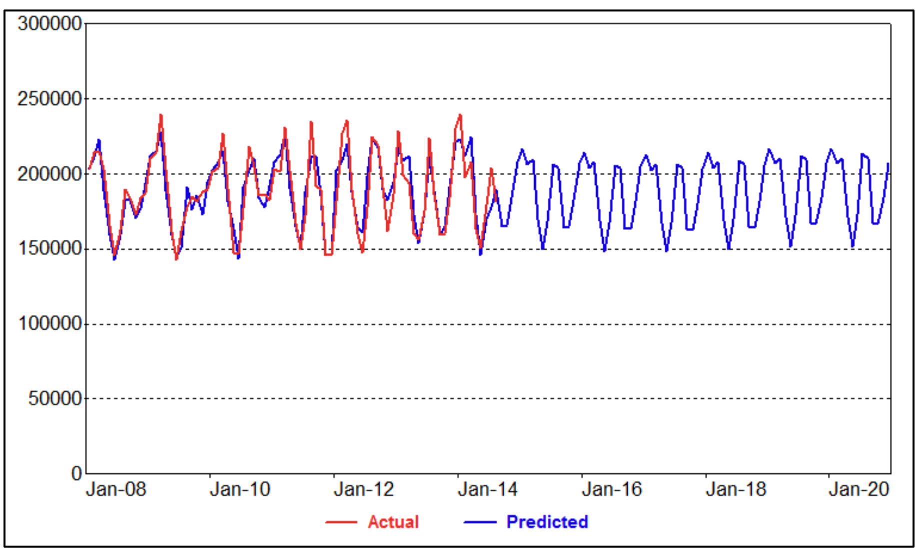
Figure 13 shows the calculated XOther variable.

## Figure 13: Residential XOther Variable




Cooling and Heating intensities are translated to a monthly variable through the interaction with monthly HDD and CDD. Annual intensities for the other end-uses are allocated to months based on estimated fraction of use in each calendar month. Figure 14 shows actual and predicted residential sales.

## Figure 14: Actual and Predicted Residential Sales




The residential sales model is estimated over the period January 2008 through August 2014. While the coefficients on XHeat, XCool, and XOther are all highly significant, the adjusted R-squared is only 0.81 and in-sample MAPE is 4.4%. This is relatively low for a residential SAE model and is a result of using the monthly billing data as a proxy for actual usage

***Customer Forecast***

The customer forecast is based on a monthly regression model that relates the number of customers to population projections. There is a strong correlation between the number of customers and reported population. The correlation between the number of customers and population is 0.997. Table 5 shows the residential customer forecast. Given population projections customers are expected to average 1.3% annual growth through 2020.

**Table 5: Residential Customer Forecast**

| Year | Residential Customers | chg |
|---|---|---|
| 2006 | 254,245 | |
| 2007 | 258,262 | 1.6% |
| 2008 | 262,786 | 1.8% |
| 2009 | 267,225 | 1.7% |
| 2010 | 271,603 | 1.6% |
| 2011 | 275,966 | 1.6% |
| 2012 | 280,254 | 1.6% |
| 2013 | 284,964 | 1.7% |
| 2014 | 289,258 | 1.5% |
| 2015 | 293,366 | 1.4% |
| 2016 | 297,343 | 1.4% |
| 2017 | 301,258 | 1.3% |
| 2018 | 305,144 | 1.3% |
| 2019 | 308,990 | 1.3% |
| 2020 | 312,786 | 1.2% |

### *3.1.2 Commercial Forecast Models*

Like the residential model, the commercial SAE sales models express monthly sales as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther). Hydro Ottawa has multiple commercial rate classes that are defined by customer demand requirements. While separate sales forecast models are estimated for each rate class, the model structure is basically the same:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

- $XHeat_m = \mathrm{EI_{heat}} \times \mathrm{EconVar_m} \times \mathrm{HDD_m}$

- $XCool_m = \mathrm{EI_{cool}} \times \mathrm{EconVar_m} \times \mathrm{CDD_m}$
- $XOther_m = \mathrm{EI_{other}} \times \mathrm{EconVar_m}$

EI is the end-use weighted energy intensity (kWh per square feet) and captures end-use saturation growth and improvements in end-use efficiency. The economic variable $\mathrm{EconVar_m}$ is equally weighted between population and GDP.

- $EconVar_m = Pop_m$^.5 x $GDP_m$^.5

Commercial sales models are estimated over the period January 2008 to August 2014. The adjusted R-squared vary from 0.70 for small commercial (GS50) to 0.91 for GS1000 non-interval rate class. While the Adjusted R-squared are not particularly strong, the end-use model variables are statistically significant and capture the rate class sales trend. Figure 15 to Figure 19 shows actual and predicted sales for the commercial rate classes. Estimated model coefficients and model statistics are included in Appendix A.

**Figure 15: Actual and Predicted GS < 50 Sales (MWh)**

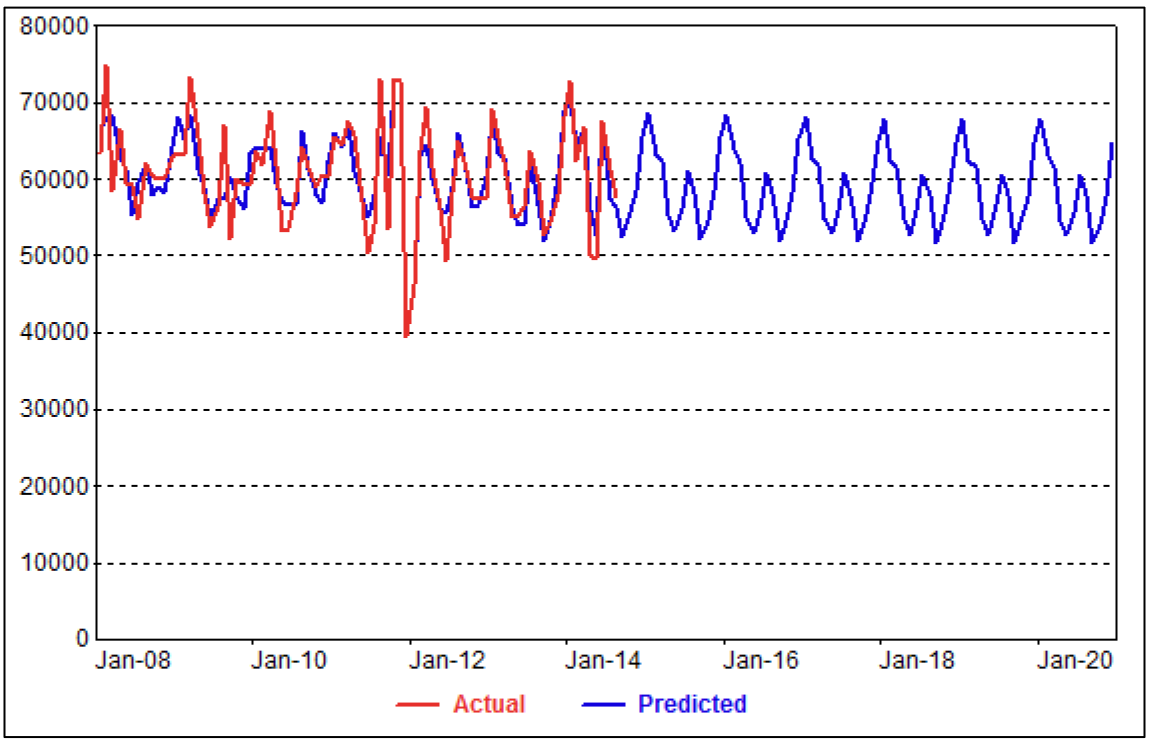


**Figure 16: Actual and Predicted GS NI 50-1000 Sales (MWh)**

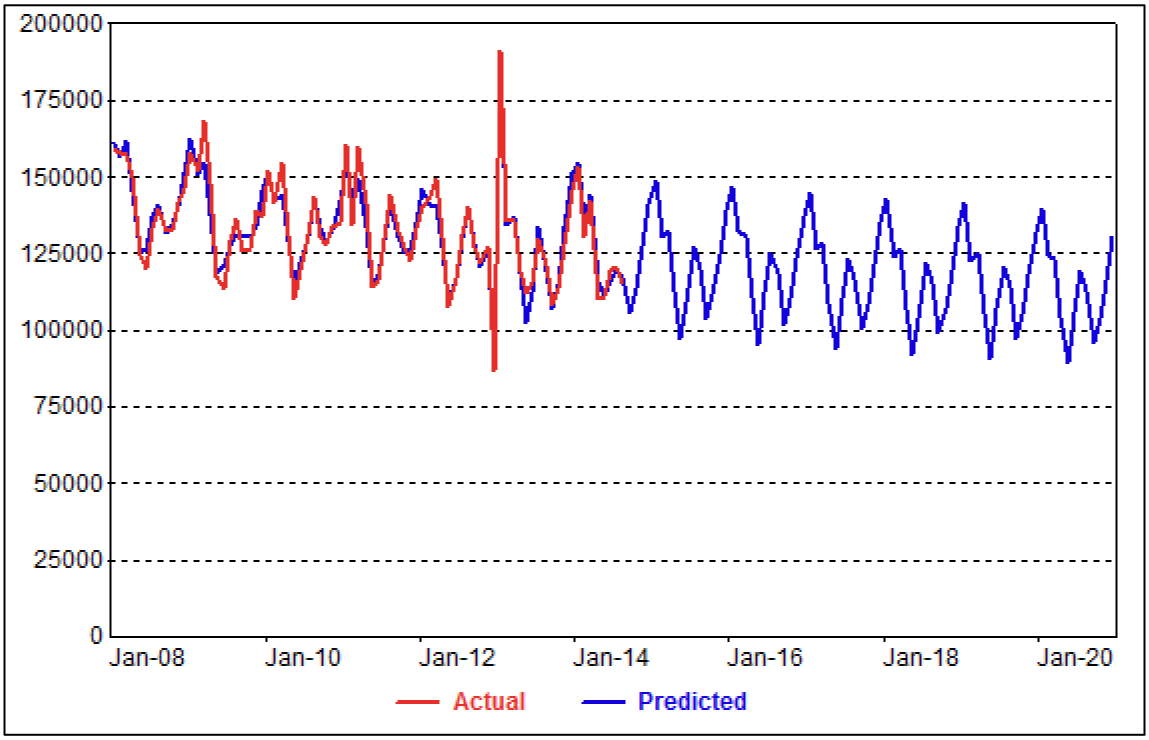



**Figure 17: Actual and Predicted GS I 50-1000 Sales (MWh)**

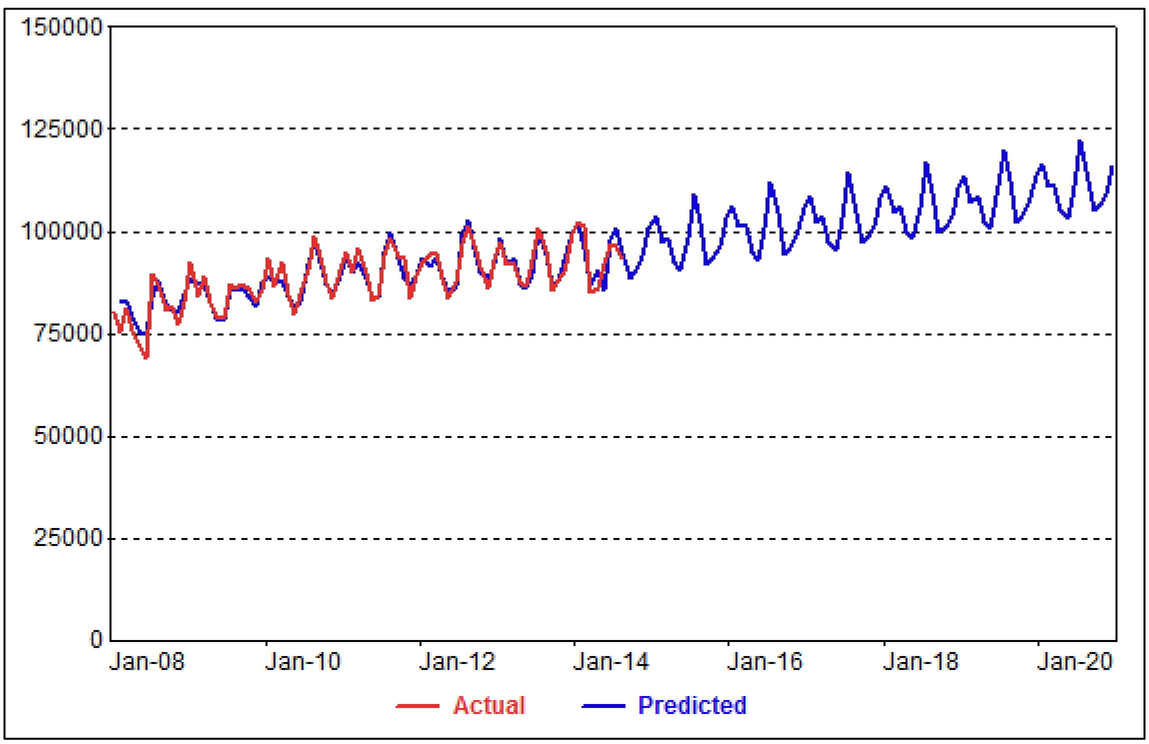


**Figure 18: Actual and Predicted GS 1000-1500 Sales (MWh)**

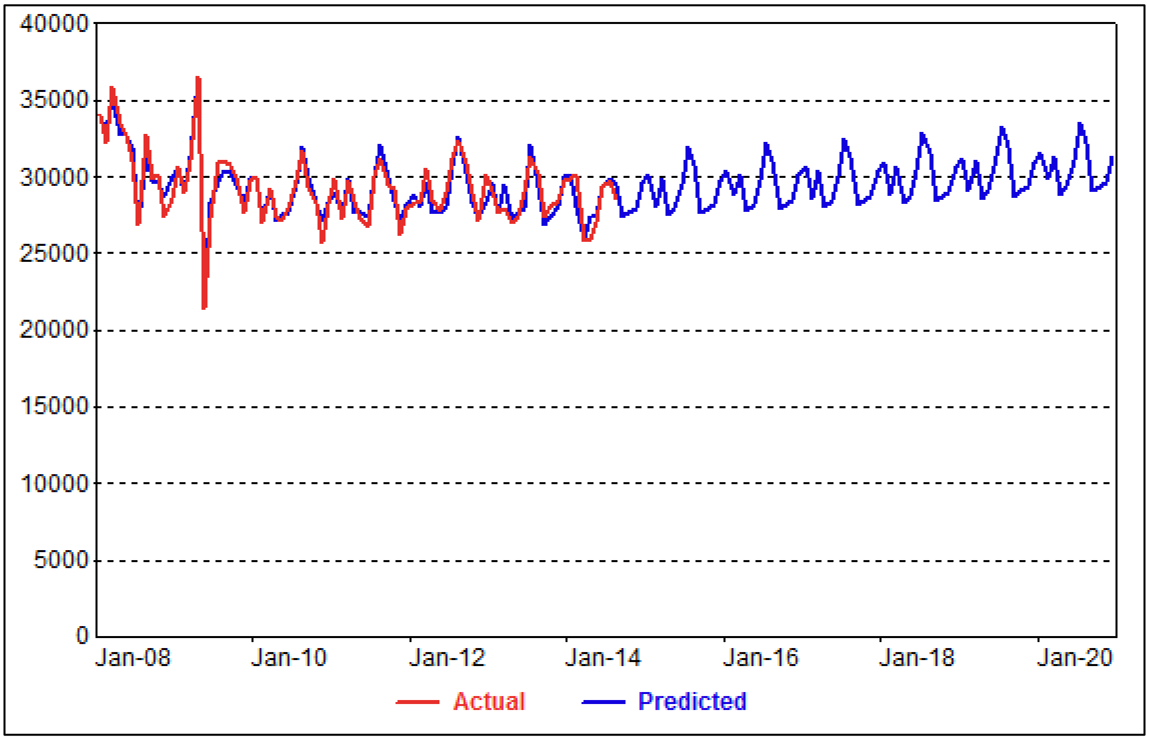
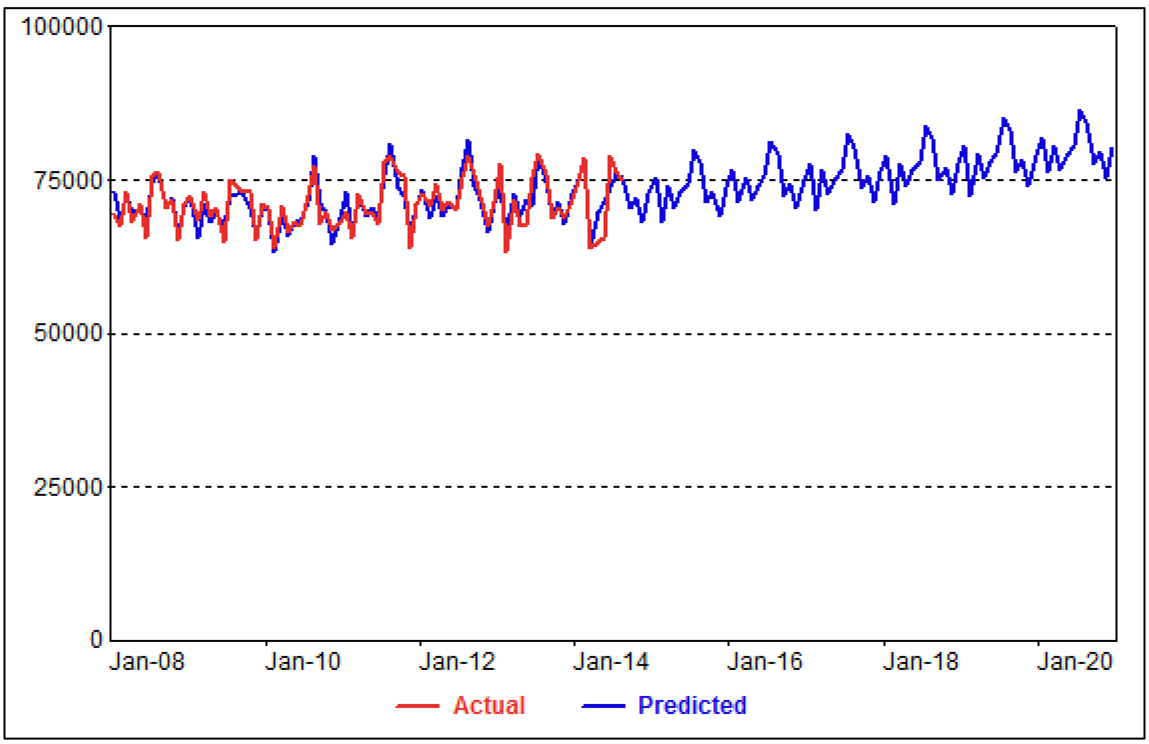



**Figure 19: Actual and Predicted GS 1500-5000 Sales (MWh)**



Separate models are estimated for commercial customers. GS50 customers are driven by the number of residential customers as the correlation between GS50 customers and residential customers is 0.97. A simple linear trend model is used to forecast customers for the GS1000 rate classes (non-interval and interval-meter classes) as customers have been migrating from non-interval rate class to the interval rate class; changes in customers could not be correlated with any economic driver. GS1500 and GS5000 customers are also estimated with simple trend models as there are very few customers in these rate classes making it difficult to estimate causal-related regression models. GS50 accounts for most of the commercial customers. GS50 customers are projected to increase 0.5% annually through the forecast period. Table 6 shows the commercial customer forecast.

**Table 6: Commercial Customer Forecast**

| Year | GS < 50 | Chg | GS NI 50-1000 | Chg | GS I 50-1000 | Chg | GS 1000-1500 | Chg | GS 1500-5000 | Chg |
|---|---|---|---|---|---|---|---|---|---|---|
| 2006 | 23,026 | | 2,733 | | 429 | | 60 | | 64 | |
| 2007 | 23,182 | 0.7% | 2,687 | -1.7% | 468 | 9.0% | 64 | 5.5% | 66 | 3.8% |
| 2008 | 23,306 | 0.5% | 2,700 | 0.5% | 494 | 5.6% | 64 | 1.2% | 67 | 0.8% |
| 2009 | 23,312 | 0.0% | 2,675 | -0.9% | 545 | 10.4% | 58 | -9.6% | 67 | -0.4% |
| 2010 | 23,434 | 0.5% | 2,648 | -1.0% | 578 | 6.0% | 53 | -9.2% | 66 | -0.6% |
| 2011 | 23,616 | 0.8% | 2,698 | 1.9% | 599 | 3.5% | 56 | 5.8% | 69 | 5.0% |
| 2012 | 23,767 | 0.6% | 2,732 | 1.3% | 628 | 4.9% | 56 | 0.5% | 74 | 6.1% |
| 2013 | 23,936 | 0.7% | 2,695 | -1.4% | 654 | 4.1% | 59 | 4.7% | 76 | 2.9% |
| 2014 | 23,944 | 0.0% | 2,770 | 2.8% | 685 | 4.7% | 61 | 3.9% | 87 | 14.3% |
| 2015 | 24,099 | 0.6% | 2,775 | 0.2% | 712 | 4.0% | 62 | 1.8% | 88 | 1.5% |
| 2016 | 24,218 | 0.5% | 2,775 | 0.0% | 739 | 3.9% | 63 | 0.6% | 88 | 0.0% |
| 2017 | 24,332 | 0.5% | 2,775 | 0.0% | 767 | 3.8% | 63 | 0.6% | 88 | 0.0% |
| 2018 | 24,445 | 0.5% | 2,775 | 0.0% | 795 | 3.6% | 63 | 0.6% | 88 | 0.0% |
| 2019 | 24,556 | 0.5% | 2,775 | 0.0% | 823 | 3.5% | 64 | 0.6% | 88 | 0.0% |
| 2020 | 24,665 | 0.4% | 2,775 | 0.0% | 851 | 3.4% | 64 | 0.6% | 88 | 0.0% |

### *3.1.3 Other Rate Classes: Large Users, Street Lighting, MU, DCL Sales Models*

Generalized econometric models are estimated for Large Users, as well as the Street Lighting, MU, and DCL. The Large Users class is a simple model specification that relates monthly sales to GDP, GDP interactive with a linear trend (*GDP x Trend*), and prior month CDD. The GDP interactive term allows the slope of the GDP variable to change over time. The resulting model has an adjusted R-squared of 0.74 and in-sample MAPE of 2.95%. Again the adjusted R-squared is not particularly strong as there is significant month-to-month sales variation that cannot be explained by macro-economic drivers. The Street Lighting class is modeled using monthly binaries and population projections. The resulting model produces a good fit with an adjusted $R^2$ of 0.93 and in-sample M.A.P.E of 5.87%. Figure 20 and Figure 21 show the actual and predicted values for the Large Users and Street Lighting classes.

**Figure 20: Actual and Predicted Large Users Sales (MWh)**

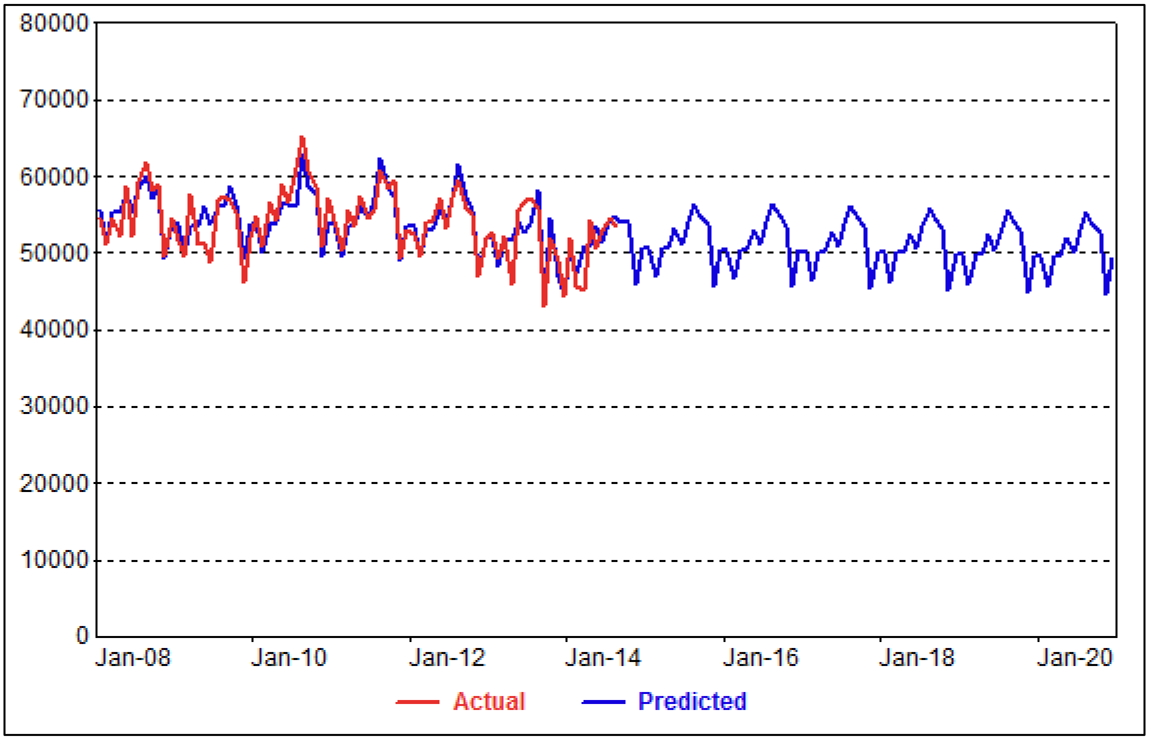
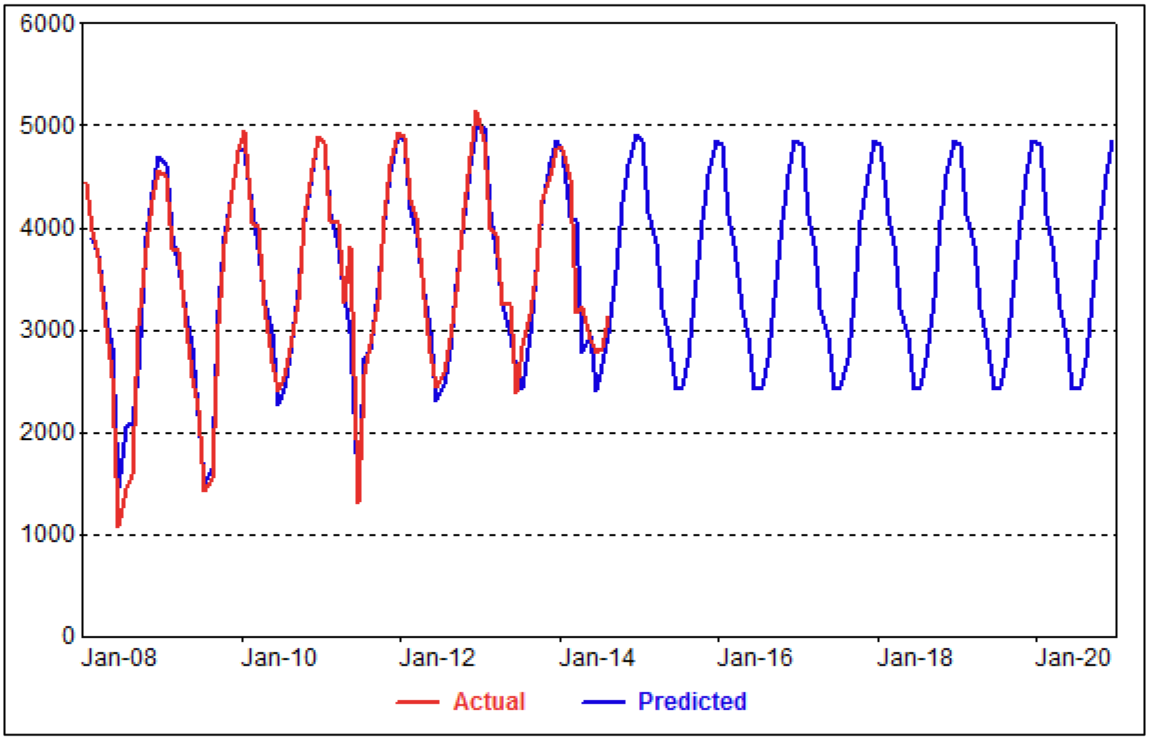


**Figure 21: Actual and Predicted Street Lighting Sales (MWh)**




The MU and DCL classes are both extremely small rate classes with little sales. Given there is little information to explain sales trends, models are estimated with simple exponential smoothing models. The estimated model coefficients and model statistics are included in Appendix A.

## 3.2 System Purchase and Peak Demand Forecast

### *3.2.1 System Purchase Forecast*

Initially, a system purchase forecast model was estimated to validate the rate class based sales forecast; when estimated over the same period and using a similar SAE model specification, system purchase forecast is very close to the sum of the rate class forecast. Given the issues related to estimating rate class sales forecast models with billed sales data, we ultimately elected to allocate total sales forecast to the rate class sales forecasts. At the system level, we are able to use more months of historical data (the model is estimated beginning in 2005) and thus pick up stronger economic growth in the estimated model coefficients. The total purchase sales forecast model is also significantly stronger (in terms of statistical fit) than the rate class models.

Like the class sales forecast, the purchase model explicitly incorporates efficiency into the model specification. Heating, cooling, and other use intensity estimates are derived by combining the residential and commercial energy intensities. The best model fit at the purchase level is a 40% weighting on residential intensity and a 60% weighting on commercial intensity. The purchase sale model is estimated using a SAE specification. Purchases in month $m$ are defined as:

$$Purchase_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

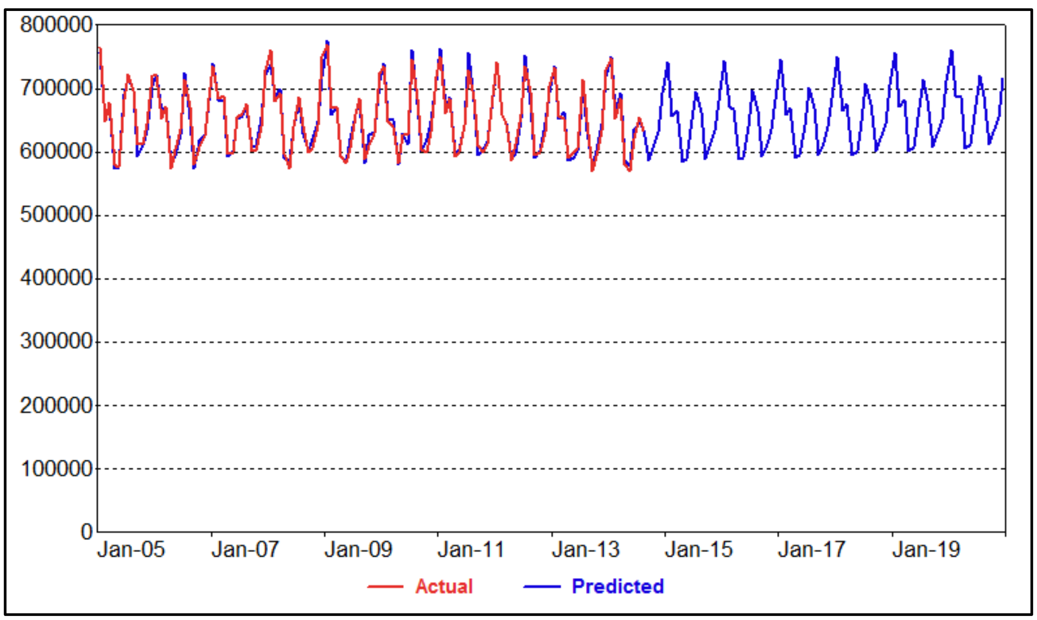
Where:

- $XHeat_m = \mathrm{SysEI_{heat}} \times \mathrm{EconVar_m} \times \mathrm{HDD_m}$
- $XCool_m = \mathrm{SysEI_{cool}} \times \mathrm{EconVar_m} \times \mathrm{CDD_m}$
- $XOther_m = \mathrm{SysEI_{other}} \times \mathrm{EconVar_m}$

*SysEI* is a weighted residential and commercial energy intensity index derived from the end-use intensity estimates. *EconVar* is an economic driver that is equally weighted between population and GDP; population captures underlying customer growth and GDP reflects regional economic activity. A weighted economic variable allows us to capture customer growth and economic activity through a single economic variable and thus avoid any modeling issues associated with multicolinearity.

The model is estimated with monthly purchase data from January 2005 to August 2014. The model explains historical sales well with an adjusted R-squared of 0.96 and MAPE of 1.2%. Figure 22 shows actual and predicted purchases.

**Figure 22: Actual and Predicted Purchases (MWh)**




The purchase model is significantly stronger in terms of statistical fit than the rate class models as purchases are measured monthly MWh and correlates with current month weather conditions. To test the purchase model performance, the last two years of actual data is held out of the estimation period. Forecast results for those two years are then compared with actual sales. The out of sample MAPE for the test period (September 2012 to August 2014) is 1.35% with an average forecast error of just -0.48%. Strong in-sample fit statistics and out-of-sample performance provides a high level of confidence in the model structure and resulting forecast. Model statistics are included in Appendix A.

### 3.2.2 Peak Forecast

The system peak forecast is derived through a monthly regression model that relates monthly peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

System peak is effectively driven by the purchase sales forecast. The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements derived from the purchase sales forecast model as well as peak-day weather conditions. Through the constructed model variables, efficiency impacts on total purchases are also captured in the peak demand model.

***<u>Heating and Cooling Model Variables</u>***

The variable *HeatVar*, is derived by combining peak-day HDD (*PkHDD*) with an estimate of monthly heating requirements (*HeatLoad*):

$$HeatVar_m = HeatLoad_m \times PkHDD_m$$

*Heatload* reflects the change in heating requirements from population and economic growth, and changes in heating intensity. *HeatLoad* is calculated from the purchase sales model by multiplying *XHeat* for normal weather conditions by the *XHeat* model coefficient $B_1$:

$$HeatLoad_m = B_1 \times NrmXHeat_m$$

The peak-day cooling variable is constructed in a similar manner. *CoolVar* is calculated as:

$$CoolVar_m = CoolLoad_m \times PkTDD_m$$

Where

$CoolLoad_m = B_2 \times NrmXCool_m$
*PkTDDm = Peak-day THI degree-day*

*NrmXCool* is equal to *XCool* variable constructed with normal monthly CDD times $B_2$ (the estimated coefficient for *XCool* in the purchase sales model). Figure 23 and Figure 24 show the peak model heating and cooling variables.

**Figure 23: Peak XHeat Variable**

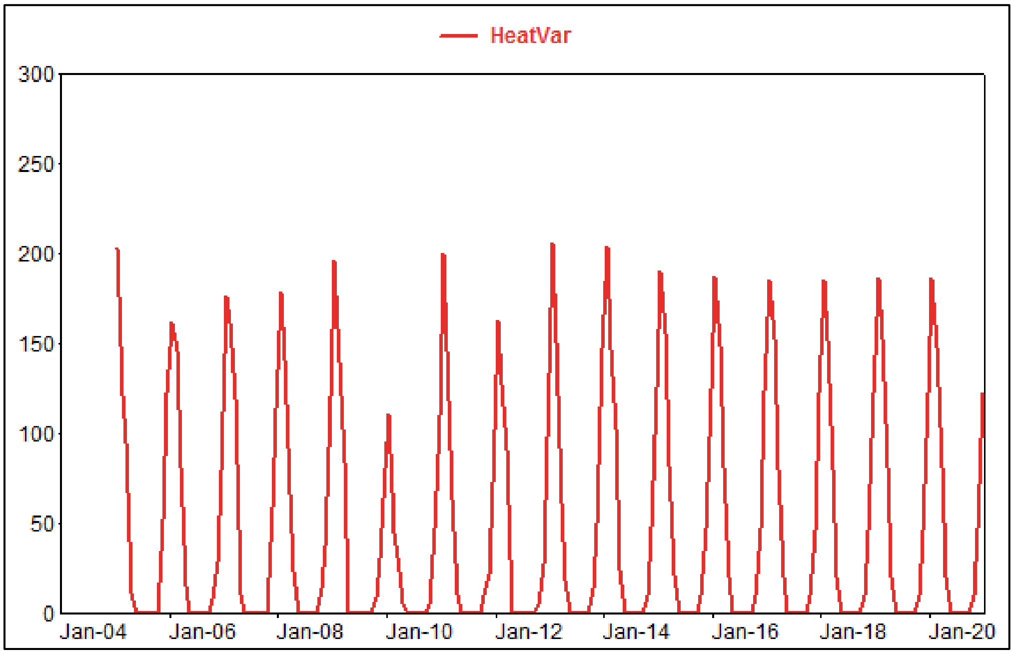
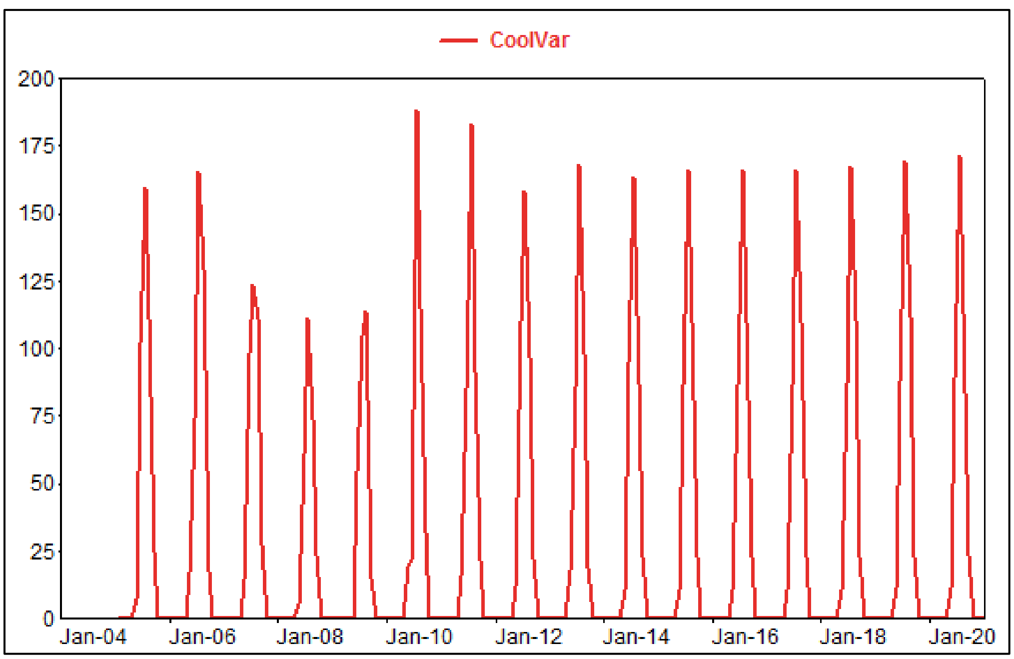



**Figure 24: Peak XCool Variable**



***BaseVar Model Variable***

BaseVar captures growth in non-weather sensitive usage at the time of the peak. It is again derived from the purchase forecast model. Basevar is calculated by subtracting weather-normal cooling and heating load requirements from weather normal total purchases and forecast.

$$BaseVar_m = WNPurchase_m – HeatVar_m - CoolVar_m$$

*BaseVar* is expressed on an average monthly MW basis by dividing *BaseVar* by the number of hours in the month. Figure 25 shows the derived model variable *BaseVar*.

**Figure 25: Peak Base Variable**

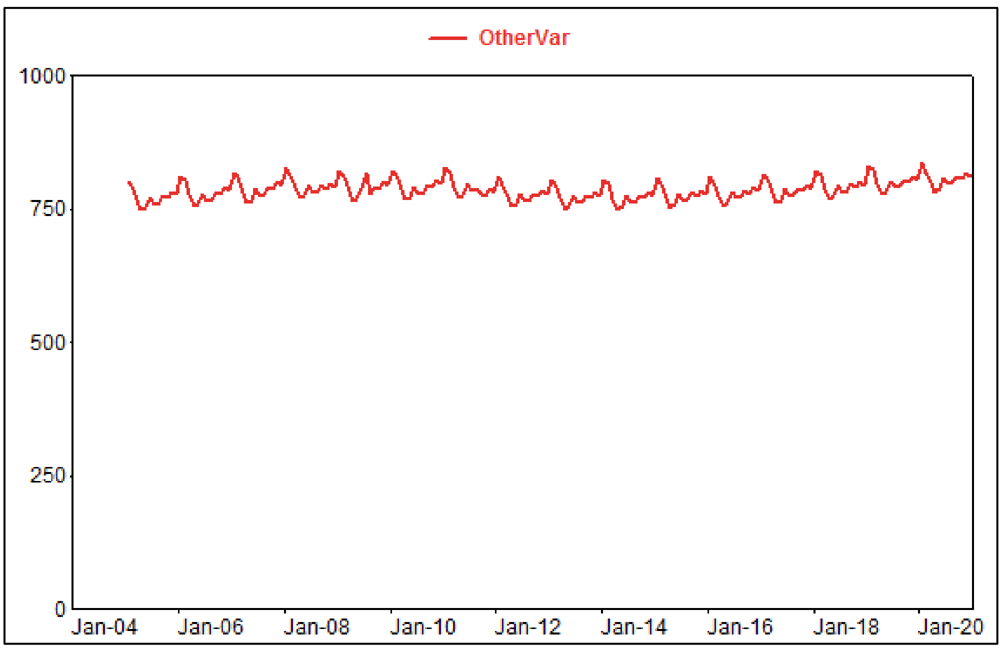
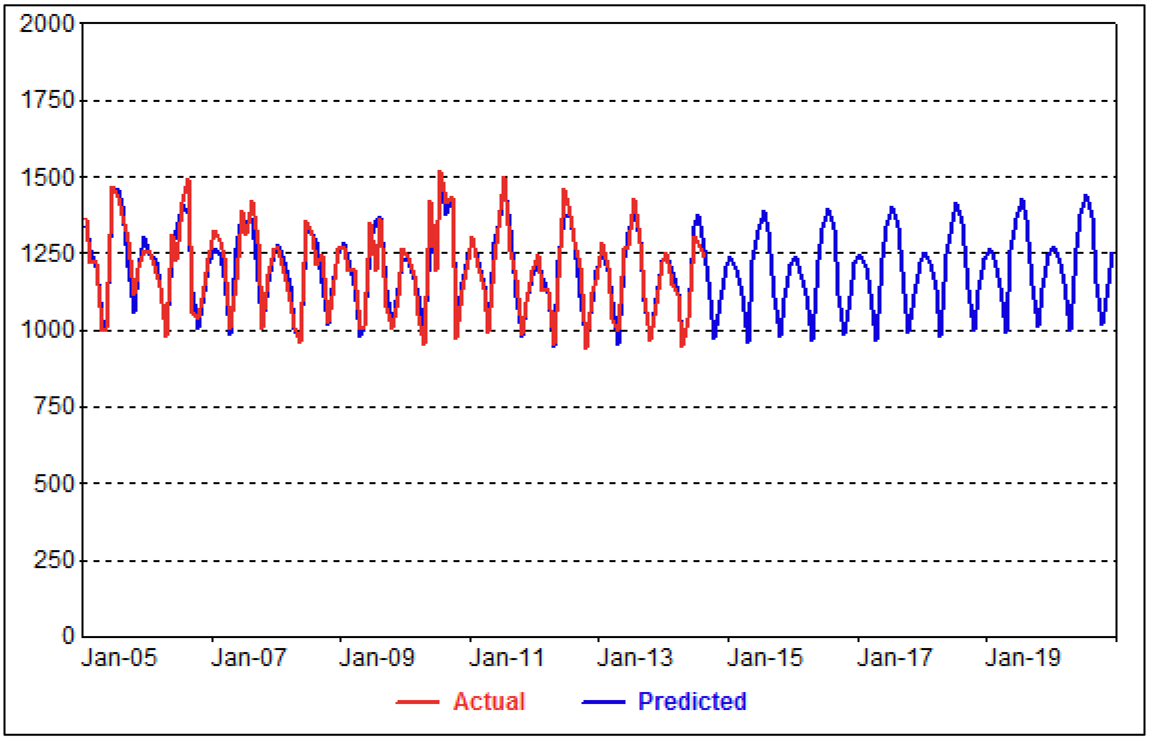



Figure 26 shows actual and predicted monthly system peak.

**Figure 26: Peak Model (MW)**




In addition to the end-use variables, the peak model includes monthly binaries for several months to account for non-weather seasonal changes in demand and a shift variable to account for a small drop in demand after September 2011. The model explains past variation relatively well with an adjusted R-squared is 0.88 with a MAPE of 2.85%. The model statistical fit is not as strong as monthly purchase model as peak demand represents just one hour in a month; any number of other factors from activity by a specific large customer, temperature pattern across the day, and the day of the peak itself will have an impact. Table 7 shows the system peak forecast with and without CDM adjustments.

**Table 7: System Peak Forecast (MW)**

| Year | Unadjusted Peak | Chg | CDM Unadjusted Peak | Chg |
|---|---|---|---|---|
| 2006 | 1,495 | 2.10% | 1,495 | |
| 2007 | 1,425 | -4.7% | 1,425 | -4.7% |
| 2008 | 1,355 | -4.9% | 1,355 | -4.9% |
| 2009 | 1,364 | 0.6% | 1,364 | 0.6% |
| 2010 | 1,518 | 11.3% | 1,518 | 11.3% |
| 2011 | 1,502 | -1.1% | 1,502 | -1.1% |
| 2012 | 1,459 | -2.9% | 1,459 | -2.9% |
| 2013 | 1,427 | -2.1% | 1,427 | -2.1% |
| 2014 | 1,304 | -8.7% | 1,304 | -8.7% |
| 2015 | 1,388 | 6.5% | 1,380 | 5.8% |
| 2016 | 1,394 | 0.4% | 1,375 | -0.4% |
| 2017 | 1,400 | 0.5% | 1,367 | -0.5% |
| 2018 | 1,412 | 0.9% | 1,367 | 0.0% |
| 2019 | 1,425 | 0.9% | 1,368 | 0.1% |
| 2020 | 1,436 | 0.8% | 1,368 | 0.0% |

## 3.3 Purchases to Total Sales

The purchase forecast must first be adjusted down to account for losses before it can be allocated to the rate classes based on the forecasted share. This is done prior to any adjustments are made for CDM. Traditionally one average system loss factor would be applied to the purchase forecast to arrive at total sales; Hydro Ottawa uses two separate loss factors, one for primary metered accounts and another for secondary metered accounts. This is done to account for the fact that primary metered accounts have much lower losses due to close or direct connection to higher capacity lines. The loss factor used for primary metered accounts is 1.0062, all other accounts are assumed to be secondary and use a loss factor of 1.0338. Of the residential, commercial, and industrial rate classes only the GS Large User rate class is assumed to be primary metered.

In order to use two different loss factors purchases must be split into two groups; one of which will use the primary loss factor and the other the secondary. To do this we first calculate implied primary and secondary purchases from the class level sales forecast. The GS Large User class sales is multiplied by the 1.0062 factor while all other classes sales are multiplied by the 1.0338 factor. With this implied purchase forecast we can calculate the share of total purchases that are primary and second. The calculated share is then used to split the actual purchase forecast into two groups. From there the appropriate loss factor is applied and the result is a sales forecast that accounts for different loss factors.

## 3.4 Adjustments for CDM

Rate class sales are adjusted for future CDM savings projections after class sales have been allocated from total purchase sales. Forecasts are adjusted for future conservation savings beginning in the first forecast month (September 2014). We assume that all historical CDM savings are embedded in the historical data and thus impacts carry through the forecast period. The underlying assumption is that any measure that was adopted as a result of CDM program activity persists over the forecast period – that is, when measures are replaced they are replaced with measures that are as least as efficient as what has been installed. Improving end-use efficiency and new end-use standards will make it exceedingly difficult to replace a more efficient end-use with something less efficient.

CDM projections are based on savings goals established by the government. Annualized savings estimates are provided for residential and nonresidential customer classes. Non-residential customer savings are allocated to the nonresidential rate classes base on the rate classes' proportion of total nonresidential sales. Table 8 shows the annualized savings projections.

**Table 8: CDM Savings Projections**

| Year | Residential | Small Commercial | Commercial |
|---|---|---|---|
| 2015 | 5,925 | 3,950 | 29,625 |
| 2016 | 11,850 | 7,900 | 59,250 |
| 2017 | 11,850 | 7,900 | 59,250 |
| 2018 | 9,875 | 6,583 | 49,375 |
| 2019 | 9,875 | 6,583 | 49,375 |
| 2020 | 9,875 | 6,583 | 49,375 |

Annualized estimates represent the savings if all the associated measures were in place for the entire year. For the forecast adjustment, we assume that the measures associated with annualized savings are installed equally across the 12 months. That is if a program involved the installation of 100,000 LED bulbs – 1/12 would be in place after the first month, 2/12 in the second month, 3/12 in the third month, and so forth until all the bulbs were installed by the end of the year. As measures are installed over the course of the year, roughly half the annualized savings are realized in the current year with the other half of the savings realized in the following year.

Monthly CDM adjustments are cumulated over the forecast period beginning in the first forecast month – September 2014. The savings in the third quarter of 2014 carries over into 2015. The savings in 2015 and 2014 carries over into 2016. By 2020, total CDM savings includes cumulative savings from September 2014 through 2020. Figure 27 shows cumulative residential and nonresidential savings adjustments.

**Figure 27: Cumulative CDM Savings (MWh)**

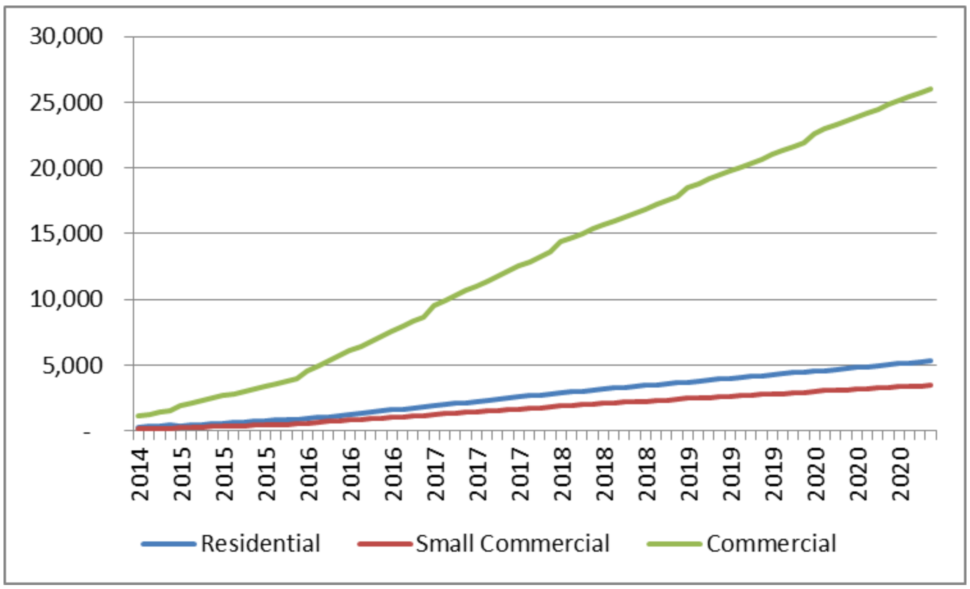
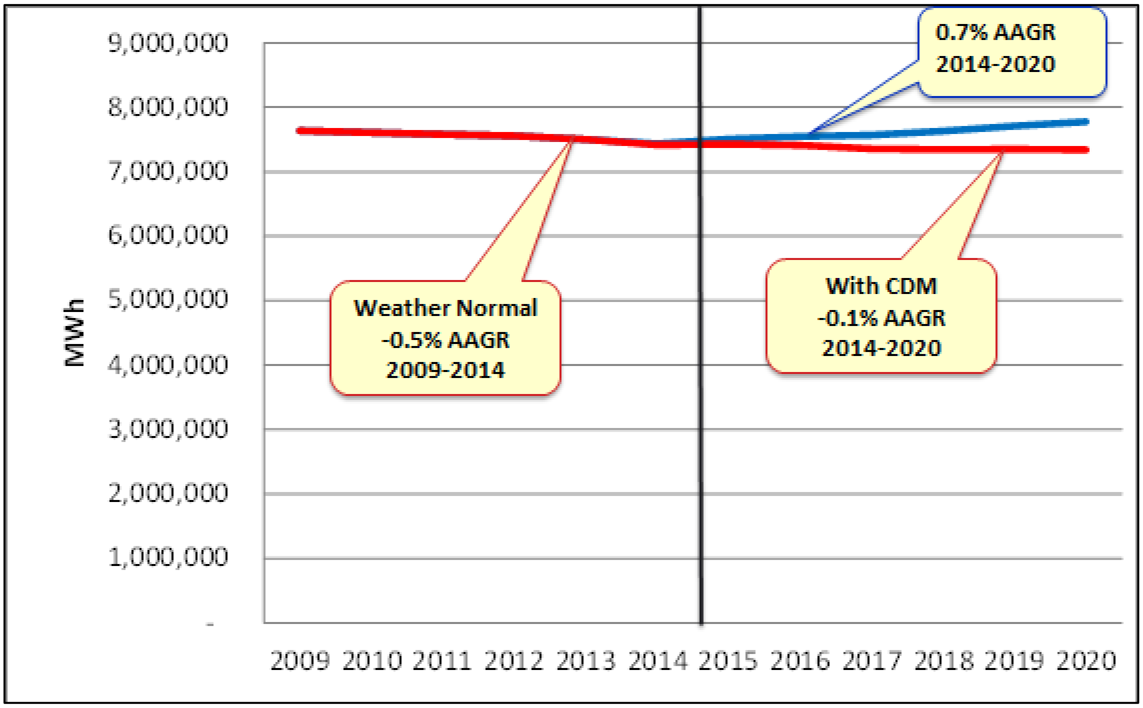


Figure 28 compares the forecast with and without CDM adjustments. Excluding additional CDM activity, sales are projected to average 0.7% annually between 2014 and 2020. CDM reduces annual sales growth by 0.8% over the next five years. The forecast with CDM sales adjustments is consistent with that over the prior five years. Normalized average sales growth is lower as it includes the economic slowdown.

**Figure 28: CDM Forecast Comparison**




CDM reduces sales growth by .8%. This is fairly consistent with the OPA Ontario forecast which shows differences between gross sales growth (without CDM adjustments) and net sales growth over the same period of 1.0%.

The rate-class sales forecasts are adjusted for CDM after the class sales forecasts are allocated from the total system sales forecast.

**Billing Demand Forecast**

Several rate classes include a billing demand as well as sales and customer component. Billing demand is a measure of a customer's highest hourly demand over the billing period. An average monthly billing demand factor is calculated for each rate class that has a billing demand component. Billing demand factors are calculated from historical billing data and are derived as the average monthly ratio of billed demands to class sales. The billing demand forecast is then generated by multiplying the class monthly billing demand factor to class sales forecast adjusted for CDM impacts

## Table 9: Class Demand Forecast

| Year | GS NI 50-1000 | Chg | GS I 50-1000 | Chg | GS 1000-1500 | Chg | GS 1500-5000 | Chg | Large Users | Chg | St Light | Chg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2006 | 460,618 | | 171,992 | | 72,566 | | 161,568 | | 114,730 | | 8,933 | |
| 2007 | 429,376 | -6.8% | 186,441 | 8.4% | 76,797 | 5.8% | 166,865 | 3.3% | 113,572 | -1.0% | 11,121 | 24.5% |
| 2008 | 431,062 | 0.4% | 202,937 | 8.9% | 75,289 | -2.0% | 169,305 | 1.5% | 125,910 | 10.9% | 9,444 | -15.1% |
| 2009 | 398,844 | -7.5% | 206,474 | 1.7% | 68,614 | -8.9% | 164,062 | -3.1% | 117,078 | -7.0% | 9,851 | 4.3% |
| 2010 | 412,793 | 3.5% | 231,545 | 12.1% | 72,361 | 5.5% | 175,079 | 6.7% | 130,827 | 11.7% | 10,352 | 5.1% |
| 2011 | 400,602 | -3.0% | 228,594 | -1.3% | 68,860 | -4.8% | 183,134 | 4.6% | 125,381 | -4.2% | 10,175 | -1.7% |
| 2012 | 375,669 | -6.2% | 230,832 | 1.0% | 70,504 | 2.4% | 182,410 | -0.4% | 123,187 | -1.8% | 10,313 | 1.4% |
| 2013 | 387,717 | 3.2% | 254,033 | 10.1% | 70,296 | -0.3% | 191,749 | 5.1% | 121,622 | -1.3% | 10,344 | 0.3% |
| 2014 | 365,768 | -5.7% | 232,563 | -8.5% | 64,565 | -8.2% | 166,541 | -13.2% | 102,647 | -15.6% | 10,283 | -0.6% |
| 2015 | 367,285 | 0.4% | 257,729 | 10.8% | 70,055 | 8.5% | 176,387 | 5.9% | 108,056 | 5.3% | 10,262 | -0.2% |
| 2016 | 360,355 | -1.9% | 260,605 | 1.1% | 69,869 | -0.3% | 179,473 | 1.8% | 108,005 | -0.1% | 10,262 | 0.0% |
| 2017 | 350,591 | -2.7% | 262,278 | 0.6% | 69,300 | -0.8% | 182,529 | 1.7% | 107,875 | -0.1% | 10,262 | 0.0% |
| 2018 | 341,289 | -2.7% | 264,563 | 0.9% | 68,890 | -0.6% | 185,831 | 1.8% | 107,711 | -0.2% | 10,262 | 0.0% |
| 2019 | 333,957 | -2.2% | 267,483 | 1.1% | 68,685 | -0.3% | 189,389 | 1.9% | 107,450 | -0.2% | 10,262 | 0.0% |
| 2020 | 326,370 | -2.3% | 270,365 | 1.1% | 68,455 | -0.3% | 192,761 | 1.8% | 107,090 | -0.3% | 10,262 | 0.0% |

# 4 Appendix A: Model Statistics

***System Purchase Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 198621 | 32683.1 | 6.08 | 0.00% |
| MVars.XOther | 4339064 | 373961.2 | 11.60 | 0.00% |
| MVars.XCool | 1161 | 34.5 | 33.59 | 0.00% |
| MVars.XHeat | 202 | 6.2 | 32.46 | 0.00% |
| BinT.Jan | 25972 | 4191.6 | 6.20 | 0.00% |
| BinT.May | -10590 | 3815.4 | -2.78 | 0.65% |
| BinT.Apr | -20055 | 3678.9 | -5.45 | 0.00% |
| BinT.Sept11Plus | -13283 | 2132.6 | -6.23 | 0.00% |
| BinT.Jul09 | 32458 | 10440.2 | 3.11 | 0.24% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 116 |
| Deg. of Freedom for Error | 107 |
| Adjusted R-Squared | 0.963 |
| Model Sum of Squares | 316,236,701,485.6 |
| Sum of Squared Errors | 11,309,715,255.0 |
| Mean Squared Error | 105,698,273.4 |
| Std. Error of Regression | 10,280.97 |
| Mean Abs. Dev. (MAD) | 7,835.46 |
| Mean Abs. % Err. (MAPE) | 1.20% |
| Durbin-Watson Statistic | 2.127 |

***System Peak Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| mCPkEndUses.OtherVar | 1.39 | 0.02 | 82.10 | 0.00% |
| mCPkEndUses.CoolVar | 2.13 | 0.14 | 15.61 | 0.00% |
| mCPkEndUses.HeatVar | 0.71 | 0.12 | 6.03 | 0.00% |
| BinT.Apr | -82.32 | 19.67 | -4.19 | 0.01% |
| BinT.May | 171.22 | 23.63 | 7.25 | 0.00% |
| BinT.Jun | 86.34 | 18.94 | 4.56 | 0.00% |
| BinT.Aug | 46.83 | 19.52 | 2.40 | 1.83% |
| BinT.Oct | -86.83 | 20.86 | -4.16 | 0.01% |
| BinT.Dec | 59.36 | 18.54 | 3.20 | 0.18% |
| BinT.Yr05 | 72.62 | 16.60 | 4.38 | 0.00% |
| BinT.May05 | -300.98 | 57.22 | -5.26 | 0.00% |
| BinT.May08 | -301.97 | 54.98 | -5.49 | 0.00% |
| BinT.May09 | -223.52 | 54.99 | -4.07 | 0.01% |
| BinT.Sep10 | 261.65 | 52.03 | 5.03 | 0.00% |
| BinT.May14 | -179.18 | 55.31 | -3.24 | 0.16% |
| BinT.Sept11Plus | -23.34 | 10.60 | -2.20 | 3.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 116 |
| Deg. of Freedom for Error | 100 |
| Adjusted R-Squared | 0.876 |
| Model Sum of Squares | 2,126,672.49 |
| Sum of Squared Errors | 257,816.71 |
| Mean Squared Error | 2,578.17 |
| Std. Error of Regression | 50.78 |
| Mean Abs. Dev. (MAD) | 34.6 |
| Mean Abs. % Err. (MAPE) | 2.85% |
| Durbin-Watson Statistic | 2.313 |

***Residential Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| MStructRev.XOtherRes | 279.37 | 7.7 | 36.06 | 0.00% |
| MStructRev.XHeatRes | 119.73 | 12.8 | 9.34 | 0.00% |
| MStructRev.XCoolRes | 190.35 | 18.2 | 10.43 | 0.00% |
| BinT.Mar | 17001.91 | 4932.9 | 3.45 | 0.10% |
| BinT.May | -13309.54 | 4944.7 | -2.69 | 0.89% |
| BinT.Jun | -26944.70 | 5179.8 | -5.20 | 0.00% |
| BinT.Jul | -17960.93 | 5277.9 | -3.40 | 0.11% |
| BinT.Nov11 | -30727.85 | 11778.4 | -2.61 | 1.11% |
| BinT.Dec11 | -43089.00 | 11666.4 | -3.69 | 0.04% |
| BinT.Jun13 | 26850.88 | 12380.8 | 2.17 | 3.35% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 70 |
| Adjusted R-Squared | 0.804 |
| Model Sum of Squares | 43,819,308,408.3 |
| Sum of Squared Errors | 9,185,597,165.2 |
| Mean Squared Error | 131,222,816.7 |
| Std. Error of Regression | 11,455.25 |
| Mean Abs. Dev. (MAD) | 8,440.73 |
| Mean Abs. % Err. (MAPE) | 4.42% |
| Durbin-Watson Statistic | 2.199 |

***Residential Customer Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Economics.Pop | 31.33 | 8.59 | 3.65 | 0.05% |
| Res_Custs.LagDep(12) | 0.87 | 0.04 | 21.72 | 0.00% |
| MA(1) | 0.55 | 0.10 | 5.64 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 77 |
| Adjusted R-Squared | 0.999 |
| Model Sum of Squares | 5,758,319,345.42 |
| Sum of Squared Errors | 3,156,026.13 |
| Mean Squared Error | 40,987.35 |
| Std. Error of Regression | 202.45 |
| Mean Abs. Dev. (MAD) | 154.08 |
| Mean Abs. % Err. (MAPE) | 0.06% |
| Durbin-Watson Statistic | 1.461 |

***GS 50 Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 37782.42 | 14963.1 | 2.53 | 1.38% |
| MStructRev.XOtherGS50 | 0.01 | 0.0 | 1.77 | 8.11% |
| MStructRev.XHeatGS50 | 0.19 | 0.0 | 10.46 | 0.00% |
| MStructRev.XCoolGS50 | 0.03 | 0.0 | 6.59 | 0.00% |
| BinT.Oct11 | 15539.44 | 3683.1 | 4.22 | 0.01% |
| BinT.Nov11 | 17672.30 | 3698.6 | 4.78 | 0.00% |
| BinT.Dec11 | -21197.143 | 3696.2 | -5.735 | 0.00% |
| BinT.Jan12 | -17741.035 | 3702.1 | -4.792 | 0.00% |
| BinT.Jun14 | 11154.278 | 3760.7 | 2.966 | 0.41% |
| BinT.TrendVar | -598.576 | 222.3 | -2.693 | 0.89% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 70 |
| Adjusted R-Squared | 0.697 |
| Model Sum of Squares | 2,514,277,449 |
| Sum of Squared Errors | 922,773,588 |
| Mean Squared Error | 13,182,480 |
| Std. Error of Regression | 3630.77 |
| Mean Abs. Dev. (MAD) | 2518.59 |
| Mean Abs. % Err. (MAPE) | 4.20% |
| Durbin-Watson Statistic | 2.582 |

## GS 50 Customer Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 15632.69 | 819.37 | 19.08 | 0.00% |
| Res_Custs.Predicted | 0.03 | 0.00 | 9.81 | 0.00% |
| AR(1) | 0.87 | 0.05 | 17.33 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 79 |
| Deg. of Freedom for Error | 76 |
| Adjusted R-Squared | 0.987 |
| Model Sum of Squares | 4,781,654.64 |
| Sum of Squared Errors | 60,718.20 |
| Mean Squared Error | 798.92 |
| Std. Error of Regression | 28.27 |
| Mean Abs. Dev. (MAD) | 20.09 |
| Mean Abs. % Err. (MAPE) | 0.08% |
| Durbin-Watson Statistic | 1.656 |

## *GS 1000NI Sales Model*

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 79060.86 | 20544.8 | 3.85 | 0.03% |
| MStructRev.XOtherGS1000 | 0.03 | 0.01 | 5.31 | 0.00% |
| MStructRev.XHeatGS1000 | 0.49 | 0.03 | 18.31 | 0.00% |
| MStructRev.XCoolGS1000 | 0.06 | 0.01 | 9.46 | 0.00% |
| BinT.May | -11276.72 | 2290.33 | -4.92 | 0.00% |
| BinT.Nov | 5200.01 | 2190.51 | 2.37 | 2.03% |
| BinT.Dec12 | -48864.12 | 5008.7 | -9.756 | 0.00% |
| BinT.Jan13 | 39837.03 | 5101.6 | 7.809 | 0.00% |
| BinT.May14 | 13484.465 | 5388.8 | 2.502 | 1.47% |
| BinT.TrendVar | -3618.718 | 301.4 | -12.01 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 70 |
| Adjusted R-Squared | 0.913 |
| Model Sum of Squares | 20,084,538,383.02 |
| Sum of Squared Errors | 1,670,587,624.30 |
| Mean Squared Error | 23,865,537.49 |
| Std. Error of Regression | 4,885.24 |
| Mean Abs. Dev. (MAD) | 3,381.37 |
| Mean Abs. % Err. (MAPE) | 2.50% |
| Durbin-Watson Statistic | 1.866 |

## GS 1000NI Customer Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 1.17 | 0.111 | 10.547 | 0 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 79 |
| Adjusted R-Squared | 0.784 |
| Model Sum of Squares | 123,777.00 |
| Sum of Squared Errors | 34,003.00 |
| Mean Squared Error | 430.42 |
| Std. Error of Regression | 20.75 |
| Mean Abs. Dev. (MAD) | 13.34 |
| Mean Abs. % Err. (MAPE) | 0.50% |
| Durbin-Watson Statistic | 2.022 |

## GS 1000I Sales Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| MStructRev.XOtherGS1000 | 0.01 | 0.00 | 7.53 | 0.00% |
| MStructRev.XHeatGS1000 | 0.17 | 0.02 | 9.55 | 0.00% |
| MStructRev.XCoolGS1000 | 0.04 | 0.00 | 10.43 | 0.00% |
| BinT.Jul | 2923.54 | 1038.93 | 2.81 | 0.63% |
| BinT.May | -1722.62 | 1006.91 | -1.71 | 9.16% |
| BinT.Jul13 | -7210.76 | 2861.49 | -2.52 | 1.40% |
| BinT.Mar14 | -14685.066 | 2578.8 | -5.695 | 0.00% |
| BinT.TrendVar | 1832.963 | 250.46 | 7.318 | 0.00% |
| AR(1) | 0.394 | 0.116 | 3.391 | 0.12% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 79 |
| Deg. of Freedom for Error | 70 |
| Adjusted R-Squared | 0.852 |
| Model Sum of Squares | 3,239,913,385.62 |
| Sum of Squared Errors | 495,898,611.33 |
| Mean Squared Error | 7,084,265.88 |
| Std. Error of Regression | 2,661.63 |
| Mean Abs. Dev. (MAD) | 1,891.68 |
| Mean Abs. % Err. (MAPE) | 2.16% |
| Durbin-Watson Statistic | 2.156 |

## *GS 1000I Customer Model*

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| BinT.TrendVar | 27.857 | 0.178 | 156.29 | 0.00% |
| AR(1) | 0.877 | 0.047 | 18.654 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 79 |
| Deg. of Freedom for Error | 77 |
| Adjusted R-Squared | 0.995 |
| Model Sum of Squares | 261,083.39 |
| Sum of Squared Errors | 1,380.48 |
| Mean Squared Error | 17.93 |
| Std. Error of Regression | 4.23 |
| Mean Abs. Dev. (MAD) | 2.78 |
| Mean Abs. % Err. (MAPE) | 0.49% |
| Durbin-Watson Statistic | 2.09 |

### GS 1500 Sales Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| CONST | 11892.29 | 3370.51 | 3.53 | 0.08% |
| MStructRev.XOtherGS1500 | 0.01 | 0.00 | 4.76 | 0.00% |
| MStructRev.XHeatGS1500 | 0.03 | 0.00 | 7.80 | 0.00% |
| MStructRev.XCoolGS1500 | 0.01 | 0.00 | 12.77 | 0.00% |
| BinT.BefJun08 | 3467.44 | 381.93 | 9.08 | 0.00% |
| BinT.AftFeb10 | -1525.89 | 226.35 | -6.74 | 0.00% |
| BinT.Mar | 830.877 | 367.58 | 2.26 | 2.70% |
| BinT.Jul08 | -3789.468 | 816.73 | -4.64 | 0.00% |
| BinT.Apr09 | 7646.246 | 814.28 | 9.39 | 0.00% |
| BinT.May09 | -7436.155 | 813.28 | -9.143 | 0.00% |
| BinT.Mar14 | -4468.297 | 855.67 | -5.222 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 69 |
| Adjusted R-Squared | 0.883 |
| Model Sum of Squares | 372,605,719.73 |
| Sum of Squared Errors | 42,526,900.97 |
| Mean Squared Error | 616,331.90 |
| Std. Error of Regression | 785.07 |
| Mean Abs. Dev. (MAD) | 558.09 |
| Mean Abs. % Err. (MAPE) | 1.91% |
| Durbin-Watson Statistic | 1.972 |

## GS 1500 Customer Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| BinT.Jan10 | -2.5 | 0.547 | -4.573 | 0.00% |
| AR(1) | 1 | 0.002 | 603.62 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 67 |
| Deg. of Freedom for Error | 65 |
| Adjusted R-Squared | 0.912 |
| Model Sum of Squares | 417.17 |
| Sum of Squared Errors | 39.45 |
| Mean Squared Error | 0.61 |
| Std. Error of Regression | 0.78 |
| Mean Abs. Dev. (MAD) | 0.38 |
| Mean Abs. % Err. (MAPE) | 0.67% |
| Durbin-Watson Statistic | 1.509 |

## GS 5000 Sales Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| MStructRev.XHeatGS5000 | 0.044 | 0.009 | 4.72 | 0.00% |
| MStructRev.XCoolGS5000 | 0.021 | 0.00 | 9.36 | 0.00% |
| MStructRev.XOtherGS5000 | 0.021 | 0.00 | 128.89 | 0.00% |
| BinT.Nov | -2710.21 | 916.84 | -2.96 | 0.42% |
| BinT.Dec | -1836.10 | 939.89 | -1.95 | 5.46% |
| BinT.Feb14 | 11176.39 | 2162.73 | 5.17 | 0.00% |
| BinT.Mar14 | -10149.74 | 2153.67 | -4.71 | 0.00% |
| BinT.Yr10 | -1915.143 | 658.67 | -2.908 | 0.48% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 72 |
| Adjusted R-Squared | 0.747 |
| Model Sum of Squares | 1,056,869,059.92 |
| Sum of Squared Errors | 317,121,691.62 |
| Mean Squared Error | 4,404,467.94 |
| Std. Error of Regression | 2,098.68 |
| Mean Abs. Dev. (MAD) | 1,459.35 |
| Mean Abs. % Err. (MAPE) | 2.06% |
| Durbin-Watson Statistic | 2.095 |

## GS 5000 Customer Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 1.074 | 0.112 | 9.576 | 0 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 79 |
| Adjusted R-Squared | 0.96 |
| Model Sum of Squares | 3,086.00 |
| Sum of Squared Errors | 128.00 |
| Mean Squared Error | 1.62 |
| Std. Error of Regression | 1.27 |
| Mean Abs. Dev. (MAD) | 0.74 |
| Mean Abs. % Err. (MAPE) | 1.03% |
| Durbin-Watson Statistic | 0 |

## Large Users Sales Model

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| MWthrT.CDD18Lag | 59.52 | 7.35 | 8.10 | 0.00% |
| MEcon.GDP | 1.28 | 0.05 | 27.60 | 0.00% |
| MEcon.GDP_Trend | -0.02 | 0.00 | -9.03 | 0.00% |
| BinT.Feb | -3742.20 | 923.01 | -4.05 | 0.01% |
| BinT.May | 2566.73 | 922.18 | 2.78 | 0.69% |
| BinT.Oct | 2209.38 | 964.81 | 2.29 | 2.50% |
| BinT.Nov | -4682.064 | 985.69 | -4.75 | 0.00% |
| BinT.Sep13 | -11796.446 | 2276.3 | -5.182 | 0.00% |
| BinT.Dec13 | -7010.182 | 2291.2 | -3.06 | 0.31% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 108 |
| Deg. of Freedom for Error | 100 |
| Adjusted R-Squared | 0.672 |
| Model Sum of Squares | 1,404,720,907.34 |
| Sum of Squared Errors | 620,712,853.93 |
| Mean Squared Error | 6,207,128.54 |
| Std. Error of Regression | 2491.41 |
| Mean Abs. Dev. (MAD) | 1810.81 |
| Mean Abs. % Err. (MAPE) | 3.41% |
| Durbin-Watson Statistic | 2.039 |

## *Large Users Customer Model*

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 1 | 0.113 | 8.888 | 0 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 79 |
| Adjusted R-Squared | 0.804 |
| Model Sum of Squares | 8.00 |
| Sum of Squared Errors | 2.00 |
| Mean Squared Error | 0.00 |
| Std. Error of Regression | 0 |
| Mean Abs. Dev. (MAD) | 0 |
| Mean Abs. % Err. (MAPE) | 0.22% |
| Durbin-Watson Statistic | 2 |

***Street Lighting Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| BinT.Jan | 4808.42 | 137.35 | 35.01 | 0.00% |
| BinT.Feb | 4127.58 | 131.48 | 31.39 | 0.00% |
| BinT.Mar | 3843.57 | 129.06 | 29.78 | 0.00% |
| BinT.Apr | 3205.38 | 128.01 | 25.04 | 0.00% |
| BinT.May | 2939.64 | 127.53 | 23.05 | 0.00% |
| BinT.Jun | 2417.16 | 138.82 | 17.41 | 0.00% |
| BinT.Jul | 2443.033 | 132.946 | 18.376 | 0.00% |
| BinT.Aug | 2712.127 | 132.888 | 20.409 | 0.00% |
| BinT.Sep | 3311.919 | 133.841 | 24.745 | 0.00% |
| BinT.Oct | 4076.863 | 136.25 | 29.922 | 0.00% |
| BinT.Nov | 4520.639 | 137.066 | 32.981 | 0.00% |
| BinT.Dec | 4855.849 | 137.303 | 35.366 | 0.00% |
| BinT.Jun08 | -723.873 | 245.278 | -2.951 | 0.45% |
| BinT.Jul09 | -840.777 | 272.299 | -3.088 | 0.30% |
| BinT.Aug09 | -969.033 | 271.359 | -3.571 | 0.07% |
| BinT.June11 | -1563.635 | 251.23 | -6.224 | 0.00% |
| AR(1) | 0.623 | 0.102 | 6.08 | 0.00 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 79 |
| Deg. of Freedom for Error | 62 |
| Adjusted R-Squared | 0.928 |
| Model Sum of Squares | 71,524,375.60 |
| Sum of Squared Errors | 4,332,591.58 |
| Mean Squared Error | 69,880.51 |
| Std. Error of Regression | 264.35 |
| Mean Abs. Dev. (MAD) | 163.07 |
| Mean Abs. % Err. (MAPE) | 5.87% |
| Durbin-Watson Statistic | 2.23 |

***Street Lighting Customer Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 1.472 | 0.099 | 14.831 | 0 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 79 |
| Adjusted R-Squared | 0.99 |
| Model Sum of Squares | 306,820,210.00 |
| Sum of Squared Errors | 3,086,076.00 |
| Mean Squared Error | 39,064.26 |
| Std. Error of Regression | 197.65 |
| Mean Abs. Dev. (MAD) | 99.27 |
| Mean Abs. % Err. (MAPE) | 0.18% |
| Durbin-Watson Statistic | 1.842 |

***MU Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 0.29 | 0.084 | 3.448 | 0.10% |
| Seasonal | 1.109 | 0.29 | 3.80 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 51 |
| Deg. of Freedom for Error | 49 |
| Adjusted R-Squared | 0.487 |
| Model Sum of Squares | 144,091.00 |
| Sum of Squared Errors | 145,641.00 |
| Mean Squared Error | 2,972.26 |
| Std. Error of Regression | 54.52 |
| Mean Abs. Dev. (MAD) | 39.95 |
| Mean Abs. % Err. (MAPE) | 2.80% |
| Durbin-Watson Statistic | 2.423 |

***MU Customer Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 0.42 | 0.092 | 4.584 | 0 |

| Model Statistics | |
|---|---|
| Adjusted Observations | 80 |
| Deg. of Freedom for Error | 79 |
| Adjusted R-Squared | 0.89 |
| Model Sum of Squares | 4,314,897.00 |
| Sum of Squared Errors | 531,398.00 |
| Mean Squared Error | 6,726.56 |
| Std. Error of Regression | 82.02 |
| Mean Abs. Dev. (MAD) | 33.35 |
| Mean Abs. % Err. (MAPE) | 1.00% |
| Durbin-Watson Statistic | 2.124 |

***DCL Sales Model***

| Variable | Coefficient | StdErr | T-Stat | P-Value |
|---|---|---|---|---|
| Simple | 1 | 0.119 | 8.426 | 0.00% |

| Model Statistics | |
|---|---|
| Adjusted Observations | 72 |
| Deg. of Freedom for Error | 71 |
| Adjusted R-Squared | 0.965 |
| Model Sum of Squares | 16,657.00 |
| Sum of Squared Errors | 611.00 |
| Mean Squared Error | 8.60 |
| Std. Error of Regression | 2.93 |
| Mean Abs. Dev. (MAD) | 0.65 |
| Mean Abs. % Err. (MAPE) | 0.24% |
| Durbin-Watson Statistic | 2 |

# 5 Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

## 5.1 Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

### 5.1.1 Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year ($y$) and month ($m$)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left( Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left( Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 5-1.

### Table 5-1: Electric Space Heating Equipment Weights

| Equipment Type | Weight (kWh) |
|---|---|
| Electric Resistance Furnace/Room units | 505 |
| Electric Space Heating Heat Pump | 190 |

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

**Price Impacts**. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left( Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left( Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \left( TenYearMovingAverageElectricPrice_{y,m} \right)^{\phi} \times \left( TenYearMovingAverageGasPrice_{y,m} \right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

**Heating system usage** levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \quad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

### 5.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year ($y$) and month ($m$)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left( Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left( Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 5-2.

### Table 5-2: Space Cooling Equipment Weights

| Equipment Type | Weight (kWh) |
|---|---|
| Central Air Conditioning | 1,661 |
| Space Cooling Heat Pump | 369 |
| Room Air Conditioning | 315 |

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

**Price Impacts.** In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left( Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left( Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \tag{13}$$
$$\left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma}$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

**Cooling system usage** levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

### *5.1.3 Constructing XOther*

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers.

The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left( Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left( Sat_{05}^{Type} \Big/ \frac{1}{UEC_{05}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{16}$$
$$(TenYearMovingAverageElectric\,Price)^{\lambda} \times (TenYearMovingAverageGas\,Price)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month ($m$)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.10} \times \tag{17}$$
$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}}\right)^{\phi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}}\right)^{\lambda}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

# 6 Appendix C: Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2010 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

## 6.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_m = a + b_1 \times \mathrm{XHeat}_m + b_2 \times \mathrm{XCool}_m + b_3 \times \mathrm{XOther}_m + \varepsilon_m \qquad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

### *6.1.1 Constructing XHeat*

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\mathrm{XHeat}_{y,m} = \mathrm{HeatIndex}_y \times \mathrm{HeatUse}_{y,m} \qquad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
$HeatIndex_y$ is the annual index of heating equipment, and
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left( HeatShare_y \big/ Eff_y \right)}{\left( HeatShare_{04} \big/ Eff_{04} \right)} \tag{4}$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left( \frac{kWh}{Sqft} \right)_{Heating} \times \left( \frac{CommercialSales_{04}}{\sum_e kWh \big/ Sqft_e} \right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left( \frac{BDays_{y,m}}{30.5} \right) \times \left( \frac{WgtHDD_{y,m}}{HDD_{04}} \right) \times \left( \frac{Output_y}{Output_{04}} \right)^{0.20} \times \left( \frac{Price_{y,m}}{Price_{04}} \right)^{-0.18} \tag{6}$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days

*WgtHDD* is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.

*HDD* is the annual heating degree days for 2004,

*Output* is a real commercial output driver in year (y), *Price* is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

### 6.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),

$CoolIndex_y$ is an index of cooling equipment, and

$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{\left( CoolShare_{y} \big/ Eff_{y} \right)}{\left( CoolShare_{04} \big/ Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh/Sqft_{e}}\right) \qquad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \qquad (10)$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.

*CDD* is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

### 6.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left( \frac{Share_y^{Type} / Eff_y^{Type}}{Share_{04}^{Type} / Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,

*Share* represents the fraction of floor stock with an equipment type, and

*Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left( \frac{kWh}{Sqft} \right)_{Type} \times \left( \frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{\Pr ice_{y.m}}{\Pr ice_{04}}\right)^{-0.18} \quad (14)$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

# ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

## 1.0 INTRODUCTION

Hydro Ottawa Limited's ("Hydro Ottawa") last rebasing year was 2012. Hydro Ottawa has not completed a detailed load forecast since this rebasing given that Hydro Ottawa has increased rates based on an Incentive Regulation Model ("IRM") for the years 2013 to 2015. As such, Hydro Ottawa felt it was financially prudent not to invest in preparing a detailed load forecast for the years in which rates would not be set by the forecast.

## 2.0 HISTORICAL ACCURACY OF LOAD FORECAST

Given Hydro Ottawa has not completed a load forecast since 2012 it can only compare the 2012 Board Approved load forecast to the actual sales and demand results and customer count and connects for that year.

Hydro Ottawa has completed Appendix 2-IA, Summary and Variances of Actual and Forecast Data, which provides a schedule of volumes, customer count and connects by rate class including total system load. This also includes a comparison of historical board-approved versus historical actual. Appendix 2-IA is provided as an attachment to this exhibit. Per Appendix 2-IA:

- Actual 2012 kWhs were 1.36% less than the Board approved forecast;
- Actual 2012 kWs were 0.61% less than the Board approved forecasts;
- Customer count and connects was within 0.01% of Boards approved forecast, customer counts and connection as the average for that year.

Hydro Ottawa has added a total variance year over year comparison to the bottom of Appendix 2-IA. 2015 to 2020 data is weather normalized. For details regarding the class level assumptions and data sources, please refer to Itron's load forecast report available in Attachment C-1(A) to exhibit C-1-1, Hydro Ottawa has utilized the format of Appendix 2-IA, please see attachment C-1(B), to provide the following comparisons:

- Historical Board-approved vs. Historical Actual – weather normalized;
- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual – weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

Hydro Ottawa has confidence that the variances between the afore-mentioned analyses are within an acceptable tolerance.

Itron's 2016-2020 load forecast and data are available in excel format as attachment C-1(C) to C-1(L)

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | C |
| **Tab:** | 1 |
| **Schedule:** | 2 |
| **Page:** | 1 |
| **Date:** | Original |

## Appendix 2-IA
## Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

| | 2012 Board Approved | 2012 | 2013 | 2014 Forecast | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test | 2012 Board Approved vs Actual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **RESIDENTIAL** | | | | | | | | | | | |
| **# of Customers** | 280,901 | 280,254 | 284,964 | 284,296 | 293,366 | 297,343 | 301,258 | 305,144 | 308,990 | 312,786 | 647 |
| **kWh** | 2,282,535,398 | 2,302,188,900 | 2,256,501,094 | 2,287,520,580 | 2,233,419,000 | 2,216,045,000 | 2,198,259,000 | 2,206,411,000 | 2,214,984,000 | 2,217,628,000 | - 19,653,502 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | -0.23% | 1.45% | 1.21% | 4.44% | 5.85% | 7.25% | 8.63% | 10.00% | 11.35% | |
| **kWh** | | 0.86% | -1.14% | 0.22% | -2.15% | -2.91% | -3.69% | -3.34% | -2.96% | -2.84% | |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **GENERAL SERVICE <50KW** | | | | | | | | | | | |
| **# of Customers** | 23,636 | 23,767 | 23,936 | 23,817 | 24,099 | 24,512 | 24,626 | 24,739 | 24,850 | 24,959 | - 131 |
| **kWh** | 770,026,295 | 702,625,952 | 720,479,340 | 746,537,340 | 705,279,000 | 726,360,000 | 716,896,000 | 709,791,000 | 704,193,000 | 699,744,000 | 67,400,343 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.55% | 1.27% | 0.77% | 1.96% | 3.71% | 4.19% | 4.67% | 5.14% | 5.60% | |
| **kWh** | | -8.75% | -6.43% | -3.05% | -8.41% | -5.67% | -6.90% | -7.82% | -8.55% | -9.13% | |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **GENERAL SERVICE 50-1999KW** | | | | | | | | | | | |
| **# of Customers** | 3,340 | 3,416 | 3,408 | 3,417 | 3,549 | 3,296 | 3,323 | 3,351 | 3,380 | 3,408 | - 76 |
| **kWh** | 3,051,141,934 | 2,982,426,722 | 3,006,131,060 | 3,052,417,630 | 2,957,727,000 | 2,954,441,000 | 2,907,445,000 | 2,875,422,000 | 2,852,593,000 | 2,835,387,000 | 68,715,212 |
| **kW** | 7,404,278 | 7,288,884 | 7,292,973 | 7,621,504 | 7,070,781 | 7,027,979 | 6,908,640 | 6,824,350 | 6,761,930 | 6,711,579 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 2.28% | 2.04% | 2.31% | 6.26% | -1.32% | -0.51% | 0.33% | 1.20% | 2.04% | |
| **kWh** | | -2.25% | -1.48% | 0.04% | -3.06% | -3.17% | -4.71% | -5.76% | -6.51% | -7.07% | |
| **kW** | | -1.56% | -1.50% | 2.93% | -4.50% | -5.08% | -6.69% | -7.83% | -8.68% | -9.36% | |
| **GENERAL SERVICE 1500-5000 KW** | | | | | | | | | | | |
| **# of Customers** | 71 | 74 | 76 | 72 | 88 | 76 | 76 | 76 | 76 | 76 | - 3 |
| **kWh** | 836,317,557 | 870,903,316 | 857,551,218 | 840,571,690 | 883,242,000 | 863,309,000 | 877,400,000 | 895,369,000 | 914,569,000 | 935,554,000 | - 34,585,759 |
| **kW** | 1,719,678 | 1,864,369 | 1,866,871 | 1,809,214 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 4.23% | 7.04% | 1.41% | 23.94% | 7.04% | 7.04% | 7.04% | 7.04% | 7.04% | |
| **kWh** | | 4.14% | 2.54% | 0.51% | 5.61% | 3.23% | 4.91% | 7.06% | 9.36% | 11.87% | |
| **kW** | | 8.41% | 8.56% | 5.21% | 9.65% | 9.65% | 9.65% | 9.65% | 9.65% | 9.65% | |
| **LARGE USER** | | | | | | | | | | | |
| **# of Customers** | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | - |
| **kWh** | 672,395,178 | 646,432,433 | 613,513,830 | 653,609,490 | 620,305,000 | 620,218,000 | 619,253,000 | 618,467,000 | 617,036,000 | 615,195,000 | 25,962,745 |
| **kW** | 1,187,623 | 1,178,836 | 1,135,342 | 1,195,741 | 1,121,629 | 1,121,449 | 1,119,726 | 1,118,300 | 1,115,702 | 1,112,342 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kWh** | | -3.86% | -8.76% | -2.79% | -7.75% | -7.76% | -7.90% | -8.02% | -8.23% | -8.51% | |
| **kW** | | -0.74% | -4.40% | 0.68% | -5.56% | -5.57% | -5.72% | -5.84% | -6.06% | -6.34% | |
| **STREETLIGHTING** | | | | | | | | | | | |
| **# of Connections** | 55,546 | 55,674 | 55,757 | 56,608 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 | - 128 |
| **kWh** | 41,153,239 | 44,699,159 | 44,767,415 | 43,962,170 | 43,501,000 | 43,552,000 | 43,653,000 | 43,765,000 | 43,876,000 | 44,015,000 | - 3,545,920 |
| **kW** | 121,500 | 123,332 | 123,947 | 129,682 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | 0.23% | 0.38% | 1.91% | -0.05% | -0.05% | -0.05% | -0.05% | -0.05% | -0.05% | |
| **kWh** | | 8.62% | 8.78% | 6.83% | 5.70% | 5.83% | 6.07% | 6.35% | 6.62% | 6.95% | |
| **kW** | | 1.51% | 2.01% | 6.73% | 1.35% | 1.35% | 1.35% | 1.35% | 1.35% | 1.35% | |
| **UMSL** | | | | | | | | | | | |
| **# of Connections** | 3,093 | 3,384 | 3,376 | 3,333 | 3,444 | 3,477 | 3,525 | 3,573 | 3,621 | 3,669 | - 291 |
| **kWh** | 17,394,983 | 17,594,132 | 17,054,550 | 16,739,310 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | - 199,149 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | 9.41% | 9.15% | 7.76% | 11.35% | 12.42% | 13.97% | 15.52% | 17.07% | 18.62% | |
| **kWh** | | 1.14% | -1.96% | -3.77% | -4.28% | -4.28% | -4.28% | -4.28% | -4.28% | -4.28% | |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **SENTINEL LIGHTS** | | | | | | | | | | | |
| **# of Connections** | N/A | 61 | 57 | 78 | 57 | 55 | 51 | 47 | 43 | 39 | N/A |
| **kWh** | N/A | 59,894 | 49,020 | - | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 | N/A |
| **kW** | 221 | 166 | 139 | - | 216 | 216 | 216 | 216 | 216 | 216 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kWh** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kW** | | -24.89% | -37.10% | -100.00% | -2.26% | -2.26% | -2.26% | -2.26% | -2.26% | -2.26% | |
| **STANDBY** | | | | | | | | | | | |
| **# of Customers** | N/A | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | N/A |
| **kWh** | N/A | | | | | | | | | | N/A |
| **kW** | 86,400 | Included in actuals for class | | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kWh** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kW** | | 0.00% | -100.00% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% | |
| **Rate Class 10** | | | | | | | | | | | |
| **# of Customers** | | | | | | | | | | | |
| **kWh** | | | | | | | | | | | |
| **kW** | | | | | | | | | | | |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kWh** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |

## Totals

| | 2012 Board Approved | 2012 | 2013 | 2014 Forecast | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test | 2012 Board Approved vs Actual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | 366,598 | 366,643 | 371,587 | 371,634 | 380,132 | 384,288 | 388,388 | 392,459 | 396,489 | 400,466 | 18 |
| **kWh** | 7,670,964,584 | 7,566,930,508 | 7,516,047,527 | 7,641,358,210 | 7,460,172,000 | 7,440,624,000 | 7,379,605,000 | 7,365,924,000 | 7,363,950,000 | 7,364,222,000 | 104,093,970 |
| **kW from applicable classes** | 10,519,700 | 10,455,587 | 10,419,272 | 10,760,940 | 10,206,132 | 10,163,150 | 10,042,088 | 9,956,372 | 9,891,354 | 9,837,643 | - |

## Totals - Variance

| | 2012 Board Approved | 2012 | 2013 | 2014 Forecast | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test | 2012 Board Approved vs Actual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | | 0.01% | 1.36% | 1.37% | 3.69% | 4.83% | 5.94% | 7.05% | 8.15% | 9.24% | |
| **kWh** | | -1.36% | -2.02% | -0.39% | -2.75% | -3.00% | -3.80% | -3.98% | -4.00% | -4.00% | |
| **kW from applicable classes** | | -0.61% | -0.95% | 2.29% | -2.98% | -3.39% | -4.54% | -5.35% | -5.97% | -6.48% | |

## Totals - Variance Year over Year

| | 2012 Board Approved | 2012 | 2013 | 2014 Forecast | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test | 2012 Board Approved vs Actual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | | 0.01% | 1.35% | 0.01% | 2.29% | 1.09% | 1.07% | 1.05% | 1.03% | 1.00% | |
| **kWh** | | -1.36% | -0.67% | 1.67% | -2.37% | -0.26% | -0.82% | -0.19% | -0.03% | 0.00% | |
| **kW from applicable classes** | | -0.61% | -0.35% | 3.28% | -5.16% | -0.42% | -1.19% | -0.85% | -0.65% | -0.54% | |

## Summary and Variances of Weather Normalized Actuals to 2012 Board Approved

Replace "Rate Class #" with the appropriate rate classification.

| | 2010 Weather Normalized | 2011 Weather Normalized | 2012 Board Approved | 2012 Weather Normalized | 2013 Weather Normalized | 2014 Forecast Weather Normalized | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RESIDENTIAL** | | | | | | | | | | | | |
| **# of Customers** | 271,603 | 275,966 | 280,901 | 280,254 | 284,964 | 284,296 | 293,366 | 297,343 | 301,258 | 305,144 | 308,990 | 312,786 |
| **kWh** | 2,267,082,000 | 2,249,645,000 | 2,282,535,398 | 2,255,121,000 | 2,252,988,000 | 2,267,127,000 | 2,233,419,000 | 2,216,045,000 | 2,198,259,000 | 2,206,411,000 | 2,214,984,000 | 2,217,628,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | -3.31% | -1.76% | | -0.23% | 1.45% | 1.21% | 4.44% | 5.85% | 7.25% | 8.63% | 10.00% | 11.35% |
| **kWh** | -0.68% | -1.44% | | -1.20% | -1.29% | -0.68% | -2.15% | -2.91% | -3.69% | -3.34% | -2.96% | -2.84% |
| **kW** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | | |
| **GENERAL SERVICE <50KW** | | | | | | | | | | | | |
| **# of Customers** | 23,434 | 23,616 | 23,636 | 23,767 | 23,936 | 23,817 | 24,099 | 24,512 | 24,626 | 24,739 | 24,850 | 24,959 |
| **kWh** | 731,617,000 | 723,597,000 | 770,026,295 | 719,380,000 | 721,817,000 | 707,782,000 | 705,279,000 | 726,360,000 | 716,896,000 | 709,791,000 | 704,193,000 | 699,744,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | -0.85% | -0.08% | | 0.55% | 1.27% | 0.77% | 1.96% | 3.71% | 4.19% | 4.67% | 5.14% | 5.60% |
| **kWh** | -4.99% | -6.03% | | -6.58% | -6.26% | -8.08% | -8.41% | -5.67% | -6.90% | -7.82% | -8.55% | -9.13% |
| **kW** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | | |
| **GENERAL SERVICE 50-1499KW** | | | | | | | | | | | | |
| **# of Customers** | 3,279 | 3,353 | 3,340 | 3,416 | 3,408 | 3,417 | 3,549 | 3,296 | 3,323 | 3,351 | 3,380 | 3,408 |
| **kWh** | 3,026,694,000 | 3,035,733,000 | 3,051,141,934 | 3,017,363,000 | 2,981,441,000 | 2,970,045,000 | 2,957,727,000 | 2,954,441,000 | 2,907,445,000 | 2,875,422,000 | 2,852,593,000 | 2,835,387,000 |
| **kW** | 7,272,741 | 7,290,048 | 7,404,278 | 7,234,407 | 7,143,842 | 7,104,743 | 7,070,781 | 7,027,979 | 6,908,640 | 6,824,350 | 6,761,930 | 6,711,579 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | -1.83% | 0.39% | | 2.28% | 2.04% | 2.31% | 6.26% | -1.32% | -0.51% | 0.33% | 1.20% | 2.04% |
| **kWh** | -0.80% | -0.51% | | -1.11% | -2.28% | -2.66% | -3.06% | -3.17% | -4.71% | -5.76% | -6.51% | -7.07% |
| **kW** | -1.78% | -1.54% | | -2.29% | -3.52% | -4.05% | -4.50% | -5.08% | -6.69% | -7.83% | -8.68% | -9.36% |
| | | | | | | | | | | | | |
| **GENERAL SERVICE 1500-5000 KW** | | | | | | | | | | | | |
| **# of Customers** | 66 | 69 | 71 | 74 | 76 | 72 | 88 | 76 | 76 | 76 | 76 | 76 |
| **kWh** | 827,600,000 | 855,055,000 | 836,317,557 | 865,127,000 | 860,146,000 | 864,262,000 | 883,242,000 | 863,309,000 | 877,400,000 | 895,369,000 | 914,569,000 | 935,554,000 |
| **kW** | 1,766,012 | 1,825,276 | 1,719,678 | 1,845,437 | 1,836,496 | 1,856,692 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | -6.92% | -2.23% | | 4.23% | 7.04% | 1.41% | 23.94% | 7.04% | 7.04% | 7.04% | 7.04% | 7.04% |
| **kWh** | -1.04% | 2.24% | | 3.44% | 2.85% | 3.34% | 5.61% | 3.23% | 4.91% | 7.06% | 9.36% | 11.87% |
| **kW** | 2.69% | 6.14% | | 7.31% | 6.79% | 7.97% | 9.65% | 9.65% | 9.65% | 9.65% | 9.65% | 9.65% |
| | | | | | | | | | | | | |
| **LARGE USER** | | | | | | | | | | | | |
| **# of Customers** | 12 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **kWh** | 683,012,000 | 659,208,000 | 672,395,178 | 641,537,000 | 628,405,000 | 617,273,000 | 620,305,000 | 620,218,000 | 619,253,000 | 618,467,000 | 617,036,000 | 615,195,000 |
| **kW** | 1,234,876 | 1,191,286 | 1,187,623 | 1,158,988 | 1,137,277 | 1,115,729 | 1,121,629 | 1,121,449 | 1,119,726 | 1,118,300 | 1,115,702 | 1,112,342 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | 9.09% | 0.76% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | 1.58% | -1.96% | | -4.59% | -6.54% | -8.20% | -7.75% | -7.76% | -7.90% | -8.02% | -8.23% | -8.51% |
| **kW** | 3.98% | 0.31% | | -2.41% | -4.24% | -6.05% | -5.56% | -5.57% | -5.72% | -5.84% | -6.06% | -6.34% |
| | | | | | | | | | | | | |
| **STREETLIGHTING** | | | | | | | | | | | | |
| **# of Connections** | 54,395 | 54,679 | 55,546 | 55,674 | 55,757 | 56,608 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 |
| **kWh** | 43,535,000 | 43,719,000 | 41,153,239 | 44,699,000 | 44,767,000 | 44,646,000 | 43,501,000 | 43,552,000 | 43,653,000 | 43,765,000 | 43,876,000 | 44,015,000 |
| **kW** | | | 121,500 | 123,332 | 123,947 | 129,682 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Connections** | -2.07% | -1.56% | | 0.23% | 0.38% | 1.91% | -0.05% | -0.05% | -0.05% | -0.05% | -0.05% | -0.05% |
| **kWh** | 5.79% | 6.23% | | 8.62% | 8.78% | 8.49% | 5.70% | 5.83% | 6.07% | 6.35% | 6.62% | 6.95% |
| **kW** | -100.00% | -100.00% | | 1.51% | 2.01% | 6.73% | 1.35% | 1.35% | 1.35% | 1.35% | 1.35% | 1.35% |
| | | | | | | | | | | | | |
| **UMSL** | | | | | | | | | | | | |
| **# of Connections** | 2,907 | 3,183 | 3,093 | 3,384 | 3,376 | 3,333 | 3,444 | 3,477 | 3,525 | 3,573 | 3,621 | 3,669 |
| **kWh** | 17,309,000 | 18,044,000 | 17,394,983 | 17,594,000 | 17,055,000 | 16,489,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Connections** | -6.01% | 2.90% | | 9.41% | 9.15% | 7.76% | 11.35% | 12.42% | 13.97% | 15.52% | 17.07% | 18.62% |
| **kWh** | -0.49% | 3.73% | | 1.14% | -1.95% | -5.21% | -4.28% | -4.28% | -4.28% | -4.28% | -4.28% | -4.28% |
| **kW** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | | |
| **SENTINEL LIGHTS** | | | | | | | | | | | | |
| **# of Connections** | 73 | 65 | N/A | 61 | 57 | 78 | 57 | 55 | 51 | 47 | 43 | 39 |
| **kWh** | 74,233 | 64,267 | N/A | 59,894 | 49,020 | Not forecasted | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 |
| **kW** | 206 | 179 | 221 | 166 | 139 | Not forecasted | 216 | 216 | 216 | 216 | 216 | 216 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Connections** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | -6.79% | -19.00% | | -24.89% | -37.10% | 0.00% | -2.26% | -2.26% | -2.26% | -2.26% | -2.26% | -2.26% |
| | | | | | | | | | | | | |
| **STANDBY** | | | | | | | | | | | | |
| **# of Customers** | 2 | 2 | N/A | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **kWh** | | | N/A | | | | | | | | | |
| **kW** | Included in actuals for class | | 86,400 | Included in actuals for class | | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | 0.00% | -100.00% | | 0.00% | -100.00% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% | -94.44% |
| | | | | | | | | | | | | |
| **Rate Class 10** | | | | | | | | | | | | |
| **# of Customers** | | | | | | | | | | | | |
| **kWh** | | | | | | | | | | | | |
| **kW** | | | | | | | | | | | | |
| **Variance Analysis** | | | | | | | | | | | | |
| **# of Customers** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | 0.00% | 0.00% | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

### Totals

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | 355,771 | 360,945 | 366,598 | 366,643 | 371,587 | 371,634 | 380,132 | 384,288 | 388,388 | 392,459 | 396,489 | 400,466 |
| **kWh** | 7,596,923,233 | 7,585,065,267 | 7,670,964,584 | 7,560,880,894 | 7,506,668,020 | 7,487,624,000 | 7,460,172,000 | 7,440,624,000 | 7,379,605,000 | 7,365,924,000 | 7,363,950,000 | 7,364,222,000 |
| **kW from applicable classes** | 10,273,835 | 10,306,788 | 10,519,700 | 10,362,330 | 10,241,701 | 10,211,646 | 10,206,132 | 10,163,150 | 10,042,088 | 9,956,372 | 9,891,354 | 9,837,643 |

### Totals - Variance

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | -2.95% | -1.54% | | 0.01% | 1.36% | 1.37% | 3.69% | 4.83% | 5.94% | 7.05% | 8.15% | 9.24% |
| **kWh** | -0.97% | -1.12% | | -1.44% | -2.14% | -2.39% | -2.75% | -3.00% | -3.80% | -3.98% | -4.00% | -4.00% |
| **kW from applicable classes** | -2.34% | -2.02% | | -1.50% | -2.64% | -2.93% | -2.98% | -3.39% | -4.54% | -5.35% | -5.97% | -6.48% |

### Totals - Variance Year over Year

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | 0.00% | 1.45% | | 0.01% | 1.35% | 0.01% | 2.29% | 1.09% | 1.07% | 1.05% | 1.03% | 1.00% |
| **kWh** | 0.00% | -0.16% | | -1.44% | -0.72% | -0.25% | -0.37% | -0.26% | -0.82% | -0.19% | -0.03% | 0.00% |
| **kW from applicable classes** | 0.00% | 0.32% | | -1.50% | -1.16% | -0.29% | -0.05% | -0.42% | -1.19% | -0.85% | -0.65% | -0.54% |

## Summary and Variances of Weather Normalized Actuals and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

| | 2010 Weather Normalized | 2011 Weather Normalized | 2012 Weather Normalized | 2013 Weather Normalized | 2014 Forecast Weather Normalized | 2015 Bridge | 2016 Test | 2017 Test | 2018 Test | 2019 Test | 2020 Test |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **RESIDENTIAL** | | | | | | | | | | | |
| **# of Customers** | 271,603 | 275,966 | 280,254 | 284,964 | 284,296 | 293,366 | 297,343 | 301,258 | 305,144 | 308,990 | 312,786 |
| **kWh** | 2,267,082,000 | 2,249,645,000 | 2,255,121,000 | 2,252,988,000 | 2,267,127,000 | 2,233,419,000 | 2,216,045,000 | 2,198,259,000 | 2,206,411,000 | 2,214,984,000 | 2,217,628,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 1.61% | 1.55% | 1.68% | -0.23% | 3.19% | 1.36% | 1.32% | 1.29% | 1.26% | 1.23% |
| **kWh** | | -0.77% | 0.24% | -0.09% | 0.63% | -1.49% | -0.78% | -0.80% | 0.37% | 0.39% | 0.12% |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **GENERAL SERVICE <50KW** | | | | | | | | | | | |
| **# of Customers** | 23,434 | 23,616 | 23,767 | 23,936 | 23,817 | 24,099 | 24,512 | 24,626 | 24,739 | 24,850 | 24,959 |
| **kWh** | 731,617,000 | 723,597,000 | 719,380,000 | 721,817,000 | 707,782,000 | 705,279,000 | 726,360,000 | 716,896,000 | 709,791,000 | 704,193,000 | 699,744,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.78% | 0.64% | 0.71% | -0.50% | 1.18% | 1.71% | 0.47% | 0.46% | 0.45% | 0.44% |
| **kWh** | | -1.10% | -0.58% | 0.34% | -1.94% | -0.35% | 2.99% | -1.30% | -0.99% | -0.79% | -0.63% |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **GENERAL SERVICE 50-1499KW** | | | | | | | | | | | |
| **# of Customers** | 3,279 | 3,353 | 3,416 | 3,408 | 3,417 | 3,549 | 3,296 | 3,323 | 3,351 | 3,380 | 3,408 |
| **kWh** | 3,026,694,000 | 3,035,733,000 | 3,017,363,000 | 2,981,441,000 | 2,970,045,000 | 2,957,727,000 | 2,954,441,000 | 2,907,445,000 | 2,875,422,000 | 2,852,593,000 | 2,835,387,000 |
| **kW** | 7,272,741 | 7,290,048 | 7,234,407 | 7,143,842 | 7,104,743 | 7,070,781 | 7,027,979 | 6,908,640 | 6,824,350 | 6,761,930 | 6,711,579 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 2.26% | 1.88% | -0.23% | 0.26% | 3.86% | -7.13% | 0.82% | 0.84% | 0.87% | 0.83% |
| **kWh** | | 0.30% | -0.61% | -1.19% | -0.38% | -0.41% | -0.11% | -1.59% | -1.10% | -0.79% | -0.60% |
| **kW** | | 0.24% | -0.76% | -1.25% | -0.55% | -0.48% | -0.61% | -1.70% | -1.22% | -0.91% | -0.74% |
| | | | | | | | | | | | |
| **GENERAL SERVICE 1500-5000 KW** | | | | | | | | | | | |
| **# of Customers** | 66 | 69 | 74 | 76 | 72 | 88 | 76 | 76 | 76 | 76 | 76 |
| **kWh** | 827,600,000 | 855,055,000 | 865,127,000 | 860,146,000 | 864,262,000 | 883,242,000 | 863,309,000 | 877,400,000 | 895,369,000 | 914,569,000 | 935,554,000 |
| **kW** | 1,766,012 | 1,825,276 | 1,845,437 | 1,836,496 | 1,856,692 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 | 1,885,562 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 5.04% | 6.60% | 2.70% | -5.26% | 22.22% | -13.64% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | | 3.32% | 1.18% | -0.58% | 0.48% | 2.20% | -2.26% | 1.63% | 2.05% | 2.14% | 2.29% |
| **kW** | | 3.36% | 1.10% | -0.48% | 1.10% | 1.55% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **LARGE USER** | | | | | | | | | | | |
| **# of Customers** | 12 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **kWh** | 683,012,000 | 659,208,000 | 641,537,000 | 628,405,000 | 617,273,000 | 620,305,000 | 620,218,000 | 619,253,000 | 618,467,000 | 617,036,000 | 615,195,000 |
| **kW** | 1,234,876 | 1,191,286 | 1,158,988 | 1,137,277 | 1,115,729 | 1,121,629 | 1,121,449 | 1,119,726 | 1,118,300 | 1,115,702 | 1,112,342 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | -7.64% | -0.75% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | | -3.49% | -2.68% | -2.05% | -1.77% | 0.49% | -0.01% | -0.16% | -0.13% | -0.23% | -0.30% |
| **kW** | | -3.53% | -2.71% | -1.87% | -1.89% | 0.53% | -0.02% | -0.15% | -0.13% | -0.23% | -0.30% |
| | | | | | | | | | | | |
| **STREETLIGHTING** | | | | | | | | | | | |
| **# of Connections** | 54,395 | 54,679 | 55,674 | 55,757 | 56,608 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 | 55,516 |
| **kWh** | 43,535,000 | 43,719,000 | 44,699,000 | 44,767,000 | 44,646,000 | 43,501,000 | 43,552,000 | 43,653,000 | 43,765,000 | 43,876,000 | 44,015,000 |
| **kW** | | | 123,332 | 123,947 | 129,682 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 | 123,144 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | 0.52% | 1.82% | 0.15% | 1.53% | -1.93% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | | 0.42% | 2.24% | 0.15% | -0.27% | -2.56% | 0.12% | 0.23% | 0.26% | 0.25% | 0.32% |
| **kW** | | 0.00% | 0.00% | 0.50% | 4.63% | -5.04% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **UMSL** | | | | | | | | | | | |
| **# of Connections** | 2,907 | 3,183 | 3,384 | 3,376 | 3,333 | 3,444 | 3,477 | 3,525 | 3,573 | 3,621 | 3,669 |
| **kWh** | 17,309,000 | 18,044,000 | 17,594,000 | 17,055,000 | 16,489,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 | 16,651,000 |
| **kW** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | 9.48% | 6.33% | -0.24% | -1.27% | 3.33% | 0.96% | 1.38% | 1.36% | 1.34% | 1.33% |
| **kWh** | | 4.25% | -2.49% | -3.06% | -3.32% | 0.98% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **SENTINEL LIGHTS** | | | | | | | | | | | |
| **# of Connections** | 73 | 65 | 61 | 57 | 78 | 57 | 55 | 51 | 47 | 43 | 39 |
| **kWh** | 74,233 | 64,267 | 59,894 | 49,020 | Not forecasted | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 | 48,000 |
| **kW** | 206 | 179 | 166 | 139 | Not forecasted | 216 | 216 | 216 | 216 | 216 | 216 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Connections** | | -10.96% | -6.15% | -6.56% | 36.84% | -26.92% | -3.51% | -7.27% | -7.84% | -8.51% | -9.30% |
| **kWh** | | -13.43% | -6.80% | -18.16% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | | -13.11% | -7.26% | -16.27% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **STANDBY** | | | | | | | | | | | |
| **# of Customers** | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **kWh** | | | | | | | | | | | |
| **kW** | Included in actuals for class | | Included in actuals for class | | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | | | | | | | | | | | |
| **Rate Class 10** | | | | | | | | | | | |
| **# of Customers** | | | | | | | | | | | |
| **kWh** | | | | | | | | | | | |
| **kW** | | | | | | | | | | | |
| **Variance Analysis** | | | | | | | | | | | |
| **# of Customers** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kWh** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **kW** | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

### Totals

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | 355,771 | 360,945 | 366,643 | 371,587 | 371,634 | 380,132 | 384,288 | 388,388 | 392,459 | 396,489 | 400,466 |
| **kWh** | 7,596,923,233 | 7,585,065,267 | 7,560,880,894 | 7,506,668,020 | 7,487,624,000 | 7,460,172,000 | 7,440,624,000 | 7,379,605,000 | 7,365,924,000 | 7,363,950,000 | 7,364,222,000 |
| **kW from applicable classes** | 10,273,835 | 10,306,788 | 10,362,330 | 10,241,701 | 10,211,646 | 10,206,132 | 10,163,150 | 10,042,088 | 9,956,372 | 9,891,354 | 9,837,643 |

### Totals - Variance

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customers / Connections** | 0.00% | -0.16% | -0.32% | -0.72% | -0.25% | -0.37% | -0.26% | -0.82% | -0.19% | -0.03% | 0.00% |
| **kWh** | 0.00% | 0.32% | 0.54% | -1.16% | -0.29% | -0.05% | -0.42% | -1.19% | -0.85% | -0.65% | -0.54% |
| **kW from applicable classes** | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

# OTHER REVENUE SUMMARY

## 1.0 INTRODUCTION

Other Revenue, also referred to as Revenue Offsets, relates to all utility revenues other than distribution and cost of power revenues. Hydro Ottawa Limited ("Hydro Ottawa") has classified these into the following categories: Specific Service Charges, Late Payment Charges, Other Operating Revenue and Other Income and Deductions. Table 1, below, provides a summary of Other Revenue from 2012 through 2016, along with the associated Uniform System of Accounts ("USofA"), rounded to the nearest $1,000.

**Table 1 - Other Revenue Summary**

| Other Revenue | 2012 Actual $000 | 2013 Actual $000 | 2014 Budget $000 | 2015 Forecast $000 | 2016 Forecast $000 |
|---|---|---|---|---|---|
| **Specific Service Charges** (4235) | 3,583 | 5,293 | 3,801 | 3,710 | 5,910 |
| **Late Payment Charges** (4225) | 872 | 907 | 956 | 899 | 899 |
| **Other Operating Revenue** (4082, 4084, 4086, 4090) | 1,197 | 1,004 | 1,064 | 925 | 1,411 |
| **Other Income & Deductions** (4315, 4320, 4325, 4330, 4355, 4360, 4362, 4375, 4405) | 2,303 | 1,777 | 3,163 | 3,313 | 3,480 |
| **Total Other Revenue** | **7,955** | **8,980** | **8,984** | **8,847** | **11,700** |

A detailed breakdown of Other Operating Revenue and Other Income and Deductions is provided in Appendix 2-H.

## 2.0 SPECIFIC SERVICE CHARGES

A specific service charge is applied for service requests or activities which primarily benefit or are attributed to the customer who requests or initiates the specific service or activity. Some specific service charges are applied as a result of a customer's inaction.

As noted in Exhibit H-7-1, Hydro Ottawa undertook a review of many routine service charges to ensure that the associated costs of providing such services were appropriately recovered.

With the exception of six (6) previously approved specific service charges, Hydro Ottawa is proposing to increase or introduce new specific service charges (“service charges”) for the years 2016 through 2020.

## 3.0 LATE PAYMENT CHARGES

An OEB-approved monthly interest rate of 1.5% (19.56 per annum) is applied to outstanding account balances that exceed sixteen calendar days from the date a bill is mailed.

## 4.0 OTHER OPERATING REVENUES

Other Operating Revenues include revenue associated from the provision of Standard Supply, Retailer and Generator services.

Generator service revenue was historically recorded under Other Income and Deductions (4325); however, as of 2016 the associated revenues shall be recorded in (4090), as part of Other Operating Revenues.

The service charges associated with these services are proposed to increase in 2016 through 2020.

## 5.0 OTHER INCOME AND DEDUCTIONS

Hydro Ottawa also earns revenue through the provision of services to customers and third parties, rental income from leased plant, gains (or losses) on the disposal or retirement of utility property, the provision of services to Hydro Ottawa's affiliates and the City of Ottawa, as well as, earning interest income on short-term investments.

## 5.1 Works for Others

### 5.1.1 Services to the City of Ottawa

In addition to the sale of electricity, Hydro Ottawa rents poles and ducts to the City of Ottawa, as well as, performs minor routine work. Revenue associated with pole attachments is recorded under Service Charge revenue. Duct rental revenue is part of Other Income & Deductions.

## 5.2 Service Affiliates

Hydro Ottawa provides services to its' affiliates Hydro Ottawa Holding Inc. and Energy Ottawa Inc. under the terms of Service Level Agreements, which are updated annually.

Hydro Ottawa provides Human Resources, Facilities, IT, Finance and Communications services to Hydro Ottawa Holding Inc. Energy Ottawa Inc. receives Human Resources, Facilities, IT, Finance, Metering/Meter Data and Mechanical services from Hydro Ottawa.

Details on the services Hydro Ottawa provides and receives from Affiliate transactions are provided in Exhibit D-2-1. For convenience, a summary of the associated revenue offsets are provided in Table 2, below.

**Table 2: Summary of Affiliate Services Revenue Earned by Hydro Ottawa**

| Services From | Services to | 2012 Actual | 2013 Actual | 2014 Budget Year | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| Hydro Ottawa Ltd. | Hydro Ottawa Holding Inc. | $743,921 | $771,477 | $785,029 | $818,932 | $835,388 |
| Hydro Ottawa Ltd. | Energy Ottawa Inc. | $532,668 | $983,140 | $989,715 | $1,043,155 | $1,061,482 |
| **Total** | | **$1,276,589** | **$1,754,617** | **$1,774,744** | **$1,862,087** | **$1,896,870** |

### 5.3 Services to Third Parties

These revenues, net of expenses, relate to services provided to customers or third parties such as installing and removing temporary services, isolating and re-energizing of services, transformer vault shutdown escort services, inspection services, generator services and a recently introduced bill reporting service. A small amount of revenue is also forecasted for providing ad hoc web portal services for viewing interval meter data in a web-based format.

Hydro Ottawa rents out its underground civil capacity to third parties, on a temporary basis, through a five-year Access Agreement ("duct rentals"). Duct rental agreements exist with the City of Ottawa and Rogers Cable. Hydro Ottawa has several third party pole attachments which pay an annual charge, per attachment (part of Specific Service Charges). These third parties include street light owners, telecoms and Hydro One. Pole attachment charges are proposed to increase, as part of this Application, as outlined in Exhibit H-7-1, Section 3.3 and calculated in Attachment H-7(A).

Water heater billing services are forecast to expire on December 31, 2015.

As noted in Section 4.0, generator service revenues will be recorded under Other Operating Revenue, as of 2016.

### 5.4 Property Rental

Property rental relates to fees paid by Hydro One Networks Inc. ("Hydro One") for land owned by Hydro Ottawa. In many locations in the City of Ottawa, Hydro Ottawa and Hydro One have joint facilities for transformer stations. For locations in which Hydro Ottawa owns the land on which Hydro One has facilities, a rental fee is paid. An additional source of income is from rent paid by the tenants of a small number of houses Hydro Ottawa purchased next to distribution stations many years ago to facilitate future station expansion.

## 5.5 Gains and Losses on Disposal of Property

Hydro Ottawa periodically disposes of assets that are no longer, necessary in serving the public (e.g. fully amortized vehicle, equipment, et cetera). Where the proceeds vary from the net book value of an asset, Hydro Ottawa treats the variances as a debit or credit to income.

Prior to 2014, the associated gains and losses were applied to USofA 4355 and 4360, respectively. As of 2014 forward, the net amount has been applied to USofA 4362.

## 5.6 Revenues from Non-Utility Operations

Non-utility income is not considered a "revenue offset" in that it does not reduce the distribution (base) revenue requirement. Hydro Ottawa has very little non-utility income with the exception of Conservation and Demand Management ("CDM") activities.

Between 2012 and 2014, Hydro Ottawa recorded a modest amount of revenue from the Ontario Power Authority micro-FIT program, from operating solar panels at two Hydro Ottawa properties, under USofA 4375. As of 2015, related revenues are not recorded under Other Revenue

## 5.7 Interest and Dividend Income

Interest income refers to interest earned on cash balances within the year. In the years 2012 to 2014 a modest amount of interest was recorded. Material cash balances are not anticipated between years 2015 and 2020.

## 6.0 OTHER REVENUE – VARIANCE ANALYSIS

Material financial and trending variance explanations are provided in the following year-to-year comparisons.

**2012 Actual to 2013 Actual**

2013 Other Revenue actuals of $8,980k were 12.9 percent higher than 2012 actuals.

Miscellaneous Service Revenues (4235) increased $1,709k, or, 47 percent in 2013 primarily due to the write-off of old outstanding account credit balances, in preparation for Hydro Ottawa's customer information system conversion to CC&B in 2014. Processes are now in place to monitor account credit balances in excess of one year, on a quarterly basis and clear such balances as appropriate.

Revenues from Merchandising and Jobbing (4325 Work for Others) were $4,652k, or, 97 percent higher primarily due to $946k associated with the commencement of the City of Ottawa Light Rail Transit ("LRT") project, which included abnormally high temporary power supply work and $1,556k resulting from a non-routine land trunk extension and major voltage conversion. $1,517k was the result of the recovery of damaged assets which were mistakenly applied to this revenue category, rather than Gain and Loss on Disposal of Property (4355 and 4360). Had this error not occurred, the 2013 Merchandising and Jobbing revenues (4325) would have been $7,897k.

Costs from Merchandising and Jobbing (4330 Work for Others) were 79 percent higher, primarily due to the City of Ottawa LRT project at $898k; the non-routine land trunk extension at $1,285k and the voltage conversion at $233k. An overall increase in construction and customer demand activity accounts for the balance of $656k.

In light of the aforementioned accounting treatment, Gain and Loss on disposal of Property (4355 and 4360)) is adjusted by $1,517k. Therefore, the actual Gain and Loss on disposal of Property for 2013 is $1,040k.

**2013 Actual to 2014 Forecast**

Overall, the 2014 Forecast is expected to trend closely to the 2013 actuals at $8,984k.

Miscellaneous Service Revenues (4235) are expected to be $1,491k lower than 2013 actuals, which were abnormally high due to non-routine credit balance write-off activity.

Revenues from Merchandising and Jobbing (4325) are anticipated to be $4,008 lower than 2013 actuals due to the anticipated return of more standard work program activities, including the LRT project.

For similar reasons, costs from Merchandising and Jobbing (4330) are expected to be $2,875 lower than 2013 actuals.

As of 2014, Gain and Loss on Disposal of Property (4355 and 4360) were consolidated under USofA 4362. A modest loss of $54k is forecast for 2014.

**2014 Forecast to 2015 Bridge Year**

Other Revenue in 2015 is forecasted to trend closely to 2014 forecast levels at $8,847k. Slight declines in Retail Service, Late Payment and Miscellaneous Service revenues are expected to be offset by modest increases in revenues associated with services to third parties and asset disposals.

**2015 Bridge Year to 2016 Test Year**

Other Revenue in 2015 is forecasted at $11,700k. The increase of $2,852k, or, 32 percent over 2015, is primarily due to proposed increases in Retail, Generation and Specific Service charges. Details on the proposed service charge changes are outlined in Exhibits H-7-1 and H-7-2. A summary of the Service Charge revenues between 2012 through 2020 is provided in Exhibit C-2-2.

**2016 Test Year to 2017 Test Year**

Other Revenue in 2016 is forecasted to trend closely to 2015 forecast levels, at $11,565k. A decline in Late Payment Charge revenue is forecasted in 2016, due to the active promotion of automated payment withdrawal services to major accounts, which have a large number of accounts. Initial trends indicate that this option is gaining momentum in the major accounts sector. For this reason, Late Payment Charge revenue is expected to decline from $75k per month to $60k per month in 2017.

The forecasted decline in Late Payment Charge revenue is partially offset by a 2.1 percent inflationary increase to new and revised service charges.

**2017 Test Year to 2018 Test Year**

Other Revenue is forecast to increase modestly in 2018 at $11,722k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

**2018 Test Year to 2019 Test Year**

Other Revenue is forecast to increase modestly in 2019 at $11,802k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

**2019 Test Year to 2020 Test Year**

Other Revenue is forecast to increase modestly in 2020 at $11,898k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

| | |
|---|---|
| **File Number:** | EB-2015-004 |
| **Exhibit:** | C |
| **Tab:** | 2 |
| **Schedule:** | 1 |
| **Page:** | 1 of 1 |
| | |
| **Date:** | ORIGINAL |

## Appendix 2-H
## Other Operating Revenue

| USoA # | USoA Description | 2012 Actual | 2013 Actual | 2014 Forecast | Bridge Year² | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|---|
| | | | | | 2015 | 2015 | 2016 |
| | *Reporting Basis* | MIFRS | MIFRS | MIFRS | | MIFRS | MIFRS |
| **4235** | **Specific Service Charges** | $ 3,583,148 | $ 5,292,621 | $ 3,801,357 | N/A | $ 3,710,267 | $ 5,910,525 |
| **4225** | **Late Payment Charges** | $ 872,023 | $ 906,905 | $ 956,249 | N/A | $ 898,752 | $ 898,752 |
| **4082** | Retail Services Revenues | $ 208,790 | $ 100,517 | $ 213,645 | N/A | $ 159,204 | $ 171,228 |
| 4084 | Service Transaction Requests | $ 7,502 | $ 5,816 | $ 7,613 | N/A | $ 5,616 | $ 6,132 |
| 4086 | SSS Admin Charge | $ 980,504 | $ 897,531 | $ 842,277 | N/A | $ 760,485 | $ 891,797 |
| 4090 | Electric Services Incidental to Energy Sales | $ - | $ - | $ - | N/A | $ - | $ 341,400 |
| 4315 | Revenues from Leased Plant | $ 1,737,805 | $ 1,768,330 | $ 1,822,147 | N/A | $ 1,823,686 | $ 1,839,502 |
| 4325 | Revenues from Merch, Jobbing | $ 4,762,170 | $ 9,414,470 | $ 5,406,047 | N/A | $ 5,486,488 | $ 5,459,437 |
| 4330 | Expenses from Merch, Jobbing | -$ 3,866,634 | -$ 6,938,273 | -$ 4,062,449 | N/A | -$ 4,186,206 | -$ 4,045,020 |
| 4355 | Gain on Disposal of Property | -$ 468,071 | -$ 2,557,273 | $ - | N/A | $ - | $ - |
| 4360 | Loss on Disposal of Property | -$ 3,687 | $ - | $ - | N/A | $ - | $ - |
| 4362 | Loss from Retirement of Utility and Other Property | $ - | $ - | -$ 54,605 | N/A | $ 189,121 | $ 198,349 |
| 4375 | Revenues from Non-Utility Operations | $ 2,712 | $ 2,513 | $ 38,450 | N/A | $ - | $ - |
| 4405 | Interest and Dividend Income | $ 139,142 | $ 86,990 | $ 13,073 | N/A | $ - | $ 27,436 |
| | | | | | | | |
| **Specific Service Charges** | | $ 3,583,148 | $ 5,292,621 | $ 3,801,357 | N/A | $ 3,710,267 | $ 5,910,525 |
| **Late Payment Charges** | | $ 872,023 | $ 906,905 | $ 956,249 | N/A | $ 898,752 | $ 898,752 |
| **Other Operating Revenues** | | $ 1,196,796 | $ 1,003,864 | $ 1,063,535 | N/A | $ 925,305 | $ 1,410,557 |
| **Other Income or Deductions** | | $ 2,303,437 | $ 1,776,757 | $ 3,162,663 | N/A | $ 3,313,089 | $ 3,479,704 |
| **Total** | | $ 7,955,404 | $ 8,980,147 | $ 8,983,804 | N/A | $ 8,847,413 | $ 11,699,538 |

| <u>**Description**</u> | <u>**Account(s)**</u> |
|---|---|
| Specific Service Charges: | 4235 |
| Late Payment Charges: | 4225 |
| Other Distribution Revenues: | 4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245 |
| Other Income and Expenses: | 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415 |

**Note: Add all applicable accounts listed above to the table and include all relevant information.**

**Account Breakdown Details**

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

**Account 4405 - Interest and Dividend Income**

| | 2012 Actual | 2013 Actual | 2014 Forecast | Bridge Year² | Bridge Year² | Test Year |
|---|---|---|---|---|---|---|
| | | | | 2015 | 2015 | 2016 |
| **Reporting Basis** | MIFRS | MIFRS | MIFRS | | MIFRS | MIFRS |
| Short-term Investment Interest | | | | | | |
| Bank Deposit Interest | $ 139,142 | $ 86,990 | $ 13,073 | | $ - | $ 27,436 |
| Miscellaneous Interest Revenue | | | | | | |
| etc.[1] | | | | | | |
| | | | | | | |
| **Total** | $ 139,142 | $ 86,990 | $ 13,073 | $ - | $ - | $ 27,436 |

**Notes:**

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that is adopting IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

# SERVICE CHARGE REVENUE

## 1.0 INTRODUCTION

As noted in Exhibit H-7-1, Hydro Ottawa Limited ("Hydro Ottawa") reviewed and revised a number of service charges as part of this application. This review included Specific Service, Generator Service and Retailer Service Charges ("Service Charges"). A complete listing of existing and proposed service charges from 2012 through 2020 is provided in Table 1, of Exhibit H-7-1.

In terms of Other Revenue impacts, the proposed Service Charges are forecasted to increase 2016 Service Charge revenues by 65.5 percent, or $2,520k, as compared to 2015 forecasted Service Charge revenues. The majority of this revenue increase is driven by proposed increases in Service Charges, as compared to volumetric increases.

Between the years of 2013 to 2015, Temporary Service revenues were recorded under Merchandising and Jobbing (4325 Work for Others). Simlarly, Generation Service revenues were recorded under (4325 Work for Others) during the years 2012 to 2015. As of 2016, the associated revenues shall be recorded under Miscellaneous Revenue (4235) and Other Operating Revenue (4090), respectively. For comparison, these amounts are shown under Service Charges, but, not included in the respective 2012 to 2015 Service Charge revenue totals.

A summary of the Service Charges and applicable revenues for the years 2012 through 2020 is provided in the following Table 1:

## Table 1 – Summary of Service Charge Revenue 2012 to 2020

| SPECIFIC SERVICE CHARGE REVENUE | 2012 Actual Revenue | 2013 Actual Revenue | 2014 Forecast Revenue | 2016 Forecast Revenue | 2017 Forecast Revenue | 2018 Forecast Revenue | 2019 Forecast Revenue | 2020 Forecast Revenue |
|---|---|---|---|---|---|---|---|---|
| Enrollment Request Fee | $100 | $100 | | | | | | |
| Account Certificate (i.e., easements, arrears) | $8,096 | $4,454 | $3,754 | $4,308 | $4,308 | $4,308 | $4,308 | $4,308 |
| Duplicate invoices for previous billing | $2,550 | $1,905 | $2,667 | $2,544 | $2,544 | $2,544 | $2,544 | $2,544 |
| Credit reference/credit check (plus credit agency costs) | $1,395 | $840 | $621 | $816 | $816 | $816 | $816 | $816 |
| Unprocessed Payment Charge (plus bank charges) | $28,725 | $29,190 | $34,164 | $28,008 | $28,008 | $28,008 | $28,008 | $28,008 |
| Account set up charge/change of occupancy charge | $1,889,773 | $1,928,323 | $2,045,859 | $1,992,321 | $2,012,253 | $2,032,376 | $2,052,700 | $2,073,227 |
| Collection of account charge - no disconnection | $18,150 | $24,870 | $25,476 | $24,792 | $24,792 | $24,792 | $24,792 | $24,792 |
| Disconnect/Reconnect at meter - regular hours | $118,675 | $208,200 | $185,916 | $189,288 | $189,288 | $189,288 | $189,288 | $189,288 |
| Disconnect/Reconnect at meter - after regular hours | $71,225 | $162,430 | $146,468 | $138,276 | $138,276 | $138,276 | $138,276 | $138,276 |
| Disconnect/Reconnect at pole - regular hours | | | | $0 | $0 | $0 | $0 | $0 |
| Disconnect/Reconnect at pole - after regular hours | $1,245 | $415 | | $0 | $0 | $0 | $0 | $0 |
| Other Billing Info Request (proposed Special Billing Service) | $4,485 | $4,335 | $4,224 | | | | | |
| Special Billing Service (formerly Other Billing Info Request) per hr | | | | $4,750 | $4,850 | $5,000 | $5,100 | $5,200 |
| Temporary service install & remove - overhead - no transformer | $11,498 | $51,000 | $36,000 | $55,790 | $56,910 | $58,100 | $59,360 | $60,620 |
| Temporary service install & remove - underground - no transformer | | | | $11,560 | $11,800 | $12,050 | $12,300 | $12,560 |
| Temporary service install & remove - overhead - with transformer | | | | $71,000 | $72,500 | $74,025 | $75,575 | $77,175 |
| Specific Charge for Access to the Power Poles (per pole attachment) | $1,410,545 | $1,321,742 | $1,335,042 | $3,211,779 | $3,211,779 | $3,268,126 | $3,268,126 | $3,268,126 |
| Dry Core Transformer Charge - Demand (per attached Table) | $16,664 | $16,923 | $17,167 | $19,476 | $20,255 | $21,390 | $22,480 | $23,245 |
| Reconnect at meter - regular hours (under account administration section - new account) | | | | $149,500 | $149,500 | $149,500 | $149,500 | $149,500 |
| Reconnect at meter - after regular hours (under account administration section - new account) | | | | $2,220 | $2,220 | $2,220 | $2,220 | $2,220 |
| Interval Meter - Field Reading | | | | $0 | $0 | $0 | $0 | $0 |
| High Bill Investigation - If billing is correct | | | | $0 | $0 | $0 | $0 | $0 |
| Service Call - Customer missed appointment - (Reg. Hours) | | | | $1,625 | $1,625 | $1,625 | $1,625 | $1,625 |
| Service Call - Customer missed appointment (After Reg. Hours) | | | | $925 | $925 | $925 | $925 | $925 |
| Energy Resource Facility Administration Charge - Without Account Set Up (one-time) | | | | $762 | $780 | $798 | $810 | $828 |
| Energy Resource Facility Administration Charge - With Account Set Up (one-time) | | | | $785 | $800 | $815 | $825 | $840 |
| Misc Revenue | $22 | $1,588,894 | | | | | | |
| **Total Service Charge Revenue** | **$3,583,148** | **$5,292,621** | **$3,801,358** | **$5,910,525** | **$5,934,229** | **$6,014,982** | **$6,039,578** | **$6,064,123** |
| **RETAILER SERVICE REVENUE** | | | | | | | | |
| Standard Charge | | | | $0 | $0 | $0 | $0 | $0 |
| Monthly Fixed Charge, per Retailer | | | | $5,184 | $5,400 | $5,616 | $5,832 | $6,048 |
| Monthly Variable Charge, per Customer, per Retailer | | | | $105,397 | $103,102 | $109,262 | $106,883 | $112,598 |
| Monthly Billing Charge ("DCB"), per Customer, per Retailer | | | | $60,653 | $59,230 | $66,103 | $64,552 | $63,037 |
| Service Transaction Requests ("STR") Fee, per request | | | | $2,891 | $2,840 | $2,790 | $3,198 | $3,141 |
| Service Transaction Requests ("STR") Fee, per process | | | | $3,239 | $3,072 | $3,156 | $2,994 | $3,058 |
| **Total Retailer Service Revenue** | **$216,292** | **$106,333** | **$221,258** | **$177,364** | **$173,644** | **$186,927** | **$183,458** | **$187,882** |
| **GENERATOR SERVICE REVENUE** | | | | | | | | |
| Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly MicroFIT monthly account management charge) | $6,777 | $26,676 | $28,253 | $152,064 | $157,248 | $171,456 | $176,928 | $182,400 |
| FIT Monthly Account Management Charge | | | | $161,364 | $164,076 | $168,144 | $170,856 | $174,924 |
| HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge | | | | $27,972 | $28,512 | $29,160 | $35,604 | $48,613 |
| **Total Generator Service Charges** | **$6,777** | **$26,676** | **$28,253** | **$341,400** | **$349,836** | **$368,760** | **$383,388** | **$405,937** |
| **Total 2016 Service Charges Updates - Forecasted Revenue** | **$3,806,217** | **$5,425,630** | **$4,050,869** | **$6,429,289** | **$6,457,709** | **$6,570,669** | **$6,606,424** | **$6,657,942** |

# OPERATING EXPENSES - SUMMARY

This Exhibit provides an overview of Hydro Ottawa's total operating costs. These costs include Operations, Maintenance and Administration ("OM&A") including property taxes, Depreciation and Amortization expenses; and Payments in Lieu of Taxes ("PILS"). Detailed information with respect to each of these operating costs is available in Exhibits D-1-2 and D-1-3, D-3-1 and D-4-1.

## 1.0 Summary of Operating Expenses 2012-2016

**Table 1**

| ($000s) | 2012 Actual | 2013 Actual | 2014 Q2 Forecast | 2015 Bridge | 2016 Test Year |
|---|---|---|---|---|---|
| OM&A (including Property Tax) | $73,076 | $75,757 | $80,767 | $83,656 | $87,106 |
| Depreciation/Amortization | $38,595 | $39,798 | $36,517 | $38,558 | $40,826 |
| PILS (income taxes) | $6,857 | $6,806 | $3,000 | NIL | $4,958 |
| **Total Operating Costs** | $118,528 | $122,361 | $120,284 | $122214 | $132,890 |

## 2.0 OM&A

Hydro Ottawa's OM&A expenses for the 2016 test year are forecasted to be $ 87.1. This represents a compound annual growth rate of 5.5% over the 2012-2016 timeframe.

The principle cost drivers underlying Hydro Ottawa's forecasted OM&A expenses include costs associated with compliance with legislative and regulatory compliance, compensation and labour costs, inflation and certain operational and maintenance costs that Hydro Ottawa must incur to continue to provide a safe and reliability electricity distribution system.

### 2.1 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an escalation factor of 3.245% is applied to OM&A expenditures which is the result of the I-X formula.

Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees.

### 2.2 Compensation Costs

Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees. Hydro Ottawa's forecasted total compensation costs for the 2016 test year are $71,944K. This represents a compound annual growth rate of 4.3% over the 2012 to 2016 timeframe. For more information regarding Hydro Ottawa's compensation costs please refer to Exhibit D-1-8.

## 3.0 Depreciation and Amortization expenses

Hydro Ottawa adheres to the Modified International Financial Reporting Standards ("MIFRS") as its accounting standard which informs its rate making and regulatory reporting requirements. Hydro Ottawa uses the half-year rule for calculating depreciation/amortization in the year that capital additions are added into rate base. For more information regarding Hydro Ottawa's Depreciation/Amortization expense, please refer to Exhibit D-3-1.

## 4.0 Payments in Lieu of Taxes ("PILS") and Property Taxes.

Pursuant to its obligations under Section 93 of the Electricity Act 1998 (Ontario), as amended, Hydro Ottawa is liable for the payment of PILS to the City of Ottawa based on its taxable income. Hydro Ottawa expects to pay $0 in PILS in 2015 and $ $4,958K in

PILS in 2016. For more information regarding PILS, please refer to Exhibit D-4-1 1 for further details.

# OM&A OVERVIEW

This schedule provides a brief qualitative and quantitative summary of Hydro Ottawa Limited's ("Hydro Ottawa" or "the Company") Operations, Maintenance and Administration ("OM&A") expenditures including a brief overview of the composition of Hydro Ottawa's OM&A costs, the significant OM&A cost drivers and year over year variances, trends and business environment changes. This schedule further describes Hydro Ottawa's approach to OM&A planning and the top down and bottom up budget process used to arrive at Hydro Ottawa's OM&A expenditures. The information contained in this schedule is informed by the OEB's filing requirements set out on page 33 in Chapter 2 of the Ontario Energy Board's (OEB's) Filing requirements for Electricity Distribution Rate Applications, as updated on July 18, 2014.

## 1.0 OM&A SUMMARY

### 1.1 Hydro Ottawa's Approach to OM&A Planning and Budgeting

Hydro Ottawa's approach to OM&A planning and budgeting for the 2016-2020 period is guided by Hydro Ottawa's planning and performance management framework which aligns the Company's corporate strategies with planning, operations, performance and the drive for continuous improvement.

The framework maintains that spending correspond to business priorities, be directed to achieve performance targets and support Hydro Ottawa's four key focus areas as set out in its *2012-2016 Strategic Direction*. The four key focus areas for the Company are:

- Customer value;
- Financial strength;
- Organizational effectiveness; and
- Corporate citizenship.

Hydro Ottawa's 2016 OM&A budget was developed as a test year rebasing budget but was guided by the constraints enunciated in the February 2014 budget memo from Hydro Ottawa's Chief Financial Officer (Attachment D-1(A)) which, among other things, included constraints on headcount and compensation and OM&A. Hydro Ottawa's 2016 OM&A budget was further informed by substantive operational investments needed to maintain service reliability and safety as well as those necessary to remain in compliance with regulatory and legislative requirements. Finally, Hydro Ottawa's OM&A budget was informed by the need to maximize productivity and minimize bill impacts while ensuring the financial health and viability of the Company.

For the 2017-2020 test years, Hydro Ottawa will adjust OM&A using an I-X formula to align with the principles of incentive regulation as enunciated in the Renewed Regulatory Framework for Electricity (RRFE). Hydro Ottawa seeks approval for final rates for a three year period beginning 2016 and ending 2018. In 2017 Hydro Ottawa proposes to apply for revised rates that will be adjusted to incorporate a revised inflation factor and updated cost of capital parameters. Hydro Ottawa's approach to adjusting the OM&A component of rates by a I-X formula, results in the Company bearing the risk associated with any shortfall between revenues collected through rates and regularly incurred costs. This difference must be recovered through productivity initiatives and operational efficiencies. Hydro Ottawa further assumes the risk associated with not adjusting rates for the first three years to reflect changes to inflation or cost of capital.

### 1.2 OM&A Budget Process

Hydro Ottawa undertook both a top down and bottom up forecasting exercise to develop the 2016 test year budget. The 2016 budget forecast exercise began with the development of the Budget Memo from the office of the Chief Financial Officer that provided top down guidance on the areas of constraints which informed the individual divisions in the development of their bottom up budgets. Examples of top down constraints include constraints on hiring and on compensation, benefits, productivity, and cost control. Bottom up funding requests were then developed and evaluated and scrutinized based on priority and alignment with core company strategic directives as well as ratepayer impacts. Adjustments were subsequently made to the 2016 OM&A budget to reflect corporate priorities and customer rate impacts. The final 2016 OM&A budget was developed to accommodate Hydro Ottawa's operational requirement to provide a safe and reliable distribution system while respecting legislative and regulatory obligations and the conditions of its license.

As noted above, the OM&A budget for the 2017-2020 test years was subsequently calculated based on an I-X formula typical of incentive regulation models. Although the budget was assessed for rate impacts no further adjustments were made. Recognizing that Hydro Ottawa cannot accurately predict all potential OM&A funding requirements that may emerge during the 2017-2020 custom IR term, it may avail itself to the cost recovery mechanism available under a Z factor application. Hydro Ottawa will only resort to using the Z factor mechanism if costs incurred arise from unforeseen events, decisions or activities, the results of which cannot be reasonably anticipated or quantified at this juncture and where the costs exceed Hydro Ottawa's materiality threshold. . Examples include unforeseen weather events or changes to laws or regulations requiring significant implementation investment.

For more details on Hydro Ottawa's Custom IR model, see Exhibit A-2-1.

### 1.3 OM&A Composition

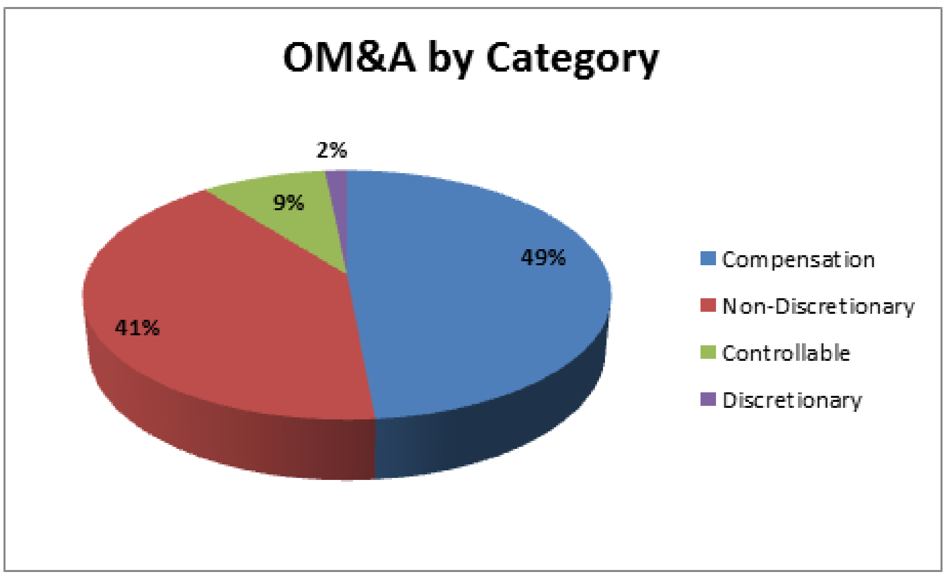
In support of the Company's cost control initiative, an OM&A review was conducted during the 2014 budget process. The review capture all the costs of the main business activities broken down into four distinct categories:

1) Compensation: Headcount costs including payroll and benefits;
2) Non-Discretionary OM&A: Statutory requirement costs that are fixed or dictated by external factors and/or minimum contracts. Examples include the OEB fees, property tax, audit fees, and insurance premium, and underground locates;
3) Controllable OM&A: Costs that must be incurred. Volumes and/or service levels are controlled by management and can be adjusted in the short term. Examples include bank charges, fuel, utilities, manhole cleaning; and

4) Costs that can be reallocated or eliminated without significant impact to current operations or customer relations. Examples include non-safety training, non-essential consulting, travel, and meals, community services.

As Figure 1 below denotes compensation costs represent 49% of Hydro Ottawa's OM&A costs while 41% are non-discretionary costs, 9% are controllable and only 2% are discretionary.

**Figure 1 – OM&A by Category**




Source: Hydro Ottawa 2014 Analysis

## 1.4 OM&A Test Year Levels

The proposed OM&A costs for the test years range from $87.1 million in the 2016 test year to $99.0 million in the 2020 test year.

2017 – 2020 test year OM&A costs are adjusted by Hydro Ottawa's Custom IR model which is based on the Conference Board of Canada's forecasted GDP IPI minus a negative productivity factor of -1.145% to provide an annual I-Xadjustment of 3.245%. The projected OM&A expenditures are necessary to maintain reasonable business continuity while managing the risks associated with the many labour, legislative and regulatory transformations taking place in the electricity industry.

## 1.5 Summary of Total OM&A Expenditures

Hydro Ottawa's OM&A costs are significantly influenced by its requirement to operate and maintain a safe and reliable distribution grid, provide service levels that are satisfactory to customers while ensuring its continued compliance with all legislative and regulatory obligations. Among other things, this entails that it strategically manages its workforce in a manner that allows it to replace retiring workers with new tradespeople and respond to the changing dynamics of the market and operating environment within which it is tasked with distributing electricity to customers.

Table 1 below provides a summary view of Hydro Ottawa's historical, bridge, test and forecast year OM&A expenditures.

**Table 1 – OM&A Variances (in thousands of dollars) and (%) by Year**

| Year | OM&A | Previous Year | Variance ($) | Variance (%) |
|---|---|---|---|---|
| **2012 Actual** | $73,076 | | | |
| **2013 Actual** | $75,757 | $73,076 | $2,681 | 3.7% |
| **2014 Q2 Forecast** | $80,767 | $75,757 | $5,010 | 6.6% |
| **2015 Bridge Year** | $83,656 | $80,767 | $2,889 | 3.6% |
| **2016 Test Year** | $87,106 | $83,656 | $3,450 | 4.1% |
| **2017 Forecast** | $89,932 | $87,106 | $2,826 | 3.2% |
| **2018 Forecast** | $92,850 | $89,932 | $2,918 | 3.2% |
| **2019 Forecast** | $95,863 | $92,850 | $3,013 | 3.2% |
| **2020 Forecast** | $98,974 | $95,863 | $3,111 | 3.2% |

## 1.6 Summary of OM&A Costs by Major Category

Appendix 2-JA provides a summary of the recoverable OM&A Expenses as summarized below in Table 2. See also Exhibit D-1-2 for a description of high level cost drivers and cost drivers by program.

**Table 2 – OM&A costs by major OM&A Category (in thousands of dollars)**

| OM&A Category | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| **Operations** | $14,994 | $15,607 | $17,497 | $18,467 | $20,491 | 8.1% |
| **Maintenance** | $9,884 | $9,612 | $9,634 | $11,073 | $10,386 | 1.2% |
| ***Subtotal*** | ***$24,878*** | ***$25,219*** | ***$27,131*** | ***$29,540*** | ***$30,877*** | ***5.5%*** |
| **Billing and Collecting** | $9,590 | $10,135 | $12,057 | $12,397 | $12,556 | 7.0% |
| **Community Relations** | $5,550 | $5,352 | $5,705 | $5,960 | $6,162 | 2.6% |
| ***Subtotal*** | *$15,140* | *$15,487* | *$17,762* | *$18,357* | *$18,718* | *5.4%* |
| **Administrative and General** | $33,058 | $35,051 | $35,874 | $35,759 | $37,511 | 3.2% |
| ***Total OM&A Expenses*** | ***$73,076*** | ***$75,757*** | ***$80,767*** | ***$83,656*** | ***$87,106*** | ***4.5%*** |

### a) Operations and Maintenance Costs

Operations and Maintenance costs increased by a compound annual growth rate of 5.5% (2012 to 2016). The increase to operations and maintenance related costs is partly attributable to increased costs associated with labour and maintenance expenses associated with operating and maintaining overhead and underground distribution lines, feeders, transformers and distribution stations. Hydro Ottawa's operations and maintenance costs were further influenced by new programs designed to invest in proactive operational and maintenance measures to avoid long term OM&A and capital costs. Examples of such programs include vegetation management and asset maintenance to name a few. The principle cost drivers of the increases are:

- Compensation costs;
- Increased regulatory and legislative obligations compelling compliance. Examples include Bill 168 (Occupational Health & Safety, Bill 8 Underground Locates; various OEB codes changes, Green Energy Act, Smart Meters and meter data costs; and
- New technology costs such as SCADA, GIS and Asset Management software.

**b) Billing and Collections & Community Relations**

Billing and Collections and Community Relations costs increased by compound annual growth rate of 5.4% (2012 to 2016). Billing and collections expenses relate to costs associated with transitioning to monthly billing, enabling customer billing services and conducting collections activities. The principle cost drivers of the increases are:

- Compensation costs;
- Increase to technology costs to enable meter data post-AMI (Automated metering Infrastructure) deployment as well as technology costs to support the customer care and billing system; and
- Increase to postage costs to support monthly billing.

**c) Administrative and General**

Administrative and General costs increased by an compound annual growth rate of 3.2% (2012 to 2016). Administrative costs generally reflect salary expenses as well as costs associated with HR, IT, Finance, Regulatory, and others. The principle cost drivers of the increases are:

- Compensation and benefits costs.

## 1.7 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an escalation factor of 3.245% is applied to OM&A expenditures which is the result of the I-X formula.

## 1.8 Business Environment Changes

Business environment changes that have occurred and that are expected to continue to occur in Hydro Ottawa's territory are changes arising from the proliferation of distributed generation and new technologies emerging within its serving territory all of which is impacting to Hydro Ottawa's current and prospective revenues. On the horizon, Hydro Ottawa anticipates further changes to be triggered by further implementation of the Ministry of Energy's Long Term Energy Plan as well as new initiatives introduced by the

Independent Electricity System Operator (IESO) such as changes to the MDM/R. Individually and collectively these changes will have an impact on the way in which Hydro Ottawa manages its business and the operational costs it must absorb.

### 1.9 Overview of OM&A Programs & Expenditures

A full quantitative description and variance of Hydro Ottawa's full program costs is available in Appendix 2-JC and a qualitative description of Hydro Ottawa's OM&A programs and an analysis of cost drivers can be found in Exhibit D-1-3.

## 2.0 OM&A COST PER CUSTOMER AND PER FTE

Table 3 summarizes Hydro Ottawa's historical, bridge and test year year over year OM&A expenditures expressed on a per customer and per Full Time Equivalent Employees ("FTE") basis. Table 3 illustrates relatively flat increases in the number of customers as well as a decreasing then flat FTE trend.

**Table 3 - OM&A Cost per Customer and FTE**

| | Last Rebasing Year – 2012 – Board Approved | Last Rebasing – 2012 – Actual | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| Reporting Basis | | | | | | |
| Number of Customers | | 309,534.00 | 314,722.00 | 313,501.00 | 323,197.00 | 327,260.00 |
| Total Recoverable OM&A from Appendix 2-JB | $73,090,393 | $73,076,334 | $75,757,157 | $80,767,417 | $83,655,809 | $87,105,564 |
| OM&A cost per customer | | $236.08 | $240.71 | $257.63 | $258.84 | $266.17 |
| Number of FTEs | | 593.5 | 610.6 | 627.8 | 622.7 | 622.7 |
| Customers/FTEs | | 521.54 | 515.43 | 499.36 | 519.03 | 525.55 |
| OM&A Cost per FTE | | $123,127.77 | $124,070.02 | $128,651.51 | $134,343.68 | $139,883.67 |

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | D |
| **Tab:** | 1 |
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## Appendix 2-JA
## Summary of Recoverable OM&A Expenses

| | Last Rebasing Year (2012 Board-Approved) | Last Rebasing Year (2012 Actuals) | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| *Reporting Basis* | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS | MIFRS |
| Operations | | $ 14,993,742 | $ 15,607,433 | $ 17,497,244 | $ 18,466,503 | $ 20,490,724 | | | | |
| Maintenance | | $ 9,883,523 | $ 9,611,544 | $ 9,634,371 | $ 11,073,276 | $ 10,386,427 | | | | |
| **SubTotal** | **$ -** | **$ 24,877,265** | **$ 25,218,976** | **$ 27,131,615** | **$ 29,539,779** | **$ 30,877,151** | | | | |
| %Change (year over year) | | | 1.4% | 7.6% | 8.9% | 4.5% | | | | |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | 24.1% | | | | |
| Billing and Collecting | | $ 9,590,081 | $ 10,135,276 | $ 12,056,732 | $ 12,397,275 | $ 12,555,619 | | | | |
| Community Relations | | $ 5,550,017 | $ 5,351,621 | $ 5,705,132 | $ 5,959,788 | $ 6,162,315 | | | | |
| Administrative and General | | $ 33,058,970 | $ 35,051,283 | $ 35,873,937 | $ 35,758,966 | $ 37,510,478 | | | | |
| **SubTotal** | **$ -** | **$ 48,199,068** | **$ 50,538,180** | **$ 53,635,801** | **$ 54,116,030** | **$ 56,228,413** | **$ -** | **$ -** | **$ -** | **$ -** |
| %Change (year over year) | | | 4.9% | 6.1% | 0.9% | 3.9% | | | | |
| %Change (Test Year vs Last Rebasing Year - Actual) | | | | | | 16.7% | | | | |
| **Total** | **$ 73,090,393** | **$ 73,076,334** | **$ 75,757,156** | **$ 80,767,417** | **$ 83,655,809** | **$ 87,105,563.90** | **$ 89,932,139** | **$ 92,850,437** | **$ 95,863,434** | **$ 98,974,203** |
| %Change (year over year) | | | 3.7% | 6.6% | 3.6% | 4.1% | 3.2% | 3.2% | 3.2% | 3.2% |

| | Last Rebasing Year (2012 Board-Approved) | Last Rebasing Year (2012 Actuals) | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| Operations | $ - | $ 14,993,742 | $ 15,607,433 | $ 17,497,244 | $ 18,466,503 | $ 20,490,724 | $ - | $ - | $ - | $ - |
| Maintenance | $ - | $ 9,883,523 | $ 9,611,544 | $ 9,634,371 | $ 11,073,276 | $ 10,386,427 | $ - | $ - | $ - | $ - |
| Billing and Collecting | $ - | $ 9,590,081 | $ 10,135,276 | $ 12,056,732 | $ 12,397,275 | $ 12,555,619 | $ - | $ - | $ - | $ - |
| Community Relations | $ - | $ 5,550,017 | $ 5,351,621 | $ 5,705,132 | $ 5,959,788 | $ 6,162,315 | $ - | $ - | $ - | $ - |
| Administrative and General | $ - | $ 33,058,970 | $ 35,051,283 | $ 35,873,937 | $ 35,758,966 | $ 37,510,478 | $ - | $ - | $ - | $ - |
| **Total** | **$ 73,090,393** | **$ 73,076,334** | **$ 75,757,156** | **$ 80,767,417** | **$ 83,655,809** | **$ 87,105,564** | **$ 89,932,139** | **$ 92,850,437** | **$ 95,863,434** | **$ 98,974,203** |
| %Change (year over year) | | | 3.7% | 6.6% | 3.6% | 4.1% | 3.2% | 3.2% | 3.2% | 3.2% |

| | Last Rebasing Year (2012 Board-Approved) | Last Rebasing Year (2012 Actuals) | Variance 2012 BA – 2012 Actuals | 2013 Actuals | Variance 2013 Actuals vs. 2012 Actuals | 2014 Q2 Forecast | Variance 2014 Actuals vs. 2013 Actuals | 2015 Bridge Year | Variance 2015 Bridge vs. 2014 Actuals | 2016 Test Year | Variance 2016 Test vs. 2015 Bridge |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Operations** | $ - | $ 14,993,742 | | $ 15,607,433 | $ 613,690 | $ 17,497,244 | $ 1,889,812 | $ 18,466,503 | $ 969,258 | $ 20,490,724 | $ 2,024,221 |
| **Maintenance** | $ - | $ 9,883,523 | | $ 9,611,544 | -$ 271,979 | $ 9,634,371 | $ 22,827 | $ 11,073,276 | $ 1,438,905 | $ 10,386,427 | -$ 686,849 |
| **Billing and Collecting** | $ - | $ 9,590,081 | | $ 10,135,276 | $ 545,195 | $ 12,056,732 | $ 1,921,456 | $ 12,397,275 | $ 340,543 | $ 12,555,619 | $ 158,344 |
| **Community Relations** | $ - | $ 5,550,017 | | $ 5,351,621 | -$ 198,396 | $ 5,705,132 | $ 353,511 | $ 5,959,788 | $ 254,657 | $ 6,162,315 | $ 202,527 |
| **Administrative and General** | $ - | $ 33,058,970 | | $ 35,051,283 | $ 1,992,313 | $ 35,873,937 | $ 822,654 | $ 35,758,966 | -$ 114,971 | $ 37,510,478 | $ 1,751,512 |
| **Total OM&A Expenses** | $ 73,090,393 | $ 73,076,334 | $ 14,059 | $ 75,757,156 | $ 2,680,823 | $ 80,767,417 | $ 5,010,261 | $ 83,655,809 | $ 2,888,392 | $ 87,105,564 | $ 3,449,755 |
| **Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)** | | | | | | | | | | | |
| **Total Recoverable OM&A Expenses** | $ 73,090,393 | $ 73,076,334 | $ 14,059 | $ 75,757,156 | $ 2,680,823 | $ 80,767,417 | $ 5,010,261 | $ 83,655,809 | $ 2,888,392 | $ 87,105,564 | $ 3,449,755 |
| **Variance from previous year** | | | | $ 2,680,823 | | $ 5,010,261 | | $ 2,888,392 | | $ 3,449,755 | |
| **Percent change (year over year)** | | | | 3.7% | | 6.6% | | 3.6% | | 4.1% | |
| **Percent Change: Test year vs. Most Current Actual** | | | | | | 7.85% | | | | | |
| **Simple average of % variance for all years** | | | | | | 19.2% | | | | | 4.5% |
| **Compound Annual Growth Rate for all years** | | | | | | | | | | | 4.5% |
| **Compound Growth Rate (2014 Q2 Forecast vs. 2012 Actuals)** | | | | | | 5.1% | | | | | |

**Note:**

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

| | |
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| **File Number:** | EB-2015-004 |
| **Exhibit:** | D |
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| **Schedule:** | 2 |
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## Appendix 2-L
## Recoverable OM&A Cost per Customer and per FTE

| | Last Rebasing Year - 2012- Board Approved | Last Rebasing Year - 2012- Actual | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reporting Basis** | | | | | | | | | | |
| **Number of Customers** | | 309,534.00 | 314,722.00 | 313,501.00 | 323,197.00 | 327,260.00 | 331,279.00 | 335,278.00 | 339,222.00 | 343,124.00 |
| **Total Recoverable OM&A** | $ 73,090,393 | $ 73,076,334 | $ 75,757,157 | $ 80,767,417 | $ 83,655,809 | $ 87,105,564 | $ 89,953,916 | $ 92,895,409 | $ 95,933,089 | $ 99,070,101 |
| **OM&A cost per customer** | | $236.08 | $240.71 | $257.63 | $258.84 | $266.17 | $271.54 | $277.07 | $282.80 | $288.73 |
| **Number of FTEs** | | 593.5 | 610.6 | 627.8 | 622.7 | 622.7 | 622.7 | 622.7 | 622.7 | 622.7 |
| **Customers/FTEs** | | 521.54 | 515.43 | 499.36 | 519.03 | 525.55 | 532.00 | 538.43 | 544.76 | 551.03 |
| **OM&A Cost per FTE** | | $123,127.77 | $124,070.02 | $128,651.51 | $134,343.68 | $139,883.67 | $144,457.87 | $149,181.64 | $154,059.88 | $159,097.64 |

**Notes:**

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

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**To**: Executive Management Team (EMT)

**Date**: February 20, 2014

**Subject**: 2015-2020 Business Plan and Budget Process Guidelines

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**Background:**

The purpose of this memorandum is to set guidelines to be used in preparation of the Hydro Ottawa Limited (HOL) 2015 to 2020 Budgets and Financial Plans. HOL will file its 2016 rate case in February 2015, in order to have new distribution rates in place on January 1, 2016. This will be a Custom Incentive Regulation application covering rates for 2016-2020. The filing will include 2015 (referred to as the Bridge year) and budgeted data for the 2016 to 2020 period (referred to as the Test years).

The Budget for 2015 and 2016 will be at the detailed Business Unit (BU) level and entered into our financial system, while the outer years (2017 to 2020) will be formulated outside of the financial system. Throughout this memorandum, 2015 and 2016 will be referred to as Budgets while 2017 to 2020 as Financial Plan.

The new conversion date for International Financial Reporting Standards (IFRS) is January 1, 2015; therefore the Budgets and Financial Plan will be prepared using IFRS.

Finance and Regulatory staff will be conducting individual Divisional meetings with Chiefs and their Rate Applications leads to review Priorities, Budget estimates, and forward looking Financial Plans.

**Key Milestones[1]:**

- Divisional 2015 and 2016 Priorities and Budgets – due end of April 2014
- Divisional 2017 to 2020 Financial Plans – due end of June 2014
- Customer / Stakeholder engagement – Q3 2014
- Final Budget and Financial Plans – due end of September 2014
- EMT approval of Final Budget and Financial Plans – Q4 2014
- Filing of application – February 2015

[1] See Appendix 1 for detailed timeline

**Budget Guidelines:**

*Productivity and Cost Control*

Productivity is a key area of focus. Some productivity measures are noted below under *Headcount & Compensation* and OM&A however each division must continue to identify productivity improvements and cost control measures over the term of the Financial Plan period.

*Alignment to Priorities*

All spending must align to business plan priorities, help achieve approved performance targets, and support the four key areas of focus as outlined in our 2012 – 2016 Strategic Direction:

- Customer Value
- Financial Strength
- Organizational Effectiveness
- Corporate Citizenship

Strategic priorities will be funded in accordance with EMT approval.

*Headcount & Compensation*

Compensation and benefit estimates to be provided by HR and will be based on the renewed collective agreement [2]and anticipated increases beyond existing term.

Requests for growth in approved headcount must be supported by the Strategic Workforce Plans and approved by EMT prior to inclusion in the budget. Similar to the 2014 Budget, all new headcount requests in the Budget submission must be offset by identification of a corresponding headcount reduction, HR will schedule meetings with EMT members to review the most up-to-date workforce plans and discuss headcount requests, and will consolidate all requests from each division for EMT approval.

Half year budgeting will be employed for any new positions identified in the Financial Plan. Vacancy allowance will continue to be budgeted at the corporate level at a rate of 2.5% per annum[3].

---

[2] 2.7% effective April 1, 2015 and 2.8% effective April 1, 2016
[3] Placeholder, detailed analysis to come

*Inflation Rate*

Use the following inflation factors[4] for non-compensation spending:

2015 --- 2.13%
2016 --- 2.01%
2017 --- 2.01%
2018 --- 2.02%
2019 --- 2.02%
2020 --- 2.02%

*Technology*

EMT is responsible for liaising with IM/IT to communicate and coordinate technology requirements to ensure alignment with the corporate IM/IT strategy. IM/IT will consolidate all requests from each division for EMT approval.

*Non-Compensation OM&A*

Existing contract pricing will be updated with the latest agreements.

Total non-compensation OM&A should not exceed the annual inflationary factor noted above.

All new or expansion of existing funding must be supported by business case / rationale or existing business plan and approved by EMT. A standard format for business case preparation will be distributed separately.

*Capital*

Capital investment will provide for customer growth and the replacement of aging infrastructure to maintain plant reliability as per the needs analysis documented in the Asset Management Plan, and key capital initiatives such as Light Rail Transit and the Real Estate Strategy.

[4] Based upon Conference Board of Canada forecasts for Ontario CPI inflation increases as of February 2014

**Appendix 1:**

**Overall Timetable**

| | |
|---|---|
| Feb 2014 | 2015 and 2016 Business Plan and Budget directions memo |
| Apr | Divisional 2015 and 2016 Budget submission |
| May | Design of key financial elements of 2016 rate application |
| May | kWh / kW Sales Forecast |
| Jun | First draft of Strategies |
| Jun | First calculation of high level bill impacts |
| Jun | Distribution System Plan complete |
| Jun | Divisional 2017 to 2020 Financial Plan |
| Jul - Sep | Customer/Stakeholder engagement |
| Sep | Final Budget numbers |
| Oct – Jan 2015 | Review by Executive / Final Edits and Printing |
| Feb 2015 | Filing of application |

# OM&A COST DRIVERS, PROGRAM DELIVERY COSTS & VARIANCE ANALYSIS

## 1.0 INTRODUCTION

This Schedule describes Hydro Ottawa's Operating Maintenance and Administrative ("OM&A") costs by major program including variances as well as a major cost driver variance summary. The schedule further provides explanations for program costs with variances greater than $750K[1] based on historical trend. The information contained in this schedule is informed by the OEB's filing requirements set out on pages 33 and 34 in Chapter 2 of the Ontario Energy Board's ("OEB") Filing requirements for Electricity Distribution Rate Applications, as updated on July 18, 2014.

## 2.0 OM&A COST DRIVERS

Table 1 below sets out the year over year cost drivers impacting Hydro Ottawa's OM&A and the major cost driver variances are described below.

[1] Materiality Threshold as per Exhibit A-5-1.

**Table 1: Recoverable OM&A Cost Driver Table (Appendix 2-JB)**

| OM&A | Last Rebasing Year (2012 Actuals) | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|
| *Reporting Basis* | | | | |
| **Opening Balance** | $ 73.1 | $ 75.8 | $ 80.8 | $ 83.7 |
| Workforce Planning | | $ 0.2 | $ 0.3 | $ 0.4 |
| Collective Agreement/Annual progressions | | $ 1.2 | $ 1.3 | $ 1.4 |
| Vacancy and Vacancy Allowance | | $ (1.6) | $ (0.5) | $ (0.1) |
| Benefits & Pensions | | $ 1.7 | $ (0.3) | $ 1.0 |
| Vegetation Management | | $ 0.3 | $ 0.9 | $ (0.4) |
| Underground Locates | | $ 0.1 | $ 0.3 | $ 0.3 |
| Changes in Capital and Allocations | | $ 0.2 | $ 0.1 | $ (0.2) |
| Postage | | $ 0.7 | $ 0.2 | $ - |
| IT Maintenance | | $ 1.2 | $ 0.4 | $ 0.5 |
| Bad Debts | | $ (0.4) | $ (0.3) | $ 0.4 |
| Inventory Scrap recovery reclass out of OMA | | $ 0.8 | $ - | $ - |
| Inflation | | | $ 0.8 | $ 0.8 |
| Other Costs/(Cost reductions) | $ - | $ 0.6 | $ (0.3) | $ (0.7) |
| **Closing Balance** | $ 73.1 | $ 80.8 | $ 83.7 | $ 87.1 |

## 2.1 Labour Compensation Costs

This includes the workforce planning, collective agreement / annual progressions and vacancy allowance. Annual salary increases and new employee progressions are governed by Hydro Ottawa's collective agreement for unionized staff. Each year unionized employee salaries are adjusted based on a negotiated percentage. Hydro Ottawa's current collective agreement with the International Brotherhood of Electrical Workers ends March 31, 2017. Adjustments for 2016 are based on the agreement. Management staff compensation is forecasted based upon comparable annual adjustments to unionized staff adjustments. Hydro Ottawa has taken several proactive measures to constrain compensation costs including adopting a flat head count by constraining workforce hiring and replacement for the 2014-2020 period.

**Table 2: Summary of Salary and Wages (Appendix 2-K)**

| Salary and Wages (000s) | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| | $ 49,369 | $ 52,268 | $ 55,232 | $ 55,734 | $ 57,759 | 4.0% |

## 2.2 Benefits & Pensions

This category includes costs associated with all of Hydro Ottawa's staff benefits and pensions including current and post-retirement health benefits, employer payroll taxes and employer pension contributions. Hydro Ottawa has taken measures to constrain these costs, one of which was partnering with a new insurance provider for benefits allowing the Company to reduce its benefits premiums while ensuring the continuance and sustainability of the current level of benefits provided to employees. Savings from these measures were incorporated as offsets into the 2016-2020 budgets to the benefit of ratepayers. For further details on Hydro Ottawa's Compensation approach, see Exhibit D-1-8.

**Table 3: Summary of Benefits and Pension costs (Appendix 2-K)**

| Benefits & Pension ($000s) | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| | $11,536 | $12,748 | $12,856 | $13,354 | $14,185 | 5.3% |

## 2.3 Distribution Operations: Vegetation Management

The costs captured in the Vegetation Management cost driver represent the costs associated with Hydro Ottawa's tree trimming and storm hardening programs. Hydro Ottawa's tree trimming program operates on two and three year cycles for the core and suburban areas and trim more than 40,000 trees per year. Hydro Ottawa's storm hardening program is a new initiative that began in 2014 and is projected to extend until the end of 2015 and is an adjunct to its normal tree trimming efforts. Hydro Ottawa's storm hardening program was initiated to remove overhang branches over 2,650 spans that are not part of the regular trim cycle and to develop new standards to govern the current trim cycle. The focus on eliminating overhang branches is specifically intended to reduce the risk of outages and equipment damage resulting from weighted, blown or broken overhang branches coming in contact with distribution wires. Moving forward, the elimination of overhang will become part of HOL's tree trimming standards and will be monitored and maintained as a part of its trim cycles. The investments made by Hydro Ottawa in its vegetation management and storm hardening are expected to yield significant long term reliability and productivity benefits. For further details on Hydro Ottawa's storm hardening efforts refer to Exhibit B-1-2(A).

**Table 4: Summary of Vegetation Management costs**

| Vegetation Management ($000s) | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| | $2,516 | $3,074 | $3,331 | $4,311 | $3,507 | 8.7% |

### 2.4 Distribution Operations: Underground Locates

The costs captured in the underground locates category arise from Hydro Ottawa's compliance with the Ontario Underground Infrastructure Notification System Act ("OUINS Act"). Released in 2012 the OUINS Act requires that members, of whom Hydro Ottawa is one, to respond within five days of notification from the Ontario One Call Corporation to a request for an underground locate.

Hydro Ottawa contracts its underground system locating to a locate contractor.
The locate contractor is selected through a competitive bid process where potential contractors are evaluated on price, technical qualifications and performance. Contracts are typically three years in duration but can be extended. Throughout the contract Hydro Ottawa performs quality assurance audits to verify the number of locates, the locate accuracy and that locates are being performed to Hydro Ottawa's standards.

Costs associated with accommodating underground locate requests are customer demand driven and hence not a cost that is controllable by the company. The table below provides detail as to the historical and forecasted number of locate requests and the actual and estimated average cost per request.

**Table 5: Summary of Underground Locate costs**

| Year | # of Requests * | Total Costs ($000) | Average Cost per Locate ($) |
|---|---|---|---|
| 2012 Actual | 52,544 | $1,622 | $30.87 |
| 2013 Actual | 59,103 | $1,861 | $31.49 |
| 2014 Q2 Forecast | 66,847 | $2,010 | $30.07 |
| 2015 Bridge Year | 71,317 | $2,216 | $31.08 |
| 2016 Test Year | 79,198 | $2,523 | $31.86 |
| CAGR | | 11.7% | |

* Requests include office clearances

### 2.5 Postage Costs

Increased postage rates coupled with Hydro Ottawa's move to monthly billing are the underlying drivers causing an increase to postage costs. To mitigate the impact of the increased postage costs, Hydro Ottawa has initiated a program to encourage its customers to adopt electronic billing or "e-billing". As of December 2014, Hydro Ottawa has approximately 85,991 or 26.9% of its customers subscribed to its e-billing program. Hydro Ottawa estimates an annualized savings of approximately 860K resulting from its move to implement e-billing.

### 2.6 IT Maintenance

Information Technology maintenance expenses relate to software purchases and upgrades to maintain legacy applications and web interfaces. Examples include the Customer Care and Billing System, AMI/MT, JD Edwards, and data security updates. As noted in Hydro Ottawa's IT Strategy filed in Exhibit B-1-3 legacy applications will be rationalized to simplify ongoing support and maintenance requirements. Continued diligence will be applied to all contracts requiring maintenance and support and efforts will be undertaken to identify where license and service consolidation is possible. As reliance on technology continues to growth through all aspects of the business, the associated IT Maintenance costs also increase.

**Table 6: Summary of IT costs**

| IT Costs ($000s) | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| | $6,342 | $6,659 | $7,179 | $7,060 | $7,616 | 4.7% |

Source: Appendix 2-JC

### 2.7 Bad Debt

Bad debt results from unpaid account balances. Bad debt continues to be a cost driver because it is an expense that is incurred by Hydro Ottawa that is not entirely within its control. The table below illustrates that bad debt increased in 2013 but is projected to stay relatively flat out to 2016.

**Table 7: Summary of Bad Debt costs**

| Bad Debt ($000s) | 2012 Actuals | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR |
|---|---|---|---|---|---|---|
| | $1,433 | $2,182 | $1,804 | $1,541 | $1,979 | 8.4% |

## 3.0 OM&A PROGRAM COST & VARIANCE ANALYSIS

Pursuant with section 2.7.3 of the OEB's Chapter 2 Filing requirements, the following section provides a variance analysis of Hydro Ottawa's OM&A costs by major program. Table 8 provides historical, bridge and test year expenditures by the program categories and the four year cumulative annual growth rate for each program category. Table 9 provides a year over year analysis of variances per program as expressed both in dollar and percentage terms, the amounts that are highlighted in red denote the variances that exceed Hydro Ottawa's $750K materiality threshold and as such an explanation for the variance is provided. The total program groupings for OM&A are shown net of the allocations to capital programs. Refer to D-1-(F) Attachment F for a description of each program category.

### Table 8 - Summary of OM&A Program Costs

| Programs | Last Rebasing Year (2012 Board-Approved) | Last Rebasing Year (2012 Actuals) | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | CAGR (%) |
|---|---|---|---|---|---|---|---|
| *Reporting Basis* | | | | | | | |
| | | | | | | | |
| Collections, Acct & Activities | | $2,892,674 | $4,068,200 | $3,642,238 | $3,543,341 | $4,059,282 | 9% |
| Corporate Costs | | $6,056,030 | $6,575,378 | $5,420,096 | $5,015,524 | $4,993,415 | -5% |
| Customer & Community Relations | | $7,716,112 | $7,573,677 | $8,087,780 | $8,785,231 | $9,084,617 | 4% |
| Customer Billing | | $8,058,100 | $8,320,362 | $10,170,188 | $10,333,939 | $10,414,125 | 7% |
| Distribution Operations | | $15,768,787 | $16,091,210 | $17,449,018 | $18,705,565 | $19,404,972 | 5% |
| Engineering & Design | | $6,090,200 | $6,019,357 | $6,829,936 | $7,585,805 | $8,159,989 | 8% |
| Facilities | | $5,518,926 | $5,656,075 | $5,794,364 | $6,027,819 | $6,108,573 | 3% |
| Finance | | $4,074,222 | $3,983,782 | $4,332,691 | $4,517,544 | $4,759,915 | 4% |
| Human Resources & Training | | $3,283,630 | $3,500,016 | $3,857,908 | $3,945,646 | $4,093,085 | 6% |
| Information Mgt & Technology | | $6,342,125 | $6,658,679 | $7,179,256 | $7,060,152 | $7,616,378 | 5% |
| Metering | | $2,384,793 | $2,327,873 | $2,355,505 | $2,423,903 | $2,532,030 | 2% |
| Regulatory Affairs | | $1,930,844 | $1,967,875 | $2,340,940 | $2,505,096 | $2,580,684 | 8% |
| Safety, Environment & Bus Cont | | $1,853,905 | $2,334,564 | $2,116,845 | $1,952,732 | $2,006,305 | 2% |
| Supply Chain | | $1,105,987 | $680,108 | $1,190,652 | $1,253,511 | $1,292,193 | 4% |
| Miscellaneous | | | | | | | |
| **Total** | **$73,090,393** | **$73,076,334** | **$75,757,156** | **$80,767,417** | **$83,655,809** | **$87,105,564** | **4%** |

### Table 9 - Summary of OM&A Program Variances (in thousands of dollars)

| Programs ($000) | 2013 2012 | | 2014 – 2013 | | 2015 – 2014 | | 2016 – 2015 | |
|---|---|---|---|---|---|---|---|---|
| Collections, Acct & Activities | **$1,176** | 41% | -$426 | -12% | -$99 | -3% | $516 | 13% |
| Corporate Costs | $519 | 9% | **-$1,155** | -21% | -$405 | -8% | -$22 | 0% |
| Customer & Community Relations | -$142 | -2% | $514 | 6% | $697 | 8% | $299 | 3% |
| Customer Billing | $262 | 3% | **$1,850** | 18% | $164 | 2% | $80 | 1% |
| Distribution Operations | $322 | 2% | **$1,358** | 8% | **$1,257** | 7% | $699 | 4% |
| Engineering & Design | -$71 | -1% | **$811** | 12% | **$756** | 10% | $574 | 7% |
| Facilities | $137 | 2% | $138 | 2% | $233 | 4% | $81 | 1% |
| Finance | -$90 | -2% | $349 | 8% | $185 | 4% | $242 | 5% |
| Human Resources & Training | $216 | 7% | $358 | 9% | $88 | 2% | $147 | 4% |
| Information Mgt & Technology | $317 | 5% | $521 | 7% | -$119 | -2% | $556 | 7% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Metering** | -$57 | -2% | $28 | 1% | $68 | 3% | $108 | 4% |
| **Regulatory Affairs** | $37 | 2% | $373 | 16% | $164 | 7% | $76 | 3% |
| **Safety, Environment & Bus Cont** | $481 | 26% | -$218 | -10% | -$164 | -8% | $54 | 3% |
| **Supply Chain** | -$426 | -39% | $511 | 43% | $63 | 5% | $39 | 3% |
| **Grand Total** | **$2,681** | **4%** | **$5,010** | **6%** | **$2,888** | **3%** | **$3,450** | **4%** |

### 3.1 Collections, Accounts and Activities

The Collections, Accounts and Activities program captures costs associated with Hydro Ottawa's collection activities and its bad debt expense. Half of the costs are attributable to compensation and benefits and the other half of costs captured in this category are primarily bad debt expense.

Headcount remains flat but compensation will be adjusted per Hydro Ottawa's collective agreement. Bad debt expenses went up in 2013 which resulted in a historical high. With several mitigation strategies, management was able to bring bad debt expense down in 2014 and back to the industry average going forward.

In 2012 bad debt as a percentage of electricity revenue was 0.16% with bad debt expense $1.4M, which is below industry average. In 2013 there was a spike that began in Q3 and resulted in a year end bad debt expense of $2.3M. The spike was explained by the economy downturn and other economic factors compounded by the OEB collections rules on residential and low income customers have added pressure on controlling our bad debt expense. This is not distinct to Hydro Ottawa; it is affecting other LDC's as well. Management reviewed the situation and came up with a number of recommendations to mitigate the impact including account set-up and collection process changes and technology changes (e.g. CC&B configuration changes and functional enhancements). In addition, the deployment of remote disconnected meters improved the collection process. In 2014, after the implementation of monthly billing, the bad debt decreased by $0.5M or 22%. Bad debt expense is projected to be in line with industry average.

### 3.2 Corporate Costs

Corporate costs category primarily captures management fees from the Holding Company (reference to Exhibit D-3-3), Insurance, Future Employee Benefits (post-retirement benefit), and vacancy allowance budget.

Corporate Costs is showing a decrease due to the vacancy allowance budgeted in 2014, 2015, and 2016. Actual vacancies are reflected in each of the program costs for 2012 and 2013, only the budgeted amounts are included in corporate costs The vacancy allowance budget is to reflect compensation savings resulting from employee turnover throughout the course of the year. The amount is estimated based on historical trend.

Excluding vacancy allowance, all the major cost components within corporate costs remain steady.

### 3.3 Customer and Community Relations

Customer and Community Relations program captures costs associated with the salaries and benefits as well as costs associated with the customer experience team, key accounts, customer contact, and communications. Half of the costs are headcount related, the other half includes the external call centre, media communications, and the OEB mandated LEAP Program.

During the reporting period, call volumes increased approximately 12% year over year and customer satisfaction increased to 89% up from 76% to 85%. Overall spending trend was steady with an annual growth rate of approximately 4%. The trend represents costs associated with the call centre volumes resulting from increased media coverage and customer outreach. Call volumes are expected to remain high due to increasing outreach and bill changes. As cost mitigation, Hydro Ottawa has committed to restrain call centre contract costs and will measure the call centre contract activity as part of quarterly productivity scorecard and monthly customer satisfaction performance scorecard.

## 3.4 Customer Billing

Customer billing includes costs associated with Billing, Meter to Cash, and Meter Data operations and staff. Compensation / headcount represents one third of the overall costs.

Compensation / headcount costs are projected to decrease by $0.4M from $3.7M in 2012 to $3.3M in 2016. The decrease is attributed to a forecasted reduction in labour costs with a corresponding increase in technology costs. Customer billing non-compensation costs (mainly technology costs and bill production including postages) are projected to increase at a 13% annual growth rate. The principle driver behind the cost increases are:

- Increase to IT costs to support meter data and a post-AMI (Automated Metering Infrastructure) deployment environment which relies on technology to ensure data and billing accuracy. IT support costs includes Savage data and CC&B to ensure Hydro Ottawa's customers are billed correctly; and
- Increase to postage costs due to postage rate increases combined with Hydro Ottawa's move to implement monthly billing. In 2013, the postage rate was $0.61. In 2014, Canada Post increased postage rate to $0.70. This represents 15% increase in postage rate. To mitigate these cost increases, Hydro Ottawa introduced "Go Paperless" and electronic Billing initiatives including MyHydroLink and Autopay. As of December 2014, Hydro Ottawa had approximately 85,991 e-bill accounts representing 26.9% of its customers. Overall OM&A annualized savings due to E-billing program now stand at approximately $860K. Despite the large increase in postage rate and the monthly billing, with its e-billing efforts Hydro Ottawa's postage expenses increased by $0.7M only or 12%.

## 3.5 Distribution Operations

Distribution Operations includes costs associated with the operations and maintenance of Hydro Ottawa's distribution assets. Programs include Vegetation Management, Underground Locates, Environmental Spills Cleanup, Load Dispatching, and other general maintenance.

Distribution Operations spending increased in 2014 and 2015. The major increases are largely attributable to the following distribution maintenance programs:

Vegetation Management – this is a prevention investment that is designed to produce a long term gain. Our SAIFI caused by tree contacts remain low at 0.05 to 0.12 while the industry average at the range of 0.18 and 0.47 (Source: 2012 CEA Service Continuity Reporting). Trees that contact power lines are one of the major causes of power failure. The increase in spending in 2014 and 2015 is mainly related to the storm hardening programs (reference D-2-1, 3.5), however 2016 is projecting a decrease, as the storm hardening work will be completed beginning of 2015. This program annual spending increased from 2.5M in 2012 to 3.5M in 2016 with an annual growth rate of 9%. Over 80% of the program costs are outside services.

Underground Locates – the costs captured in this program increased significantly following the introduction of Bill 8 (Ontario Underground Infrastructure Notification System Act) which became law in June 2012. The program costs increased from $2.0M in 2012 to $2.9M in 2016, which represents a 12% annual growth rate. Two third of the increases are volume related (customer demand), the remaining one third of the cost increase is due to inflationary cost increase in Hydro Ottawa's contractor with Promark (reference D-2-1, 3.6)

Despite the significant increases in these two programs, overall distribution operations remained within a 5% annual growth rate.

### 3.6 Engineering and Design

Engineering and Design program includes costs associated with Distribution Design, System Operations (SCADA), Asset Planning, Policies, Procedures, and Standards.

Over 80% of the costs are labour costs, remaining 20% are mainly technology costs related to the GIS system, SCADA, and the new asset management software.

Annual growth rate 8% with a spike in 2014. It is explained by the increased technology costs for GIS, SCADA, and Asset Management. In addition, the company has conducted a large review of our Conditions of service. This revision is the largest the company has seen, including substantial policy, tariffs and charges review. Furthermore, in keeping with Hydro Ottawa's commitment to provide excellent Customer Service, the document will be revamped to more navigable, understandable and user-friendly. The new version is expected to be published in 2015.

### 3.7 Other Programs

Other Programs including Facilities, Finance, Human Resources, Information Technology, Metering, Regulatory, Safety, Environmental & Business Continuity, and Supply Chain are all projected to experience minor growth. No major spending variances. Some programs have benefit from the productivity initiatives such as Metering. With the deployment of remote disconnected meters, field activities reduced, therefore annual growth rate at 2% only.

## 4.0 CAPITALIZATION OF OVERHEAD OM&A

Table 10 below sets out OM&A by program before capitalization as set out in Appendix 2-D. Hydro Ottawa's capitalized overhead costs are consistent with the OEB's policy on capitalization. Table 11 sets out OM&A that has been capitalized as set out in Appendix 2-D. For details of the Company capitalization policy, please see Exhibit B-5-3. The policy remains the same since 2012 with the percentage capitalized in a range of 25% and 27%.

## Table 10 – OM&A by Program before Capitalization

| OM&A Before Capitalization | 2012 Historical Year | 2013 Historical Year | 2014 Q2 Forecast Historical Year | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| Collections, Acct & Activities | $ 2,937,418 | $ 4,070,580 | $ 3,649,114 | $ 3,543,341 | $ 4,059,282 |
| Corporate Costs | $ 6,056,030 | $ 6,575,378 | $ 5,420,096 | $ 5,015,524 | $ 4,993,415 |
| Customer & Community Relations | $ 7,716,112 | $ 7,605,947 | $ 8,220,736 | $ 8,785,231 | $ 9,084,617 |
| Customer Billing | $ 9,176,802 | $ 9,736,344 | $ 10,664,787 | $ 10,432,583 | $ 10,511,497 |
| Distribution Operations | $ 33,380,038 | $ 34,860,050 | $ 37,834,129 | $ 39,785,778 | $ 40,824,588 |
| Engineering & Design | $ 10,863,198 | $ 11,693,463 | $ 12,451,538 | $ 12,975,442 | $ 13,677,111 |
| Facilities | $ 5,518,926 | $ 5,656,285 | $ 5,794,592 | $ 6,027,819 | $ 6,108,573 |
| Finance | $ 4,074,222 | $ 3,988,437 | $ 4,368,115 | $ 4,517,544 | $ 4,759,915 |
| Human Resources & Training | $ 3,395,830 | $ 3,675,121 | $ 4,010,176 | $ 4,051,662 | $ 4,180,257 |
| Information Mgt & Technology | $ 6,343,145 | $ 6,717,794 | $ 7,521,460 | $ 7,500,528 | $ 7,862,963 |
| Metering | $ 2,712,295 | $ 2,807,318 | $ 2,846,087 | $ 2,842,465 | $ 2,956,322 |
| Regulatory Affairs | $ 1,930,844 | $ 1,967,875 | $ 2,340,940 | $ 2,505,096 | $ 2,580,684 |
| Safety, Environment & Bus Cont | $ 1,853,905 | $ 2,334,564 | $ 2,116,845 | $ 1,952,732 | $ 2,006,305 |
| Supply Chain | $ 2,233,136 | $ 1,985,925 | $ 2,491,808 | $ 2,498,434 | $ 2,744,524 |
| | | | | | |
| **Total OM&A Before Capitalization (B)** | $ 98,191,900 | $ 103,675,081 | $ 109,730,424 | $ 112,434,180 | $ 116,350,054 |

## Table 11 – Capitalized OM&A

| Capitalized OM&A | 2012 Historical Year | 2013 Historical Year | 2014 Q2 Forecast Historical Year | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| Supply Chain | $ 1,127,115 | $ 1,305,256 | $ 1,301,156 | $ 1,244,923 | $ 1,452,331 |
| Supervision | $ 1,831,800 | $ 2,157,288 | $ 1,826,399 | $ 2,034,276 | $ 2,077,315 |
| Engineering | $ 1,996,465 | $ 2,815,805 | $ 2,843,934 | $ 2,904,091 | $ 2,997,522 |
| Fleet | $ 2,613,093 | $ 2,593,457 | $ 2,737,548 | $ 2,627,424 | $ 2,698,352 |
| Labour | $ 17,547,092 | $ 19,046,118 | $ 20,253,970 | $ 19,967,657 | $ 20,018,970 |
| **Total Capitalized OM&A (A)** | $ 25,115,566 | $ 27,917,925 | $ 28,963,007 | $ 28,778,371 | $ 29,244,490 |

| | | | | | |
|---|---|---|---|---|---|
| **% of Capitalized OM&A (=A/B)** | 26% | 27% | 26% | 26% | 25% |

| | |
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## Appendix 2-JB
## Recoverable OM&A Cost Driver Table

| OM&A | Last Rebasing Year (2012 Actuals) | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| *Reporting Basis* | | | | | | | | | |
| **Opening Balance** | $ 73.1 | $ 73.1 | $ 75.8 | $ 80.8 | $ 83.7 | | | | |
| Workforce Planning | | | $ 0.2 | $ 0.3 | $ 0.4 | | | | |
| Collective Agreement/Annual progressions | | $ 1.1 | $ 1.2 | $ 1.3 | $ 1.4 | | | | |
| Vacancy and Vacancy Allowance | | | $ (1.6) | $ (0.5) | $ (0.1) | | | | |
| Benefits & Pensions | | $ 0.1 | $ 1.7 | $ (0.3) | $ 1.0 | | | | |
| Vegetation Management | | $ 0.4 | $ 0.3 | $ 0.9 | $ (0.4) | | | | |
| Underground Locates | | $ 0.2 | $ 0.1 | $ 0.3 | $ 0.3 | | | | |
| Changes in Capital and Allocations | | $ (0.6) | $ 0.2 | $ 0.1 | $ (0.2) | | | | |
| Postage | | $ (0.1) | $ 0.7 | $ 0.2 | $ - | | | | |
| IT Maintenance | | $ 0.5 | $ 1.2 | $ 0.4 | $ 0.5 | | | | |
| Bad Debts | | $ 0.8 | $ (0.4) | $ (0.3) | $ 0.4 | | | | |
| Inventory Scrap recovery reclass out of OMA | | $ - | $ 0.8 | $ - | $ - | | | | |
| Inflation | | | | $ 0.8 | $ 0.8 | | | | |
| Other Costs/(Cost reductions) | $ - | $ 0.3 | $ 0.6 | $ (0.3) | $ (0.7) | | | | |
| **Closing Balance** | $ 73.1 | $ 75.8 | $ 80.8 | $ 83.7 | $ 87.1 | $ 89.9 | $ 92.8 | $ 95.9 | $ 99.0 |

**Notes:**

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | D |
| **Tab:** | 1 |
| **Schedule:** | 3 |
| **Page:** | 1 |
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## Appendix 2-JC
## OM&A Programs Table

| Programs | Last Rebasing Year (2012 Board-Approved) | Last Rebasing Year (2012 Actuals) | 2013 Actuals | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year | Variance (Test Year vs. 2014 Q2 Forecast) | Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved) | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Reporting Basis* | | | | | | | | | | | | |
| **Collections, Acct & Activities** | | $2,892,674 | $4,068,200 | $3,642,238 | $3,543,341 | $4,059,282 | $417,045 | $4,059,282 | | | | |
| **Corporate Costs** | | $6,056,030 | $6,575,378 | $5,420,096 | $5,015,524 | $4,993,415 | -$426,681 | $4,993,415 | | | | |
| **Customer & Community Relations** | | $7,716,112 | $7,573,677 | $8,087,780 | $8,785,231 | $9,084,617 | $996,837 | $9,084,617 | | | | |
| **Customer Billing** | | $8,058,100 | $8,320,362 | $10,170,188 | $10,333,939 | $10,414,125 | $243,937 | $10,414,125 | | | | |
| **Distribution Operations** | | $15,768,787 | $16,091,210 | $17,449,018 | $18,705,565 | $19,404,972 | $1,955,955 | $19,404,972 | | | | |
| **Engineering & Design** | | $6,090,200 | $6,019,357 | $6,829,936 | $7,585,805 | $8,159,989 | $1,330,053 | $8,159,989 | | | | |
| **Facilities** | | $5,518,926 | $5,656,075 | $5,794,364 | $6,027,819 | $6,108,573 | $314,209 | $6,108,573 | | | | |
| **Finance** | | $4,074,222 | $3,983,782 | $4,332,691 | $4,517,544 | $4,759,915 | $427,224 | $4,759,915 | | | | |
| **Human Resources & Training** | | $3,283,630 | $3,500,016 | $3,857,908 | $3,945,646 | $4,093,085 | $235,177 | $4,093,085 | | | | |
| **Information Mgt & Technology** | | $6,342,125 | $6,658,679 | $7,179,256 | $7,060,152 | $7,616,378 | $437,121 | $7,616,378 | | | | |
| **Metering** | | $2,384,793 | $2,327,873 | $2,355,505 | $2,423,903 | $2,532,030 | $176,526 | $2,532,030 | | | | |
| **Regulatory Affairs** | | $1,930,844 | $1,967,875 | $2,340,940 | $2,505,096 | $2,580,684 | $239,744 | $2,580,684 | | | | |
| **Safety, Environment & Bus Cont** | | $1,853,905 | $2,334,564 | $2,116,845 | $1,952,732 | $2,006,305 | -$110,540 | $2,006,305 | | | | |
| **Supply Chain** | | $1,105,987 | $680,108 | $1,190,652 | $1,253,511 | $1,292,193 | $101,541 | $1,292,193 | | | | |
| **Miscellaneous** | | | | | | | $0 | $0 | | | | |
| **Total** | **$73,090,393** | **$73,076,334** | **$75,757,156** | **$80,767,417** | **$83,655,809** | **$87,105,564** | **$6,338,147** | **$14,015,171** | **$89,932,139** | **$92,850,437** | **$95,863,434** | **$98,974,203** |

***Notes:***

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

# Operations, Maintenance & Administration Program Descriptions

This attachment provides a description of each program category

**Collections, Accounts and Activities**

This program group has the staff and costs for the collection of both active and inactive residential and commercial electricity accounts. This program also includes the bad debt costs for electricity customers and costs for external collection agencies. Collection agencies are used when staff have exhausted all other methods to collect overdue accounts.

**Corporate Costs**

This program summarizes costs for the General Counsel and Legal departments along with cost allocations from Hydro Ottawa Holding Inc., Employee future benefits, Vacancy provisions, Insurance, Interest and bank charges.

**Customer and Community Relations**

This program includes the staff and costs for the Customer Contact center and Community Relations & Public Affairs group.

The Customer Contact team is responsible for all customer account and relationship activities including the handling of customer telephone calls, correspondence, new customer account requests and changes to existing customer accounts. This group also handles paper based move requests, miscellaneous correspondence, return mail, lawyer's letters, Auto Pay and Budget Billing requests, escalations and reporting. Also in this program are expenses related to providing service to large customers referred to as "key accounts". These key accounts are the highest consumers of electricity within Hydro Ottawa's service area and merit ongoing and more complex service support.

The Community relations and Public Affairs team is responsible for the delivery of customer communication and community initiatives that promote customer and public awareness of the distribution business and industry activities. This function also maintains Hydro Ottawa's branding, website, social media presence and develops customer brochures, organizes community information sessions, interfaces with the media and local government representatives and manages the on-call and outage support procedures, schedules and training.

**Customer Billing**

This program includes the Billing department costs, Meter data Services and IT support personnel for the Customer Care and Billing System (CC&B) used to produce the residential and commercial electricity bills. Smart Meters and Time of Use billing has completely changed the way utilities provide customer billing. The complexity and speed of issuing bills has dramatically changed and continues to evolve with the investments in technology. Hydro Ottawa switched monthly billing in early 2014 to better align consumption with the billing dates. Refer to Exhibit B-1-12, for further details. Meter Data Services, the technical group in the Customer Billing program is responsible for remote meter reading, includes data management for all remote meters including residential and small commercial Smart Meters.

**Distribution Operations**

This group is comprised of operations and maintenance personnel and costs to properly operate and maintain Hydro Ottawa's distribution system and provide quality, reliable, cost effective service to customers. Operations is defined as work that encompasses actions of a detective, preventative, and/or monitoring nature. Maintenance is defined as the routine activity to ensure the equipment or device operates correctly (generally work performed in a reactionary manner based on the results of an Operation activity). Within this program the major functions are: Construction and Operations/Maintenance staff for Overhead and Underground lines, Stations, System Operations along with the costs for major programs such as: Underground locates, Graffiti abatement, Insulator washing, $CO_2$ Washing, Station Transformer Oil Analysis, Asbestos Removal and Arc-Proofing of Cables, Thermographic Scans, and Inspection Tree Trimming / Vegetation Management. The Stations section is made up of electrical and mechanical trades and technical staff. Its primary functions are installation, commissioning, testing and maintenance of substation equipment. System Operation's primary responsibility is to ensure the safety and reliability of the Hydro Ottawa Distribution System. This department includes the Control Room which monitors and controls the Distribution System, Field Crews that respond to electrical emergencies, and perform operations switching, and the Operations Planning section which plans all work to be performed on the System. All Hydro Ottawa planned capital and maintenance activities must interface through this department in order for all crews to carry out their work safely and ensure system reliability is maintained.

**Engineering and Design**

This program group is responsible for the safe, efficient and effective planning and execution of our reliability and demand (customer driven) capital programs as well as our planned maintenance programs using internal and external workforces. This program includes personnel and costs for such departments as: Asset Planning, Distribution Design, and Grid Technology. Asset Planning manages the annual asset reliability capital program. Design teams work with the Asset Planning group to develop designs for electrical system infrastructure, prepare cost estimates, and provide project management. The Grid Technology department is responsible for the day-to-day support of the utilities operational technologies such as SCADA, Outage Management Systems (OMS) and Geographic Information Systems (GIS). They provide user support, software upgrades, enhancements and monitoring services to ensure the System Operations team has the tools required to efficiently run Hydro Ottawa's distribution grid. Grid Technology is also responsible for Smart Grid pilot projects.

**Facilities**

Costs for the maintenance and upkeep of Hydro Ottawa's facilities are in this program. This includes the corporate administrative office, three additional operations centres across the city, a separate fleet/training facility and approximately 70 distribution stations. Costs for maintaining the general plant (i.e. office buildings) are part of

Facilities expenses whereas maintenance for facilities at transformer stations is part of Distribution Operations program costs.

**Finance**

Included within the Finance program group are personnel and costs for General accounting,
Accounts receivable, Accounts payable, Payment processing (including electricity bill payments), Retail settlements, Budgeting/business planning, Tax and Treasury services.

**Human Resources**

The Human Resources program grouping has the personnel and costs for payroll processing, labour relations, compensation management, internal communications, employee events and the development and oversight of human resources polices. In addition costs for employee training for safety and trades, professional and management leadership courses.

**Information Technology**

The Information Management & Technology program has personnel and costs for all core IT infrastructure, the corporate ERP application JD Edwards, voice services, network and data services and maintenance contracts for the associated hardware and software applications. Business specific systems such as: SCADA, Outage Management System, and Geographic Information System are included in the Design and Planning Group; costs for the support of the Customer Care & Billing system are included with the Customer Billing Program grouping.

**Metering**

This program contains the personnel and support costs for the revenue meter assets for residential, commercial, industrial and wholesale metering. Activities include; the management of approximately 316,000 installed meters in service and to support Operations projects including new growth in our service territory as well as maintenance programs for the established meter population. Metering operates a Measurement Canada meter accreditation program S-A-01 and the criteria for the accreditation to perform Inspections pursuant to the Electricity and Gas Inspection Act as well as ISO 9001-2008 quality assurance program.

**Regulatory**

Regulatory Affairs program contains personnel and costs the for filings with the Ontario Energy Board and the Independent Electricity System Operator ("IESO") including comments on consultations, rate and other applications, compliance reporting, licence applications and renewals and the reporting and record-keeping requirements. Major expenses for the Regulatory Affairs program grouping include the Board Annual Cost Assessment, Cost Awards paid to intervener's and annual fees to the Electrical Safety Authority.

**Safety, Environmental and Business Continuity**

Safety, Environment & Business Continuity includes personnel and expenses for the design, implementation and oversight of Hydro Ottawa's safety, environmental and business continuity programs and regulatory compliance. This group oversees Hydro Ottawa's Occupational Health, Safety and Environmental ("OHSE") Accountability Program that details the expectations for all employees on activities they are expected to do to maintain a safe and healthy workplace.

**Supply Chain**

This program has personnel and costs for the procurement and warehouse functions. This group sets and oversees procurement policies and procures all products and services for the company along with managing the inventory used by the operations group.

# HISTORICAL AND FORWARD LOOKING PRODUCTIVITY INTIATIVES

## 1.0 INTRODUCTION

This schedule sets out a summary of the evidence and initiatives that Hydro Ottawa relies on to illustrate its commitment to sustainable productivity and continuous improvement. This schedule responds to the OEB's expectations as it relates to outcomes based productivity and sustainable efficiency measures and is intended to compliment the initiatives discussed in Hydro Ottawa's Distribution System Plan (Exhibit B5). The information contained in this schedule is designed to facilitate the OEB's assessment of the adequacy of Hydro Ottawa's past and future productivity as required pursuant to the Renewed Regulatory Framework for Electricity ("RRFE").

The measures and initiatives described in this schedule pertain to efficiency savings in Operating, Maintenance and General (OM&A) expenditures as well as savings in capital expenditures through more efficient and effective execution of construction and maintenance programs. The productivity and efficiency measures described below have both tangible and non-tangible elements, the consequence of which is that they may not be adequately quantified with precise accuracy but nevertheless contribute to productivity savings that are factored in Hydro Ottawa's Custom IR rate-setting approach as described in detail in Exhibit A-2-1. Hydro Ottawa's outcome based capital planning is described in greater detail in Exhibit B, while Hydro Ottawa's measured performance is set out in its corporate scorecard results which are discussed further below.

In what follows, Hydro Ottawa provides a qualitative and quantitative description of the measures and initiatives that it has implemented and a qualitative description of those initiatives that it intends to implement as part of its commitment to continuous improvement.

## 2.0 HYDRO OTTAWA'S APPROACH TO PRODUCTIVITY

Hydro Ottawa's commitment to productivity is embodied in its four strategic objectives contained in the company's 2012-2016 Strategic Direction. These objectives are a) customer value; b) financial strength; c) organizational effectiveness; and d) corporate citizenship. These strategic objectives all underlie Hydro Ottawa's mission to create long term value for our shareholder, customers and the communities we serve. Indeed, putting the customer at the centre of everything we do is a key tenet of Hydro Ottawa's Strategic Direction. Hence creating value for Hydro Ottawa's customers and sharing the benefits of its productivity has and will continue to be at the heart of Hydro Ottawa's purpose and mission within the greater Ottawa community.

As discussed further below, Hydro Ottawa encourages a culture of innovation and productivity. Indeed since its amalgamation in 2000, Hydro Ottawa management has encouraged the adoption of productivity improvement measures that focus on maximizing the efficiency and effectiveness of its operations by reducing waste and optimizing sustainable productivity opportunities. Hydro Ottawa management and employees are encouraged to identify opportunities to streamline processes or leverage new technologies to improve business operations and services. Over the years several initiatives were introduced including the following:

### 2.1 Initiative # 1 – Lean Continuous Improvement

In 2009-2010 Hydro Ottawa introduced the concepts of the LEAN method of management. Lean is a continuous improvement program focused on eliminating waste from business processes or value streams. Waste is defined as any step or task in a process that adds time or cost to the product or service but adds no value from a customer's perspective. Lean has been used in many process reviews across the organization with positive results. Hydro Ottawa continue to apply these concepts and tools today as it reviews core business processes for opportunities to improve.

### 2.2 Initiative # 2 – Corporate Productivity Scorecard

In 2013 a cross-functional team was established to design a scorecard to measure productivity for Hydro Ottawa. The purpose was to develop a suite of metrics to measure and monitor productivity gains achieved across the organization beyond the industry standard measures used like OM&A per customer. The cross functional team identified the following expected outcomes:

- Identify the current corporate productivity measures and assess available baseline data from multiple industry sources;
- Identify best practices in productivity measures within the electricity sector and any other applicable sectors;
- Recommend additional productivity measures and targets;
- Recommend reporting periods for each measure; and
- Catalogue data sources for the measures, and recommend accountability for data collection and assessment.

The result of their efforts was a scorecard focussed in the following four key focus areas: People – Internal Workforce, Operating Maintenance & Administration Costs, Capital Asset Efficiency, and Profitability Metrics. See Attachment D-1(C) for a copy of the December 2014 Scorecard. This scorecard is produced on a quarterly basis, is provided to both the Executive Management team and the Board of Directors for review and discussion and is designed to encompass all of Hydro Ottawa's lines of business. The organization has yet to set targets for the metrics included in the scorecard. The approach has been to establish a scorecard that is aligned with the OEB's expectations and monitor progress throughout 2014. Once Hydro Ottawa has confirmed that it is measuring the right things and has enough data history to establish a baseline it will move ahead with setting annual targets. Hydro Ottawa anticipates being in a position to have targets in place by year end 2015.

### 2.3 Initiative # 3 – CEO Productivity and Innovation Award

Hydro Ottawa's employees respond and contribute to a culture that is reflective of organizational values they collectively defined. Core to our culture is the value of Excellence, which the company and its employees define in part as, "using our assets effectively to achieve the best possible outcomes" and as "embracing innovation and continuous improvement." To further entrench the importance of living this organizational value, in 2013, Hydro Ottawa introduced the CEO's Award for Productivity and Innovation, which recognizes teams and individuals who have driven a tangible or measureable productivity improvement or innovation. The creation of this award has spurred competition among employees and teams seeking to have their initiatives recognized for driving organizational effectiveness.

## 3.0 HYDRO OTTAWA'S CULTURE OF INNOVATION

Hydro Ottawa's culture of innovation is illustrated in the many division and corporate wide initiatives that are designed to drive change and increase operational efficiency. Below is a brief discussion of initiatives undertaken by some of the divisions within Hydro Ottawa to identify and initiate productivity enhancing opportunities. The section also describes additional initiatives that are planned or are underway to measure and improve its operating performance.[1]

### 3.1 Distribution Operations and Asset Management

Distributions Operations and Asset Management are groups responsible for the planning, design, construction, maintenance and operation of the distribution system within Hydro Ottawa's service territory.

#### *3.1.1 Capital Execution – Process Review*

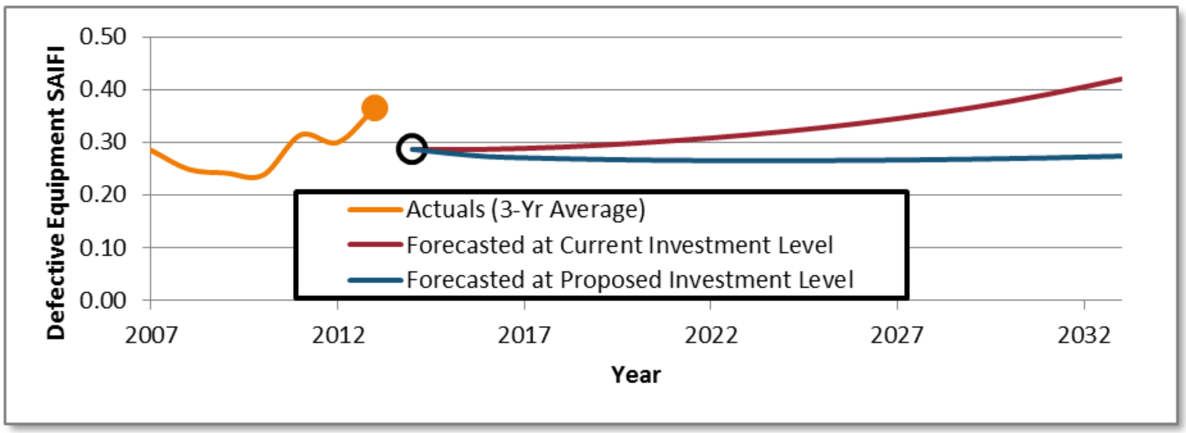
Hydro Ottawa's 2014 Annual Planning Report (see Attachment B-1(B)) shows a financial need much larger than the current spending levels to maintain Hydro Ottawa's current system performance.

If current spending levels remain consistent on a go forward basis, Hydro Ottawa expects plant failure capital to increase along with a corresponding increase in the

[1] Some of the information set out in this section is also provided in Hydro Ottawa's DSP found in Exhibit B-1-2.

percentage of internal labour spent on this reactive type of capital. Increases in equipment failures will result in a significant increase in Defective Equipment SAIFI by 2032.

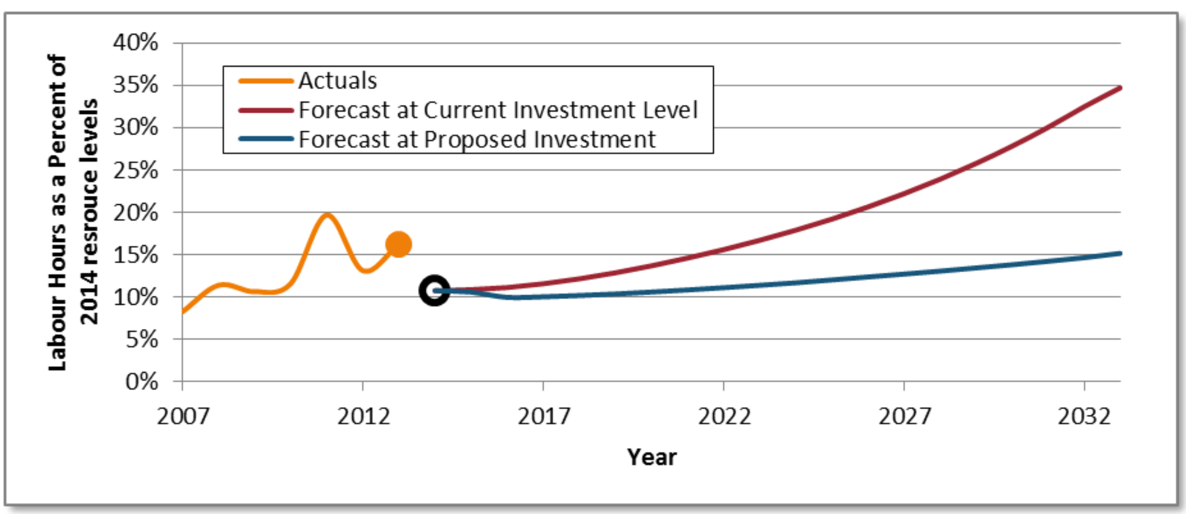
**Figure 1 – Defective Equipment Contribution to SAIFI**




Source: 2014 Annual Planning Report

In addition, distribution plant failure will account for 36% of available labour hours by 2032 if the current annual replacement levels are not increased.

**Figure 2 – Plant Failure Labour Hours as a Percentage of Available Hours**




Source: 2014 Annual Planning Report

Hydro Ottawa recognizes the situation and the primary focus within the operations group has been on enhancing the productivity and efficiency of Hydro Ottawa's processes and operations staff to help close this gap between need and actual spend. Hydro Ottawa's sustainment and demand capital spend has increased significantly over the last number of years, while overall head count in Distribution Operations and Asset Management has remained flat. In order to avoid hiring new staff to keep up with the increasing work, Hydro Ottawa had to find ways of working smarter and more efficiently.

In 2011 Hydro Ottawa completed a Lean review of its capital execution process from project initiation and design through to project closure. A cross functional team of employees involved in different aspects of projects was assembled to review the current state, identify issues and opportunities and make recommendations for implementation that would demonstrate improvements to how Hydro Ottawa does business.

An action plan was developed to address many of the key issues and findings including an inconsistent organizational structure, need for enhanced communications, inconsistent application of Hydro Ottawa's project management processes, and the need for better resource planning and scheduling. The following provides further details into the specific initiatives that have been undertaken and the results.

#### *3.1.1.1 Aligned Staff Geographically*

Hydro Ottawa's structure when the review was completed was a combination of functional and geographic. This inconsistent approach was making communication and collaboration more difficult. As a result Hydro Ottawa realigned its Asset Management and Design groups to match the geographic structure of the company's Construction and Maintenance field forces. The result is area specific teams consisting of planning and asset engineers, distribution designers, scheduling resources, and construction and maintenance staff that have resulted in better relationships and much stronger, timely communication. One of the added benefits of the team approach is the coaching and mentoring available by pairing more junior staff with seasoned veterans regardless of what area of the organization they reside.

In conjunction with the restructuring, Hydro Ottawa established Operational Briefing meetings in each of the areas with all key stakeholders in attendance. In addition to the area teams, Hydro Ottawa has representatives from Health and Safety, Procurement and System Operations. These meetings, held biweekly, are typically less than one hour in length, and are designed to communicate important information about safety, the schedule, reliability statistics, progress against capital plans and financial results. Hydro Ottawa also discusses and resolves or actions issues so that they are addressed in a timely fashion.

#### *3.1.1.2 Distribution Asset Planning and Projects (DAPP) Portal*

To improve internal communications of asset planning and projects, a web portal called DAPP was created in 2011. The DAPP is a centralized repository of asset and project information located on the HOL Intranet where internal stakeholders can find templates or reference data to utilize on an as needed basis. In the past, this information was physically and virtually stored in several different locations and was sometimes not accessible or difficult to find. The site is now a valuable collection of cradle to grave information on projects as well as other broader information and reporting including, but not limited to:

- Annual planning reports;
- Financial reports;
- Project lessons learned;
- Reliability statistics and graphs;
- The consolidated schedule;
- Technical standards; and
- Procurement and stores reports.

This saves staff time and effort searching for information and data that they need to perform their jobs.

#### *3.1.1.3 Streamlined Project Management Processes*

In 2003 Hydro Ottawa introduced a project management tool called "Project Coach". Project Coach was designed to better align and integrate the internal processes across Distributions Operations and Asset Management. The goal was to improve the planning, design and construction of approximately 600 projects completed annually. In 2012 Hydro Ottawa undertook a review of the Project Coach tool using a team of Hydro Ottawa System Designers and field staff that use the methodology every day. The review produced a number of important process modifications that were implemented.

- More frequent financial reporting on projects to ensure proper cost controls, timely change requests and accurate forecasting.
- Build in additional safety elements to minimize risk on projects. Pre-design, pre-construction, and pre-energizing meetings are now vital to ensure communication is clear, risks are managed and all team members are clear on their roles and responsibilities.
- Improved formal communication between project team members by adding critical steps to eliminate errors. The development and use of detailed checklists and guidelines assist new staff and staff who are working on new functional disciplines for the first time be able to process the work more efficiently.
- Streamlined front end design time, typically one draft drawing for circulation with comments results in only one trip to the GIS drawing team for final approved drawing.
- Reduced field changes after design completed. The Field Technician agrees with and signs off on design and material is ordered based on this design. This also reduces stranding material ordered for the approved project.
- Hydro Ottawa has created three years of rolling work plans. Current year projects are scheduled or in construction. Year two projects have detailed designs ready to be moved into the schedule if plans change due to project delays. Year three is high level estimates and preliminary project scoping so that we have inventory of projects ready well in advance of the planned year of execution. This approach provides additional flexibility to Hydro Ottawa's scheduling and construction staff. Hydro Ottawa now has a portfolio of projects

in the queue that allow for the dynamic reallocation of resources to reduce the frequency and duration of downtime.

The realignment of operations staff, enhancements to Hydro Ottawa's Project Coach Processes and tools, in combination with better access to information and templates on the DAPP and its central design repository, has resulted in productivity savings of approximately one hour per designer per day. This represents 5,500 hours or approximately $400,000 annually.

#### *3.1.1.4 Centralized Scheduling*

In 2010 Hydro Ottawa undertook a review of its scheduling systems for capital and maintenance programs and determined that greater efficiencies could be derived from implementing a centralized system. The objective of introducing a new centralized scheduling tool was to provide better visibility into work being scheduled so that those responsible for the design, material, permits, etc. were aware of the progress of each stage completed before construction. The centralized scheduling tool was also designed to better inform decision making regarding the need for use of external contractors for excess workload.

To give visibility into Hydro Ottawa's internal resource capacity, the schedule includes all resources in its overhead, underground and stations work groups. It includes details on all "paid time off" hours such as training, statutory holidays, vacation and sick time which is used to calculate the effective capacity to complete maintenance and capital work. Comparing this effective capacity to the actual volume of work from Hydro Ottawa Asset Management Plan, Demand Capital Forecasts and Maintenance plans provides good information to make better decisions about the need for external contractors.

Hydro Ottawa has been effectively using external contractors to assist in the completion of capital and maintenance work for a number of years. The contractors represent a good alternative to hiring full time staff or apprentices due to the flexibility of being able to increase or decrease the number of contractors on the ground based on the actual workload at the time. Access to qualified high voltage contractors in Eastern Ontario is limited compared to the Greater Toronto Area. To ensure a reliable supply, Hydro Ottawa signed three year standing offer agreements with two Toronto based contractors. Hydro Ottawa also has a third standing offer signed with a local contracting company that provides service including emergency response to Hydro Ottawa's customers in its Casselman service territory.

The schedule provides a consolidated plan to key stakeholders in Operations that allows them to be more effective in the completion of work in the annual plan. The schedule, in combination with the biweekly Operational Briefings has allowed us to be more flexible and adaptable when faced with unforeseen events or delays on any projects. Hydro Ottawa is able to more quickly redeploy Hydro Ottawa's construction forces to other sustainment or demand work with limited downtime.

The scheduling efforts are helping. In 2014 there was an increase in the average number of regular hours per chargeable employee of approximately 27 hours, translating to productivity of $450,000. There was also a decrease in overtime charged to work orders of over 2,700 hours, or approximately $400,000.

#### *3.1.2 Service Desk Enhancements*

The Service Desk is a group of staff that assist customers and contractors with new service connections, disconnect/reconnects, demolition permits, etc. In 2010, HOL completed a review of the processes and tools that were in place with a view to reducing the amount of paper produced and to streamlining the processes to enhance service efficiency to improve overall customer service.

As a result of this review HOL developed an electronic workflow management system called Service Manager that helps staff track the status of requests and work orders throughout their entire lifecycle. Hydro Ottawa also introduced an electronic service request form on its external website to make it easier for customers to initiate requests for service. Customers have the ability to complete and submit requests on-line at a time that is most convenient for them. The requests are received in the Service Manager and actioned by staff to begin the process of obtaining a quote for the service. HOL also introduced electronic service work orders for both internal and contract resources. These work orders are issued and closed off in the field electronically and automatically populate Hydro Ottawa's customer billing system with information like meter badge numbers and meter readings, improving overall timeliness and accuracy.

The more automated work flow resulted in a significant reduction in the amount of manual work related to these customer requests for Service Desk staff. As a result of these efficiencies Hydro Ottawa was able to reallocate two resources from the Service Desk to Hydro Ottawa's Scheduling Group to complete higher value work. Hydro Ottawa has established a back office function in scheduling to improve the hand off of construction packages from Design to Construction. This represents a productivity savings of two resources or approximately $160,000 annually.

#### *3.1.3 Consolidating Dispatch Systems - Metering*

Metering is an operational department within the Construction and Maintenance Group of Hydro Ottawa. The activities support the many operational functions required to support the revenue meter asset for residential, commercial, industrial and wholesale metering.

In 2013 the Metering department converted from the CGI Workforce Management tool to Intergraph In-Service. The In-Service product is the core system related to Hydro Ottawa's Outage Management System and was already being leveraged to dispatch a variety of other field activities including new service connections, collections, forestry inspections and excavation supervisions. By consolidating to one dispatch system Hydro Ottawa was able to save ongoing support costs and license fees for CGI of approximately $35,000 annually. In addition we avoided the $200,000 one-time cost of professional services and licenses associated with a required CGI upgrade. The upgrade savings were offset by a one-time cost of approximately $75,000 to convert to the In-Service product.

### *3.1.4 Annual Interval Metering Inspections*

Hydro Ottawa's 842 largest customers use complex interval meters that should be inspected annually to verify their configuration and validate that the service is electrically correct for risk management and due diligence purposes. Based on an average of three man hours per unit, a physical visit to each of these meters would consume approximately 2,500 man hours including travel time. In 2012, the Metering group began utilizing meter diagnostic software from Elster, Hydro Ottawa's meter supplier. This diagnostic software allowed Hydro Ottawa to complete their annual inspection from the Hydro Ottawa offices. This was carried out via phone lines and prevented a truck roll to the 842 customer sites resulting in a savings of approximately 2,400 man hours. This translates into productivity savings of approximately $177,000 annually.

### *3.1.5 Expansion of Meter Inspection and Sealing*

Hydro Ottawa has a Measurement Canada recognized Quality Assurance program that permits us to inspect and seal meters at its facilities instead of having this completed by a third party. Up until 2012 the scope of this program did not include Hydro Ottawa's most complex Schneider Ion meters. Annually there are approximately 80 of these meters that require inspection and sealing. In 2012 Hydro Ottawa completed the necessary training and expanded the scope of its testing and inspection program through its federal regulator Measurement Canada to include these meters. This has results in a savings of $270 per unit annually. The cost of having this inspection and sealing completed by a third party was $500 per unit, while Hydro Ottawa was able to complete the same work for $230 per unit using internal staff. The estimated operating savings is $21,600 annually.

### *3.1.6 Operations Process Liaison Committee*

In late 2014 a new cross functional committee was established within the Operations group consisting of staff and management from Design, Scheduling, Service Desk and Construction. The mandate of this cross functional group is to take a look at core business processes that cut across departmental lines to continue to look for opportunities to improve overall efficiency and effectiveness. The initial focus is on accurately documenting the as-is state one process at a time and ensuring a clear and common understanding of all of the steps from start to finish. After documenting these processes and taking advantage of obvious quick-wins, the cross-functional group is tasked with reviewing each process in more depth to identify and implement opportunities for improvement.

#### *3.1.7 Multi-Disciplined System Designer*

Hydro Ottawa's System Designers have been primarily functionally focussed. Each Designer is a specialist in one of four disciplines: overhead, underground, residential, or commercial. Another continuous improvement initiative Hydro Ottawa is pursuing is a move to a multi-disciplined Designer model. Instead of focussing on a specific discipline, the Designers will be learning all disciplines. This transition and development will take some time to mature; however, the increase in productivity by having only one Designer handle all aspects of a project are expected to be significant. An example would be a new customer connection with requirements to relocate a pole adjacent their property, provide temporary service for construction, and finally provide service to their new building. Instead of having three different design staff assigned to this site, one System Designer handles will handle all functions required to meet the customer's needs. This will result in better service for customers, better coordination of the construction activities to complete the work, and less Hydro Ottawa labour to complete the project.

#### *3.1.8 Unit Bills*

Distribution Design is responsible to create designs and estimates for both demand and sustainment projects. These designs are based on construction standards that have standard bill of materials. Every design is unique but has to be built to Hydro Ottawa's approved technical standards. In the old process, a Designer was required to input each unit of material and labour into JD Edwards (HOL Enterprise System) on a job by job basis. For material this meant individually adding each pole, nut, bolt, washer, bracket, etc. to the work order for a pole replacement project. This made the task of creating material lists for projects very labour intensive. To reduce this, in 2014 Distribution

Design began the task of assigning labour and trucking units to each overhead standard. To avoid the task of building material lists for each overhead job, each standard had a list or unit bill of material, labour and trucking created for it. So the standard for installing a pole, for example, will have the pole and all of the necessary hardware required to install and dress the pole included in a standard list of materials. When designs are created the Designer will be able to use these unit bills for repetitive activities in a single project, like setting poles, to complete the estimate and material list and easily transfers this into JDE in a shorter timeframe. In 2014, Hydro Ottawa was able to save approximately 10 minutes of design time per pole, or 90 hours for our pole replacement and voltage conversion programs. The Asset Management Plan is forecasting the number of poles being replaced to increase to 1,350 from 2015 – 2020. This process improvement will result in an estimated savings of 225 design hours, or over 5 weeks annually.

#### *3.1.9 Asset Investment Planning (AIP)*

Hydro Ottawa is in the process of implementing an Asset Investment Planning (AIP) software package that focuses on project optimization and analytics with a risk based approach in line with the PAS55 asset management model. The software package is CopperLeaf's C55 program. Quality Asset Planning is critical to Hydro Ottawa's ongoing corporate success, especially as it relates to Productivity and Reliability. It is a capital investment decision making and analytics tool that is used as the central repository for this information eliminating the need for countless Excel spreadsheets. By having all of this critical information in one place it reduces the time to organize the data and frees up staff to spend more time on analyses and decision making.

Currently Hydro Ottawa's Annual Planning Report (Attachment B-1(B)) shows a financial need much larger than the current spending levels to maintain its current system performance. The AIP software will help to close that gap by improving the efficiency of Hydro Ottawa's spending, essentially getting more results for the same spending levels Taking a conservative approach, indications are that improved forecasting at Hydro

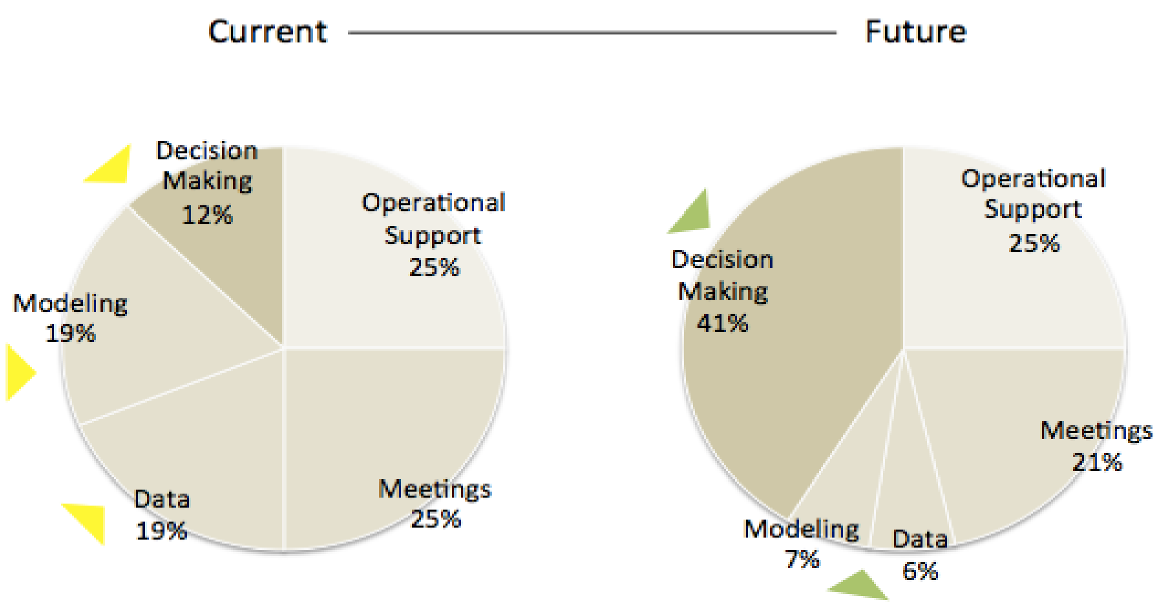
Ottawa can improve capital efficiency by between 1% - 5% or $3,000,000 - $15,000,000 cumulative benefit over five years.

**Table 1 – Capital Efficiency Gains from AIP Implementation**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 5 Year Total |
|---|---|---|---|---|---|---|
| **Capital Deployed** | | | | | | |
| | 50 M | 55 M | 60.5 M | 66.5 M | 73.2 M | 305.2 M |
| **Gain** | | | | | | |
| 1 % | 500 K | 550 K | 605 K | 665 K | 732 K | 3.05 M |
| 2% | 1.5 M | 1.65 M | 1.8 M | 2 M | 2.2 M | 9.16 M |
| 3% | 2.5 M | 2.75 M | 3 M | 3.33 M | 3.66 M | 15.3 M |

Hydro Ottawa is anticipating an additional productivity gain in its Engineering group. The AIP tool will allow engineers to focus their time on better decision making, scenario modeling and optimization of work flow by reducing the amount of time spent organizing data and managing countless Excel spreadsheets. Based on a typical day, it is anticipated that this tool will increase the time spent on value add activities by almost three hours. This will not reduce the number of engineers needed, but rather avoid the need to increase the number of planning engineers to accomplish this level of detailed planning.

**Figure 3 – Engineer Productivity Gains**




#### *3.1.10 Mobile Workforce Management*

Hydro Ottawa has a large mobile workforce that is responsible for a wide range of work from simple disconnect, reconnects or meter changes to the more complex and longer duration pole changes and cable replacements. To date we have been using a combination of Excel spreadsheets, in-house developed databases, and our Intergraph In-Service system for scheduling and dispatching work. This is accomplished in a decentralized model with several different groups dispatching mainly to their own resources. Although this has been relatively effective, the organization needs to invest in a Mobile Workforce Management (MWM) tool to drive productivity to the next level. The objectives underlying the expected investment fall into the following Categories:

**Improve Productivity** – Less than optimal dispatching and routing of work using Hydro Ottawa's current systems and tools is leading to latent capacity in the field service teams, and presents a real opportunity to increase daily job completion rates. Another area of opportunity is that of administrative tasks, more specifically, time capture. Hydro Ottawa's review of new capabilities indicated the ability to automate time capture for field service staff. Savings in these two areas will increase capacity of field staff to complete more tasks per day.

**Reduce Operating costs** – Implementing unified dispatching tool with route optimization capabilities has been shown to reduce kilometers driven and fuel consumption. Given current fuel prices and the size of Hydro Ottawa's service territory, the potential is not insignificant. A reduction in travel time could also lead to additional work being completed within a regular business day and is expected to result in a reduction in overtime costs.

**Exploit Unfulfilled Opportunity Costs** – Most every field services discipline is maintaining a backlog of work that they are expected to deal with, on top of the ongoing daily workload. Often these backlog items are important from the perspective of avoiding future outages and can have a detrimental impact on SAIFI and SAIDI if gone unattended. The new system will allow the Company to begin taking advantage of available time at the start of the day and between customer appointments for completing these backlog items, testing, inspection, or maintenance activities that otherwise can see long delays in being completed. The system also has the ability to schedule these jobs and take advantage of a crew's sudden availability due to a canceled appointment or other unforeseen event.

**Increase performance against service levels, and enhance customer satisfaction** – MWM tools have the capability to tailor dispatching rules to prioritize work based on a variety of factors including those represented by proximity to missing a service level agreement target. This will ensure that higher priority work orders, like customer appointments, are completed on time leading to enhanced customer satisfaction.

**Execute better informed decisions with Performance Management** – Many of the tools Hydro Ottawa researched have strong performance management capabilities to provide Supervisors and Managers access to timely, relevant and accurate data. Daily the Supervisors will have access to reports that will summarize activity from the prior day while allowing them to drill down into specific areas of concern quickly and easily. MWM tools provide sophisticated performance management capabilities needed to assist decision makers, while reducing the need for time spent aggregating data.

**Meet the standards set by the OEB's performance-based Renewed Regulatory Framework** – The performance management and business intelligence modules of the MWM system will help ensure that HOL is tracking and monitoring performance against those metrics and key performance indicators that Hydro Ottawa's regulatory body expects regular reporting against.

A more detailed description of the initiative can be found in the DSP, Material Investments Attachment B-1(A).

### *3.1.11 Vegetation Management – Storm Hardening*

Hydro Ottawa's storm hardening program is a new initiative that began in 2014 and is projected to extend into 2015. It represents an adjunct to its normal tree trimming efforts that operate on two and three year cycles and was initiated to remove overhang branches from over 2,650 spans. A key aspect of the program is a change to Hydro Ottawa's standard on tree trimming that increases our clearance to a "wire to sky" approach. The focus on eliminating the overhang is specifically to reduce the risk of outages and equipment damage resulting from weighted, blown, or broken branches contacting distribution wires. The investments made are expected to yield significant long term reliability and productivity benefits.

### *3.1.12 Mobility and Damage Assessment Module*

In 2003 Hydro Ottawa introduced its first fully mobile computers for field staff. Those laptops were used to dispatch outages and provided field workers with information about distribution assets from Hydro Ottawa's Geographic Information System (GIS). Since 2003 the mobile deployment has grown to more than 75 units (a combination of laptops, tablets and handheld devices) providing staff with a multitude of tools and applications to help them do their jobs, faster and more efficient than ever before.

Some of the specific tools are described below.

**Mobile GIS:** Mobile GIS is the system where all assets are recorded and made available to staff, including field staff. Hydro Ottawa is proud to be one of the first utilities to produce all of its new construction drawing directly in GIS. This makes sure that staff has a complete picture of existing assets and what is proposed, helping them make better decisions and avoiding duplication and re-work.

**Mobile OMS:** Mobile OMS is the system that allows Hydro Ottawa workers to track all outage and major storm dispatching. Field workers not only receive all of their work electronically but are able to view system maps, get information on asset attributes; trace circuits back to the source and also create follow-up jobs if additional work is required such as pole replacements after traffic accidents.

**Electronic Service layouts:** Field staff can produce service layouts for new customer directly in the field and print a copy for the customer. This means less time is spent by office staff preparing and mailing new connection to customers. The customer is provided with better service by having all the information they need regarding the cost and details of the service they require in a more timely fashion.

**Electronic Asset Inspections:** Inspectors are now equipped with mobile inspection forms that are directly tied to the GIS system so they know exactly which asset they are inspecting. All of the assets are linked to the GIS and clearly identifiable increasing accuracy of inspection results.

One of Hydro Ottawa's key initiatives in 2014 was the implementation of the Outage Management System's Damage Assessment Module for mobile field workers. Using mobile resources minimizes customer impact, reduces restore times and keeps repair cost under control.

The Damage Assessment Module provides a simple electronic means to capture outage impacted information and make it available centrally to improve storm restoration, logistics management and follow-up processes using Hydro Ottawa's existing mobile systems. Hydro Ottawa anticipates that this technology and the information it provides will save approximately five hours of restoration time per crew in major events. Assuming Hydro Ottawa has 20 four person crews involved in one major event per year this translates into an operating savings of approximately $30,000 per year.

#### *3.1.13 Field Operators*

A Field Operator is a new position, working a rotational 24/7 shift, that was created in 2013 in part to respond to, assess and take the appropriate action during electrical emergency situations on Hydro Ottawa's high and low voltage power system and assist in the first response to emergencies calls as defined by OEB. The position was also designed to enhance the productivity of our day time construction crews by performing much of the ground level network switching required for large projects during off hours when there is less traffic congestion, especially in the downtown core. The position will also free up additional capacity of Hydro Ottawa's skilled lines trades resources currently working on the 24/7 shift so they can be redeployed to higher value construction work.

#### *3.1.14 Align Metering Staff Geographically*

A decision was made in 2014 to realign the metering group regionally versus functionally. The move to regional areas better aligns with operational demands and it ensures that Hydro Ottawa develops supervisors and field staff that have a broader knowledge of the various technical standards and diverse metering technologies. Hydro Ottawa's field staff will be better suited to handle all types of work as opposed to specializing in one or a few specific functions. It is anticipated that this initiative with result in productivity savings realized through reduced travel time and other delays beginning in 2015.

#### *3.1.15 Commercial Metering Cost Recovery*

During 2013 – 2014, a decision was made to begin charging new commercial customers the capital costs of meters. This decision emanated from a review the metering staff undertook to revise their existing standards documentation to consolidate it into a single source of information on the broad array of metering designs and installations. It is estimated this recovery will free up $135,000 of capital annually based on an average of 300 commercial meter installations with a capital cost of approximately $450 per unit.

### 3.2 Customer Service

Productivity in the Customer Service group has been focussed on identifying and implementing process improvements, automation, and incrementally offering new self-serve features for customers. The objectives are to enhance customer service, to respond to identified customer preferences, and to increase Hydro Ottawa's operational efficiency and effectiveness.

#### *3.2.1 E-Billing Enhancements*

Hydro Ottawa introduced E-billing in 2008. The objective of providing an e-billing service is to reduce paper, postage and people costs of creating a paper bill. By the end of December 2014, approximately 86,000customers had signed up for the E-billing service. This represents 26% of the Hydro Ottawa customer base and makes us one of the industry leaders in this regard. The total cost of a paper bill including paper, envelope and postage is $0.83 compared to only $0.02 for an e-bill. Hydro Ottawa estimates the annual savings from e-billing to be $836,000.

#### *3.2.2 Move-In-Move-Out (MIMO) improvements*

MIMO is an online self-serve functionality that converts fax submissions to an electronic format allowing them to be managed more efficiently. A key benefit of MIMO is its ability to search for completed moves, store data electronically, and streamline the processing of all move requests. Productivity is increased for Customer Service Representatives by eliminating the need to manage paper requests and filing. This is particularly important given the large population of university and colleges students in Ottawa that drive a significant number of MIMO transactions annually. This automation has enabled Customer Contact agents to take on new, incremental activities which they would not have otherwise been able to do, particularly during peak move season, an estimated productivity savings of approximately 0.5 FTE or $40,000 annually. That employee effort is now directed towards higher customer value tasks, in alignment with our Customer Experience focus.

#### *3.2.3 Outage Alerts and Communications*

Hydro Ottawa's outage alerts program is a web-based program that provides e-mails or text messages to Hydro Ottawa employees when outages occur. The speed of dissemination as well as the completeness and consistency of messaging facilitates power outage restoration and communication efforts internally. In 2009, Hydro Ottawa expanded the service by automating the communication of power outage information to the media, City Councillors and Key Account clients. By sharing this information promptly and proactively, customers can access outage reports and updates immediately via email and consequently they no longer initiate direct contact with HOL resources or our On Call Management Call Centre. The alerts provide customers with timely, accurate information on the outage duration to help them determine the impact on their plans and make alternate arrangements if necessary.

#### *3.2.4 Power Outage Reporting Line*

In 2010 Hydro Ottawa partnered with Nortel/Avaya to develop an intelligent Interactive Voice Response (IVR) application that provides customers with an efficient and effective way to report an outage and/or to get information about an existing outage. This ability to solicit this first-hand insight into an outage incident allowed Hydro Ottawa to streamline its power outage business process and further leverage the diagnostic capabilities of its Outage Management System. In addition to the benefits of automated report generation, this service has reduced the average outage call duration by up to 90% (from three minutes per call to 30 seconds for most calls). These enhancements have reduced the number of blocked calls (busy signal) to 0.45% (2010) and reduced the number of customers who experienced a dropped call to less than .01% (2011). These customers were able to easily access the outage information they were looking for without speaking to an On Call Management agent.

### *3.2.5 Introduced Power Outage Maps*

Hydro Ottawa's website includes a Power Outage map that provides details of confirmed and unconfirmed outages including area affected, estimated time of restoration (ETR), status of crews and the number of customers affected. This feature enhances the timeliness of delivering Outage information and the progress of the restoration process, and has proven to be very popular with customers, City Councillors, and the media. The power outage map is a North American Chartwell Award winning system that continues to add value to Hydro Ottawa customers' experience through automation that has freed up resources within the Customer Contact, Communications and Operations departments. This allows employees to focus on value-added tasks to increase customer value.

### *3.2.6 Credit Card Payments*

Hydro Ottawa's Interactive Voice Response (IVR) was updated with the addition of a credit card payment option. Customers can now call and make a credit card payment over the phone, at their convenience. The Hydro Ottawa web site introduced a direct credit card payment link for customer ease that can be accessed through the HO Mobile application as well. This direct link provided customers with a quick and easy way to make a payment towards their account. This service is offered 24/7 and supports the organizations focus on providing 24/7 accessible services that are driven by the customer; putting them in control. Since introduction of these options in mid-2013, credit card payments, totalling over $5.5 million have been made through the IVR, HO Website and HO Mobile credit card payment channels. The customer ability to make the credit card payment without call centre assistance translates into cost savings and efficiencies.

### *3.2.7 My Hydro Link (MHL)*

MHL is Hydro Ottawa's customer self-serve web portal that allows Hydro Ottawa's customers to track their consumption, submit a move request, and make payments on their account. MHL has a proven track record as the tool of choice for customers who have embraced the self-serve model with over 122,000 accounts or approximately 38% of customers having registered for the service as of the end of 2014. Offering these customers access to accurate, timely and reliable data and information about their consumption, billing and account information and resulted in a reduction in the total number of call to Hydro Ottawa's call centre with a corresponding reduction in the call centre costs. Some of the features available are detailed below.

**MHL Bill Comparison:** This MHL feature provides customers with the ability to compare bills year over year at their convenience. Billing period comparisons assist the customer with understanding increased or even decreased energy costs. Functionality was developed in MHL that allows customer to view billing information in a side by side format with the added benefit that highlights differences between bills, i.e. number of days, rate changes and even the weather. Prior to this being developed, customers interested in doing this analysis would call Hydro Ottawa to request that copies of bills be mailed to them.

**MHL Summary Pages:** New features added in the spring of 2012 provide MHL registrants the opportunity to customize their view of account information and details on a single page view. This service was further extended to customers with multiple accounts allowing them to have a high level view of all of their accounts while still maintaining a customized view at the individual account level.

**MHL Alerts:** Allows customers to determine their own thresholds to receive notices for their electricity usage, money spent and to monitor on peak usage, this services puts the customer in control of their electricity consumption and the amount of money they are spending in a billing period or if they have missed the payment due date for their bill. Alerts are delivered by e-mail to customers detailing their predicted bill amount during the current billing period, at intervals of their choosing, daily, weekly or monthly. The model uses forecasting tools in conjunction with actual usage details.

**MHL Predict My Bill:** The Predict My Bill section is designed to help My Hydro Link registrants manage their electricity by predicting the bill amount for usage consumed during the current billing period and also offers a Predicted Bill Comparison feature to compare the current bill period with previous ones. The cost is updated daily and becomes increasingly accurate as the bill period progresses. Users have the option to register for Prediction emails at the frequency of their choice, daily, weekly or monthly.

**MHL Agent assisted registrations:** Formerly a customer driven activity, a secondary registration process was developed to allow agents to enrol customers over the phone, new scripting for Concentrix Call Centre and Customer Care agents encourages the discussion with customers to up sell the MHL Self-Serve option.

**MHL Single Sign On:** Single sign on seamlessly integrated MHL with the HOL website for an improved customer experience.

**MHL Mobile Applications:** A mobile version of MHL was introduced in 2012 for a variety of smart phone platforms. In the first five months of 2013, unique visits to the mobile site surpassed the 2012 results by 63%. The Hydro Ottawa mobile site has experienced an average of 3,750 unique visits monthly since May 2013 which contributes to reducing overall call volumes.

The various customer self-serve options are having a significant financial impact. Hydro Ottawa estimates savings of approximately $400,000 annually as a result of reduced call volumes due to the fact that customers are able to access the information they require whenever they want from wherever they happen to be. These estimated savings were partially offset in 2014 due to a spike in call volumes specifically related to the introduction of monthly billing and the abnormally cold winter.

### 3.3 Human Resources & Workforce Planning

Hydro Ottawa's Talent Management Framework is critical to effectively fulfilling the company's core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to customers. The company's aim is to sustain a high performance workforce and operations that deliver ever-improving value to our customers and stakeholders, and to ensure our company's success and sustainability. Hydro Ottawa's 2012-2016 Strategic Direction articulates that this will be achieved by cultivating a culture of innovation and continuous improvement focusing on three outcomes in particular: a safe and healthy work environment; an engaged, aligned and prepared workforce; and efficient and effective operations that enhance the customer experience.

Hydro Ottawa's comprehensive and integrated approach to Human Resources emphasizes that strategic talent management is essential in building the right workforce necessary for business execution. The following initiatives demonstrate an emphasis on generating talent outcomes that drive productivity at Hydro Ottawa.

### *3.3.1 Workforce Planning Strategy*

As outlined in Exhibit D1, Hydro Ottawa's Workforce Planning Strategy not only anticipates and adopts proactive strategies to bridge talent supply gaps that are crucial to maintaining organizational effectiveness; it also plays a critical role in containing costs, improving organizational productivity, and generating customer value.

### *3.3.2 Labour Efficiencies*

In 2013, Hydro Ottawa and the IBEW, Local 636 reached a renewed 4-year collective agreement that resulted in several labour efficiencies which included: longer periods of employment for temporary employees, improved distribution of overtime during emergencies, parameters with respect to the payment of responsibility pay, the pro-rating of leaves for new employees, the ability to designate specific vacation periods, a simplified process for the relocation of employees for accommodations, rationalization of flame resistant clothing, and an improved process for the replacement of tools and equipment.

### *3.3.3 Designated Vacation Periods*

In 2014, Hydro Ottawa introduced a formal a company-wide designated vacation period from December 24 to January 1, inclusive. This approach has enabled Hydro Ottawa to redirect typically lower-productivity working days in this timeframe to ensure optimal staffing during peak periods at other times of the year.

### *3.3.4 Insured Benefits*

In 2014, Hydro Ottawa transitioned to a new insured benefits provider following a competitive marketing process. The transition has resulted in cost savings which is associated with the reduced costs of benefits premiums, streamlined administrative processes and enhanced self-serve options.

### *3.3.5 Attendance Management*

Hydro Ottawa's Attendance Management Program monitors employee attendance, recognizes positive attendance and provides a framework for addressing excessive absenteeism. The company has decreased its average number of sick days per employee from 7.4 in 2007 to 5.9 in 2014.

### *3.3.6 Training Delivery*

Hydro Ottawa is implementing a new approach to delivering training commencing in 2015. This new approach aims to improve productivity through better scheduling and the delivery of training at employee work centres, as well as leveraging e-learning and classroom technology to gain efficiencies. In particular, training will focus on maximizing productive time by leveraging inclement weather days for the delivery of fast-deploy refresher training modules – ensuring that employees remain in the field during optimal work periods to focus on service delivery.

### *3.3.7 Leveraging Technology in the Delivery of Human Resources Services*

In 2012, Hydro Ottawa introduced an Intranet that resulted in more efficient and robust communications within the organization, and which eliminated the cost, maintenance and inefficiency of over 42 individual micro-sites within the company. Building on this success, Hydro Ottawa is focused on driving productivity and innovation in the delivery of human resources services through the streamlining and automation of processes. This includes increased self-serve capability for employees and people leaders, and the deployment of mobile tools and technology to enable more flexible and efficient completion, recording and reporting of health and safety related planning and monitoring activities in the field.

## 3.4 Information Technology

From the Information Management, Information Technology portfolio, productivity gains will be actualized through a number of core initiatives.

### *3.4.1 Mobile Device Management*

A Mobile Device Management strategy will reduce the number of cell phones (blackberry devices) and personal computers replaced through the provision of agile mobile computing devices. This will facilitate enhanced technologies, services and increased productivity to the field where otherwise, computing and communications capabilities had been limited. More information will be available or presented on location, processed in real-time and consumed as needed. In parallel, costs to administer devices and telecommunication subscriptions will be reduced. Centralized management of all accounts, information stores, and permissions will ensure broader security and administrative controls throughout.

### *3.4.2 Improving Communications*

Facilitating the IM/IT network with virtual “Go-To-Meeting” visual/audio conferencing capabilities will improve communications and information sharing while significantly reducing costs (time and materials) of a disparate geographic placement of employees, services and partners. Virtual meeting, information sharing and spontaneous connection/communication capabilities further enhances productivity regardless of location. The Operations group has been successfully using this technology for over a year for the bi-weekly Operational Briefing meetings as a means of saving time and fuel associate with travel to various work depots.

### *3.4.3 Printing Services*

Printing services will be moved to an external managed-service provider to reduce hardware footprint and administrative overhead. SecurePrint and follow-me features will expand available functionality while reducing the footprint within the business.

Continued diligence in reducing the "server footprint" through a virtualization exercise begun in 2014, has retired 65 servers within the infrastructure with many more targeted through the coming years. Information Technology will adopt an Infrastructure as a Service (IaaS) approach to further reduce procurement activity while increasing time-to-market responsiveness to business needs.

### *3.4.4 Configuration Management*

Configuration Management Database (CMDB) will be investigated with a view to centralizing the management of all configurations, releases, change for all infrastructure assets deployed within the business. While the value will increase security and efficiency of the practice, centralized controls generate productivity gains, particularly where response to urgent patching/upgrades may be warranted.

### *3.4.5 Enterprise Resource Planning System*

From an enterprise solutions perspective, a recent tools upgrade ensured a stable, reliable ERP capability to meet current business needs. There is a desire to move to a commercial off-the-shelf (COTS) solution with minimal customization to reduce support overhead as well as continue to provide the level of functionality needed. A decision will be needed in terms of how to meet enterprise resource planning needs while driving productivity within the operation.

### *3.4.6 Enterprise Service Bus*

The Enterprise Service Bus (ESB) provides a longer term strategy for standardized technology growth and integration but provides shorter term efficiency gains as well. Continued development of point-to-point integrations of individual applications into the organizational pool of services was assessed as growing to unsustainable numbers, increasing the burden of support and multiplicity of tasks as changes were introduced. The ESB provides a middle-ware capability to present and allow “one-time” integrated solutions the ability to consume target data without complex integration consideration and significantly reduced cost. As part of the preparedness/evolution strategy, new and emerging technologies are being produced SOA-enabled, thereby integration-ready. The development of a high-availability environment further enhances the reliability of the network infrastructure and facilitates the evolution of all existing and future integration needs.

### *3.4.7 Database Management*

Productivity and efficiencies will be improved in terms of ongoing management of databases with the establishment of Oracle Database Appliance (ODA) to house Oracle applications, middleware and databases together within a virtual context. Rapid deployment, expansion of services is possible through the use of virtual templates, reducing processes and management time. Centralized management of data and device can be achieved through a reduced footprint and at significantly less time and impact to the organization.

### *3.4.8 SharePoint*

The SharePoint application will be more aggressively mined across the business to produce greater collaboration and information sharing, reduction in file-shares/stores, reduction in duplication of information and very significant strides in the identification and management of true data (authoritative) source. This will constitute a shift for many Hydro Ottawa groups but will nonetheless produce immediate results in terms of information collaboration and real-time access to key data.

### *3.4.9 Customer Care and Billing*

The PeopleSoft CIS (Customer Information System) reached end-of-life and was replaced in 2014 with the Oracle Customer Care and Billing (CC&B) application in a like-for-like rollout strategy. The CC&B application supports all critical meter-to-cash functions through an automated billing and revenue data stream. Along with the implementation of CC&B, monthly billing was introduced for Hydro Ottawa's residential and small commercial rate classes to meet its customer expectations. There were efficiencies gained with the implementation of the CC&B application which have improved internal business processes, audit requirements as well as help provide better service to Hydro Ottawa customers. Some examples of this is the automation of generation billing/payment in CC&B, the adjustment approval process using the application rather than queries, streamlined collection and write off processes by leveraging monthly billing, just to name a few. There will be continuous enhancements planned for CC&B in the forthcoming years to help support changes for innovative customer service solutions such as landlord reversion and the ability to provide unilingual bills to Hydro Ottawa customers. CC&B will also serve as a platform to implement a Customer Self Service solution that would allow automation of customer web initiated move ins/outs and account set-up through CC&B without the need to rekey data resulting in productivity improvements. Several key upgrades to CC&B are planned for 2016-2020 where, as applied, will further contribute to efficient and effective internal process.

## Balanced Productivity Metrics

HydroOttawa

| | Measures | Description | 2011 | 2012 | 2013 | Unaudited 2014 Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|---|---|---|---|---|
| Labour Utilization | Productive Time | % of Billable Hours / Total Regular Hours | 70% | 71% | 69% | 71% | 70% | 69% | 71% |
| | Labour Allocation to CAPEX | % of Labour Time on Capital Activities / Total Productive Time | 61% | 55% | 56% | 60% | 59% | 60% | 60% |
| | Average Sick Days per FTE | Total Sick Days / Total Employees | 5.3 Days | 5.9 Days | 6.0 Days | 8.0 Days | 7.2 Days | 6.6 Days | 5.9 Days |
| OM&A Measures | Cost per Underground Locate | Total Underground Locate costs / Total Locate Requests | $27.6 | $29.1 | $30.0 | $36.1 | $27.8 | $28.0 | $28.7 |
| | Vegetation Management Cost Value Metric | Total Vegetation Management Costs / (1 - Tree Contacts SAIFI) | $36K | $24K | $29K | $37K | $34K | $32K | $42K |
| | Customer Service Cost Value Metric | External Call Centre Costs / Customer Satisfaction % | $28K | $27K | $25K | $26K | $30K | $29K | $28K |
| | Bad Debt as a % of Total Electricity Revenue | Bad Debt / Total Electricity Revenue | 0.18% | 0.16% | 0.25% | 0.28% | 0.27% | 0.19% | 0.19% |
| Asset Efficiency | Sustainment Asset Reliability Cost Value Metric | Asset Replacement and Plant Failure Costs / (1 - Defective Equipment SAIFI) | $433K | $413K | $504K | $217K | $331K | $429K | $524K |
| | Cost per Pole replaced | Planned Pole Replacement Program Costs / # of Poles Replaced | $15K | $20K | $23K | $21K | $21K | $27K | $33K |
| | Cost per metre Cable replaced | Cable Replacement Program Costs / metres of Cables Replaced | $363 | $186 | $328 | $375 | $229 | $290 | $437 |
| | Cost per metre Conductors extended | Line Extension Program Costs / metres of Conductors Extended | $67 | $61 | $136 | $60 | $94 | $97 | $128 |
| | Technology Infrastructure Cost per Employee | (External IT support costs + computer hardware & software depn) / # of FTE | $21.8K | $21.9K | $22.2K | $16.6K | $19.7K | $20.2K | $21.5K |
| | Normalized Derecognized Assets net of Proceeds | $ Derecognized Assets net of Proceeds (all companies) | N/A | $0.7M | $2.1M | $0.4M | $0.5M | $0.7M | $0.9M |
| | Generation Plant Availability | Sum individual plant availabilities / number of generation stations | 95.5% | 94.5% | 95.3% | 93.5% | 99.1% | 88.0% | 89.0% |
| Profitability Metrics | EBITDA as a % Revenue | EBITDA $ / Total Revenue - Generation | 70% | 59% | 64% | 68% | 69% | 68% | 67% |
| | | EBITDA $ / Total Revenue - Hydro Ottawa Limited | 55% | 48% | 46% | 48% | 44% | 46% | 44% |
| | Cost per kWh Generated | Total Costs (excluding BD, depn, interest, and taxes) / kWh generated | 0.0250 | 0.0175 | 0.0247 | 0.0198 | 0.0231 | 0.0233 | 0.0238 |
| | Inventory Turnover Ratio | Cost of Materials Used / Average Inventory | 1.70 | 2.25 | 2.12 | 2.13 | 2.10 | 2.07 | 1.83 |

### Narratives

| Q4 | Q3 | |
|---|---|---|
| | | **Labour Utilization** |
| ● | ▲ | Productive Time was up from 2013. Total regular labour hours charged to jobs were up, overtime was down. Field Operators increased chargeable hours from prior year. |
| ● | ● | Labour Allocation to CAPEX exceeded budget and prior year. Higher Capex activities offset by lower Work for Others, the most notable shift was at Service Desk. |
| ● | ● | Average Sick Days per FTE was down to 5.9 Days. Q4 has improved due to several employees returning to work after a long term absence. The 2014 full-year result has improved slightly from 2013. |
| | | **OM&A Measures** |
| ● | ▲ | Cost per Underground Locate was lower than the past two years. However total program costs exceeded budget and prior year actual due to 13% or 8000 more locate requests. |
| ▲ | ▲ | Vegetation Management cost value was up, indicating costs increased larger than SAIFI improvement. 57% increased costs from 2013, partially explained by Storm Hardening. SAIFI 0.049 below 2013 and 10-yr avg. |
| ▲ | ▲ | Customer Service value did well in Q4 - lower costs and higher satisfaction, the full year result was skewed by the negative Q2 result. Overall 88% satisfaction with higher costs than budget and prior year. |
| ● | ▲ | Bad Debt as a % of Total Electricity Revenue has improved from prior year and first half year, slightly better than the 2013 industry average 0.20%. Bad debt expense exceeded budget by $0.7M. |
| | | **Asset Efficiency** |
| ▲ | ▲ | Sustainment Asset cost value was up, indicating costs increased larger than SAIFI improvement. 29% increased costs. SAIFI 0.279 below 2013 and 10-yr average (CCRA not considered asset replacement, therefore excluded) |
| x | ▲ | Capital program costs were up while the units completed in 2014 were down. The increased costs were explained by increased downtown projects which required additional costs for crane and labour. |
| ● | ● | Technology Infrastructure cost per employee was lower than prior years because 2014 did not have a full year of CC&B depreciation included. IT maintenance was up by $1.2M or 22% from prior year. |
| ● | ▲ | Total Derecognized Fixed Assets $1.7M, offset by $0.8M proceeds. The derecognized fixed assets include $0.5M cables and $0.3M meters. Asset Impairments excluded from this measures. |
| ● | ● | Generation Plant Availability 89% due to generation station 2 and grinder shut down for the planned Bronson Bulkhead construction, completed in November. |
| | | **Profitability** |
| ● | ● | Generation EBITDA as a % of Revenue was down due to the planned production shutdown for Bronson Bulkhead construction. EBITDA well exceeded budget and prior year result. |
| x | ● | HOL EBITDA as a % of Revenue was down. The expenses were up by 4% while revenue increased by 2%. The HOL EBITDA below budget and prior year result. |
| ● | ● | Cost per kWh Generated lower than prior year. Production was 1% lower than prior year, costs were 8% lower. |
| ▲ | ● | Inventory Turnover Ratio was down due to increased inventory, mainly cables increased in Q4. Total inventory was up, $9M reported in 2012, $10M in 2013, currently $11M. |

# PRODUCTIVITY & BENCHMARKING OVERVIEW

This schedule provides an overview of the evidence filed by Hydro Ottawa to facilitate the Ontario Energy Board's (OEB)'s review and evaluation of Hydro Ottawa's continued commitment to sustainable efficiency and productivity.

## 1.0 Introduction

The OEB's Renewed Regulatory Framework for Electricity ("RRFE") report sets out that Custom Incentive Regulation ("Custom IR" or "CIR") applications should facilitate the OEB's "assessment of the adequacy of past and future productivity levels"[1] …. and the reasonableness of the distributor's forecasts."[2]

The OEB's focus on productivity is one of the centerpieces of its outcomes-based approach to regulation that is designed to ensure "Ontario's electricity system provides value for money for customers" and a sharing of benefits by emphasizing "results rather than activities".[3] In defining the outcome expectations, the OEB concluded that the following four categories of outcomes would be appropriate, namely a) customer focus; b) operational efficiency; c) public policy responsiveness; d) financial performance. The OEB's focus on benchmarking is intended to provide an appropriate gauge for assessing the reasonableness of the utility's forecasts against its own past performance and the performance of other distributors, as appropriate.

To facilitate the achievement of the four afore-mentioned outcomes, the OEB established three policies, namely a) rate setting policies that ensure continued productivity improvements; b) capital planning to ensure paced and prioritized capital spending including in smart grid investments; and c) measured performance.

[1] Renewed Regulatory Framework for Electricity, October 18, 2012 Report of the Board Page 70
[2] Ibid, page 20.
[3] Ibid., page 13, Table 1

## 2.0 Hydro Ottawa's fulfillment of the OEB's Productivity Expectations

Evidence illustrating Hydro Ottawa's commitment to efficiency and continuous improvement is woven throughout each Exhibit filed as part of its Custom IR application. For the purposes of facilitating the OEB's assessment of the reasonableness of Hydro Ottawa past and future productivity levels, Exhibit D-1-4 provides a detailed discussion of its historical and forward looking productivity initiatives that were, are, or will be implemented as illustration of Hydro Ottawa's continuing commitment to efficiency and long run net efficiency savings for the company's customers. Other examples of evidence that speaks to Hydro Ottawa's commitment to productivity and continuous improvement:

a) Exhibit B-1 Hydro Ottawa's Distribution System Plan for continuous improvement metrics and Annual Planning Report;
b) Exhibit D-1-2 Hydro Ottawa's Operating, Maintenance and Administrative ("OM&A") evidence;
c) Exhibit D-1-6 Hydro Ottawa's Customer Service Strategy;
d) Exhibit D-1-7 Hydro Ottawa's Workforce Planning Strategy
e) Exhibit A-3-1 Hydro Ottawa's Customer Engagement Plan

### 2.1 RRFE – Rate Setting Policy - Productivity (X) Factor

The key feature of every incentive regulation framework is the inclusion of a productivity offset or X factor which is designed to share the benefits of productivity and efficiency gains of a company with its consumers. The productivity factor is a built in sharing mechanism that provides a year over year obligation on a company to find efficiency savings the results of which is a guaranteed consumer benefit. The Board described the components of an X-factor in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[4]

In the design of its Custom IR formula Hydro Ottawa has incorporated two separate and distinct sharing mechanisms, namely a) the productivity factor and b) an earnings sharing mechanism. A full discussion of Hydro Ottawa's proposal for defining the productivity factor and the earning sharing mechanism is set out in Exhibit A-2-1. In addition to these benefits sharing mechanisms, Hydro Ottawa believes that there are productivity and efficiency benefits that can be derived from long term budget forecasting that are not easily quantified. Similarly, Hydro Ottawa believes that some productivity initiatives that produce an intangible benefit at best and consequently may not be fully quantified monetarily.

### 2.2 RRFE – Capital Planning

Another feature of the RRFE and expected productivity and performance outcomes relates to the capital planning process. The OEB's specific expectations related to efficient capital planning are set out in Section 5.2.3 of Chapter 5 of the Filing Requirements. Chapter 5 requires that utilities identify qualitative and quantitative measures and metrics to assess the performance of their capital planning and

[4] Page 12 July 14, 2008 EB-2007-0673, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

implementation practices as a part of their Distribution Service Plan filing. The Chapter 5 Filing Requirements specifically break down the measures that the utilities are expected to provide into three categories, which are:

- Customer-Oriented Performance;
- Cost Efficiency of Planning Quality and Implementation; and
- Asset / System Operation Performance.

Hydro Ottawa uses performance metrics to promote improvement in asset management planning, capital investment planning and in customer oriented performances. These metrics include quantitative measures used to monitor the utility's planning processes, efficiencies to carry out those plans, as well as identify shortfalls and areas for improvement. Hydro Ottawa's performance metrics are captured in its Corporate Scorecard and are measured and reported internally on a quarterly basis. Below is a summary of what is measured for each of the three categories specified in the Chapter 5 Filing Requirements.

### 2.2.1 Customer-Oriented Performance

The reliability of Hydro Ottawa's system is tracked using the following metrics:[5]

- System Average Interruption Frequency (SAIFI);
- System Average Interruption Duration Index (SAIDI);
- Customer Average Interruption Duration Index (CAIDI); and
- Feeders Experiencing Multiple Sustained Interruptions (FEMI).

SAIFI and SAIDI are currently captured in the OEB's Scorecard while CAIDI and FEMI are not Chapter 5 requirements but are captured in Hydro Ottawa's corporate scorecard.

Hydro Ottawa's fulfillment of the OEB's focus on customer-oriented performance can also be found in the numerous customer engagement initiatives designed to cater to our

[5] These metrics are discussed in more detail in Hydro Ottawa's Distribution System Plan

customer's preferences and respond to their concerns. For more details on Hydro Ottawa's customer engagement initiatives, please refer to Exhibit A-3-1.

#### 2.2.2 Cost Efficiency of Planning Quality and Implementation

Hydro Ottawa uses a cost efficiency metric to report on the progress and efficiency of planned projects for each fiscal year. The cost efficiency metric captured in Hydro Ottawa's Corporate Scorecard as "Distribution Sustainment Capital Program Completion" is a ratio of the amount of actual capital activities completed throughout the year as compared to the planned capital activities. It is strictly a measure of the planned capital system renewal projects and does not include system access investments. The target of the metric is to achieve 100% completion of the annual planned work.

In addition, Hydro Ottawa tracks labour utilization performance using Productive Time and Labour Allocation indicators. Productive time represents the total regular hours charged to work orders as a ratio to total regular hours worked. The objective is to maximize the time charged to work orders by identifying and improving efficiencies across the organization.

The labour allocation index represents the amount of labour spent on capital activities as a ratio to the total productive time. This measure is monitored to ensure that the appropriate amount of time is spent on capital activities versus operating and maintenance activities as per the annual work plans.

#### 2.2.3 Asset / System Operation Performance.

In order to track asset performance and efficiency, Hydro Ottawa uses a variety of metrics including:

- The contribution of defective equipment outages by asset class to overall system SAIFI per 100 customers; and
- Health, Safety and Environment metric that tracks public safety concerns and the amount of oil spilled into the environment.

Additional measures to track system operation performance include:

- Stations exceeding planning capacity;
- Feeders exceeding planning capacity; and
- System Losses

Further details on the definitions and historical performance against these metrics are included in Section 1.3 of Exhibit B-1-2(A).

Hydro Ottawa`s corporate objectives and targets outline the framework for the distribution system plan. Reliability, cost efficiency, Testing, Inspection and Maintenance programs, asset performance and system operation performance have been the main contributors to the company`s overall performance metrics. Tracking of the performance indices will allow Hydro Ottawa to set benchmarks and milestones to ensure that the company objectives of continuous improvement are achieved across all areas.

A full discussion of all of the metrics, a summary of Hydro Ottawa's performance and the effect these performance metrics have had on the Distribution System Plan is included in Section 1.3 of Exhibit B-1-2(A). Also, refer to Exhibit A-2-2 for further discussion on how Hydro Ottawa's Custom IR application aligns with the Board's expectations set out in the RRFE.

**RRFE – Measured Performance**

Finally another feature of the OEB's RRFE framework and its productivity and performance outcome expectations relates to the Board's focus on measured performance. Hydro Ottawa fulfills this requirement in three ways.

First, Hydro Ottawa completes the OEB's scorecard. The OEB scorecard allows distributors to measure their performance outcomes against their previous performance and against the industry average. The OEB scorecard was introduced in 2013 by the Board in the RRFE and is a compilation of twenty performance measures within nine performance categories and four performance outcomes. Many of the measures captured in the OEB scorecard were formally reported in the annual Reporting & Record

Keeping Requirements (RRR). Measures are added to the OEB scorecard or refined as deemed appropriate by the OEB in consultation with the industry. Like other distributors, Hydro Ottawa reports annually.

Second and as noted above, Hydro Ottawa has set out a number of new performance measurement metrics in section 1.3 of Exhibit B-1-2(A). These metrics principally relate to asset performance and system operation performance, testing inspection and maintenance that have downstream impacts on reliability and cost efficiency. Tracking of the performance indices allows Hydro Ottawa to set benchmarks and milestones to ensure that the company objectives of continuous improvement are achieved across all areas.

Third, Hydro Ottawa has developed its own Corporate Productivity Scorecard wherein it has established corporately relevant key performance indicators ("KPIs") that it monitors for the purpose of measuring continuous improvement in areas that are of internal or strategic concern to the company. A copy of Hydro Ottawa's Corporate Productivity Scorecard is available as Attachment 1 to Exhibit D-1-4.

## 3.0 Hydro Ottawa's fulfillment of the OEB's Benchmarking Expectations

According to Table 1 on page 13 of the RRFE, the role of benchmarking in a Custom IR application is to assess the reasonableness of the distributor's forecasts. In a fourth generation IR application it would be utilized to assess reasonableness of forecasts "and" assign a stretch factor.

On November 21, 2013 the Board issued its Report of the Board entitled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379). In that report, the Board determined that distributors will be assigned to one of five groups with stretch factors based on their efficiency as determined through an econometric total cost benchmarking model.

Furthermore, the Board determined that the approach would be based on a distributor's actual costs relative to its predicted costs as estimated by the benchmarking model.

To fulfill the OEB's expectations related to benchmarking Hydro Ottawa engaged Power System Engineering ("PSE") to conduct an econometric benchmarking study of Hydro Ottawa's past and projected total cost performance and its historical reliability performance. The benchmarking study provided by PSE analyzes Hydro Ottawa's historical cost and reliability data against a data set of comparable U.S. distributors. PSE concludes that Hydro Ottawa was a statistically superior utility from a cost performance during the 2011-2013 period and that the projected cost levels for the Custom IR period remain below the benchmark prediction allowing it to remain a statistically superior cost performer. A copy of the PSE study is available in Exhibit D-1-5, Attachment A.

Power System Engineering, Inc.

Full-service consultants

# Econometric Benchmarking of Hydro Ottawa's Historical and Projected Total Cost and Reliability Levels

**Prepared by:**

Power System Engineering, Inc.

April 27, 2015

# Econometric Benchmarking of Hydro Ottawa's Historical and Projected Total Cost and Reliability Levels

for

Hydro Ottawa Limited

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# 1 Executive Summary

On October 18, 2012 the Ontario Energy Board ("the Board") released a report entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" ("RRFE"). In the RRFE, three rate-setting methods were discussed. One of those methods was labeled "custom incentive regulation," or "Custom IR."

On page 18 of the RRFE, the Board states that "[i]n the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes." The RRFE also lays out the use of benchmarking as a key element used to inform the Board of the reasonableness of the revenue forecasts.[1]

In a November 21, 2013 report from the Board, titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" ("November 2013 Board Report"),[2] the Board indicates its preference for econometric benchmarking over peer group benchmarking. Furthermore, the Board indicates its preference for total cost benchmarking over partial cost benchmarking.[3]

Power System Engineering, Inc. ("PSE") was asked by Hydro Ottawa Limited ("Hydro Ottawa") to conduct an econometric benchmarking study of: (1) Hydro Ottawa's past and projected total cost performance, and (2) its historical reliability performance, in reference to the utility's 2016-2020 Custom IR application. Hydro Ottawa asked PSE to conduct this research using similar methods to those used in PSE's benchmarking research conducted within the recent Toronto Hydro Custom IR application.[4] [5]

We started our study for Hydro Ottawa by using PSE's latest total cost benchmarking research within the Toronto Hydro proceeding (as found in the "PSE Reply" report in Case EB-2014-0116). For the Hydro Ottawa total cost study, PSE followed the Toronto Hydro total cost benchmarking analysis, with the following three changes:

- Added high voltage expenses into Hydro Ottawa's total cost definition,
- Updated the forecasted input prices for the projected years of the sample, and
- Expanded the data to include 2013.

[1] Found in "Table 1: Rate-Setting Overview – Elements of Three Methods," on page 13 of the RRFE.

[2] Case EB-2010-0379.

[3] See page 19 of the November 2013 Board Report.

[4] EB-2014-0116

[5] On April 27, 2015 PSE was requested by the client, Hydro Ottawa, to undertake an empirical analysis of the productivity influence of a high prevalence of extreme temperatures. PSE will undertake the analysis and update the benchmarking study, if appropriate, at a later date.

For Hydro Ottawa's reliability benchmark analysis, PSE used U.S. and Hydro Ottawa reliability indexes that exclude major event days. Excluding major event days eliminates extreme weather events that can distort data. This exclusion meant that the models used for Hydro Ottawa's reliability benchmarking differed from those used for the Toronto Hydro reliability benchmarking.

## 1.1 Overview of PSE's Benchmarking Process

The purpose of PSE's benchmarking analysis is to evaluate the reasonableness of Hydro Ottawa's historical and projected total cost amounts and the historical system reliability metrics of the company. This is done by comparing Hydro Ottawa's actual or projected values with the benchmarking model's predicted values.[6]

The benchmarking analysis uses historical cost and reliability data from a U.S. dataset comprised of multiple utilities to create a model; this model relates cost and reliability to certain variables. The model is then used to predict Hydro Ottawa's "expected" (benchmarked) cost and reliability. A dataset which includes U.S. observations is required for an accurate benchmark assessment of Hydro Ottawa's performance. This is due to Hydro Ottawa's large number of customers relative to an Ontario-only dataset joined with its unique combination of serving both developed and rural areas. The general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as customer levels, weather, wage levels, etc.
2. Using the historical data, PSE estimated an econometric model that expresses the relationship between the variables and cost or reliability.
3. For each utility in the sample, we can then produce "benchmark" values. In Hydro Ottawa's case, the benchmarks represent the costs or reliability we would expect for an average-performing utility with the number of customers, weather, wage levels, etc. faced by Hydro Ottawa.
4. We then compare the costs or reliability that are expected (predicted) by the model to Hydro Ottawa's historical and projected costs or historical reliability, which allows us to: (1) evaluate the historical cost and reliability performance, and (2) determine whether forecasted costs are reasonable.

## 1.2 Total Cost Benchmark Findings

As stated earlier, the RRFE requests that distributors include benchmarking research of revenue forecasts in their Custom IR applications. In the November 2013 Board Report, the Board cites total cost econometric benchmarking as its preferred method for setting stretch factors.

PSE believes the Board's preference for total cost econometric benchmarking is the correct

[6] In this paper we will use "forecasted" or "projected" costs to refer to Hydro Ottawa's estimates of those values in the future, and "predicted" or "expected" or "benchmark" costs and reliability to refer to the econometric model's outputs for those metrics.

approach when benchmarking cost levels. Total costs are defined as the sum of (1) OM&A expenses, and (2) the depreciation and opportunity costs of capital. This is quite similar to how revenue requirements are calculated, and so total costs are somewhat analogous to the distribution portion of revenue requirements.[7] Partial cost benchmarking approaches, such as OM&A benchmarking, exclude large swaths of cost, which can skew performance evaluations.

PSE also endorses econometric benchmarking because of its increased accuracy relative to peer group approaches. The econometric benchmarking method contains the ability to statistically test included variables and results, includes a relatively large number of variables that enter the analysis, and does not require the researcher to choose a peer group or exclude large portions of the available data.

For the present study PSE used a total cost econometric benchmarking model to benchmark Hydro Ottawa's historical costs and its projected total costs throughout the Custom IR period (2016 to 2020). PSE first derived an econometric model from the historical dataset. Using that model and its parameter values, we then calculated total cost benchmarks. For past years, we used historical variables to calculate the benchmarks. For 2014 to 2020 benchmarks, we used Hydro Ottawa projections for the variables that enter the model.

Our total cost econometric benchmarking results indicate the following findings.

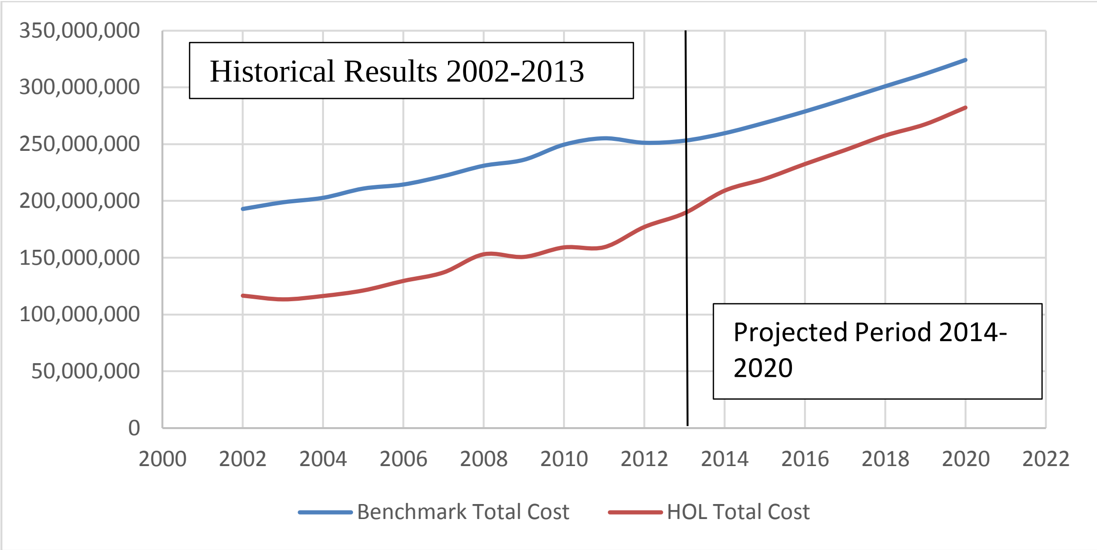
1. The historical 2011-2013 average total cost levels of Hydro Ottawa are below benchmark expectations by 37%, indicating statistically superior cost performance at a 90% confidence level.

2. The projected total cost levels during the Custom IR period remain below the benchmark predictions and continue to indicate statistically superior cost performance at a 90% confidence level.

The following graph illustrates the historical and projected benchmarked costs and company costs for Hydro Ottawa. Hydro Ottawa's historical costs are below what the model predicts for them, and its projected costs remain below what the model predicts.

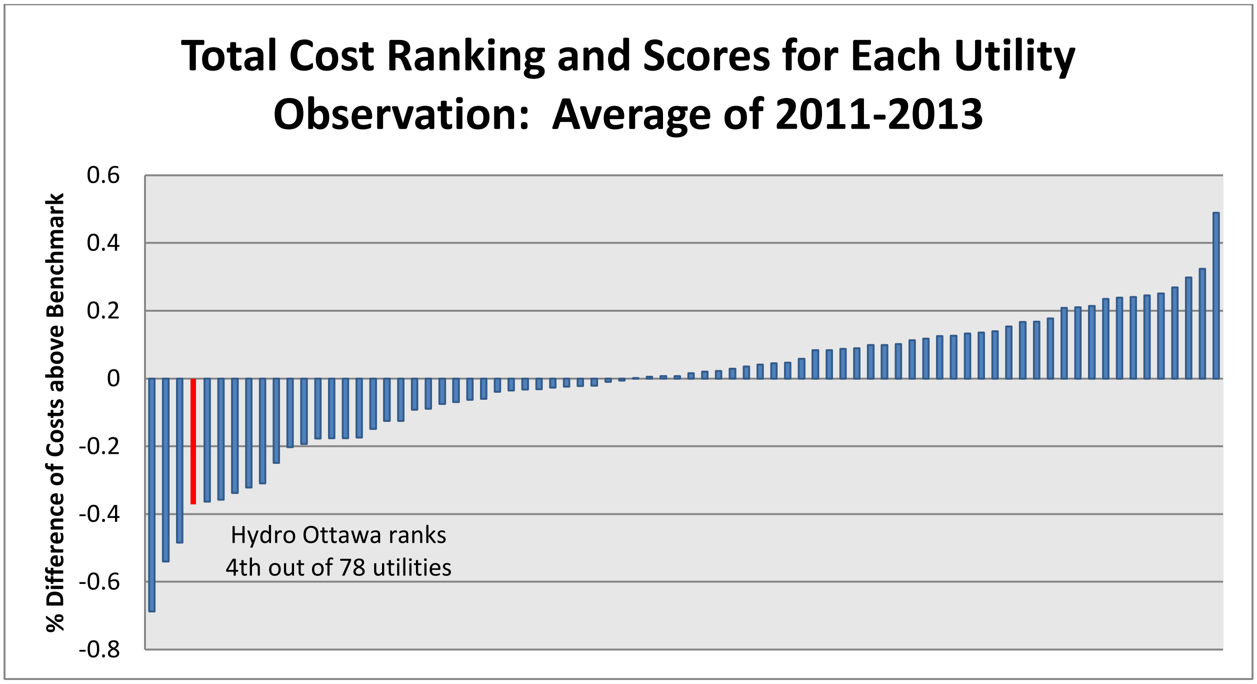
[7] Total costs are not <u>exactly</u> analogous to revenue requirements because of the generalizations needed to offer a fair analysis between utilities with varying depreciation rates, rate of returns, capital addition patterns, and cost definitions.

**Figure 1-1 Historical and Projected Total Costs vs. Benchmarked Costs**




Over the last three historical years (2011-2013), Hydro Ottawa's total cost performance score ranks 4th out of the 78 utilities in the sample. The performance scores are ranked on the figure below, with Hydro Ottawa's score colored in red.

**Figure 1-2 Total Cost Ranking for Sample Utilities**




## 1.3 Reliability Benchmark Findings

In addition to total cost benchmarking, PSE conducted econometric reliability benchmarking of Hydro Ottawa's system average interruption frequency index ("SAIFI") and system average interruption duration index ("SAIDI"). The reliability study benchmarks Hydro Ottawa's historical

(2005-2014) data after major event day ("MED") exclusions are made. The reliability benchmarking used a U.S. data set comprised of 57 utilities, who are also included in the total cost benchmarking data.

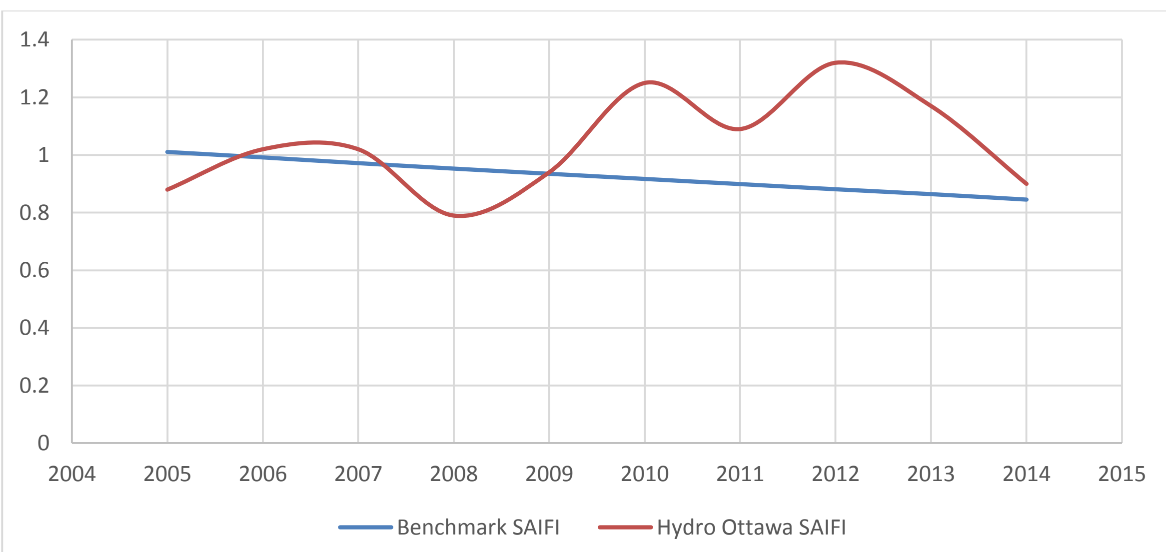
When Ontario distributors report SAIFI and SAIDI to the Board, they include all outages regardless of the cause and concentration of interruptions. In many jurisdictions throughout North America, on the other hand, utilities report SAIFI and SAIDI on a weather-normalized basis. They do this by excluding MEDs from the calculation of the metrics, which permits them to gauge reliability performance during more normal operating conditions. In order to compare reliability performance on an equal footing absent the influence of large storm events, PSE used data from U.S. utilities that excluded MED outages in their reliability metrics and requested this same data from Hydro Ottawa.[8]

PSE gathered U.S. data on utilities' normalized reliability indexes and their MED definitions from publicly-available regulatory filings. The collected data has been verified and can be sourced. PSE's reliability benchmarking analysis indicates the following findings.

1. 2012-2014 SAIFI metrics for Hydro Ottawa are higher than the benchmark values by 25.7%. This is not statistically significant at a 90% confidence level, although the finding is right on the border of statistical significance (p value = 0.103).
2. 2012-2014 SAIDI metrics for Hydro Ottawa are higher than benchmark values by 7.2%. This finding is not statistically significant at a 90% confidence level.

The following graph illustrates the historical SAIFI values for Hydro Ottawa (red line) against the benchmarked values (blue line).

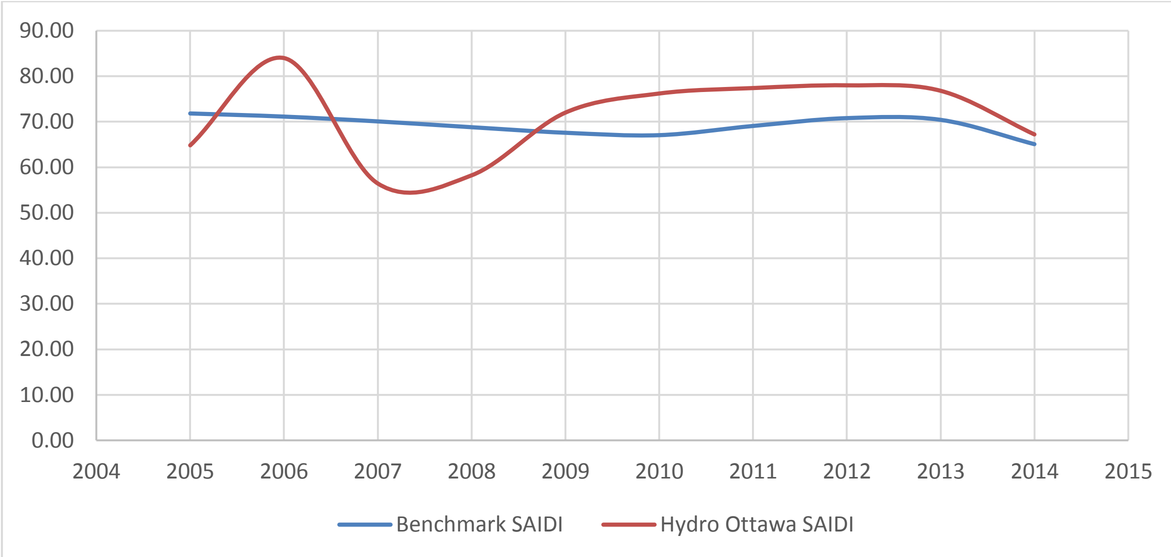
**Figure 1-3 Historical SAIFI vs. Benchmarked SAIFI**




The following graph illustrates the historical SAIDI values for Hydro Ottawa (red line) relative to the benchmark SAIDI values (blue line).

[8] PSE requested Hydro Ottawa provide PSE with reliability indexes that use the IEEE MED and 5-minute sustained outage definition. These data were calculated by Hydro Ottawa and provided to PSE.

**Figure 1-4  Historical SAIDI vs. Benchmarked SAIDI**




# 1.4 Evaluation of Hydro Ottawa's Custom IR Application

The graphs below illustrate how Hydro Ottawa's historical total cost and reliability performances relate.  Our results indicate that the company is missing its reliability benchmarks but beating the total cost benchmarks.

Figure 1-5 illustrates Hydro Ottawa's current position in regards to the balance between costs and reliability.

**Figure 1-5 Hydro Ottawa Total Cost and SAIFI Performance Position**

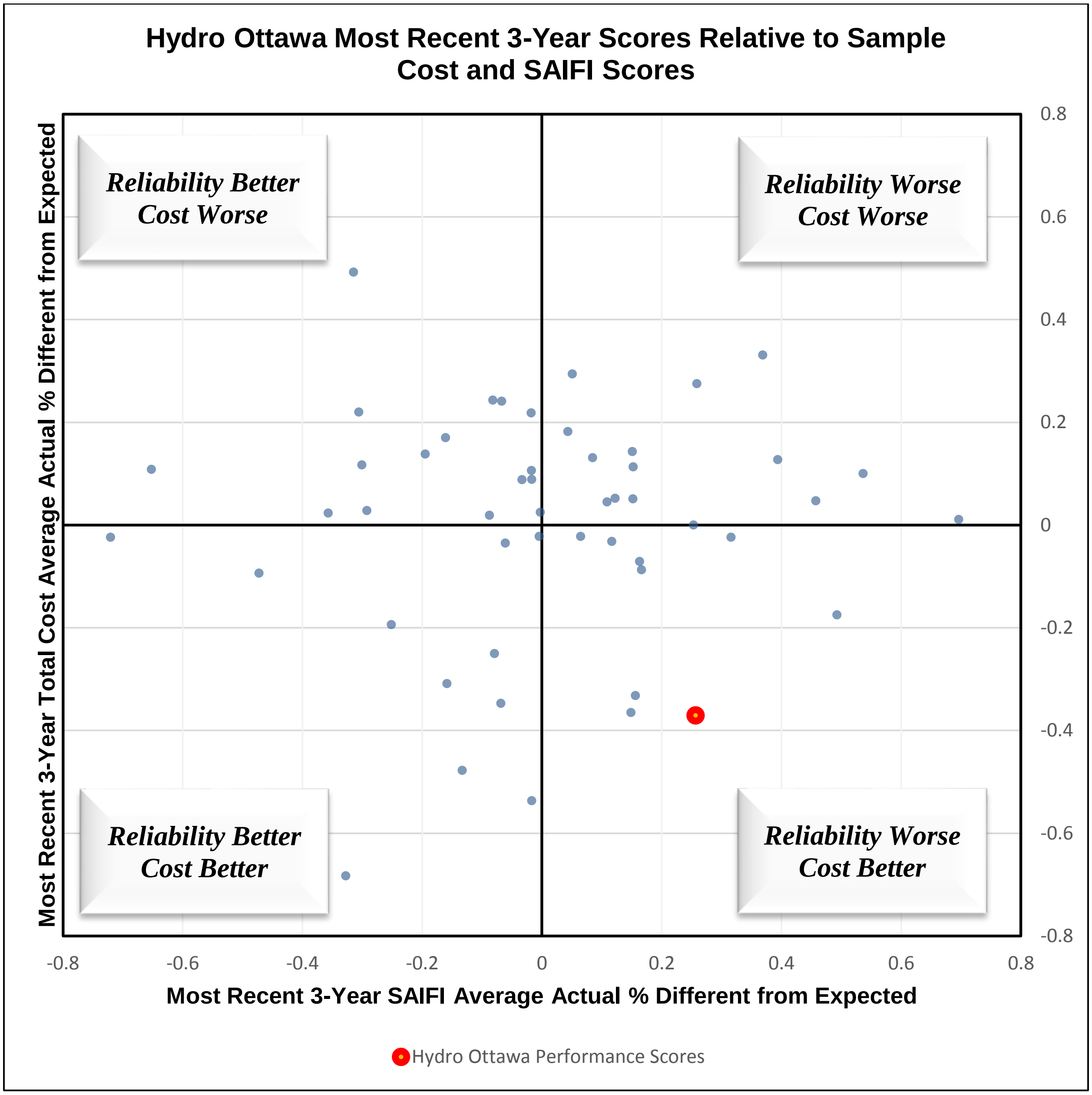
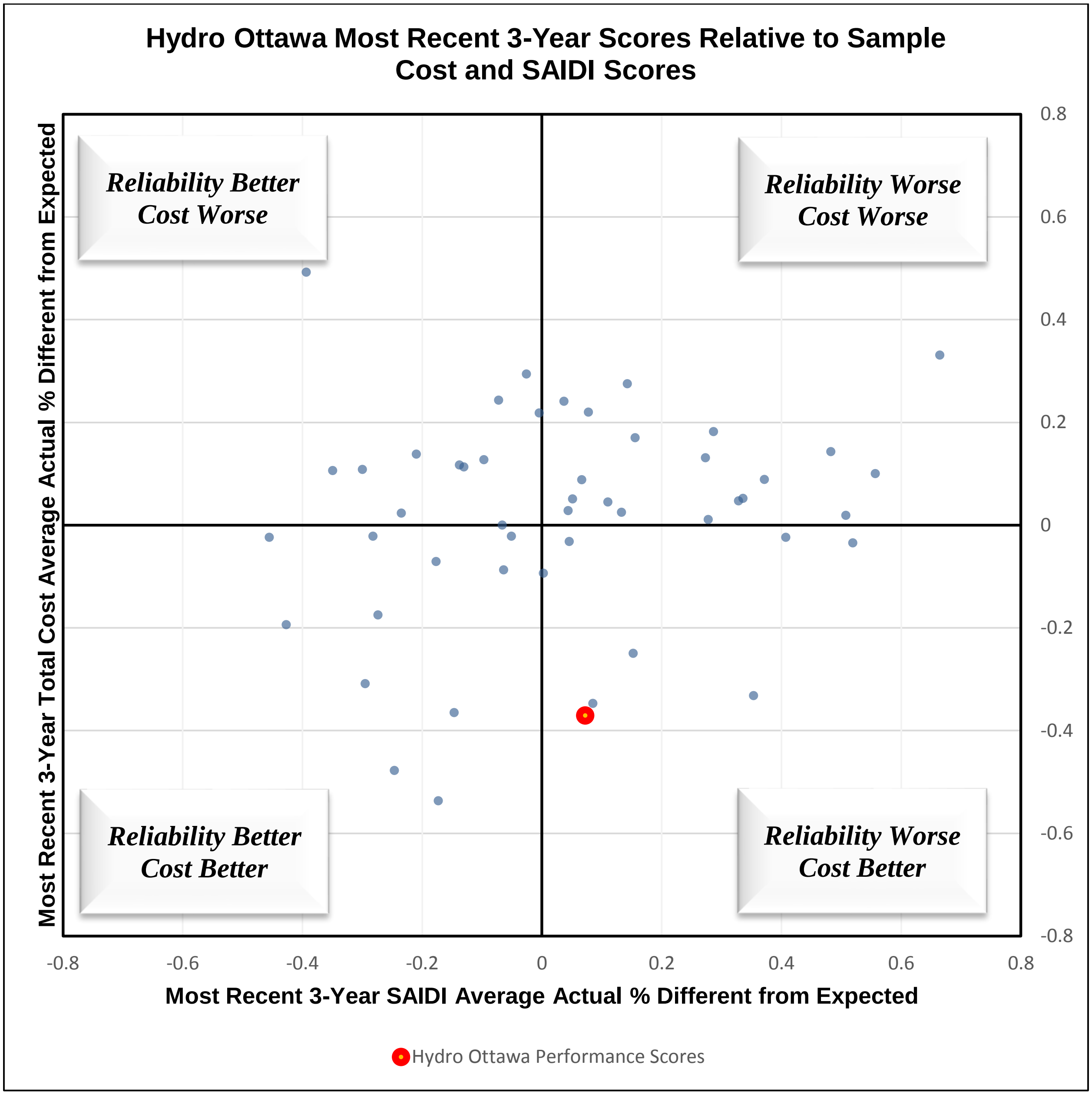


Figure 1-6 illustrates the current position of the company's SAIDI and total cost performance scores relative to the rest of the sample.

**Figure 1-6 Hydro Ottawa Total Cost and SAIDI Performance Position**



## 1.5 Custom IR Conclusions

PSE's benchmark research leads us to the following statements relating to Hydro Ottawa's Custom IR proposal:

1. Hydro Ottawa is entering the Custom IR period with strong recent cost performance (i.e., costs are below the expected values), with its average 2011 to 2013 total costs being estimated at 37.1% below benchmark values. This is statistically superior cost performance at a 90% confidence level. This performance level is commensurate with a 0.0% stretch factor (Group 1), using the 4th Generation IR criteria put forth in the November 2013 Board report. Hydro Ottawa ranks 4th out of the 78 distributors included in the sample.

2. Hydro Ottawa's Custom IR period (2016 through 2020) total cost level projections remain below benchmark expectations. By 2020, the company is estimated to still be below benchmark values by 13.9%. For the final three years of the Custom IR period, Hydro Ottawa continues to be a statistically significant superior cost performer at a 90% confidence level. This performance level indicates placing Hydro Ottawa in the 0.15% stretch factor level (Group 2).

3. The company's SAIFI for their 2012-2014 average is 25.6% above benchmark expectations. This implies Hydro Ottawa customers experience 25.6% more outages versus what the models predict. This result, in conjunction with the total cost result of low-cost performance, is suggestive of an aged infrastructure.

4. The company's SAIDI for their 2012-2014 average is 7.2% above benchmark expectations. This implies Hydro Ottawa customers experience 7.2% more outage minutes versus what the models predict. This is because of the higher than expected SAIFI value discussed in the prior conclusion.

# 2 Total Cost Benchmarking Datasets, Methods, Variable Definitions

The data for the U.S. utilities used in the study were acquired from publicly available data sources. There are 77 U.S. utilities in the sample, plus Hydro Ottawa. The utilities in the dataset along with their 2011 number of customers are provided in the table below.

**Table 2-1 Total Cost Sampled Utilities**

| Company | Number of Customers (2011) | Company | Number of Customers (2011) |
|---|---|---|---|
| Hydro Ottawa Limited | 305,266 | Louisville Gas and Electric Co | 394,063 |
| Alabama Power Co | 1,434,487 | Madison Gas and Electric Co | 141,414 |
| AmerenUE | 1,190,478 | MDU Resources Group, Inc. | 125,802 |
| Arizona Public Service Co | 1,120,236 | Metropolitan Edison Co | 552,631 |
| Atlantic City Electric Co | 547,762 | Mississippi Power Co | 185,768 |
| Appalachian Power Company | 961,129 | Monongahela Power Co | 386,819 |
| Avista Corp | 358,303 | Nevada Power Co | 838,482 |
| Baltimore Gas & Electric Co | 1,240,291 | New York State Electric & Gas Corp | 878,845 |
| Black Hills Power Inc | 68,172 | Niagara Mohawk Power Corp (National Grid) | 1,297,616 |
| Carolina Power & Light Co | 1,445,158 | Northern Indiana Public Service Co | 456,937 |
| Central Hudson Gas & Electric Corp | 274,152 | Northern States Power Co (XCEL) | 1,399,830 |
| Central Maine Power Co | 606,813 | Ohio Edison Co (First Energy) | 1,034,534 |
| Cincinnati Gas & Electric Co (Duke Energy OH) | 685,859 | Oklahoma Gas and Electric Co | 786,522 |
| Cleco Corp | 280,857 | Orange and Rockland Utilities Inc | 224,608 |
| Cleveland Electric Illuminating Co (First Energy) | 748,935 | Pacific Gas and Electric Co | 5,248,288 |
| Commonwealth Edison Co | 3,818,690 | Pennsylvania Electric Co | 589,651 |
| Connecticut Light & Power Co | 1,212,276 | Pennsylvania Power Co | 160,250 |
| Consolidated Edison Co of new York Inc | 3,329,304 | Portland General Electric Co | 823,171 |
| Consumers Energy Company | 1,788,799 | Potomac Electric Power Co | 787,137 |
| Dayton Power & Light Co | 513,539 | PP&L Inc | 1,403,889 |
| Delmarva Power & Light Co | 500,998 | PSI Energy Inc (Duke Energy IN) | 782,879 |
| Detroit Edison | 2,120,262 | Public Service Co of Colorado | 1,372,892 |
| Duke Energy Corp | 2,396,555 | Public Service Co of New Hampshire | 498,175 |
| Duquesne Light Co | 587,610 | Public Service Co of Oklahoma | 532,395 |
| El Paso Electric Co | 378,547 | Puget Sound Energy | 1,083,395 |
| Empire District Electric Co | 166,207 | Rochester Gas and Electric Corp | 367,300 |
| Entergy Arkansas Inc | 695,397 | San Diego Gas & Electric Co | 1,385,784 |
| Entergy Mississippi Inc | 438,140 | South Carolina Electric & Gas Co | 663,433 |
| Entergy new Orleans Inc | 159,431 | Southern California Edison Co | 4,921,228 |
| Florida Power & Light Co | 4,547,047 | Southern Indiana Gas and Electric Co (Vectern) | 146,136 |
| Florida Power Corp | 1,642,146 | Tampa Electric Co | 675,799 |
| Gulf Power Co | 432,401 | Tucson Electric Power Co | 403,340 |
| Idaho Power Co | 493,532 | United Illuminating Co | 323,738 |
| Indiana Michigan Power Co | 582,822 | Virginia Electric and Power Co | 2,438,226 |
| Indianapolis Power & Light Co | 468,195 | West Penn Power Co (Allegheny Power) | 717,269 |
| Jersey Central Power & Light Co | 1,099,194 | Western Massachusetts Electric Co (Northeast Utilities) | 206,279 |
| Kansas City Power & Light Co | 512,082 | Wisconsin Electric Power Co | 1,120,964 |
| Kentucky Power Co (AEP) | 173,641 | Wisconsin Power and Light Co | 458,041 |
| Kentucky Utilities Co | 540,839 | Wisconsin Public Service Co | 439,481 |

The total cost observations span the years 2002 to 2013. The large number of observations is more than sufficient for the creation of a statistically robust econometric model.

The output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

- Regional input prices,
- Percent residential deliveries,
- Percent electric customers (out of total gas and electric customers),
- A binary variable for urban population above one million,
- Percent electric distribution in total electric gross plant,
- Elevation standard deviation, and
- Forestation of the service territory.

Both OM&A and total costs used in the benchmarking models for the U.S. distributors are derived using FERC Form 1 filing data.[9] U.S. electric utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing, administrative and general). Form 1s also include plant in service and accumulated depreciation information that is used in constructing capital costs. PSE has added in all of Hydro Ottawa's CDM expenses and high voltage expenses to assure cost comparability between Hydro Ottawa and the U.S. data set.

The historical calculations for U.S. utilities' capital cost have been conducted using parallel procedures implemented by Pacific Economics Group ("PEG") in their benchmarking and productivity research of Ontario distributors found in Case EB-2010-0379 ("4$^{th}$ Generation Incentive Regulation"). Regarding Hydro Ottawa's capital cost definition, the historical data comes directly from PEG's 4$^{th}$ Generation IR dataset; projected data was provided to PSE by Hydro Ottawa. PSE has used PEG's "benchmark-based" capital cost definition found in their 4$^{th}$ Generation IR research, but has subtracted contributions in aid of construction ("CIAC") and added high voltage costs to Hydro Ottawa's data to make costs comparable to the U.S. dataset.

The OM&A cost definition used for Hydro Ottawa is used to create cost comparability with the U.S. sample. PSE began with Hydro Ottawa's benchmark-based cost definition and added in CDM expenses only for Hydro Ottawa. This was done since some of the U.S. utilities report CDM expenses within their customer service and information expenses, making CDM part of their total cost definition.[10] PSE also added Hydro Ottawa's high voltage expenses to the company's cost

[9] All FERC form data was downloaded by PSE from SNL Energy's database tool.

[10] This treatment is likely to be somewhat unfair to Hydro Ottawa since we cannot verify that all U.S. utilities report CDM expenses within customer service and information expenses. However, excluding CDM expenses would likely be advantageous to Hydro Ottawa. For this reason, PSE decided to include all of Hydro Ottawa's CDM expenses, to be conservative and to assure the results did not over-state the cost performance of the company.

definition. The FERC Form 1 does not break out high versus low voltage distribution expenses like Ontario does. For that reason, Hydro Ottawa's high voltage expenses have been added to make costs comparable. The table below summarizes the cost definition treatment.

**Table 2-2 Cost Definitions**

| Cost Element | Treatment |
|---|---|
| **4th Generation IR Benchmark-Based Costs** | Used this as a starting point for Hydro Ottawa |
| **CIAC** | Subtracted from Hydro Ottawa costs, since U.S. cost data does not include CIAC |
| **High Voltage Expenses** | Added to Hydro Ottawa costs, since U.S. cost data includes distribution high voltage costs |
| **CDM** | Added all CDM expenses to Hydro Ottawa costs, since some U.S. cost data includes CDM expenses |

For U.S. utilities, the output variables are calculated from FERC Form 1s and Platts UDI directories.[11] The historical output data for Hydro Ottawa comes from the Board's fourth generation incentive regulation data. Hydro Ottawa's projected outputs comes from forecasts provided to PSE by Hydro Ottawa.

Input prices are divided into two categories: capital and OM&A. The capital input price calculation is discussed in detail in the following section. The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro Ottawa, we gathered job occupation wage estimates from Statistics Canada, using wage data from Ottawa, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Hydro Ottawa regarding labour input prices and also puts the input price in terms of each country's currency. We then escalated labour prices for U.S. utilities using BLS employment cost indexes for the utility sector and escalated Hydro Ottawa prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the gross domestic product price index (GDP-PI) for the U.S. utilities. The Ontario non-labour component uses the same GDP-PI in each year, but adjusted for the purchasing power parity ("PPP") index. This translates the non-labour input price component into Canadian dollars. To construct the overall OM&A input price we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting

[11] We gathered data from annual editions of Platts, "UDI Directory of Electric Power Producers and Distributors" starting in 2003 through 2013.

used by PEG in their benchmarking research.

The “residential percentage of sales volume” variable is calculated based on data from FERC Form 1 (for U.S. utilities) and the Board’s 4th Generation Incentive Regulation data (for Hydro Ottawa). The percentage of residential volume compared to total volume is a proxy for the variance in electricity loads. Commercial and industrial customer loads tend to be more level across hours of the day. As the proportion of residential volume increases, distribution systems tend to increase their system peaks and load variability. This results in higher volatility in the loads served by the system.

The variable that measures the percentage of electric customers out of total gas and electric customers is derived from both FERC Form 1 data and FERC Form 2 data. The FERC Form 2 data includes the number of gas customers served by a natural gas distributor. This variable measures the economies of scope available from serving both electric and gas customers. The value is set to 100% for Hydro Ottawa, since the company does not serve natural gas customers.

The urban core variable used in the total cost benchmarking models is a “binary” or “indicator” variable. This variable provides key information on the added costs of serving electricity to a highly urban area. All utilities are given a value of zero unless they serve the urban core of a city whose population is above one million (U.S. cities are designated by the 2010 U.S. census). Hydro Ottawa’s value is set to “0” for this variable, since Ottawa’s city population does not exceed one million.[12]

The percentage of electric distribution plant in total distribution plant measures the available economies of scope that result from being a vertically integrated utility, as opposed to a distribution-only utility. We expect distribution unit costs to be lower for utilities that also have transmission and generation activities. For U.S. utilities, data for this variable is found from the utilities’ FERC Form 1s. The value is set to 100% for Hydro Ottawa, since the company does not have transmission or generation assets.

The percentage of forestation variable is based on GIS (geographic information system) forestation maps. Such maps are matched with the areas served by each utility to create the variable. We would expect that the higher the level of forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Hydro Ottawa.

The elevation standard deviation variable is computed using GIS maps of elevation in each utility’s service territory. The variability of elevation levels poses both construction and maintenance challenges for local delivery systems. We capture this difficulty by computing the standard deviation of the elevation levels obtained from GIS maps.

## 2.1 Perpetual Inventory Capital Cost Method

This report evaluates Hydro Ottawa’s capital costs as a component of the total cost definition. PSE’s measure of capital cost is based on a service price approach. This approach has a solid basis

[12] According to Statistics Canada, Ottawa’s 2011 city population was 883,391.

in economic theory, and is the same method chosen by PEG in their 4th Generation IR research.[13] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period $t$ is the product of indices of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period $t$, $CK_t$ is the cost of capital, $WKS_t$ is the capital service price index, and $XK_{t-1}$ is the capital quantity index value at the start of the period.

The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year, and on gross plant additions in subsequent years. It also uses an assumption about service lives. For the sake of consistency, we use 1989 as the benchmark year in the current study, based on PEG's prior decision in their 4th Generation IR benchmarking work. We use 1989 for all U.S. sampled utilities. Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 1989. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. For consistency, the plant additions have been calculated using PEG's methodology found in their 4th Generation IR research. This method is used both for Hydro Ottawa and U.S. distributors. The formulas for the capital quantity index in 1989 and in subsequent years are provided below.

$$XK^i_{1989} = \frac{Net\ Plant^i_{1989}}{TWA^i_{1989}}$$

$$XK^i_t = XK^i_{t-1} * d + \frac{Add^i_t}{WKA^i_t}$$

$$Add_t = (Gross\ Plant_t - Gross\ Plant_{t-1}) + .005 * Gross\ Plant_{t-1}$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, $r_t$ is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital

[13] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

costs, so that decisions by regulators do not enter into the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter $d_t$ is the economic depreciation rate. We use the same value as PEG did, 4.59%, for this parameter in the study.

The variable that the capital service price components have in common is $WKA_t$. This is an index of the price of capital assets used in power distribution. We compute this index using data on differences in the cost of constructing utility plant between regions, and within regions over time. In particular for U.S. distributors, we use the Handy-Whitman indexes for total power distribution plant, which vary over time and across six geographic regions. For Hydro Ottawa, we use the annual Electric Utility Construction Price Index ("EUCPI") for the historical data and Conference Board of Canada forecasts of construction costs for future years.

We determine the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*.[14] These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for both U.S. and Hydro Ottawa. The index is already adjusted for currency differences between the two countries.

[14] RS Means (2011).

## 2.2 Econometric Method

The benchmarking approach used in this report is the econometric approach. PSE believes this is the most accurate and fair method to use when comparing utility cost and reliability levels. It is also the same method preferred by the Board in the November 2013 Board Report.

The econometric approach explicitly adjusts for differences in utilities' service territories. In the power distribution industry, simple rate or reliability index comparisons do not provide appropriate benchmarks when evaluating performance. Uncontrollable factors influence attainable levels of total costs; such factors include geographical size, level of forestation, regional wage levels, mix of consumer classes, or serving an urban core. Therefore, more sophisticated tools that normalize for specific influencing factors must be employed to accurately assess performance. With this concept in mind, PSE has developed econometric benchmarking models that take into account factors that have proven to be statistically influential on distribution utility costs and reliability indexes.

The econometric benchmarking approach relies on comparisons between observed data values to the predicted values obtained from regressions. The researcher determines an appropriate functional form for the relationship between the studied metric and factors that influence it, and develops appropriate econometric methods for obtaining good parameter estimates of the specified model. In this report, we estimate the "translog cost function." The translog cost function is well established in academic literature and provides a high level of flexibility in estimating costs. This is also the same functional form preferred by the Board in the 4th Generation IR proceeding.

Cost predictions for each firm are obtained by inserting company-specific variable values into the estimated equation. Performance is defined as the percentage difference of the observed data to the predicted value of the data, as shown below.

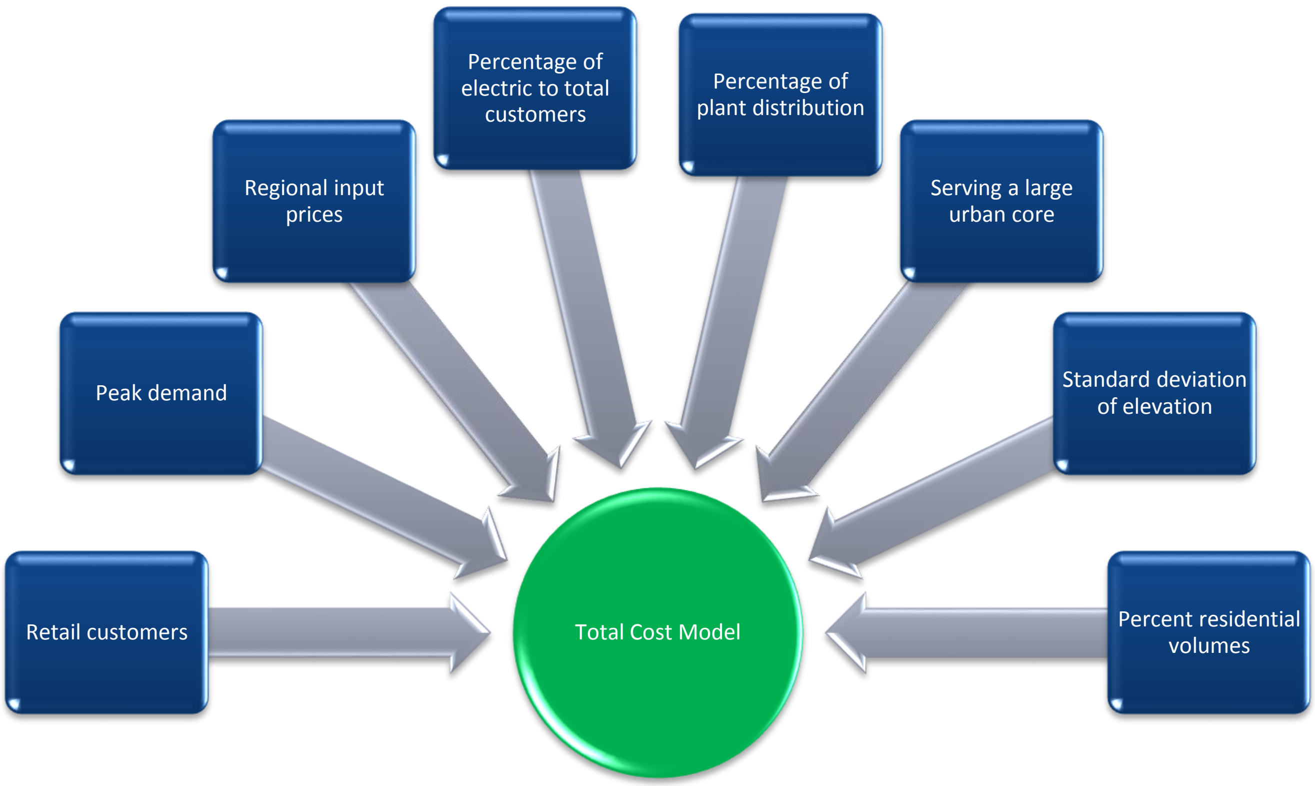
$$Performance = \ln\left(\frac{Observed\ or\ Projected\ Cost\ Data}{Predicted\ Cost\ Data}\right)$$

> <u>NOTE:</u> The term "ln" above denotes the natural log. The formula above is the calculation for log arithmetically calculating percentage differences. It is typically used by both PSE and PEG to display benchmark scores.

### 2.2.1 Variables Used

The variables included in the combined total cost analysis are shown in the figure below.

**Figure 2-1 Variables in Econometric Cost Models**




A diverse dataset which includes utilities with varying operational conditions is necessary to determine the influence on costs and reliability resulting from those conditions. There are many U.S. utilities which are either larger or smaller than Hydro Ottawa. This is in contrast to an Ontario-only dataset, where Hydro Ottawa tends to be an outlier due to its size. Due to this outlier status within the Ontario dataset, PSE considers the U.S.-only benchmarking results to be more robust in revealing the cost and reliability performance of the company, relative to an Ontario-only sample.

The specification used in the cost models includes three types of variables: outputs, input prices, and business condition variables. Outputs are defined as the "work" that the utility is doing. We defined two variables as outputs: the number of retail customers served and peak demand.

The input prices are defined as the external market price for operation, maintenance, and administration (OM&A) expenses and capital service costs. The market prices for labour and capital will vary depending on the geographic location of each sampled utility. The business condition variables are the other service territory characteristics that statistically influence total cost levels. Examples of business condition variables are serving an urban core, percentage of electric customers in total customers, percentage of forestation, etc.

### 2.2.2 Estimation Procedure and Translog Cost Function

As a starting point, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers," can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely outside the control of a firm's managers. On the other hand, the number of employees hired are within management's control, and thus cannot serve as an independent variable.

In general, cost is assumed to be a function of input prices, the output produced by the firm, and other independent variables that affect cost but are outside management's control. While a function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = \beta_o + \beta_1 * Y + \beta_2 * P + \varepsilon$$

In this equation, the terms C, Y, and P denote cost, output, and input prices, respectively. The $\beta$ terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost, and the error term captures random noise. The latter is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2002 and extending to 2013. Additionally, we included Hydro Ottawa's cost projections through 2020, allowing us to also benchmark those forecasts "out of sample". We use the model that is based on historical data and apply the estimated coefficients and projected independent variable values for Hydro Ottawa to calculate a predicted benchmark value. This predicted benchmark value is then compared to Hydro Ottawa's projected total cost amount.

A cost function can be specified as a single equation or a system of equations to get parameter estimates. A single equation model is specified as noted above. A system of equations results from applying economic theory that permits the derivation of cost share equations that are estimated along with the cost function to obtain more precise parameter estimates. The estimation procedure used for the total cost studies incorporates a system of equations that are based on the cost shares of OM&A and capital costs. This produces more precise estimates and benchmark results. The reliability benchmarking exercise uses a single equation model only.

### *2.2.2.1 Statistical Tests*

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would "expect" to see costs rise as the number of customers served increases (i.e. the customer parameter would be positively signed).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than did a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

### *2.2.2.2 Model Specification*

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form chosen by PEG in their 4th Generation Incentive Regulation benchmarking research and the same one preferred by the Board in the November 2013 Board Report. Its general form, after suppressing time and firm subscripts, is given by:

$$\ln C = \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \beta_j \ln W_j + \sum_h \gamma_h \ln Z_h + \frac{1}{2}\left[\sum_i \sum_k \alpha_{ik} \ln Y_i \ln Y_k + \sum_j \sum_n \beta_{jn} \ln W_j \ln W_n\right] + \sum_i \sum_j \alpha_{ij} \ln Y_i \ln W_j + \alpha_t t + \varepsilon$$

In this specification, $\alpha's$ and $\beta's$ are model parameters, and $\varepsilon$ is the random noise term. In addition, $Y_i$ quantifies output, $W_j$ input prices, $Z_h$ other business condition variables, and *t* is a time trend term. This form has been widely used in cost function research.[15] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[16]

We also note several theoretical assumptions that aid in model specification and estimation. Among these is the idea that if all input prices rise, cost also rises proportionally. This is known as linear homogeneity, and it allows the restriction that the sum of input price parameters equals one. An additional restriction is symmetry in the parameters of the price interaction terms. In addition, we use Shepherd's lemma to derive cost share equations that we estimate jointly with the cost function. The general form of the cost share equation for input *j* is given by:

$$S_j = \beta_j + \sum_i \alpha_{ij} \ln Y_i + \sum_n \beta_{jn} \ln W_n + \upsilon_j$$

For the reliability models, we also specify quadratic models that include first-order explanatory terms and their squared counterparts. These models are specified as single equation models. The following presents the general form the reliability models take. Both the SAIDI and the SAIFI models are constructed in the same manner. We illustrate the basic form of the SAIDI model below.

$$SAIDI_j = \beta_o + \sum_i \alpha_i \ln X_i + \sum_i \beta_{ii} \ln X_i * \ln X_{\mathrm{i}} + \alpha_t t + \varepsilon$$

*2.2.2.3 Estimation Approach*

One of the reasons for joint estimation of cost and cost share model parameters is that there is contemporaneous correlation between the error terms in these systems of equations. Such correlation allows the use of a system of regression equations that result in more efficient (precise) estimates. In this study, the systems estimator we use is Feasible Generalized Least Squares ("FGLS").

In particular, PSE uses an iterative FGLS procedure that estimates the unknown error matrix consistently.[17] The estimates we compute are equivalent to Maximum Likelihood Estimates ("MLEs").[18] Our estimates thus possess all the desirable properties of MLEs, which include consistency and efficiency. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and is dropped. This does not pose a problem, since yet another property of the MLE procedure is that it is invariant to any such parameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

The single equation model is estimated using generalized least squares (GLS) in order to correct for cross-sectional heteroskedasticity and autocorrelation. The parameter estimates that result from

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[15] In their Monte Carlo studies of functional forms' performance, Gagne and Ouellette (1998) use the translog as a benchmark because "it is the most widely used" functional form.

[16] See Guilkey, et al. (1983)

[17] See Zellner, A. (1962).

[18] See Dhrymes, P.J. (1971), Oberhofer, W. and J. Kmenta (1974) and Magnus, J.R. (1978).

this procedure are both consistent and efficient.

## 2.3 Benchmarks for Future Years

The same econometric model and its associated parameter values that are estimated using historical data (and used to develop Hydro Ottawa's historical benchmarks) are also used to calculate the company's benchmarks for future years. These parameter values are combined with projected variable values to calculate the expected total costs of Hydro Ottawa in the future years of the Custom IR period.

This procedure assumes that future total costs will be influenced by the independent variables in the same way that historical costs have been estimated to be influenced by the independent variables. Absent robust projected costs from a large sample of utilities, PSE is of the opinion that using the historical relationships between variables found to be statistically significant in the models is the best and most straightforward way of benchmarking future total cost levels.

PSE was provided OM&A expense, plant addition, reliability, customer counts, and demand projections from Hydro Ottawa. We then inserted these projections in each future year into the estimated econometric model.

Input prices need to also be projected into the future years. For the labour and non-labour components of the OM&A input price, PSE used price forecasts of the GDP-IPI and Ontario weekly average earnings from the Conference Board of Canada. The forecasts only go to 2019, so for the 2020 observation we used the 2019 growth rate and applied that same growth rate to 2020. We used the Implicit Price Index of Gross Fixed Capital Formation, Engineering Structures Electric Power Generation, Transmission, and Distribution (Canada) for the future-year capital construction cost estimates.[19]

Other projected variables that enter the models include percent residential, urban core, electric customers in gas and electric operations, electric distribution plant as a % of total electric gross plant, percent forestation, and the elevation standard deviation. Since these variables are not likely to meaningfully change over time, they were set at their most recently available historical value for the future years.

[19] These are the same escalators used by PEG in their benchmarking report prepared for Oshawa PUC Network's Custom IR application dated December 18, 2014.

# 3 Total Cost Benchmarking Results

The estimates from the total cost model are presented in Table 3-1. We note that the cost function parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant.

**Table 3-1 Total Cost Model Estimates**

| | |
|---|---|
| K= | Capital Price |
| N= | Number Retail Customers |
| D= | Peak Demand |
| F= | Percent Forestation |
| R= | Percent Residential Delivered |
| E= | Percent Electric Customers |
| Dx= | Percent Distribution in Total Electric |
| Esd= | Std. deviation of elevation |
| U= | Urban Core |

| EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T STATISTIC | EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T STATISTIC |
|---|---|---|---|---|---|
| K | 0.572 | 153.377 | E | 0.194 | 7.841 |
| KK | 0.061 | 3.451 | | | |
| KN | -0.057 | -4.985 | Dx | 0.084 | 4.817 |
| KD | 0.060 | 5.126 | | | |
| | | | Esd | 0.011 | 1.857 |
| N | 0.803 | 30.880 | | | |
| NN | 0.574 | 6.421 | U | 0.014 | 6.392 |
| ND | -0.476 | -5.220 | | | |
| | | | Trend | 0.002 | 1.585 |
| D | 0.170 | 6.479 | | | |
| DD | 0.447 | 4.517 | Constant | 20.086 | 1492.238 |
| F | 0.016 | 3.041 | System Rbar-Squared | 0.961 | |
| R | 0.044 | 2.253 | Sample Period: | 2002-2013 | |
| | | | Number of Observations | 881 | |

Total cost increases with higher capital prices and output quantities. At the sample mean, a 1% increase in the number of customers (N on the table) and peak demand (D) are estimated to raise cost by 0.803% and 0.170%, respectively. The number of customers served is the dominant output-related cost driver, which is an expected result for an electric distribution total cost model. Input prices also will increase total costs. Holding the effect of all other variables constant, we find that a 1% increase in the price of capital (K) raises cost by 0.572%. This is higher than the elasticity of the price of the OM&A input, which is about 0.428% (based on linear homogeneity, the OM&A input price estimate is predetermined to be one minus the capital price estimate). The estimates reflect the capital intensiveness of the power distribution business.

The business condition coefficients are also signed as our hypothesis would suggest. All business condition variables are plausibly signed and statistically significant at a 90% confidence level. The estimate of the trend variable parameter is 0.2%. This suggests a modest upward shift in cost over time. This econometric trend indicates a modest negative productivity trend for the U.S. electric distribution industry.

The next table presents the Hydro Ottawa benchmark results for an average of the 2011 to 2013 years.

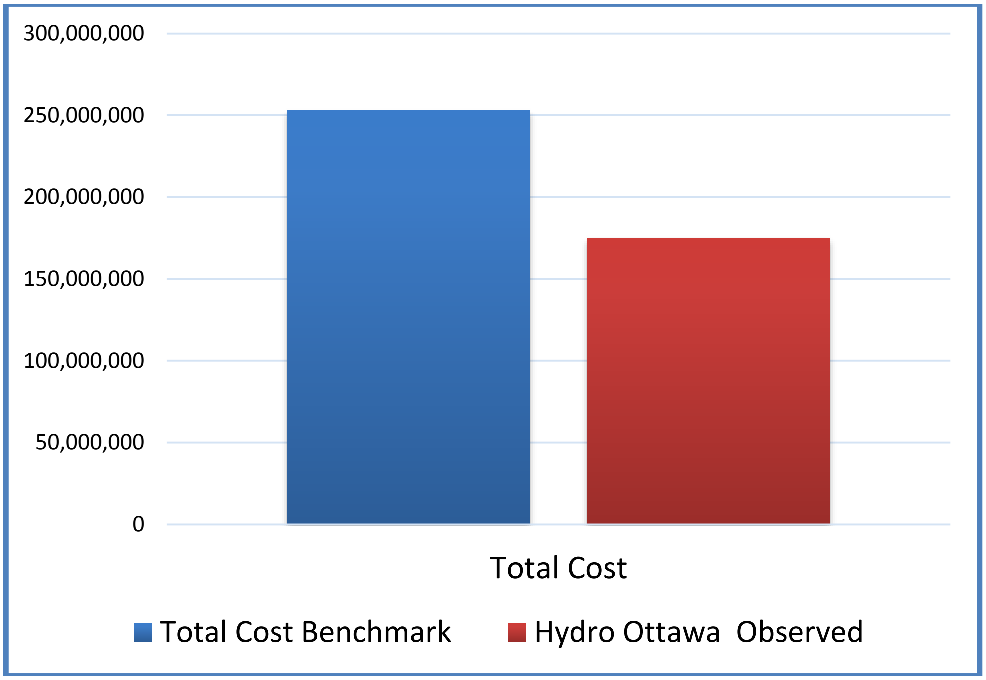
**Table 3-2 Average 2011-2013 Hydro Ottawa Total Cost Benchmark Results**

| Year | Actual | Predicted | % Difference | P-Value |
|---|---|---|---|---|
| **Average 2011-2013** | $175.1 Million | $253.1 Million | -37.1% | 0.001 |

Actual cost is below the predicted or benchmark value by about 37 percent. This is a statistically significant difference with a 90 percent degree of confidence, and shows that when benchmarked relative to the power distributors of the U.S., Hydro Ottawa has a statistically significantly superior total cost performance.

Put into dollar terms, the 2011-2013 average total costs of Hydro Ottawa were expected to be $253.1 million, but were actually $175.1 million. This is $78.0 million per year below the benchmark expectation over the 2011-2013 period. This result is illustrated in the figure below.

**Figure 3-1 2011-2013 Benchmarked Total Costs vs. Actual Costs (3-Year Average)**




The following table breaks down the historical and forecast year benchmark and company total costs from 2002 to 2015, and then during the Custom IR period of 2016 to 2020. During the historical period Hydro Ottawa has consistently been below its expected benchmark levels. In the second column, the percent below benchmark is illustrated.

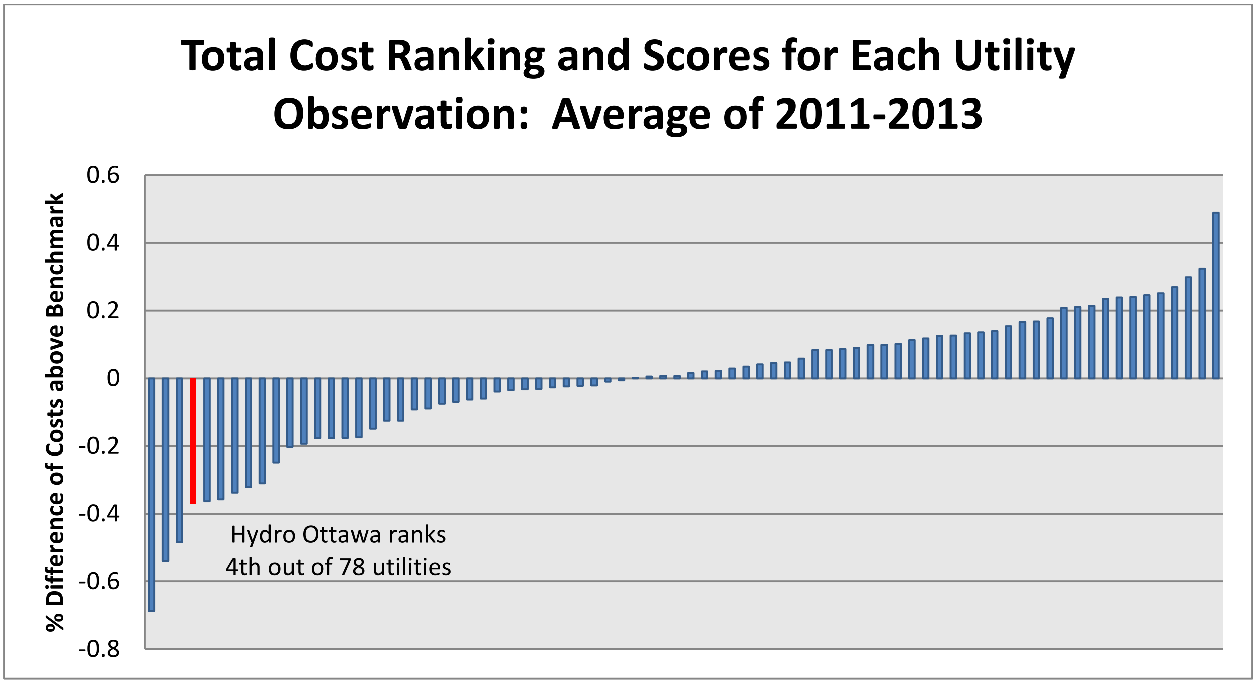
The company's Custom IR forecasts for OM&A and capital spending keep the company below benchmark levels, although not by as much as in the historical years. Nevertheless, they indicate that the company's proposed spending levels are reasonable and below model benchmark expectations.

**Table 3-3 2002-2020 Benchmark Total Costs vs. Historical and Projected**

| Year | Percent Below Combined Sample Total Cost Econometric Benchmark | Total Cost Econometric Benchmark, $M | Total Cost Hydro Ottawa, $M |
|---|---|---|---|
| 2002 | 50% | $193 | $117 |
| 2003 | 56% | $199 | $113 |
| 2004 | 56% | $203 | $116 |
| 2005 | 55% | $211 | $121 |
| 2006 | 50% | $214 | $129 |
| 2007 | 48% | $222 | $137 |
| 2008 | 41% | $231 | $153 |
| 2009 | 45% | $236 | $151 |
| 2010 | 45% | $249 | $159 |
| 2011 | 47% | $255 | $159 |
| 2012 | 35% | $251 | $177 |
| 2013 | 29% | $253 | $189 |
| 2014 | 22% | $260 | $209 |
| 2015 | 20% | $269 | $219 |
| 2016 | 18% | $279 | $232 |
| 2017 | 17% | $290 | $245 |
| 2018 | 16% | $301 | $257 |
| 2019 | 15% | $312 | $267 |
| 2020 | 14% | $324 | $282 |
| (Years shaded in green are during the Custom IR period) | | | |

The total cost observations for each utility can be ranked based on the percent difference in the actual total costs to the benchmark total costs. Hydro Ottawa is ranked 4th out of 78 utilities included in the sample when comparing the 2011-2013 scores (scores are the % difference between model-predicted and actual). The distribution of utilities and the company's placement is illustrated in the following figure.

**Figure 3-2 Econometric Total Cost Ranking**



# 4 Reliability Benchmarking Variables and Models

Nearly all jurisdictions that require reporting of reliability indicators include the metrics of SAIDI, SAIFI, and Customer Average Interruption Duration Index ("CAIDI").[20] SAIDI measures the average duration of sustained interruptions per utility customer. SAIFI is a gauge of the average frequency of sustained interruptions per customer. CAIDI evaluates the average duration time per sustained interruption. SAIDI is thus the product of SAIFI and CAIDI.

$$\text{SAIDI} = \frac{\Sigma_i \text{Minutes Customer } `i' \text{ is without Service}}{\text{Total Number of Customers on System}}$$

$$\text{SAIFI} = \frac{\Sigma_i \text{Frequency Customer } `i' \text{ is without Service}}{\text{Total Number of Customers on System}}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

Several jurisdictions exclude extraordinary events from reliability statistics, with the goal of increasing historical comparability. The bulk of excluded events stem from major storms. These severe storms vary in number and intensity from year to year. MED definitions are determined by each regulatory commission. Definitions vary by state; some use the IEEE standard 1366-2003 to determine what constitutes a MED.[21] Other states have customized definitions. States are gradually shifting towards the IEEE standard; however, considerable differences across states remain.

PSE requested Hydro Ottawa provide us with their historical SAIDI and SAIFI indexes with MEDs excluded (using the IEEE definition of a MED). This enables Hydro Ottawa's data to conform to the most prominent MED definition found within the industry. Excluding MEDs enables all of the data to be used and assures it is not unduly influenced by extreme weather events.[22]

The industry reliability data for U.S. utilities is gathered through reports and rate case filings made public by state commissions. Reliability data used has been verified and sourced.

The reliability benchmarking models we developed use the following variables:

[20] Some states only require reporting of two of these measures. However, the excluded indicator can still be determined by the researcher. SAIDI is equal to the product of SAIFI and CAIDI.

[21] The IEEE 1366-2003 standard defines the "beta" method. If outages for a certain day exceed 2.5 standard deviations from the normal day, a major event day is declared. A normal day and the standard deviation are determined by the utility's previous five years of normal day data (not including the MEDs).

[22] In PSE's work for Toronto Hydro's Custom IR application, we benchmarked SAIDI and SAIFI with no MED exclusions. This was due to the inclusion of Ontario distributors who only report reliability statistics in this manner. In that proceeding, PEG argued that 2012 U.S. data should be excluded because of Hurricane Sandy. By excluding MEDs, all available years can be used in the study.

- Density (customers per line mile);
- The number of retail customers;
- Forestation;
- Percent of distribution plant that is underground;
- A binary variable on if the major event day exclusion uses the IEEE-2003 standard;
- The level of wind within a given service territory; and
- A time trend.

The following table lists the utilities included in the reliability dataset. All of these utilities were also in the cost dataset; however, some of the utilities in the cost dataset did not have reliability data publically available.

**Table 4-1 Sampled Utilities for Reliability Benchmarking**

| Company | Company |
|---|---|
| AmerenUE | Metropolitan Edison Co |
| Avista Corp | Minnesota Power Inc |
| Baltimore Gas & Electric Co | New York State Electric & Gas Corp |
| Central Hudson Gas & Electric Corp | Niagara Mohawk Power Corp |
| Central Maine Power Co | Northern Indiana Public Service Co |
| Cincinnati Gas & Electric Co (Duke Ohio) | Ohio Edison Co (First Energy) |
| Cleco Corp | Ohio Power Co (AEP) |
| Cleveland Electric Illuminating Co | Oklahoma Gas and Electric Co |
| Commonwealth Edison Co | Orange and Rockland Utilities Inc |
| Connecticut Light & Power Co | Pacific Gas and Electric Co |
| Consolidated Edison Co of New York | Pennsylvania Electric Co |
| Consumers Energy Company | Pennsylvania Power Co |
| Dayton Power & Light Co | Portland General Electric Co |
| Delmarva Power & Light Co | Potomac Electric Power Co |
| Detroit Edison | PP&L Inc |
| Duke Energy Corp | PSI Energy Inc (Duke Energy IN) |
| Duquesne Light Co | Public Service Co of New Mexico |
| Entergy Arkansas Inc | Public Service Co of Oklahoma |
| Florida Power & Light Co | Puget Sound Energy |
| Florida Power Corp | Rochester Gas and Electric Corp |
| Georgia Power Co | San Diego Gas & Electric Co |
| Gulf Power Co | Southern California Edison Co |
| HYDRO OTTAWA LIMITED | Southern Indiana Gas and Electric |
| Indiana Michigan Power Co | Tampa Electric Co |
| Indianapolis Power & Light Co | Toledo Edison Co (First Energy) |
| Kansas City Power & Light Co (MO) | United Illuminating Co |
| Kentucky Power Co (AEP) | West Penn Power Co |
| Louisville Gas and Electric Co | Western Massachusetts Electric Co |
| Madison Gas and Electric Co | |

## 4.1 Econometric Reliability Benchmarking Models

PSE's method of econometric modeling applies regression techniques to the sampled data to form a mathematical model. The model accepts inputs (operating conditions, service territory data, etc.) and produces an expected reliability index for each observation. By using the model, given a set of operating conditions, PSE can estimate an "expected" or benchmark reliability level for each utility in each year. This technique allows for "apples-to-apples" comparisons, and therefore produces a more accurate assessment of performance relative to simply making industry comparisons of SAIDI and SAIFI.

Both the SAIDI and SAIFI model uses data with MEDs excluded. Each model includes utilities with varying time-series lengths covering the years 2002 to 2013.[23] This type of dataset requires an estimation procedure that accounts for the cross-sectional time-series ("panel") nature of the data. We use a feasible generalized least squares ("FGLS") estimator that corrects for cross-sectional heterogeneity and addresses the panel form of the data. The estimator accomplishes this by correcting for group-wise (utility-by-utility) heteroskedasticy, and results in parameter estimates that are more accurate, consistent, and precise than methods that do not correct for group-wise heteroskedasticy.

The results from the SAIDI model is presented in the following table.

**Table 4-2 SAIDI Econometric Model Coefficients**

| Variable | Coefficient Estimate | T-Stat |
|---|---|---|
| Constant | 4.732 | 193.385 |
| Customers (Y) | 0.039 | 3.647 |
| Customer Density (D) | -0.174 | -5.570 |
| Wind Hours (W) | 0.042 | 2.654 |
| Percent Underground (U) | -0.511 | -22.742 |
| Percent Forestation (F) | 0.111 | 5.409 |
| IEEE (I) | 0.184 | 9.948 |
| Trend | -0.015 | -5.146 |

All parameter estimates have the expected signs and are statistically significant. Utilities that serve more densely populated and have more underground plant tend to have shorter outage durations per customer. On the other hand, utilities that serve more forested and windy service territories have longer outage durations per customer. Using the IEEE MED standard tends to increase SAIDI values versus other MED definitions in the sample.

The SAIFI results are presented in the table below.

[23] Utilities in the States began reporting reliability metrics at different times. Hydro Ottawa historical data goes through 2014.

**Table 4-3 SAIFI Econometric Model Coefficients**

| Variable | Coefficient Estimate | T-Stat |
|---|---|---|
| Constant | 0.157 | 7.945 |
| Customers (Y) | -0.024 | -2.530 |
| Customer Density (D) | -0.214 | -10.057 |
| Percent Forestation (F) | 0.093 | 5.891 |
| IEEE (I) | 0.032 | 1.893 |
| Trend | 0.032 | 1.893 |

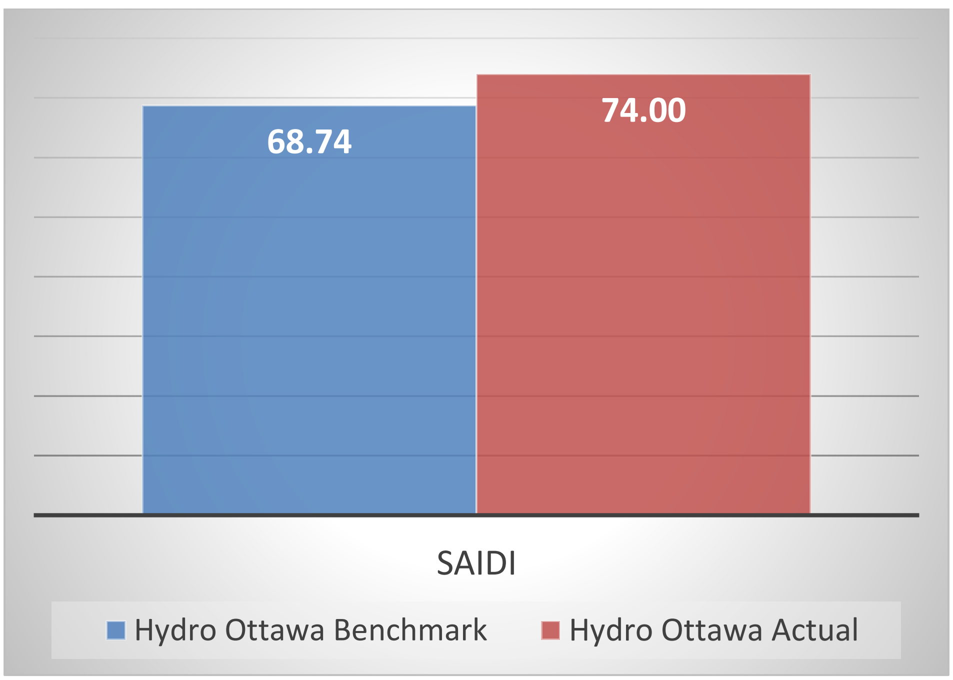
Utilities with more densely populated service territories experience fewer outage frequencies per customer. Conversely, utilities with service territories that are more forested have more frequent outages per customer. Utilities using the IEEE MED definition tend to have higher SAIFI values than those within the sample using other definitions.

## 4.2 Econometric Reliability Results

We find that Hydro Ottawa's 2012-2014 average SAIDI is 7.2 percent above the benchmark value. This result is not statistically significant at the 90 percent confidence level.

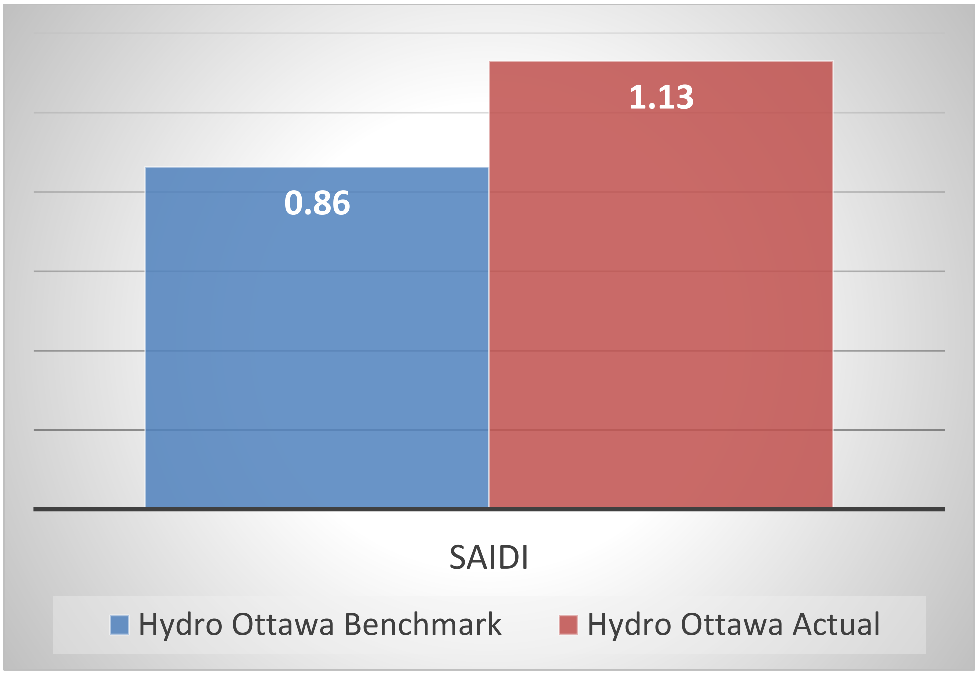
Our research on Hydro Ottawa's 2012-2014 average SAIFI indicates that the reliability level is 25.6 percent above the benchmark value. This not statistically significant at a 90 percent confidence level although is very close and is statistically significant at the 85 percent level. The benchmark comparisons for SAIDI are summarized in the following graph.

**Figure 4-1 2012-2014 Benchmarked SAIDI vs. Actual SAIDI (3-year Average)**



The benchmark comparisons for SAIFI are summarized in the following graph.

**Figure 4-2 2012-2014 Benchmarked SAIFI vs. Actual SAIFI (3-Year Average)**




The year-by-year breakdowns for both SAIDI and SAIFI are provided in the following table. This table provides both the actual reliability values for Hydro Ottawa, along with the econometric benchmark value.

**Table 4-4 Year-by-Year Reliability Benchmarks vs. Actual**

| Year | SAIDI (Econometric Benchmark) | SAIDI (THESL Value) | SAIDI (% Difference) | SAIFI (Econometric Benchmark) | SAIFI (THESL Value) | SAIFI (% Difference) |
|---|---|---|---|---|---|---|
| 2005 | 71.8 | 64.8 | -10.3 | 1.01 | 0.88 | -13.9 |
| 2006 | 71.1 | 84.0 | 16.7 | 0.99 | 1.02 | 2.8 |
| 2007 | 70.0 | 56.4 | -21.7 | 0.97 | 1.02 | 4.8 |
| 2008 | 68.8 | 58.2 | -16.7 | 0.95 | 0.79 | -18.8 |
| 2009 | 67.6 | 72.0 | 6.4 | 0.94 | 0.94 | 0.6 |
| 2010 | 67.0 | 76.2 | 12.8 | 0.92 | 1.25 | 31.0 |
| 2011 | 69.0 | 77.4 | 11.4 | 0.90 | 1.09 | 19.3 |
| 2012 | 70.8 | 78.0 | 9.7 | 0.88 | 1.32 | 40.4 |
| 2013 | 70.4 | 76.8 | 8.7 | 0.86 | 1.17 | 30.3 |
| 2014 | 65.0 | 67.2 | 3.3 | 0.84 | 0.90 | 6.3 |

Figure 4-3 below illustrates Hydro Ottawa's 2012-2014 average SAIDI performance relative to the most recent 3-year scores for the rest of the sample. The company ranks 37th out of the 57 utilities, with its three year average SAIDI score of 7.2 percent above its benchmark value.

**Figure 4-3 SAIDI Econometric Ranking and Scores**

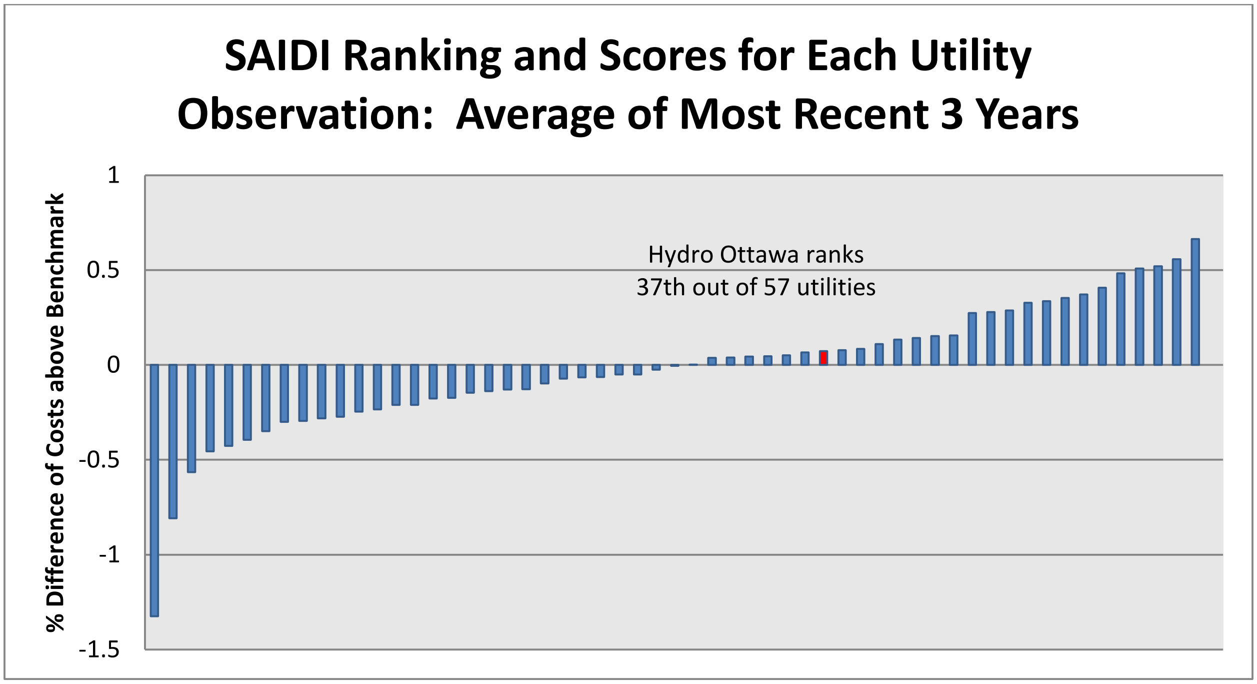
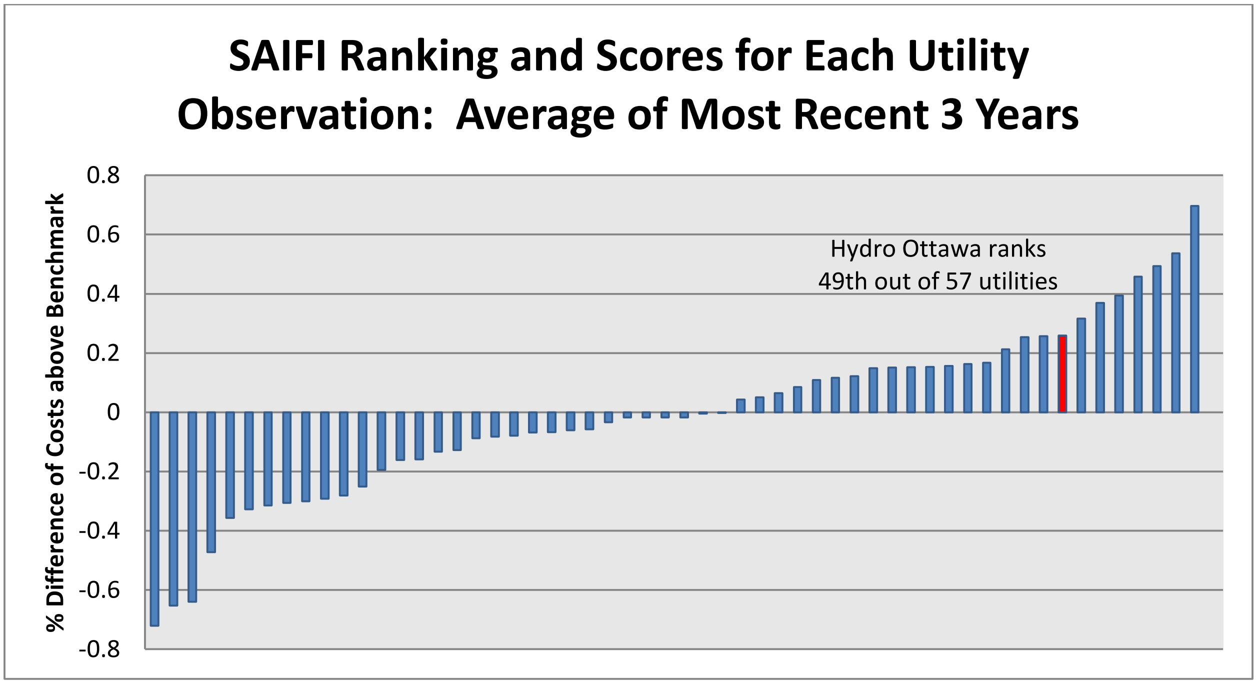



Figure 4-4 below illustrates Hydro Ottawa's 2012-2014 average SAIFI performance relative to the most recent 3-year scores for the rest of the sample. The company ranks 49th out of the 57 utilities, with its three year average SAIFI score of 25.7 percent above its benchmark value.

**Figure 4-4 SAIFI Econometric Ranking and Scores**

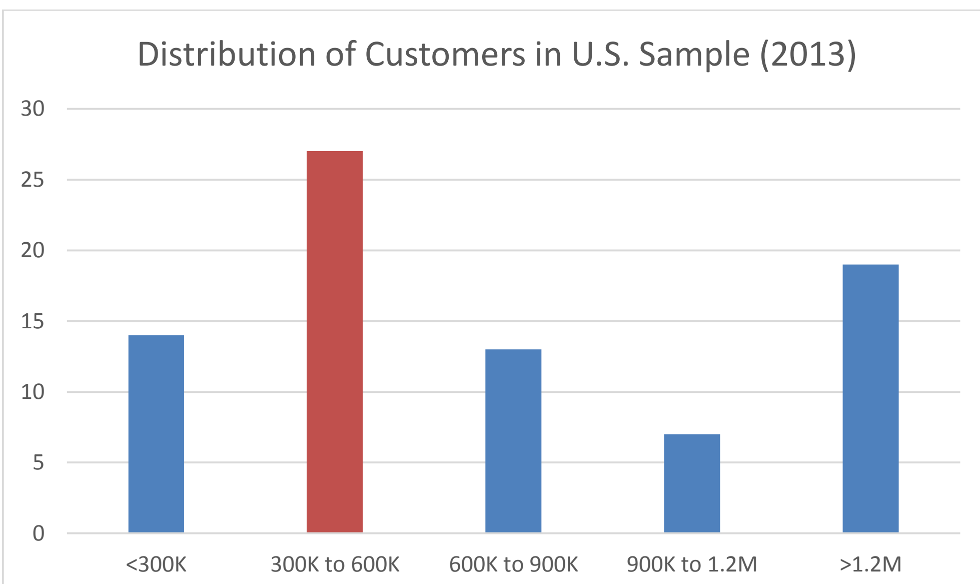


# 5 Importance of U.S. Data for Benchmarking Hydro Ottawa

The benchmarking exercise evaluates utility performance relative to a given sample, which produces a benchmark value for each utility in the sample. The benchmark value is generated using the specific utility's independent variable values; each utility's benchmark reflects what would be an average efficiency for that utility, relative to the sample. Thus, Hydro Ottawa's benchmark values represent the values we would expect from a hypothetical average utility with Hydro Ottawa's specific circumstances and service territory. If the average efficiency embodied in the benchmark value is generated using firms that are very dissimilar than the utility being benchmarked (i.e., the benchmarked utility is an outlier), then its performance evaluation has a high chance of being inaccurate.

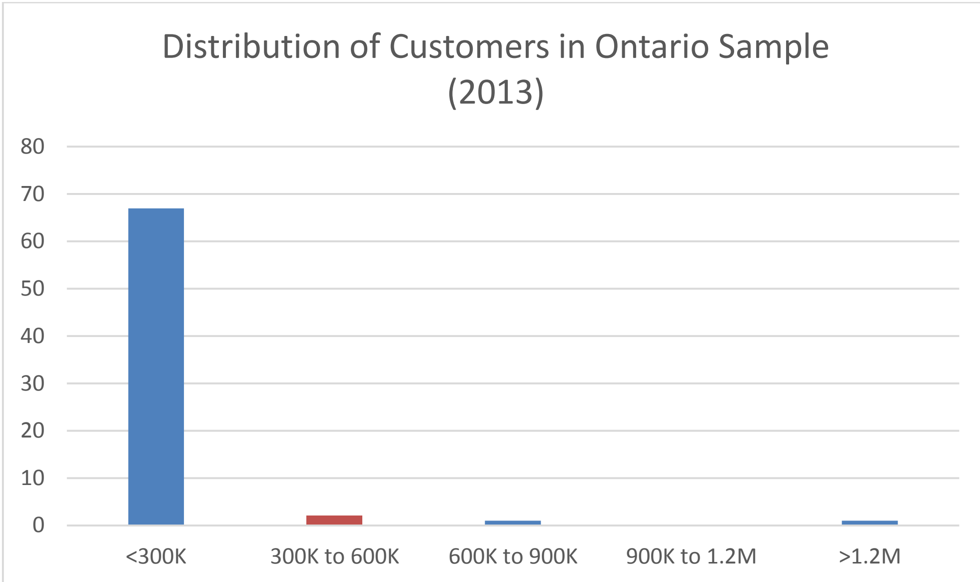
The number of customers served is the dominant output for electric distribution. The figure below displays the distribution of the number of customers per utility, within the sample used for this study. Hydro Ottawa's customer count grouping is indicated in red (i.e. 27 utilities in the sample, including Hydro Ottawa, had between 300,000 and 600,000 customers). Hydro Ottawa has a fair number of utilities that are both smaller and larger than the company within the U.S. sample—i.e., it is not an outlier in the U.S. sample with respect to number of customers.

**Figure 5-1 Distribution of Utilities in the U.S. Cost Sample, by Number of Customers (including Hydro Ottawa)**




Conversely, an Ontario-only sample of distributors does not adequately encompass the size of Hydro Ottawa. The figure below illustrates the outlier status of Hydro Ottawa, with only Hydro One Networks, Toronto Hydro, and Powerstream larger than Hydro Ottawa in terms of the number of customers. Of those three, only Powerstream is within the same grouping as Hydro Ottawa.

**Figure 5-2 Distribution of Utilities in the Ontario Cost Sample, by Number of Customers**




Based on the previous figures, we can conclude that an attempt to benchmark Hydro Ottawa's cost performance against only Ontario utilities is unlikely to produce a fair assessment. The model used to generate such a benchmark will embody performance based on utilities whose scale of operation are unlike Hydro Ottawa's.

The estimation procedure is designed to fit the data through the mean of model variables. As a result, parameter estimates are most accurate for those utilities with operating conditions that vary within a reasonable range of the mean of model variables. The further a utility's operating conditions are from the mean, especially if there are minimal sample observations nearby, the less accurate the cost benchmark based on the model.

# 6 Final Remarks

This report develops a framework for evaluating Hydro Ottawa's 2016-2020 Custom IR application. The parameters of this framework are set by considering three important questions: (1) What is Hydro Ottawa's historical total electric distribution cost performance? (2) What is the company's historical reliability performance? and (3) Are the proposed spending levels during the Custom IR period reasonable from a benchmarking perspective and what stretch factor do the proposed spending levels indicate?

**Question 1: What is Hydro Ottawa's historical total electric distribution cost performance?**

Hydro Ottawa's historical total cost performance reflects statistically significant superior performance at a 90% confidence level. Hydro Ottawa's 2011-2013 performance score is 37.1% below its benchmark. This value implies a 0.0% stretch factor based on the 4$^{th}$ Generation IR stretch factor criteria. Out of the 78 utilities in the cost sample, Hydro Ottawa ranks fourth.

**Question 2: What is the company's historical reliability performance?**

Hydro Ottawa's average 2012-2014 SAIDI indexes have been 7.2% above benchmark expectations. This is not a statistically significant difference. Hydro Ottawa's average 2012-2014 SAIFI indexes have been 25.7% above benchmark expectations. This is not a statistically significant difference at a 90% confidence level, but is significant at an 85% level.

**Question 3: Are the proposed spending levels during the Custom IR period reasonable from a benchmarking perspective and what stretch factor do the proposed spending levels indicate?**

The Hydro Ottawa Custom IR spending projections still indicate a strong total cost performance benchmark outcome. In the 2016 test year, Hydro Ottawa's total cost performance is 18.2% below the benchmark. By 2020, the projections indicate total cost performance will be 13.9% below the benchmark. Hydro Ottawa's Custom IR total cost performance remains statistically superior at the 90% confidence level. These results indicate a stretch factor of 0.15% based on the 4$^{th}$ Generation IR stretch factor criteria.

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## About PSE's Economics and Market Research Group

Founded in 1974, PSE is a full-service consulting firm. PSE's benchmarking experience includes research for regulatory purposes and utility management improvement. Our benchmarking team consists of economists, planning and design engineers, rate and financial analysts, communications infrastructure consultants, and smart grid technology experts. In addition to our statistical benchmarking research, PSE's Economics and Market Research group has expertise in the areas of demand response, energy efficiency, value-based reliability planning, T&D merger valuations, load forecasting, load research, survey design, alternative regulation, and cost of service studies. For more information on PSE and a full list of services, visit our website at www.powersystem.org.

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Mr. Fenrick has fourteen years of consulting experience in the evaluation of utility cost and reliability efficiency. He leads PSE's Economics and Market Research group which conducts research for the utility industry in the areas of benchmarking and productivity analysis, alternative regulation, demand response and energy efficiency, load forecasting, survey design, and market research. He has provided expert witness testimony on performance benchmarking, presented to Board of Directors at utilities, authored numerous reports, and has published papers in peer-reviewed journals. Mr. Fenrick has evaluated performance relating to electric and gas distribution, power transmission, power plant performance, and water distribution. These evaluations have been conducted for utilities, regulatory agencies, and consumer advocates. Mr. Fenrick earned a BS in Economics (Mathematical Emphasis) and a Master's in Applied Economics, both from the University of Wisconsin-Madison.

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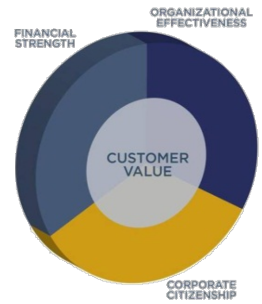
# CUSTOMER SERVICE STRATEGY (2016 – 2020)

## 1.0 BACKGROUND - CUSTOMER VALUE AND INNOVATION




At Hydro Ottawa, customer value is at the core of our corporate strategic plan[1]. Hydro Ottawa is committed to delivering value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates.

Hydro Ottawa has been on a Customer Service improvement journey since 2004. Over the past number of years, many initiatives have been put in place and significant progress has been made. These improvements have had a positive impact in a number of areas including achieving Customer Satisfaction levels averaging 87 percent over ten years, as compared to a 76 percent Customer Satisfaction level in 2004; increasing First Call Resolution to an average of 82 percent, as compared to 74 percent in 2007; a 40 percent customer uptake of MyHydroLink (Hydro Ottawa's customer web portal) and a 28 percent adoption rate of Electronic Billing, as of March 31, 2015, to name, but, a few.

Concurrently, Hydro Ottawa has experienced a significant drop in customer complaints and calls, per customer, to the call centre, averaging 1.22 calls per customer in 2005 to an average of 1.03 calls per customer in 2014. During this period, the customer base increased by approximately 40,975 accounts, while call centre volumes reduced by approximately 9,078 calls.

Hydro Ottawa's customer service initiatives have also been recognized within the industry and by customers, alike. For example the:

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[1] Corporate Strategic Plan, 2013 Annual Report, Hydro Ottawa Holding Incorporated, Pg. 6

- 2010 – Chartwell Best Practices Award Communications, EDA – Customer Service Award Finalist – Outage Communications project
- 2011 – EDA Customer Services Excellence Award – Customer Self Service
- 2012 – Chartwell – Customer Services Best Practices Award – Runner Up – Customer Self Service
- 2014 – EDA Communications Excellence Award – Go Paperless Campaign, BOMA – Pinnacle – Customer Service, Chartwell Best Practices Award Ebilling – Customer Service

In 2010, Hydro Ottawa introduced a Customer Service strategy[2]. This strategy initially focused on four areas: Complaint Management, Service Standards, Accuracy and Completeness and Quality. A fifth focus area was subsequently added: Innovation.

By listening to our customers through annual customer satisfaction surveys and other forms of engagement, Hydro Ottawa has delivered innovative customer services such as a 2010 North American Best Practices award winning Outage Communications solution and additional customer self-serve MyHydroLink enhancements such as “Bill Comparison” and a customer account “Dashboard”.

In 2012 Hydro Ottawa introduced a Mobile service. This industry leading and award winning initiative allowed Hydro Ottawa’s customers to access their billing information through the best of our MyHydroLink web portal features, along with extensive Outage Communication information, all from a mobile device of their choice.

In 2011, Hydro Ottawa received a Chartwell award for Best Practices in Outage Communications. Building on Hydro Ottawa’s success, further automation and

[2] Customer Service Strategy, Presentation to Enterprise Executive Team, September 15, 2010

communication features were added, including web maps and Twitter updates. Hydro Ottawa continues to validate the outage communications system and has identified further areas for improvement. Hydro Ottawa has implemented efficiency initiatives and has developed business requirement specifications to improve both the customer experience and internal productivity regarding outage communications. For further details and examples, please refer to Exhibit D-1-4, Section 3.2, Customer Service.

In addition, Hydro Ottawa has implemented many other customer service improvement initiatives including:

1. **Customer Service training** - has been provided to all staff including our field workers. This has included the development and dissemination of "Let's talk electricity" booklets to all employees so that they have relevant company and industry facts at their fingertips.

2. **Customer Care & Billing** (CC&B) – Hydro Ottawa has converted from a de-standardized billing system (PeopleSoft CIS) to a leading utility billing solution (Oracle CC&B).

3. **Monthly Billing** – Hydro Ottawa has transitioned all customers to monthly billing from bi-monthly billing in response to Hydro Ottawa's customer preferences for a more frequent bill cycle and for operational efficiencies.

4. **Electronic Billing** – Hydro Ottawa's customers now have the choice of receiving their bills electronically to their device of choice in place of traditional paper bills. Over 89,991customers (28%) as of March 31, 2015 now receive their bills electronically.
5. **Payment Options** - Customers are offered a number of payment options including pay by cheque, bank auto-withdrawal, equal monthly payment, or pay by credit card.

6. **MyHydroLink Web Account Portal** - Customers can control their interface with Hydro Ottawa through MyHydroLink (MHL) - a 24/7 web-based customer preference electronic "dashboard". 126,469 customers (40%) as of March 31, 2015 have registered as MHL subscribers where they can select options such as:

   ***a) My Electricity Usage***
   - Where they can view their electricity consumption with a variety of viewing options i.e., Hourly, Daily, Weekly, Monthly, et cetera.
   - Download My Data – where they can export their data to print, PDF, Excel and Green Button formats for further analysis.

   ***b) Moving***
   - Moving in/moving out instructions can be provided to Hydro Ottawa 24/7 at the customer's convenience.

   ***c) Payment Methods***
   - Preauthorized Payment – where the customer can set up a preauthorized payment arrangement without the need to speak with an agent.
   - Credit Card – where the customer can set up a credit card payment without the need to speak with an agent.

   ***d) My Bill***
   - E-Billing – the customer has an option to view their bills and have them electronically stored for up to two years.
   - Account History – where full billing and payment history is available.
   - Predict My Bill – where the customer has the option of receiving predictions of a future bill partway through the billing cycle. Predictions can be requested daily or weekly. This service can help to reduce "sticker shock" and promote conservation.

   ***e) My Profile***
   - Where customers can *add* and *remove* accounts conveniently.
   - Manage Profile – where the customer can manage their own account information, such as their mobile number, name prefix

(Mr., Mrs., Ms., Dr., et cetera), email and other social media contact information.

***f) My Account Summary***

- Account Summary – provides a convenient "at a glance" view of customer-selected account information.
- Bill Comparison – enables the comparison of a customer bill to their other Hydro Ottawa bills identifying variables such as consumption, rates, bill dates, weather, et cetera.
- View Multiple Accounts – enables customer to conveniently search for all associated accounts from one location.

**g)** ***Account Alerts including***:

- **Bill Alert** – an electronic alert requested by the customer when the customer-set threshold has been exceeded during the billing period. For example, if a customer sets a threshold to be alerted when the amount owing within a bill period reaches $50, the customer shall be notified automatically.
- **Consumption Alert** – an electronic alert is sent to a customer when the customer-set threshold has been exceeded during the billing period. For example, if a customer sets a threshold to be alerted when the consumption within a bill period reaches 600 kWhs, the customer shall be notified automatically.
- **Peak Consumption Alert** - an electronic alert is sent to a customer when the customer-set threshold has been passed within a given billing period. For example, if a customer sets a threshold to be alerted when the peak consumption within a bill period reaches 20%, the customer shall be notified automatically.
- **Payment Reminder Alert** – When chosen by the customer, an electronic alert shall be sent to a customer the day before their bill is due.

7. **Customer Value Performance Metrics** – Hydro Ottawa has developed an extensive list of measures, metrics and targets that report progress against historic trends, with circulation to Executive Management and our Board of Directors.

8. **Operational Notifications** – Hydro Ottawa has undertaken improvements to proactively notify customers regarding tree trimming requirements and planned outages.

9. **Website Improvements** – several navigational improvements have been made to Hydro Ottawa's web site and further enhancements are planned.

10. **Conservation and Demand Management** – many programs have been implemented with excellent results – both from a customer engagement and results perspective. Please refer to Exhibits A-3-1 and ?? for more details.

11. **Community Involvement** – Hydro Ottawa has been actively involved as active volunteers and contributors to United Way Ottawa and Christie Lake Kids, among other charitable activities

12. **Industry Involvement** – Hydro Ottawa is an active member within the Ontario electricity industry, as a participating member of the Coalition of Large Distributors and the Electricity Distributors Association. In Canada, Hydro Ottawa holds leadership positions within the Canadian Electricity Association (Chair of the CEA Customer Council, Chair of the CEA Distribution Council). In North America, Hydro Ottawa is an active participant and speaker within high profile industry organizations such as CS Week and Chartwell. Through these activities Hydro Ottawa learns and shares best practices so that Hydro Ottawa may continue to be on the leading edge of providing innovative customer services.

## 2.0 TRANSITIONING FROM CUSTOMER SERVICE TO CUSTOMER EXPERIENCE

With many customer service improvements implemented, in 2012-2013 Hydro Ottawa returned to basics – asking its customers what they would like to see Hydro Ottawa doing. Hydro Ottawa conducted market research and subsequently developed Hydro Ottawa's customer "personas" to help guide future Customer Service priorities.[3] Customer personas have enhanced Hydro Ottawa's understanding its customer diversity and segments so that their respective needs can be more effectively addressed in future customer service offerings.

Although Hydro Ottawa has been recognized as a Customer Service industry leader, Hydro Ottawa recognizes the need to continually monitor, anticipate and plan for the future. Hydro Ottawa's customers want more. Their expectations are high and will only get higher with forecasted price increases. The customer landscape is changing – customers are more mobile than ever, technology and choice continues to rapidly evolve and social media has become a core fabric in our market. Hydro Ottawa must respond by providing customers with innovative, leading-edge services that continue to meet their evolving needs and expectations.

Concurrently, Hydro Ottawa is focused on empowering every employee to act as an ambassador on behalf of the company in order to deliver "best-in-class" service to customers.

[3] The Customer Persona Research Program, Presentation by the Strategic Counsel, May 2013.

## 3.0 CUSTOMER EXPERIENCE VISION 2020

Based on input from Hydro Ottawa's customers garnered through the development of the customer personas, market research, customer satisfaction surveys and the Customer Service Strategic Plan, Hydro Ottawa developed a Customer Experience Strategy in Q4 2013 which was anchored by Hydro Ottawa's Customer Experience Vision and applied to the entire company.

**Hydro Ottawa's Customer Experience Vision is to be:**

- **Easy to do business with**
- **Caring**
- **Efficient**
- **Knowledgeable**

Supporting this Customer Experience vision, Hydro Ottawa has adopted Guiding Principles for Customer Service to address customers stated desire that Hydro Ottawa be Competent, Dependable, Understanding, Good Communicators, Accessible and Responsive.

In response to customer feedback, Hydro Ottawa has transitioned from a "**Customer Service**" to a "**Customer Experience**" focus. Customer Service initiatives typically address transactional items such as: how quickly a telephone is answered, how long an issue took to resolve, et cetera. Customer Experience initiatives take an overall view of how the customer is "feeling" related to the entire experience with the utility, including the transactional elements generally associated with Customer Service.

Some programs already implemented or in progress include Hydro Ottawa's transition to monthly (versus bi-monthly) billing, programs to transition customers to electronic billing, a Strategic Account Management Program and recommendations related to improving Hydro Ottawa's relationships with Developers and Contractors.

## 4.0 THE CUSTOMER EXPERIENCE IN 2020

By the year 2020, Hydro Ottawa's customer experience will be driven by choice – our customer's choice. Customers will be given options to allow them to be in control and to interact with Hydro Ottawa how and when they want. Customers will see Hydro Ottawa as an organization that is easy to do business with. Hydro Ottawa will be an organization that is customer centric in nature

A key to delivering this experience is transitioning from treating all customers in the same way to serving customers when, where and how they wish to interact with us.

In addition to the many steps, programs, tools and services already in place as outlined previously, by 2020 Hydro Ottawa's customers will:

1. Receive a **simpler, redesigned bill that is easier to understand and unilingual** in their language of choice (English or French)

2. Receive **video messages as a part of their electronic bill** to help keep them up to date on relevant news and information

3. Have the **option of automatically receiving Outage Communication Alerts** to notify them of power outages. They will have the choice of how they wish to be contacted, in the event of a planned or unplanned power outage with relevant information including outage location, estimated time of restoration, crew status, et cetera. Contact options will include email, text and telephone (including times not to call, if selected)

4. Be able to **compare their consumption to other customers** if they wish

5. Have **access to an Energy Calculator** which will allow them to further understand the impact of various end use devices in their home on consumption and pricing

6. For those customers that have adopted a Micro FIT installation – **information to show how Micro FIT energy production is progressing**

7. For Commercial Customers – have **online access to elements used in the calculation of their bills such as Demand, kVA and Power Factor readings**

8. **When contacting our call centre, receive a robust multi-channel experience.** Our call centre will be upgraded to handle the customer's choice of access including; phone, email, text, chat, fax, social media, agent routing and interactive voice response. These upgrades will enable our customers to experience the following benefits:
    - **a.** Quicker access to agents, and where necessary, to subject matter experts;
    - **b.** The option of receiving a call back instead of waiting in a call queue;
    - **c.** Automated access without the need to speak with an agent for common inquiries, such as account balance, due dates, et cetera;
    - **d.** Receive automated reminders (appointments, payment, et cetera).

9. **For Large Key Accounts, experience Hydro Ottawa transitioning from the historic "reactive" mode to a "proactive" account management approach,** with personal attention along with specific account services including enhanced bill service offerings

10. **Encounter an upgraded web experience that will** allow a smooth and seamless interface, including sophisticated search engine technology to enable quick access to desired information

## 5.0 ACHIEVING HYDRO OTTAWA'S CUSTOMER EXPERIENCE VISION 2020

To achieve Hydro Ottawa's 2020 Customer Experience Vision between the years 2016 - 2020, Hydro Ottawa will invest in selected technologies and processes building upon the foundational steps taken in 2014 and 2015, as outlined below.

**Table 1 – Achieving Hydro Ottawa's Customer Experience Vision**

| Customer Experience Category | Solution | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| **Technologies** | 1) CC&B and Monthly Billing | | | | | | | |
| | 2) CC&B Enhancements | | | | | | | |
| | 3) Outage Communications System Upgrade | | | | | | | |
| | 4) MyHydroLink Development and Support | | | | | | | |
| | 5) Oracle Customer Self-Serve | | | | | | | |
| | 6) Customer Relationship Management System | | | | | | | |
| | 7) Avaya CC6 | | | | | | | |
| | 7.1) Workforce Automation | | | | | | | |
| | 7.2) Multi-Media | | | | | | | |
| | 7.3) Experience Portal | | | | | | | |
| | 7.4) Rescripting MPS 500 | | | | | | | |
| | 7.5) Proactive Outreach Manager | | | | | | | |
| | 7.6) Proactive Outreach for Payments | | | | | | | |
| | 7.7) Call Back Assist | | | | | | | |
| | 7.8) Customer Survey | | | | | | | |
| | 8) Pre Pay Billing | | | | | | | |
| **Process** | 1) Strategic Account Management Program | | | | | | | |
| | 2) Promoting "Go Paperless" | | | | | | | |
| | 3) Bill Redesign & Unilingual Bills | | | | | | | |
| **Foundational Customer Experience Components** | 1) Customer Value Analysis | | | | | | | |
| | 2) Customer Experience Journey Mapping | | | | | | | |
| | 3) Transactional Surveys | | | | | | | |
| | 4) Change Management | | | | | | | |
| | 5) Customer Experience Index | | | | | | | |
| | 6) Phase 2 | | | | | | | |

| |
|---|
| Implementation |
| Planning & Support |

### 5.1 Technologies

1. **Customer Care & Billing (CC&B) and Monthly Billing** – Hydro Ottawa has converted from a de-standardized billing system (PeopleSoft CIS) to a leading utility billing solutions (Oracle CC&B). All customers were transitioned in March, 2014 in response to our customer's preference for a more frequent bill cycle and for operational efficiencies.

2. **CC&B Enhancements** – Hydro Ottawa will continue developing opportunities to further enhance the base CC&B system to ensure that processes continue to meet regulatory requirements and customer's needs (i.e., Landlord Agreement functionality and a number of features to assist with bad debt management, et cetera.)

3. **Outage Communications System** – Hydro Ottawa will upgrade the existing outage communications system to eliminate potential points of failure, while providing premise-based outage reporting (behind a customer preference dashboard) to deliver the information to the customer through their choice of communications medium (i.e., phone, email, text).

4. **MyHydroLink Development and Support** – Hydro Ottawa will continue to support the popular web portal offering and will further enhance this service through further improvements such as:
    - **a)** A "Face lift" (refresh) of the MHL site;
    - **b)** Community Compare – Social bench marking, targeting and monitoring which would also be implemented on the mobile site;
    - **c)** Basic Energy Calculator;
    - **d)** Micro Fit information for customers who are generating electricity;
    - **e)** Administrative functionality;
    - **f)** Expanded usage information for all commercial customers such as Demand, KVA and Power Factor readings.

5. **Oracle Customer Self-Service (CSS)** – this capability will allow automation of customer web-initiated move ins/outs and account set-up through CC&B without the need to re-key data which will result in productivity gains.

6. **Customer Relationship Management System (CRM)** – provides robust information regarding the customer beyond their billing and payment status. This would be a specific system tailored for Key Account Customers.

7. **Avaya CC6** – A robust, multi-channel customer experience portal that manages phone calls, email, chat, fax, social media, agent routing, Interactive Voice Response (IVR), reporting and analysis. Features include:
   a. **Workforce Optimization** – Automated routing and reporting of assigned work to staff.
   b. **Multi-Media** – Expanding in-bound media options to include Short Message Service ("SMS"), Text, Web Chat and Email. This functionality provides the ability to intelligently route and report on various channels allowing customers to communicate with Hydro Ottawa when and how they wish to do so.
   c. **Experience Portal** – Enhancing IVR technology to offer such services as account balance, due dates, et cetera, through technology, thereby reducing call centre agent volumes.
   d. **Rescripting MPS 500** – providing a more streamlined IVR experience.
   e. **Proactive Outreach Manager** – A market leading application to create and manage agent based and automated voice, email, SMS text campaigns and notifications. This feature enables agent-free personalized contacts using any available media type to provide reminders or regular information updates such as account status, confirmation that a customer is home for an installation appointment, appointment rescheduling, payments, fraud notifications, et cetera.
   f. **Proactive Outreach for Payment** – Utilizing technology to automate the collections process.

g. **Callback Assist** – Offering callers in queue the option of a callback instead of continuing to wait in queue.
h. **Customer Survey** – The provision of automated customer surveys.

## 5.2 Processes

1. **Strategic Account Management Program** – a program to transition from a current reactive account management approach to a proactive account management approach.

2. **Promoting "Go Paperless"** – to continually drive postage and paper billing costs down

3. **Bill Redesign & Unilingual Bills** – to address Hydro Ottawa's customers desire to simplify their bills through an easier to understand bill, in the language of their choice (English or French).

The Strategic Counsel

HydroOttawa

# A Presentation to EMT

## Who are our customers? Results of the Customer Persona Research Program

May , 2013

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# The Customer Persona Research Program: Objectives and Components

- Who are our customers?
- How do they segment?
  - What proportion do they comprise of our total customer base?
  - What are the key trends affecting each segment?
  - How are they growing/shrinking?
- How do they want to interact with Hydro Ottawa?
  - How can we engage them? Do they want to be engaged?
  - What information and/or tools do they need?
  - What are their preferred modes of communication?
- What messages resonate with them?
  - How do we enhance reputation and trust?

**A combined qualitative/quantitative approach was taken**

## Recap of the Research Program

Sept. 2012

Survey of 2000 residential customers

Survey of 500 small/medium-sized business customers

One-on-one interviews with key accounts (20)

Focus groups with residential customers (7 segments/14 groups)

Focus groups with contractors and developers (1 with each)

Focus groups with small/medium-sized business customers (6 segments/12 groups)*

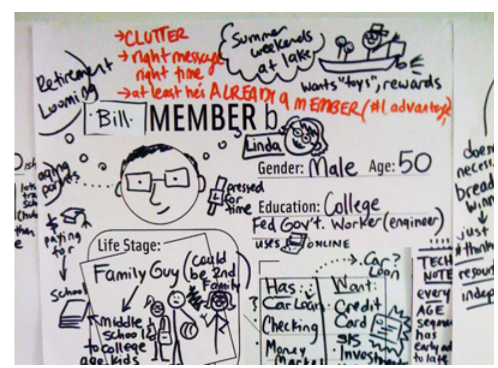
Feb. 2013

*Note: 2 additional 'make-up' groups were conducted among two segments for which attendance at the original groups was poor.

# How The Residential and Business Customer Personas Were Developed

- The results of the surveys of residential and small/medium-sized business customers were the basis for the initial segmentation. Segments were created based on:
  - Demographic/Firmagraphic data;
  - Lifestyle, general attitudes and characteristics;
  - Technology adoption;
  - Views of Hydro Ottawa;
  - Cost/bill sensitivity; and
  - Attitudes toward and interest in environment/energy conservation.

- Once the segments were determined, focus groups were conducted with participants who met the criteria (a simulator was developed to screen potential participants). These groups:
  - Developed our understanding of customers' attitudes and behaviours;
  - Explored how, if at all, Hydro Ottawa could connect/engage with these customers (wants, needs); and
  - Helped us to put context, language and personality to the segments.



# Labelling The Segments as *Primary* or *Secondary* Targets

- The segments/personas are identified as either *Primary* or *Secondary* targets based on the following:
  - Level of trust in Hydro Ottawa
  - Willingness to engage
  - Openness to information and communications
  - Extent to which they view Hydro Ottawa as credible source for information
  - Potential for Hydro Ottawa to shape future behaviours:
    - Interest in conservation
    - Interest in saving money
    - Stage-of-life/point of entry marketing
  - Trend data – how the segment might change (grow/shrink) over time

# Future Outlook: Key Trends Affecting Hydro Ottawa's Customer Base

Data for this section have been sourced from a number of organizations, including:

City of Ottawa

CMHC

TD Bank

Conference Board of Canada

# Demographic Trends

- **Ottawa's population is expected to grow faster than the average for Eastern Ontario.**
  - By 46.8%, from 910,000 in 2011 to over 1.3 million in 2036.

- **The most significant demographic force will be an aging population with fixed incomes and saddled with higher rates of debt.**
  - Proportion of seniors 65+ will rise from 12% to 20% by 2031, accounting for almost 50% of Ottawa's population growth. The very elderly (80+) will more than double. Over the next 20 years, the suburban and rural areas will experience more rapid aging than Ottawa's urban areas.
  - While Ottawa will continue to be slightly younger than the national average, the 25-34 age cohort is expected to continue to shrink as Baby-Boomers exit from this group.
  - Women currently outnumber men by a ratio of 107:100. This ratio is higher among seniors and will increase as the population ages.
  - The ratio of debt to disposable incomes is currently between 150%-165%, fuelled by consumer credit. While the aging population will have a moderating effect on this trend, it will be more than offset by increasing levels of debt carried by those born in later years.

- **Diversity will continue to be a predominant feature of Ottawa's population.**
  - Ottawa is a multi-ethnic city – 22% of the population are foreign-born, 156 ethnic groups speaking more than 70 languages are represented. Almost 30 per cent of Ottawa residents speak non-official languages: the top five being Chinese, Arabic, Italian, Spanish and German.
  - By 2031, nearly all of Ottawa's population growth is expected to come from immigration as the city ages. Notably, recent immigrants are, on average, more educated than their previous counterparts.

# Construction and Development Trends

- **Housing starts are forecast to slow in 2013 and beyond.**
  - An aging population, with a desire to remain homeowners while also downsizing, will fuel demand for condominium apartments.
  - Younger age cohorts, seeking greater affordability, are forecast to redirect their home ownership propensity toward multiple-unit dwellings.
  - Construction of new single-family homes will decline by over 20 per cent, while the number of new apartments will increase by 90 per cent. 2013 will mark the first period in 15 years where single-family housing starts are less than 2000 units. This level of starts, however, still constitutes 27 per cent of all new home starts in 2012. Multiple-unit dwellings comprise the other 73 per cent and of those, apartments make up the largest group at 2,800.

- **Construction activity is also down.**
  - Ottawa issued building permits worth $232 million in November 2012, down nearly 10 per cent from the previous year. The cooling in both residential and non-residential construction intentions is not unique to Ottawa, but a trend that is currently being witnessed across the province.
  - 2 major construction projects: redevelopment of Lansdowne Park ($300 million) and the Ottawa Light Rail system ($1.2 billion) with completion dates of 2014 and 2018, respectively.

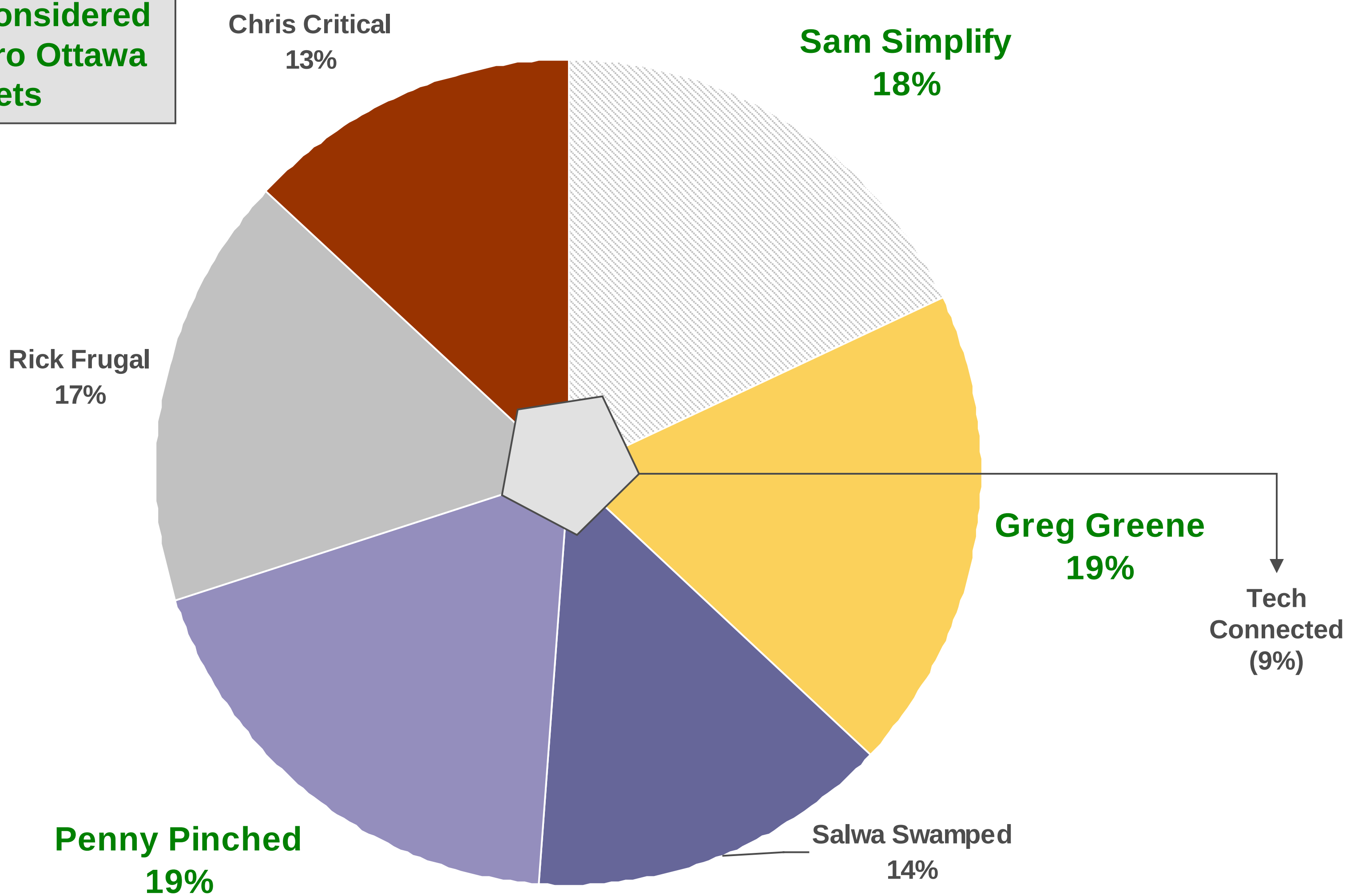
# Customer Trends

- Rising customer expectations
- Social media as an early warning system – problem detection/resolution platform.  Unhappy customers have a platform to 'amplify' their anger or frustration
- Speed of service whether on the phone, web or at the service desk
- Customers are more resourceful and feel empowered – they determine if, when and where they engage with a brand – and they want to be respected
- Customers expect companies to anticipate needs and act as the information aggregator – they expect technologies to make experiences easier, instantaneous and intuitive
- Desire for self-service options
- Growth of video and mobile for customer service – creating more personalized customer experiences and opportunities to deepen the relationship
- Shifting of the relationship from transactional to 'trusted advisor'
- 'Greening' of customers – particularly among younger segments

# The Residential Personas

# Residential Customer Segments

**Those highlighted in green are considered *Primary* Hydro Ottawa Targets**



PRIMARY

# Penny Pinched (19%)

"I don't think I could save any more money on Hydro than what I already do."

money is tight

family is dependent on me

own a home

single mom

living month to month

day-to-day life is stressful and busy

I have a lot of expenses

I try to save money wherever I can – look for discounts and use coupons.
Hydro is one of my largest household expenses, and I am doing as much as I can to reduce it.
I don't always have time to do things at night, so can't take full advantage of TOU rates.
I'm not sure what else I can do to lower my bill without spending money that I don't have.
I feel powerless when dealing with large companies – they should do more to make me feel that I'm important to them.

## Implications for HO Service

GROWING

Demonstrate customer empathy and, to the extent possible, flexibility

Empower these customers via self-serve and online solutions

### Relationship & Attitudes Toward HO

- I am more knowledgeable about Hydro Ottawa and the electricity sector than the average person
- Though I have adjusted to Time of Use rates, I don't like it

### Products and Services

- I would prefer a once monthly, or bi-weekly billing cycle
- You could move me to e-billing, for example, by, giving me $1 off each bill

### Communications & Messaging

- I want to be treated with respect and dignity
- You'll get my attention with contests, rewards, coupons and incentives

PRIMARY

# Greg Greene (19%)

"I do things according to what I believe, and I believe in taking action for the environment. I also like to know what's going on and to understand exactly how something works … I do a lot of research and have a lot of questions. I am open, analytical, fair and reasonable, but not impulsive."

**Stress-free lifestyle**

Up-to-speed on world events and the news

**financially secure**

work full-time

**middle age**

**not a lot of free time**

good life

**busy household**

Own a house in a wonderful neighbourhood

I am fairly comfortable with technology, but not obsessed with it.
I like to understand the big picture as well as the details.
When I make decisions, I research and weigh my various options. I am not impulsive.
I conserve energy wherever I can. I do not like waste.
I am prepared to pay more for things that are important to me – for example, I am more inclined than most to purchase electricity from Bullfrog Power – a small, but important action I can take to prevent climate change.

## Implications for HO Service

**GROWING**

at a moderate pace

A target for more information and education, especially about green options and HO's 'green' agenda

Possible positioning as a future 'premium' customer. Offer more choice and service bundles

Pilot new products

### Relationship & Attitudes Toward HO

- I am looking to Hydro Ottawa to be a trusted advisor
- I am loyal, but will consider switching to greener options
- I haven't joined Peaksaver because I don't want others controlling the thermostat

### Products and Services

- Green initiatives will appeal to me
- To catch my attention, ideas and innovation will have to make sense for the bigger picture, not just provide value for money

### Communications & Messaging

- When I call, I want to speak to someone who can answer my many questions
- Send me information by e-mail – I will follow any links to more information to get my many questions answered

# Sam Simplify (18%)

"I don't really think about Hydro, it's just part of our life. The fact that I don't think about them very much is probably a good thing. I don't want to be hearing from them all the time. If they do what they are supposed to do, and I am getting power, can afford it, and can understand the bill, that's all I want."

do not worry about finances

single

building my career

Worry about relationships

young professional

simple life

rent an apartment

I maintain connections with friends and family using technology and social media.
I am flooded with information and requests electronically.
I prefer that companies know as little as possible about me. When they have a good reason to collect information, I want to have the option of how the information will be used.
I don't think about hydro or the environment very much. My hydro bills are relatively low, so any efforts that I make to conserve make no difference on my bill.

## Implications for HO Service

DECLINING

These are your future homeowners

Possibility to shape their thinking and behaviour with appropriate messages and services

Affinity for technology, especially games, offers a potential route to connect

### Relationship & Attitudes Toward HO

- I just don't think about or know much about Hydro Ottawa, and that's OK with me
- I don't completely trust HO, perhaps because of the lack of transparency around the bill
- I pay fair value for Hydro

### Products and Services

- Anything you could offer to *simplify things* would be great
- I would be interested in loyalty programs, challenges, contests, and/or competitions
- YouTube videos are a good way to connect with me

### Communications & Messaging

- Help shape my future behaviours!
- I will only pay attention to quick, simple information – such as a tip beside the amount on the bill
- I prefer to contact HO online (chat) or by telephone (live person)
- I ignore the bill inserts – e-mail me

SECONDARY

# Salwa Swamped (14%)

"Hydro used to be one of the bills I didn't have to worry about. But now it just keeps on going up. It's like my son's eating habits."

care for aging parents

paying off debt

worry a lot about finances

sandwich generation

worry about son's health which isn't great

live with adult son in an apartment

I worry a lot about finances and money. I have some debt that I am trying to pay off, and worry about being laid off.
Technology is not a big part of my life.
I am not a pushy or an aggressive customer, but I would like to be treated with respect.
In regards to Hydro I am doing everything I can think of already to conserve, but if I can save a few more dollars with a new idea, that would be great.

## Implications for HO Service

GROWING

Treat with respect

Simplify interactions and solutions (one-step)

Take a 'low-tech' approach

Repeat conservation tips at regular intervals

### Relationship & Attitudes Toward HO

- I have a positive impression of HO, but their bills are increasing
- I monitor all expenditures closely, including Hydro
- I am not very aware of HO programs
- I am doing what I can to lower my bills

### Products and Services

- More frequent payment options.
- Give me tips on how to lower my bill quickly and cheaply
- Respect and help me
- Compensate me for moving to paperless bills and paying on time!
- Reward me for good behaviour!

### Communications & Messaging

- Take the opportunity to inform me if I call in
- I am overwhelmed, so sound bites please!
- I am unlikely to call HO, so they will need to pro-actively reach out to me
- I will tend to minimize a problem

SECONDARY

# Chris Critical (13%)

"I would pay attention if I wasn't used to it not being useful.  The whole debt retirement thing from previously poorly planned decisions --  if I have to assume responsibility for that then we do need to be more engaged, because clearly the people in charge have made massive mistakes."

average

actively read the news

work full-time

high school graduate

technology laggard

active in the community

Though I don't have nor want the latest and greatest technology.  I like the access to information it provides and am often Googling things to educate myself.
Good customer service involves educating me.  I want explanations.
With respect to hydro, I don't understand why we should be doing things to reduce our energy costs when the actual part of the bill that I control is negligible.
I find it outrageous that we are charged the debt retirement charge and the delivery fee.

## Implications for HO Service

STABLE

Education through earned media (dailies, talk radio)

Ongoing reputation management

Important to lay the foundation for and manage expectations around rate increases and/or capital investments

### Relationship & Attitudes Toward HO

- I feel that the bill is out of my control.  The largest % of the bill is fees, not my usage
- Most issues I have are more to do with the broader system than HO.
- I am willing to conserve, but I don't fully trust anything HO tells me

### Products and Services

- I'm not really interested in products and services

### Communications & Messaging

- I want to know more about HO and conservation, but I'm quite cynical about them, so I'm not sure I would listen to anything they say
- Use low cost ads and earned media to avoid my complaints about expensive advertising

SECONDARY

# Cy Burnett (9%)

"It's a travesty when companies don't provide choice. There should be a "I use very little of this service" option…a no frills option. Sometimes basic is best."

busy

Love technological gadgets

active social life

young

relationship-oriented

prize simplicity

My place is filled with the latest gadgets –iPhones, iPads, laptops, tvs, gaming system, computers, a server, etc.. I can't live without my smartphone in particular – it's my life in my hands.
I want companies to treat me as a partner.
I like customer service where the tone of the interaction is warm, where you can hear the smile
Satisfied with the Hydro service, but I don't know much about them.

## Implications for HO Service

GROWING

Authenticity

More choice/options

Personalized, but ensure privacy

Offer an avenue to feedback (this is the group that will move from active to participatory in terms of the customer relationship)

## Relationship & Attitudes Toward HO

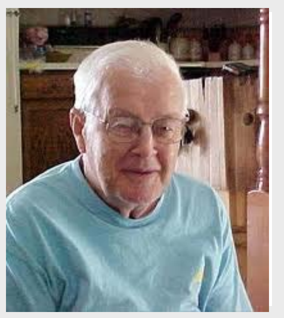
- HO is a trusted company
- I don't feel like I am paying too much–it's not a huge cost factor
- I favour conservation initiatives and clean energy
- HO needs to set the example "Walk the talk"

## Products and Services

- Apps, but I don't want to have to log-in or remember passwords
- Provide me with real time info
- Give me conservation tips beside the amount owed on the bill
- I prefer choice; opt-in approaches
- I worry about privacy of info

## Communications & Messaging

- I prefer a genuine tone, and dislike sales pitches
- I use live chat features on websites
- I prefer to be contacted by e-mail
- A combination of traditional and new media will reach me.
- Note: I only read headlines



SECONDARY

# Rick Frugal (17%)

"I want them to understand my needs. I want things presented in a simple fashion, reliability, reasonable rates and somebody who can deal with the problem."

**older kids help me with technology**

frugal

old-school values

**recently retired**

own a house

Conservation and being frugal is second nature to me, being brought up the way I was as a kid. I try to do as many chores as possible, such as the laundry, during the low-rate periods, and I have a clothesline in the basement so that I can avoid using the dryer.
I want customer service to feel like it does in a mom and pop business.
The best customer service remembers that I am environmentally conscious and dollar conscious.

## Implications for HO Service

GROWING

Very little adaptation required other than simplification to the bill – making it clearer, more legible and understandable

Attuned to messages about conservation and saving, but can only process limited number at a time

## Relationship & Attitudes Toward HO

- I am paying too much for hydro, even if I am actively conserving
- I don't understand the bill – It doesn't give me the information I need to further conserve
- It's my responsibility to conserve, but HO needs to educate me

## Products and Services

- I would be interested in getting an energy audit and learning more about green energy.
- I would love to be able to monitor conservation on a daily basis
- Give me simple tips on things I can do to impact the bill.

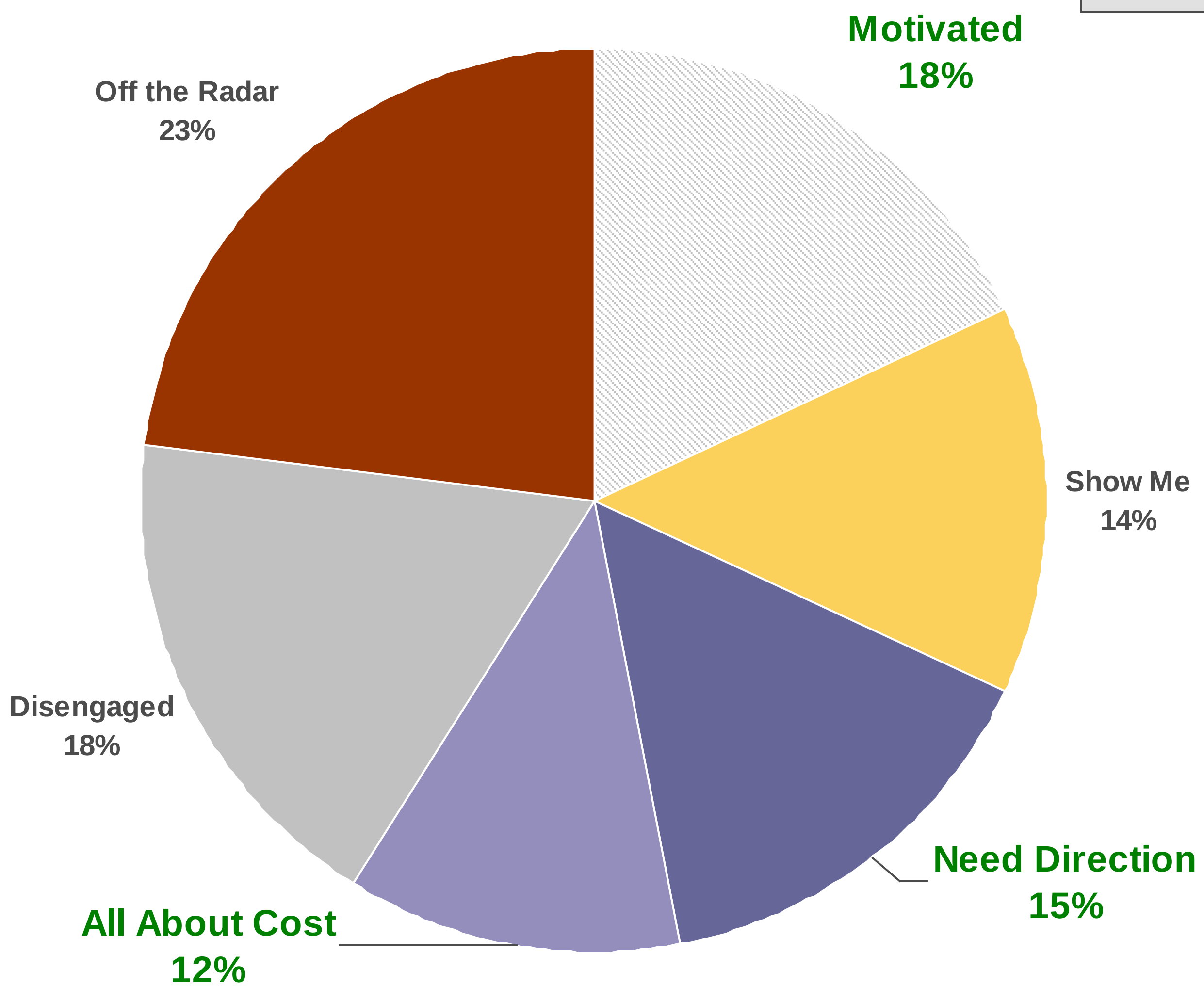
## Communications & Messaging

- My kids are major enablers – you can get me hooked through them.
- Give me tips via E-mail, person-to-person contact (e.g in a mall), calling me, or by placing them next to the amount on the bill.
- Make bill inserts more eye-catching

# The Business Personas

# Business Customer Segments

**Personas in green are those identified as *Primary* Hydro Ottawa Targets**



PRIMARY

# Motivated (18%)

"It's not only about getting the service, it's about creating a partnership…helping us do better.  Conserving is a huge priority for us. The meter is running as we speak."

serve long-term loyal customers

demanding of suppliers

large business

looking for cost-savings

constantly improving

We are always looking for cost-savings, especially since the recession hit us.
We use technology where we can to make us more efficient.  Likewise, if we can lower our costs by conserving energy, we are on board!
We are currently happy with the service we get from Hydro Ottawa in that it is very reliable. However, we would welcome a more engaged relationship with them.

## Implications for HO Service

STABLE

–

Higher demand on CSRs for dedicated SME service offering

Potential for closer integration of information systems between SMEs and HO

Key target for conservation programs

## Relationship & Attitudes Toward HO

- HO provides reliable service.  They are green, innovative and helpful.
- We are aware of HO programs and are actively using them
- We find the bill confusing
- The value for money offered by Hydro Ottawa services in unclear

## Products and Services

- Educate us!  We would love to use your advisory services
- Rewards, discounts, and loyalty programs are appealing to us
- Tailoring services to small businesses.
- Create customer profiles and use them to provide us with relevant energy-saving tips

## Communications & Messaging

- We want Hydro Ottawa to be more engaged with us
- We would contact Hydro Ottawa by phone or by using a Chat function
- Hydro Ottawa should contact us by text message or e-mail

PRIMARY

# Needs Direction (15%)


"They need to get to know us, but I'm not honestly sure what else I'd like them to be doing. I've already done everything I can to bring down my hydro costs."

established
passion
local
small business
long-lasting relationships
shrinking margins

The best suppliers that we work with are local…they have a passion that the big box stores don't. They are proactive, and take the time to get to know me and my staff.
Technology doesn't play a big part in our business.
Our margins are shrinking in this economy, so we are trying to decrease our expenses.
I've done everything I can think of to bring costs down on my utilities, but I don't think a lot about it any more.
If they could show us what else we could be doing, we would definitely listen.

## Implications for HO Service

GROWING

Combination of high-tech/low-tech approaches required

Relationship-oriented

Field rep visits would be well received (the personal touch)

Will take action on targeted, simplified advice + automated bill

## Relationship & Attitudes Toward HO

- We are happy with the service we are receiving from Hydro Ottawa
- I'm not sure how they could help us

## Products and Services

- I want to be recognized for being a good customer – make me feel important
- If Hydro Ottawa have ideas, they could pro-actively show us what else we can be doing to conserve

## Communications & Messaging

- I would like Hydro Ottawa to feel like a small, local supplier that listens
- I should call in and get the same person every time

PRIMARY

# All About Cost (12%)

“Utilities make you feel like you are non-existent.”

Very busy

long memory

in operation for a long time

low-tech

want to feel valued

We expect our suppliers to provide reliable service – if they don’t, it’s a problem.
We prefer face-to-face service.
We get poor service from the utilities. I want to feel valued by them.
ToU rates are a grab for money -- we have no choice but to use power during peak times
Hydro Ottawa are a monopoly, so they have no reason to work with us. But if they did offer suggestions on how to conserve, we would implement them.

## Implications for HO Service

STABLE

This group has the potential to damage HO brand

Interaction must look and be cost effective

Automated billing + occasional simple tips)

Benefit from yearly or bi-annual HO seminars

### Relationship & Attitudes Toward HO

- We see TOU as a grab for money
- We are not sure about the impact of retrofits
- We are frustrated over the bill and our inability to bring it down
- We understand the bill, but not the costs

### Products and Services

- You should connect with us as we are opening up our businesses and offer sector specific programs.

### Communications & Messaging

- Call us once a year to see if we have any problems.
- We don’t want a close relationship, but want to feel valued
- We need more hand-holding than most – we want the details, and to be able to meet in person if necessary

SECONDARY

# Disengaged (18%)

"The service I get from Hydro Ottawa is not stellar because I don't interact with them, and they're not at the bottom of the list because I don't interact with them so they don't piss me off. But I don't have a choice. I couldn't run my business without them."

Worry about collecting receivables

Internet is essential

**Professional firm**

constantly communicating with clients via e-mail

**revenues down**

Technology is important to my business. If the internet go down, it's a catastrophe.
Hydro is not a primary expense of our firm.
My bill went up when the smart meter went in. But, it's just the cost of doing business…it's like breathing. I still wish they could have different rates for businesses who can't divert their power usage to the off-hours
Short of Hydro Ottawa giving us lower rates, I'm not sure how I can bring my bill down.

## Implications for HO Service

STABLE

–

Customer service strategy should focus on 'drafting' this group via initiatives aimed at primary personas

Peaksaver program may be of interest (low requirement for engagement)

### Relationship & Attitudes Toward HO

- I don't know much about Hydro Ottawa or its services
- We don't question our hydro bills, as long as the cost stays consistent. Its an essential service
- Unless there is a problem, we prefer a hands off relationship with Hydro

### Products and Services

- We are unaware of programs we could participate in
- Energy audits would be helpful
- A dedicated business line would be greatly appreciated

### Communications & Messaging

- We are open to messages about conservation, but the challenge will be to get our attention
- Earned media or a formal letter with my name on it would work best. We don't pay attention to inserts. I may or may not look at e-mails

SECONDARY

# Off the Radar (23%)

"As a customer, you are provided with a lot of information, and you have to make sense of it. I'm not that knowledgeable about the whole thing. I have to get familiar with it just so I can operate properly. I would rather have someone come in…I am paying a lot of money on my bill, so why don't they take 15 minutes to sit down with me and give me some quick pointers."

lack time

shrinking margins

worry about costs

small

technology laggards

I worry about my costs, because I know that if they go up, I can't pass them on to my customers.
I'm not sure if we are getting good value for service from Hydro Ottawa. We do have reliable power, but the prices are going up and the company does not appear to be run well.
Happy with a hands-off relationship with Hydro Ottawa.
Only want a more engaged relationship if they're telling me how I can save money --I don't have time for much more.

## Implications for HO Service

GROWING

Same as for Disengaged

Customer service strategy should focus on 'drafting' this group via initiatives aimed at primary personas

Peaksaver program may be of interest (low requirement for engagement)

### Relationship & Attitudes Toward HO

- I don't really know much about Hydro Ottawa or its services.
- TOU has increased our bills
- Delivery and debt repayment charges upset me, as does the complexity of the bill

### Products and Services

- We would be interested in Conservation programs that would save us money
- Energy Audits would be helpful

### Communications & Messaging

- Hydro Ottawa will have a hard time getting our attention. I don't pay attention to the inserts
- I may look at e-mails, but it's not guaranteed


SECONDARY

# Show Me (14%)

"Seems like all the utilities have conservation programs…but when the amount we use goes way down, they jack rates up or add service fees so they can make money.  I feel like we are getting ripped off.  I would love it if they could come out to our location to talk to us and help bridge the red tape."

challenged to keep costs in check

technology is important

time pressures

large

Under expansion

We are in the process of upgrading our facilities, so I also worry about expanding our customer base to make it pay off.
Technology  allows all of us to be more accessible and efficient.
We feel electricity rates are cheap and delivery is reliable.
We don't like bureaucracy at Hydro Ottawa and the extra costs on the bills.
We would appreciate Hydro Ottawa to check-in every once in a while.  I would like to be heard, and to get feedback.

## Implications for HO Service

DECLINING

Some level of engagement will be important as a civic responsibility

Annual or bi-annual seminars, reaching out to include their 3rd party advisors (i.e., architects, engineers, accountants)

### Relationship & Attitudes Toward HO

- HO provides reliable service, but it's bureaucratic
- I try to conserve to bring down my bill, and then the fees go up, and new charges appear on the bill
- HO should be more pro-active in helping us conserve energy

### Products and Services

- Energy Audits would be helpful, as would webinars
- Provide consulting services on making new buildings more efficient
- Treat businesses differently than residential customers.  Give us special rates and a dedicated customer care team

### Communications & Messaging

- Tailor made for a case study approach to communications
- Examples of HO programs and services (by sector) is key to 'showing' this audience what can be done and the potential cost savings
- BOT, COC, professional associations as intermediaries

# Key Account Personas

# The Key Account experience is dependent on the extent of interaction with Hydro Ottawa's Key Account team.

- Those having **regular contact** with their Hydro Ottawa key account representative:
  - Find Hydro Ottawa to be responsive, supportive, helpful, a partner.
  - Hydro Ottawa is very engaged with their businesses, something that is greatly appreciated.

- Those having **little or no contact** with their Hydro Ottawa key account rep:
  - Are frustrated with the service and bureaucracy at Hydro Ottawa, in part because they are often calling the call centre when a need arises.
  - Often do not know who their account representative is or when they should be contacting that person (e.g. after a storm causes damage? To plan a retrofit?)
  - Would prefer a more engaged relationship, with Hydro Ottawa advising and educating them and their management teams on conservation, including retrofits.

- Conservation is an important priority for all Key Accounts, driven mostly by reducing costs.
- All are highly receptive to ideas and programs for reducing energy consumption.
- Capital costs are the largest barrier to conservation; incentive programs are valued.

# Contractor and Developer Personas

# Contractors

"The way to do business with Hydro Ottawa is to find someone on the inside to help you get something done.  The official route is not working for us.  I don't have any of the official numbers on my phone."

"They need to know that we are getting pressure from our clients.  We can't be responsive to our owners…..there's only so many times that we can tell them that we're trying."

| What works well | Suggested Improvements to Products and Services | Suggested Improvements to Pricing and Communications |
|---|---|---|
| • Design and planning on-site.<br>• Work on-site<br>• On-site crew are intelligent and knowledgeable.<br>*"Trades people are second to none."*<br>• High level of safety standards.<br>• Friendliness of staff.<br>• 24/7 crew. | • Provide quicker responses on the engineering side – the queue for a call-back is perceived to be 3-4 weeks long.<br>• Extend the working hours of inspectors to 6 pm to match those of contractors.<br>• Take steps to meet demand for inspectors during busy periods.<br>• Take on accountability for changes.<br>*"If their plans change, they need to be accountable."*<br>*"If we make a mistake, we eat it.  So should they."* | • Better communicate what is expected from contractors, as well as any changes.<br>*"When they change their specifications I find out about it when the inspectors come….I would prefer to know at the start of a project."*<br>• Provide more detail or transparency in pricing.<br>*"I would like some idea of what is going into the costs."*<br>• Provide fixed costs.<br>*"How can you explain to the client that you can't guarantee the cost?"* |

HydroOttawa The Strategic Counsel

# Developers

"We are often told *'We are aiming for February to have power in a subdivision'*. How can you plan on *we're aiming*. People are moving in in March. But we need to get the Hydro earlier to get proper dry walling done, etc..."

"Hydro fees come at the end of the process, you've started selling your homes, and all of a sudden you get a bill, and if there is a surprise, there is no recourse."

| What works well | Suggested Improvements to Products and Services | Suggested Improvements to Pricing and Communications |
|---|---|---|
| • The quality of work<br>• The level of service comparable to other utilities, particularly with respect to the service provided by:<br>–The main contact person<br>–The on-site crews<br>–Hydro Ottawa's designer<br>• Its emergency services | • Provide more precise scheduling, quicker timelines and meeting agreed upon deadlines.<br>• Develop strategies to decrease the 17-20 week lag time when waiting for transformers<br>• Simplify the registration of easements.<br>• Consider adapting a section of the website to be geared to developers as opposed to the end user. | • Communicate more pro-actively (e.g. notify developer if a delay occurs, etc.).<br>• Provide more detail and transparency on costings<br>• Provide costings earlier in the process.<br>• Lower any costs which may be significantly higher than those charged by other hydro utilities. |

# Recommendations

# Common Themes And Issues

- A number of recommendations would address issues that affect all residential and business customer segments, including:
  - Taking steps to build the brand and reputation of Hydro Ottawa, putting a personality/face to the company
  - Employing earned media to positively profile Hydro Ottawa, correct misconceptions, educate customers and other stakeholders, and counteract negative impressions of the industry
  - Using prime real estate on the website to support the brand and deliver key messages regarding tools and programs such as MyHydroLink, PeakSaver+, energy savings tips and Hydro Ottawa success stories
  - Continuing the work currently underway to improve First Call Resolution (FCR) across all contact points
  - Developing a Customer Relationship Management strategy to maximize opportunities for exchange of information with customers each time there is a contact (i.e., capturing e-mail address, type of dwelling, etc. and relaying important/relevant Hydro Ottawa messages).
  - Simplify the bill

- For small and medium-sized business segments:
  - Creating a dedicated small business CSR team

# Residential Customer Segments

- Other recommendations speak to certain personas more than others.

| | PRIMARY TARGETS | | | OTHERS | | | |
|---|---|---|---|---|---|---|---|
| | Penny Pinched | Greg Greene | Sam Simplify | Cy Burnett | Chris Critical | Salwa Swamped | Rick Frugal |
| Increase billing cycle to monthly or bi-monthly | ■ | | | | | ■ | |
| Provide short conservation tips on the bill that are quick and inexpensive to implement | ■ | | ■ | ■ | | ■ | ■ |
| Written communication from Hydro Ottawa needs to be short to capture the attention of customers | | | ■ | ■ | | ■ | |
| Provide links to more information on all communication for those who want to understand the bigger pictures, or who have questions they want answered. | | ■ | | | ■ | | |
| Communications regarding conservation programs should avoid the use of the word savings | ■ | | | | | ■ | |
| Develop a social media strategy | | | ■ | ■ | | | |
| Consider engaging customers through discounts, contests and incentives | ■ | | ■ | | | ■ | |
| Develop a Point of Entry Marketing Strategy to connect with customers at key milestones when the relationship with Hydro Ottawa changes | | | ■ | | | | |
| Consider offering advisory services and/or education | ■ | | | ■ | | ■ | |

# Business Customer Segments

- Other recommendations speak to certain personas more than others.

| | PRIMARY TARGETS | | | OTHERS | | |
|---|---|---|---|---|---|---|
| | Motivated | Needs Direction | All About Cost | Disengaged | Off the Radar | Show Me |
| Investigate the possibility of extending the hours of business | ■ | | ■ | | | |
| Written communication from Hydro Ottawa needs to be short to capture the attention of customers | | ■ | | ■ | ■ | |
| Develop a social media strategy | ■ | | | ■ | | |
| Develop a Point of Entry Marketing Strategy to connect with customers when they open a business or change locations | | | ■ | | | ■ |
| Consider leveraging the successful marketing tools used in the Small Business Lighting Program to market other conservation programs to businesses in the future | | ■ | | | ■ | |
| Consider developing sector specific conservation related products and services | ■ | ■ | ■ | | | |
| Consider engaging customers through rewards, discounts and loyalty programs | ■ | ■ | | | | ■ |
| Offer advisory services/education | ■ | ■ | ■ | | ■ | ■ |

Now What?

# How Do We Action the Personas Across the Organization?

- Not all parts of the organization will immediately see the relevance of the personas to their ongoing responsibilities and tasks. Ideally, they will become internalized across the organization over time and as they become more regularly deployed.

- **Creating Customer Empathy:**
  - Fundamentally, the personas are a tool to assist Hydro Ottawa in educating all staff about customers – who they are, what's important to them, what their issues and 'hot buttons' are – and building a stronger sense of empathy and understanding.
  - This is key to moving toward becoming a customer-centric organization.

- **Acting as a Filter in the Design of New Products, Services and Programs:**
  - Helps the design teams have a shared understanding of the real users in terms of their goals, capabilities, desires, limitations and contexts.
  - By asking "Would Salwa Swamped use this?" or "How would Penny Pinched react to this tool?" teams can stay focused on designing for the end user

- **Helping to Prioritize Projects and Investments:**
  - Based on an understanding of primary versus secondary target segments, proposed projects can be prioritized according to how well they address their needs and wants.

# Final Words

# Review:  The Research Program Objectives

- Who are our customers?
- How do they segment?
  - What proportion do they comprise of our total customer base?
  - What are the key trends affecting each segment?
  - How are they growing/shrinking?
- How do they want to interact with Hydro Ottawa?
  - How can we engage them?  Do they want to be engaged?
  - What information and/or tools do they need?
  - What are their preferred modes of communication?
- What messages resonate with them?
  - How do we enhance reputation and trust?

# WORKFORCE PLANNING STRATEGY

## 1.0 INTRODUCTION

This schedule describes Hydro Ottawa's workforce planning challenges and discusses the measures being taken by Hydro Ottawa to address these challenges. The workforce planning challenges discussed in this schedule stem largely from shifting workforce demographics resulting from an aging workforce and the need to attract and retain skilled workers to fulfill Hydro Ottawa's corporate priorities including its obligation to safely and reliably deliver electricity to Ottawa residences and businesses.

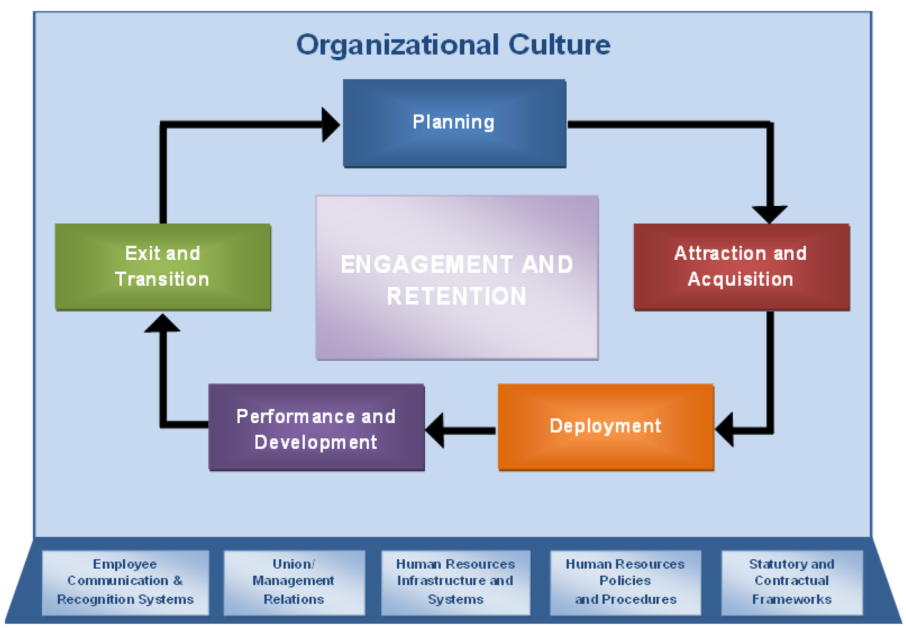
In its 2012 Cost of Service Application (EB 2011-0054), Hydro Ottawa outlined to the Ontario Energy Board ("OEB") the shifting demographics associated with an aging workforce, and the resulting need to attract and hire additional trades apprentices to off-set expected retirements – an essential requirement to continue enabling asset renewal and reliability programs through a sustained and prepared workforce. Hydro Ottawa further outlined the need to strategically build on its existing workforce by supplementing key support functions with additional resources and expertise to strengthen its capacity to deliver on business priorities tied to operational delivery, compliance and sustainability.

Anticipating and adopting proactive strategies to bridge talent supply gaps is crucial to ensuring a prepared and sustained workforce. Hydro Ottawa depends on a highly skilled, properly trained and knowledgeable workforce to maintain and enhance the reliability of the electricity distribution system, to execute its comprehensive asset management plan, and attend to increasing legislative and regulatory requirements all while addressing customer growth and an evolving customer relationship. Hydro Ottawa's 2016-2020 workforce planning is accordingly guided by current and probable requirements to address the known challenges arising from an aging workforce and infrastructure renewal, as well as the anticipated challenges arising from technological innovations and an ever-changing business landscape. In what follows, Hydro Ottawa addresses the measures it has implemented to proactively plan for these challenges.

## 2.0 TALENT MANAGEMENT FRAMEWORK

Hydro Ottawa has leveraged workforce planning, integrated within its Talent Management Framework, to enable business execution into the future and to mitigate the ongoing risk of an insufficient talent pipeline of skilled, prepared and knowledgeable workers. The Talent Management Framework (illustrated in Figure 1 below) provides a comprehensive and integrated human resources management model upon which priorities and initiatives are aligned. The Talent Management Framework centres around five key components of the employee experience in order to build performance and realize potential throughout the talent lifecycle: planning, attraction and acquisition, deployment, performance and development, and exit and transition. The Talent Management Framework is supported by systems that act as a strong foundation of enabling mechanisms.

**Figure 1 – Talent Management Framework**



Priorities and initiatives under the Talent Management Framework are informed through strategic workforce planning, which assesses changes in workforce demographics and environmental conditions, and responds with talent management approaches. The aim is to ensure operational capacity and continuity by supplying the right talent with the right skills, within the right structure, at the right time. The need to drive innovation and increase productivity has also been integrated into how Hydro Ottawa approaches workforce planning. To this end, workforce planning plays a role in containing costs, creating efficiencies, and in generating added value for our customers. Hydro Ottawa has focused its workforce planning into three areas as follows:

- Workforce Demographics
- Workforce Modeling
- Talent Strategies to Sustain and Prepare the Workforce

## 3.0 WORKFORCE DEMOGRAPHICS

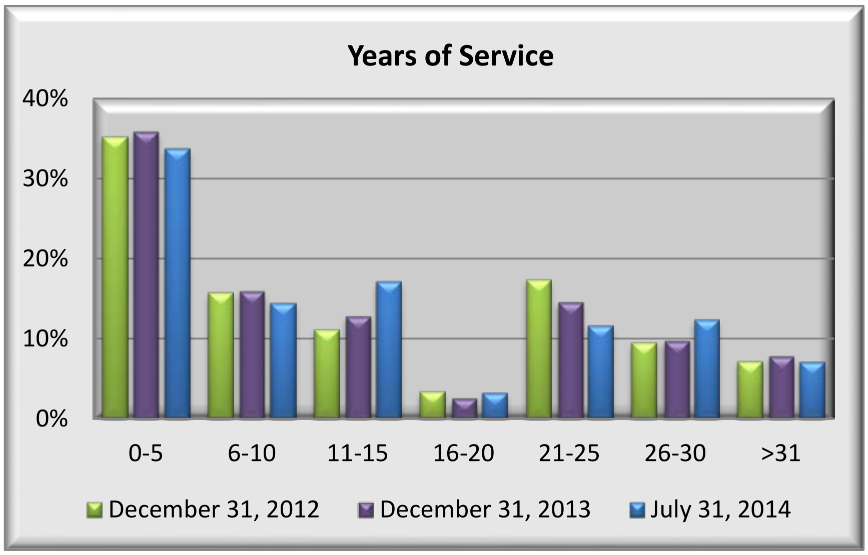
### 3.1 Aging Workforce

As outlined in the Electricity Sector Council's widely cited "Power in Motion Labour Market Information Study" ("LMI"), the electricity sector is anticipating that an aging workforce will challenge its ability to attract skilled workers into the next several years.[1] The LMI in part attributes these pressures to past hiring trends within the electricity sector, with an influx of skilled workers in the 1970s and 1980s as the legacy distribution system was built. Employment reached record levels in the early 1990s, and then fell in the mid-1990s until the mid-2000s as a result of decreased investments in infrastructure and, in Ontario, because of the amalgamation of local distribution companies. As depicted in Figure 2, Hydro Ottawa's years of service distribution is consistent with this

[1] Electricity Sector Council (now, Electricity Human Resources Canada) works to strengthen the ability of the Canadian electricity industry to meet current and future needs for their workforce, which includes having conducted and disseminated Labour Market Information Studies in 2008 and 2011 (Updated 2012).

historical trend. The average years of service for a Hydro Ottawa employee is 13 years.[2]

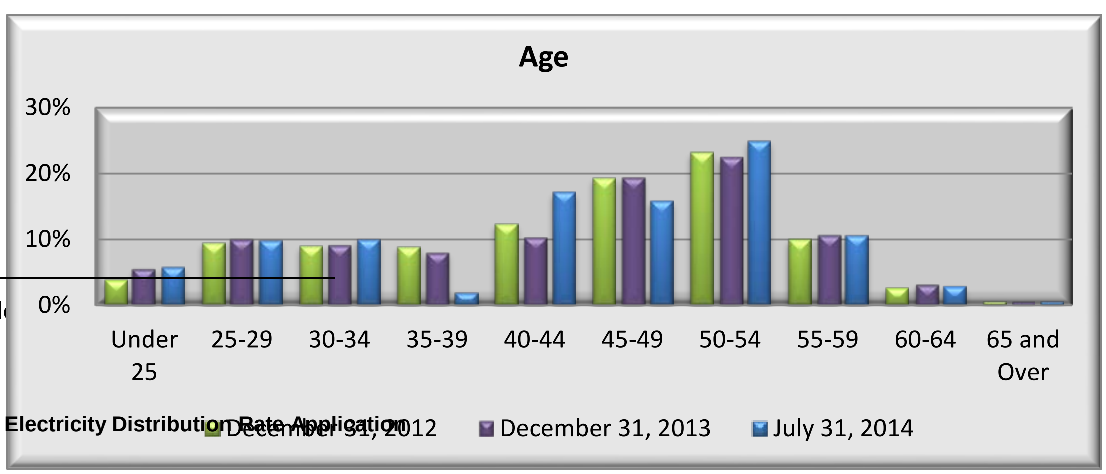
**Figure 2 – Years of Service Distribution**




The average age of Hydro Ottawa's current workforce is 43, with an overall age distribution depicted in Figure 3. Employees under the age of 30 represent 15.7% of the workforce, an increase from 13.6% since 2012 that is attributable to increased hiring of trades apprentices and engineering graduates since that time.

Employees aged 50 or over represent 39.3% of the workforce, an increase from 32.9% since 2012. The surge of new entrants into the electricity sector, including at Hydro Ottawa, prior to the mid-1990s are now aged 50 plus, reflected by an overall demographic peak for 45-54 year old

**Figure 3 – Age Distribution**




[2] Unl

### 3.2 Anticipated Retirement Attrition

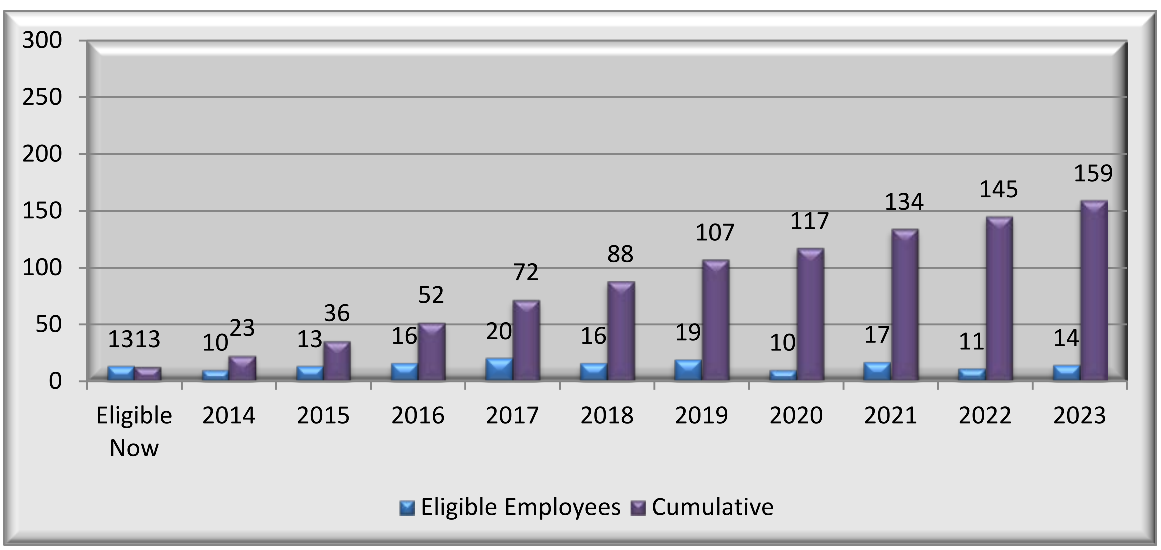
In 2014, Hydro Ottawa began to experience a predicted increase in retirements that is expected to continue into the next ten years as employees elect to retire from the organization at their earliest unreduced eligibility date.[3] On average, employees are retiring at age 59, with 60% retiring within two years of eligibility. The average age of retirement has increased from 57 in 2012, in part attributable to pro-active measures outlined in Section 5.4. This means that employees are choosing to leave the organization at a slightly later age, with 6% of those currently eligible to retire instead choosing to maintain their employment with Hydro Ottawa.

Despite this positive trend, the volume of forecasted retirement eligibility over the next ten years is significant and Hydro Ottawa must effectively address these anticipated departures from the workforce to ensure operational capacity and continuity. Slightly over 40% of Hydro Ottawa's workforce will have become eligible to retire by 2023, of which almost 60% are skilled workers in trades or technical professions. Based on the existing trades and technical workforce, this means that up to 44% of these employees are forecasted to retire by 2023. The number of eligible retirements for all employees is represented in Figure 4, and the eligible retirements in the trades and technical workforce is represented in Figure 5.

[3] Employees are deemed "eligible to retire" for an unreduced early pension based on criteria established under the Ontario Municipal Employees Retirement System ("OMERS").

**Figure 4 – Eligible Retirements, All Employees**


**Figure 5 – Eligible Retirements, Trades and Technical Employees**




Over the next ten years, Hydro Ottawa projects the potential loss of approximately 7,693 years of experience from the organization as a result of retirements, including approximately 4,854 years of trades and technical experience. With more than one-third of the existing workforce population having five years of service or less and the projected retirement of employees, the workforce at Hydro Ottawa is increasingly less experienced in what is an increasingly complex and a safety focused business operating environment. As a result, given that almost half of the existing trades and technical talent within the organization will have reached retirement eligibility within ten years, it is critical that the organization proactively forecast talent demands and anticipated supply gaps early – particularly for positions filled through apprenticeship programs.

Workforce demographic assessments are a key element in Hydro Ottawa's workforce planning approach. Monitoring and planning for retirements in particular is critical to ensuring Hydro Ottawa's continued ability to deliver on its core business objectives with skilled and trained resources.

## 4.0 WORKFORCE MODELING

A key component of workforce planning, workforce modeling is primarily used at Hydro Ottawa to forecast the supply of labour in relation to operational demand for resourcing. The objective of workforce modeling is to anticipate gaps and inform proactive strategies to address said gaps. The modeling approach provides insight across work segments to identify potential supply gaps based on a number of variables that are validated annually to adjust projected hiring and talent strategies in response to Hydro Ottawa's internal and external environments. Hydro Ottawa's workforce modeling serves to identify the best combination of internal resources, overtime utilization, and contracted services for the delivery of services and programs.

Hydro Ottawa's workforce modeling is leveraged in the deployment of its Distribution System Plan and Asset Management Plan, where prudent cost management efforts require managing the renewal of its distribution system and delivering on daily operating requirements within the resources allocated in capital and operating plans.

### 4.1 Labour Demand and Supply

Hydro Ottawa's workforce modeling is integrated with operational demand to ensure that forecasting optimally aligns with business requirements by considering projected operational labour requirements.

In order to determine labour supply, Hydro Ottawa's workforce modeling considers the available number of journeypersons or skilled technical employees in a given profession or trade, retirement eligibility, the apprentice pipeline feeding each trade, and supplementary labour resources that contribute to the work undertaken. The modeling is then adjusted based on productive time.

### 4.2 Retirement Rate

As outlined above, workforce modeling of forecasted retirements assumes that employees will retire at a rate of 60% within two years of reaching retirement eligibility.

### 4.3 Non-Retirement Attrition Rates

As competition for skilled talent increases due to escalating retirements within the electricity sector at large, Hydro Ottawa's modeling also considers non-retirement attrition due to resignation to be a key variable. Current workforce modeling assumes a non-retirement attrition rate of 2.05% based on 2013 actuals; this rate is adjusted annually, based on the prior year.

### 4.4 Internal Movements

Hydro Ottawa continues to foster its internal talent pipeline as demographics shift throughout our business, and this results in internal movements of our trades and technical workforce as employees take on leadership roles or grow their professional capacity within our operations in another role. As skilled trades or technical workers leverage their expertise, it is important to proactively anticipate the gaps they leave behind. With this in mind, Hydro Ottawa's workforce modeling assumes that 2.43% of the trades and technical workforce will move laterally or as a result of promotion within any year. This rate is based on 2013 actuals and is adjusted annually, based on the prior year.

### 4.5 Modeling Outputs

Based on the above-noted variables, workforce modeling enables Hydro Ottawa to identify its projected gaps in internal labour, and to determine how best to fill these gaps using contracted services, overtime, and/or hiring. Several factors are considered, such as: costs of contracted services or overtime utilization, labour market availability, appropriate ratio of journeypersons to apprentices, legislated allowances for overtime on a per employee basis, and the influence of environmental factors or business considerations that may impact assumptions used to inform modeling.

## 5.0 TALENT STRATEGIES TO SUSTAIN AND PREPARE THE WORKFORCE

Hydro Ottawa's workforce planning approach serves to inform the organization's talent management priorities and initiatives, including the design of key programs and strategies that emerge or are adjusted to ensure that talent demands are met and sustained.

### 5.1 Sustaining the Trades

Through structured in-house apprenticeship programs, Hydro Ottawa is revitalizing the trades employee-base to ensure a ready supply of trades talent. Hydro Ottawa has five Apprenticeship Programs in the following trades: Powerline Maintainer, Cable Jointer, Meter Technician, Station Electrician and System Operator. The total number of apprentices is 43, which represents 21% of our trades workforce. The number of apprentices as a proportion of each trade varies from 13% to 33%. Since the introduction of formalized Apprentice Programs in 2005, Hydro Ottawa has enabled 51 apprentices to achieve journeyperson status, representing approximately 29% of the existing trades workforce.

With the anticipated number of retirements over the next ten years, combined with forecasted increases in labour demand as a result of additional work requirements associated with the asset management plan, municipal infrastructure projects, and organic growth in the customer base, Hydro Ottawa expects to continue investing in apprenticeship as a viable source of talent for the skilled trades. To ensure that planned training investments remain prudent and to limit overall headcount increases within the organization as a whole as our trades are replenished, Hydro Ottawa based forecasted hiring on the following principles:

- Increase overall productivity to ensure greater availability of productive time, while also establishing initiatives to gain efficiencies that increase the quality of the time worked.
- Hire apprentices by using vacancies as they become available, including the redistribution of vacancies from support functions to the trades.
- Where available in the labour market, attract and hire journeypersons to fill vacancies, with the aim of reducing the overall required training investment in apprenticeship and leverage qualified resources with a shorter lead time to achieve maximum productivity.
- Balance hiring with the appropriate use of overtime to supplement labour gaps, and continue to leverage contracted services where cost-effective and available to meet demand. These options offer flexibility to Hydro Ottawa in resourcing peak or temporary demands for labour, without unnecessarily inflating the overall workforce complement.

With the application of these principles in mind, Table 1 outlines the forecasted hiring projections for the Powerline Maintainer trade at Hydro Ottawa. In particular, workforce modeling indicates that the demand for labour has the potential to outpace Hydro Ottawa's ability to replenish anticipated retirements, non-retirement attrition, and internal movements from the Powerline Maintainer trade solely through apprentice hiring. In addition to hiring apprentices, Hydro Ottawa will continue to simultaneously attract and hire qualified Powerline Maintainers at the same rate it has been able to attain in the past few years.

**Table 1 – Forecasted Hiring in Powerline Maintainer Trade**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| Apprentice Hiring | 6 | 5 | 5 | 5 | 5 | 4 | 4 | 34 |
| Journeyperson Hiring | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 14 |

In anticipation of future hiring requirements within the Powerline Maintainer trade, in 2011, Hydro Ottawa entered into a partnership with Algonquin College to design and deliver a two-year Powerline Technician Diploma Program. Through this Diploma Program, students develop the essential skills and knowledge required to design, plan, construct and maintain electrical distribution lines through class work and hands-on learning. Algonquin College provides theory based courses and leads program administration, while Hydro Ottawa delivers safety and core skills instruction in a practical field environment. This program leverages the skills of experienced Hydro Ottawa Powerline Maintainers, including those who are being developed for leadership roles and those who are nearing retirement or have retired.

As a result of this strategic educational partnership with Algonquin College, Hydro Ottawa has hired 10 Powerline Technician Diploma Program graduates since 2013 when the first cohort completed their program. In doing so, Hydro Ottawa avoided the ongoing costs of intra-provincial apprentice recruitment, and was able to significantly reduce the costs of apprenticeship through a shortened vestibule training period for these hires. This has enabled safe and early field deployment of apprentices to on-the-job learning in the delivery of capital projects.

Forecasting suggests that Hydro Ottawa's remaining trades are appropriately supplied relative to labour demand, and resulting hiring plans focus on replenishing each trade with apprentices based on forecasted attrition. Hiring projections for apprentice hiring in the remaining trades are outlined in Table 2. Due to the specific nature of these trades, which are not regulated under the *Ontario College of Trades Apprenticeship Act (2009)*, Hydro Ottawa is currently limited in hiring qualified journeypersons from the external labour market for these trades.

**Table 2 – Forecasted Apprentice Hiring in Remaining Trades**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| Cable Jointer | | | 2 | | 2 | | 2 | 6 |
| Meter Technician | | 2 | 2 | 2 | 2 | | | 8 |
| Station Electrician | 3 | 4 | | | | | | 7 |
| System Operator | | 1 | 1 | 2 | 2 | 1 | | 7 |

### 5.2 Talent Attraction and Acquisition

The Occupational Projection Summary[4] for Electrical Trades and Telecommunications Occupations, over the 2013-2022 period, forecasts that national job openings within this occupational group are expected to total 76,948 (arising from expansion demands and replacement resulting from retirements or mobility) and that 62,002 job seekers (arising from graduates, immigration and mobility) are expected to be available to fill those job openings. The associated analysis establishes an expectation that solid economic growth will translate to a faster increase in the number of Electrical Power Line and Cable Workers (NOC 7244), among other occupations in this group, than the average increase in workers in the rest of the economy. Power System Electricians (NOC 7243) are projected to experience a labour shortage during the projection period. Further, it is expected that the primary source of talent for this occupational group will be from the post-secondary educational system.

The labour market, once driven by employer demand, now hinges on labour supply, making an employer's brand and its ability to attract the best talent possible matter now more than ever before. Hydro Ottawa makes a concerted effort to attract the next generation of workers to meet the organization's present and future talent needs by extending our brand through cost-effective social media channels, trades-focused career

[4] Employment and Social Development Canada's Canadian Occupational Projection System (COPS) develops national job projections and analysis for 140 occupations in Canada.

fairs that reach students at critical junctures in their decision-making about careers, and community outreach to support internationally trained workers in accessing employment. Both co-operative educational placements and a robust summer student program are a valuable source of future employees. Hydro Ottawa also emphasizes strategic partnerships with educational institutions that foster a vibrant and viable talent supply on a sustainable basis, such as the Powerline Technician Diploma Program through Algonquin College and associated applied research opportunities with students in Algonquin's Electrical Engineering Technology program.

In addition to investing in apprenticeships, Hydro Ottawa offers training and development opportunities to attract engineering graduates. The training and development internship for engineering graduates is based on performance-measured deliverables that align with criteria defined by the Professional Engineers of Ontario, and leads to acquisition of the Professional Engineer designation and transition into a Distribution Engineer role at Hydro Ottawa.

Hydro Ottawa also believes it is imperative to attract, retain and develop diverse professionals to spur innovation, drive growth and sustain competitive advantage in the marketplace. Doing so enables Hydro Ottawa to offer additional customer value; create an inclusive culture that leverages diversity in everyday business enhancing engagement and innovation; and broadening involvement to initiatives and organizations that promote diversity, adding a new dimension to Hydro Ottawa's brand. Hydro Ottawa's diversity initiatives focus on attracting and engaging diverse populations represented within the current workforce and its customer communities, including: women, visible minorities, people with disabilities, those who identify as LGBT, and youth. Recognizing the value of immigrant populations within the Canadian workforce and, specifically, as an under-leveraged talent pool within the electricity sector, new Canadians are also considered to be a critical talent segment. Hydro Ottawa's focus on diversity consists of foundational initiatives intended to foster overall inclusion, complemented by specific initiatives targeted towards the identified diversity groups.

### 5.3 Strategic Talent Deployment

Hydro Ottawa's approach to talent deployment focuses on the strategic preparation and positioning of new hires and new people leaders in order to achieve reduced time to productivity and value realization, better integration of new hires into company culture, increased retention of new hires and a smoother transition of new people leaders. This approach ensures that new employees are proactively brought on board to replace employees leaving due to retirement or other forms of attrition, and that measures are in place to ensure the transfer of knowledge accumulated by older workers throughout their careers.

As Hydro Ottawa moves into 2016, its approach to strategic talent deployment ensures that resources are provided with optimal leadership and that productivity is enabled by effective organizational design. To this end, and in anticipation of prolonged leadership turnover as the result of retirements, Hydro Ottawa is ever mindful of its responsibility to ensure supervisory spans of control are designed to maximize onsite safety and productivity. Hydro Ottawa is further mindful of the need to yield productivity benefits through consolidation of work, rationalization of headcount for redeployment in trades hiring, and ongoing evaluation of possibilities to outsource work that is not considered to be a core or valued-added aspect of service delivery.

### 5.4 Knowledge Management and Transfer

With the prospect of losing a significant proportion of experienced workers to retirement over the next ten years, Hydro Ottawa must stem the loss of knowledge unique to the organization through effective knowledge transfer mechanisms. This is consistent with the findings reflected in "Knowledge Management and Transfer for the Electricity Industry in Canada,"[5] which supports mitigating initiatives against the loss of explicit and tacit knowledge within the electricity sector. With specialized skills powering our workforce and the risk of losing depth in our corporate knowledge base, Hydro Ottawa recognizes that engaging older workers and retirees is a key consideration in ensuring

[5] Knowledge Management and Transfer for the Electricity Sector in Canada, Electricity Sector Council, 2010

operational capacity and continuity. As a result, Hydro Ottawa has introduced an initiative aimed at:

- Delaying retirements, where appropriate, to maintain a culture that values experience and supports knowledge transfer opportunities.
- Determining how to best engage employees transitioning into retirement by leveraging ability for hiring overlaps for unique positions and integrating pre-retirement older workers into mentoring programs to enhance knowledge transfer.
- Exploring how retirees can continue to be engaged after retirement and remain Ambassadors in the community which includes establishing a retiree resource pool.
- Reviewing policies, practices and procedures to identify enhancements to better serve older workers and keep retirees engaged.

Branded as Prime Time to reflect that older workers are at the height of their careers rather than at the end, this initiative is in part responsible for increased retention of late-career experienced workers. In 2014 alone, the average age of retirement reached a peak of 60 years.

As part of its Prime Time offerings, Hydro Ottawa continues to support a knowledge transfer overlap to an experienced incumbent retiring from a unique position within the organization. In approving hiring overlaps of this nature, Hydro Ottawa is cognizant that each request must be assessed on a case-by-case to weigh the importance of a specific position to its business operations, the type of knowledge that must be transferred, and the required duration for knowledge transfer to occur. By adopting this methodology, Hydro Ottawa can ensure that the knowledge, skills and corporate memory are passed on to the next generation of the electricity workforce and that this transition is seamless. Without the implementation of knowledge transfer mechanisms, Hydro Ottawa is at risk of losing significant corporate memory, declines in productivity, compromised business continuity, and losses of intellectual capital.

### 5.5 Leadership Capability and Capacity

Over the next five years, 35% of Hydro Ottawa's existing people leaders will be eligible to retire, increasing to 57% by 2023. With this in mind, Hydro Ottawa continues to focus on replenishing its talent pipeline through effective succession planning and management activities.

As Hydro Ottawa continues to replenish the leadership pipeline, it also recognizes the sector-wide challenge of increasing overall leadership performance within electricity organizations. The Centre for Creative Leadership's 2009 study on "The Leadership Challenge in the Energy Sector" indicated that the top priority for leadership development into the future is to improve the ability to lead employees with notable skill gaps in building and leading a team, confronting difficult employee situations, building a broad functional orientation and career management.[6]

To strengthen the leadership capability of people leaders, Hydro Ottawa has a comprehensive approach to management and leadership development in which learning progresses from foundational to enrichment to leadership excellence. People leaders and emerging leaders receive targeted development opportunities which are supplemented by a coaching program to accelerate leadership development, in addition to mentorship opportunities with the aim of transferring knowledge cross-functionally and cross-generationally within the business.

## 6.0 CONCLUSION

Hydro Ottawa will continue to experience the effect of the changing landscape in which it operates, including experiencing the full impact of employee demographics and the associated loss of highly skilled, experienced and knowledgeable employees due to retirements and other attrition. The responses to this rapidly changing environment, if

[6] The Leadership Challenge in the Energy Sector, Centre for Creative Leadership, 2009.

not proactive and meaningful, will inevitably hamper the continued successes of the organization and challenge the organization's ability to fulfill its responsibilities to its customers. Hydro Ottawa must maintain and ensure that the current and future level of its business is sustained throughout these changing times by ensuring that it has a sufficient, sustainable and prepared workforce.

Hydro Ottawa's multi-prong workforce planning efforts are designed to synergistically manage the effects of the dynamically changing electricity industry while ensuring appropriate resources and skills are in place to meet the existing and long-term needs of the business and its customers.

# EMPLOYEE COMPENSATION

## 1.0 INTRODUCTION

This schedule sets out Hydro Ottawa Limited's ("Hydro Ottawa") approach to total compensation and its headcount actuals and projections.

Hydro Ottawa's approach to compensation is driven by the need to attract and retain a highly skilled workforce and to support a performance-driven work culture by appropriately and fairly rewarding performance in the achievement of the company's strategic direction, while at the same time controlling total compensation costs. Hydro Ottawa also rewards performance and productivity in accordance with the company's organizational values and position competencies.

## 2.0 TOTAL COMPENSATION

Hydro Ottawa's approach to total compensation consists of the following major components which reinforce the total value proposition: salaries, incentive-based pay for senior employees only, benefit plans, pension plan, premiums and allowances.

### 2.1 Merit-based Salaries

Hydro Ottawa's salary structure for executive, management and non-union employees consists of a number of salary scales representing positions of similar scope and responsibility. A formalized point factor system is in place to evaluate positions and determine the salary scale in which they are placed. This ensures internal equity. Salary scales are reviewed on an ad-hoc basis to ensure competitiveness within the utility, industrial and broader public sectors.

Employees are paid an annual salary within the salary scale based on education and experience. Annual increases to salaries, within the salary scales, are solely merit-based and determined by performance and contributions made in the previous year. A robust performance management system is in place for this purpose. An overall performance rating is established and a merit increase associated with the rating is provided. Performance and merit increases are directly tied to Hydro Ottawa's corporate performance scorecard, to ensure that the focus of this workforce segment[1] is aligned to the advancement of Hydro Ottawa's strategic direction.

In determining the appropriate range of merit increases associated with each performance rating, Hydro Ottawa reviews the national, provincial and local salary projections of major compensation consulting firms, including those projections for the utility and broader public sectors, as well as consumer price indices.

### 2.2 Incentive Based Pay

Since 2008, only senior management employees are eligible for annual incentive-based pay, as a component of their total cash compensation, which is expressed as a percentage of annual salary. These employees have a direct line of sight to the success of the company's strategic direction. Approximately 40 or less than 7% of employees are eligible for incentive-based pay in any given year.

Incentive-based pay is determined based on the achievement of financial and non-financial corporate, divisional and individual objectives. Financial targets and non-financial targets for senior management employees are established and approved each year by the Board of Directors and are designed to achieve continuous improvement in relation to the company's strategic direction, which include a number of strategic objectives focused on customer service, operational and organizational efficiency and effectiveness, and service reliability.

Table 1 below demonstrates the variability in this component of total cash compensation as it relates to the achievement of priorities.

[1] Executive, management and non-union employees.

**Table 1 – Average Annual Incentive-Based Pay**

| | 2012 Actuals | 2013 Actuals | 2014 Actuals | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| **Number of Employees** | 40 | 39 | 37 | 42 | 42 |
| **Average Amount** | $15,825 | $17,558 | $16,527 | $16,358 | $16,816 |

## 2.3 Collective Agreement

The International Brotherhood of Electrical Workers ("IBEW"), Local 636 represent Hydro Ottawa's unionized employees. This includes the company's trades, technical, clerical and administrative employees.

The current collective agreement is in effect from April 1, 2013 until March 31, 2017. The collective agreement provides for negotiated wage increases and employee step progressions. Negotiated wage increases are 2.6% for 2013, 2.7% for 2014, 2.7% for 2015 and 2.8% for 2016. The wage increases are on average 10% lower than the increases from the previous three year collective agreement.

A number of labour efficiencies were achieved during the most recent round of collective bargaining, some of which directly and indirectly relate to total compensation. These include longer periods of employment for temporary employees, improved distribution of overtime during emergencies, parameters with respect to responsibility pay, the pro-rating of leaves for new employees, the ability to designate specific vacation periods, a simplified process for the relocation of employees for accommodations, rationalization of flame resistant clothing, and an improved process for the replacement of tools and equipment.

## 2.4 Pension Plan

Hydro Ottawa employees are part of the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer, contributory, defined benefit pension plan established by the Province for employees of municipalities, local boards and school boards in Ontario. Pension benefits are determined by a formula based on the highest consecutive five-year average of contributory earnings and years of service. Both participating employers and participating employees are required to make equal contributions to the plan based on the participating employees' contributory earnings.

Employers and employees that are members of the OMERS pension plan contribute a lesser percentage on earnings received up to the annual Yearly Maximum Pensionable Earnings (YMPE), and a higher percentage on earnings above the YMPE. The YMPE is equal to the Canada Pension Plan (CPP) earnings limit as the OMERS pension plan is designed to work together with the CPP to provide a stable retirement income.

Hydro Ottawa's contribution rates to OMERS have steadily increased over the years from 7.4% in 2011 to 9% in 2015 for earnings below the YMPE and from 10.7% to 14.6% for earnings above the YMPE. In an effort to continue to reduce the funding deficit that occurred due to the 2008 global economic downturn, OMERS contribution rates increased in 2012 and 2013 and, due to better returns in 2013, contribution rates have remained unchanged since that time. The OMERS Sponsors Corporation put in place a Funding Management Strategy[2] in late 2014 which limits contribution rate increases at slightly more than 1% higher than the 2014 blended contribution rate. Given the continued deficit position of the OMERS pension plan, it is projected that over the period of this rate application contribution rates will likely increase, both below and above the annual YMPE, for the employee and employer portions respectively.

### 2.5 Insured Benefits

Hydro Ottawa's insured benefit plans provide employees with income security and protection from catastrophic and life events. Insured benefits coverage is provided to active full-time employees in the following areas:

- Health, including vision care, prescription drugs and paramedical services;
- Dental, including major dental and orthodontics services;
- Long term disability benefits;
- Short term disability benefits; and

[2] As described in *Managing the Benefits and Contributions of the OMERS Primary Plan*, October 27, 2014.

- Life Insurance

As part of the most recent round of collective bargaining in 2013, slight increases in some insured benefit provisions were made, spread out over the four year period of the collective agreement; however, at the same time, further cost containment measures were introduced to supplement those measures already in place, such as reasonable and customary limitations and generic substitution.

In addition, given the increasing costs over the last decade of Hydro Ottawa's insured benefit plans, along with the company's aging demographics, competitive marketing of the plans was undertaken in 2013. In late Q3 of 2014, Hydro Ottawa partnered with a new insured benefits provider for all of the company's insured benefit plans. This change resulted in the reduction of benefits premiums, streamlined administrative processes and enhanced self-serve options while ensuring the sustainability of the current level of benefits.

### 2.6 Post-Retirement Benefits

Hydro Ottawa's post-retirement benefits consist of life insurance and a small retirement grant for eligible employees primarily linked to positive attendance at work.

Hydro Ottawa completes a full actuarial valuation of the future value of the post-retirement benefits every three years, which is consistent with industry standards. In the interim years, an extrapolation is completed to determine if there has been a material change from the previous year.

The most recent actuarial valuation was performed as at December 31, 2014. A copy of this report is available in Attachment D-1 (B). The valuation determined that the accrued post-retirement life insurance obligation increased from 2013 to 2014, which is primarily attributable to a reduction in the discount rate used in 2014. The accrued retirement grant amount decreased from 2013 to 2014, which is attributable to the retirement of employees in 2013 that were paid their retirement grant, thereby reducing the company's future obligations.

Hydro Ottawa has taken steps to contain its future benefit costs by limiting the type, scope and applicability of post-retirement benefits.

## 3.0 HEADCOUNT

Hydro Ottawa has categorized employees/positions into three groups in calculating the total full time equivalents ("FTE"). These groups are comprised of full-time permanent equivalents and temporary equivalents (which can be full-time or part-time)[3].

- Management – includes executives, directors, managers, supervisors and senior professionals such as professional engineers.
- Non-Union – includes non-unionized professionals such as engineers-in-training, budget officers and executive assistants.
- Union – includes all employees who are represented by the IBEW.

The tables below summarize Hydro Ottawa's FTEs for 2012 Actual, 2013 Actual, 2014 Budget Forecast, 2015 Budget Forecast, and 2016 Budget Forecast. Hydro Ottawa's FTE count is determined using standard methodology. For the 2012 and 2013 actuals, FTE is a calculated value derived from the total regular hours paid each year divided by the regular hours of work scheduled each year by a single employee in that group. For the 2014, 2015 and 2016 forecasted budgets, FTE is calculated as all budgeted positions, adjusted for part-year budgeting for new positions.

### 3.1 Full-time Permanent Equivalents

Table 2 below illustrates Hydro Ottawa's forecasted plan to stabilize its total number of permanent full-time employees/positions.

[3] Summer students and co-op students are not included as these short term hires are viewed as developmental in nature.

**Table 2 – Full-time Permanent Equivalents**

| | 2012 Actuals | 2013 Actuals | 2014 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| **Management** | 129.1 | 124.4 | 128.7 | 132.6 | 132.6 |
| **Non-Union** | 36.7 | 44.0 | 42.1 | 39.7 | 39.7 |
| **Union** | 417.3 | 424.6 | 431.2 | 429.8 | 429.8 |
| **Total** | 583.1 | 593 | 602 | 602.1 | 602.1 |

Since 2012, the total number of full-time permanent management and non-union employees combined has remained relatively static. Increases to FTEs have been and are forecasted to be primarily in the union group. In accordance with its Workforce Planning Strategy (Exhibit D1-5-1), Hydro Ottawa is continuing to revitalize the trades employee-base to ensure a ready supply of trades talent to meet operational demand.

The management group FTEs decreased in 2013 versus 2012. This was largely attributable to not filling a number of positions when they became vacant due to employee departures and retirements. Hydro Ottawa employs a stringent vacancy management process to ensure that position replacements or backfills are justified and aligned with its Workforce Planning Strategy (Exhibit D1-5-1). The 2014 forecast shows a marginal increase in the total FTE count for the management and non-union groups combined, as a result of the requirement for additional developmental supervisory positions in order to meet safety and operational demand needs.

As Hydro Ottawa moves into 2015 and 2016, its Workforce Planning Strategy (Exhibit D1-5-1) outlines the principles by which it is moving forward in managing overall headcount within the organization as a whole while its trades are replenished by the redistribution of vacancies from support functions.

## 3.2 Temporary Equivalents

Table 3 below summarizes the number of actual and forecasted temporary equivalents for 2012 to 2016, which includes temporary full-time and part-time resources. In 2013, Hydro Ottawa increased its usage of a temporary workforce. This increase in temporary equivalents is attributable to Hydro Ottawa's efforts to have a more flexible workforce which addresses seasonal and other workloads and can be more easily adjusted upwards or downwards as required. Hydro Ottawa's 2014, 2015 and 2016 forecasts continue this approach, allowing the company to contain compensation costs.

**Table 3 – Temporary Equivalents (full-time or part-time)**

| | 2012 Actuals | 2013 Actuals | 2014 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| **Management** | 2.0 | 2.1 | 2.3 | 4.8 | 4.8 |
| **Non-Union** | 6.3 | 4.9 | 9.5 | 8.0 | 8.0 |
| **Union** | 2.0 | 10.8 | 14.0 | 7.7 | 7.7 |
| **Total** | 10.3 | 17.8 | 25.8 | 20.5 | 20.5 |

### 3.3 Full-time Permanent and Temporary Equivalents

Table 4 below provides the total number of actual and forecasted permanent and temporary FTEs, and demonstrates Hydro Ottawa's plan to stabilize its workforce.

**Table 4 – Full Time Equivalents – Permanent and Temporary**

| | 2012 Actuals | 2013 Actuals | 2014 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| **Management** | 131.1 | 126.4 | 131.0 | 137.5 | 137.5 |
| **Non-Union** | 43.1 | 48.8 | 51.6 | 47.7 | 47.7 |
| **Union** | 419.3 | 435.4 | 445.2 | 437.5 | 437.5 |
| **Total** | 593.5 | 610.6 | 627.8 | 622.7 | 622.7 |

In 2013 there was a net increase of FTEs over 2012. This overall increase is comprised of a reduction in the total FTEs for the management group and an increase in the union and non-union groups. The increase of FTEs in the union group was primarily due to the hiring of additional trades apprentices, journeypersons and technical employees consistent with Hydro Ottawa's Workforce Planning Strategy (Exhibit D1-5-1), as well as the use of more temporary equivalents. The increase in non-union FTEs is largely as a result of an increase in the number of engineers in training.

Table 4 also shows the number of FTEs in the 2015 and 2016 forecasts decreasing as compared with the total number of FTEs in the 2014 forecast.

## 4.0 TOTAL COMPENSATION

Table 5 below summarizes Hydro Ottawa's actual and forecasted total compensation including salary, wages and benefits from 2012 to 2016.

**Table 5 - Total Compensation (Salary, Wages, & Benefits)***

| | 2012 Actuals | 2013 Actuals | 2014 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| **Management** | $17,406,925 | $17,636,573 | $19,151,701 | $18,986,945 | $19,602,474 |
| **Non-Union** | $4,145,040 | $4,778,621 | $4,973,974 | $4,528,497 | $4,794,319 |
| **Union** | $39,353,778 | $42,601,466 | $43,963,563 | $45,573,310 | $47,547,490 |
| **Total** | $60,905,742 | $65,016,660 | $68,089,238 | $69,088,752 | $71,944,283 |

*Hydro Ottawa has completed Appendix 2-K, Employee Compensation Breakdown, (Attachment AC).

### 4.1 2013 Actuals versus 2012 Actuals

The total compensation increase from 2012 to 2013 is largely due to the increase in FTEs in the union and non-union groups as discussed in section 3.3 above, as well as an increase in OMERS contributions for 2013 as outlined above in section 2.4.

Additionally, there was an increase in overtime costs in 2013, primarily as a result of the mutual aid provided by Hydro Ottawa trades employees to Toronto Hydro, Hydro One and Hydro One Brampton in response to the restoration efforts arising from the significant ice storm which occurred in the Toronto area and across much of Eastern and Central Ontario in December 2013.

### 4.2 2014 Forecast versus 2013 Actual

The increase in the total compensation forecast for 2014 versus the actuals for 2013 is attributed to the forecasted increase in FTEs for all groups, in particular, the hiring of additional temporary employees as noted in Table 3 above and the requirement for additional developmental supervisory positions in order to meet safety and operational demand needs, as indicated in section 3.1 above.

### 4.3 2015 and 2016 Forecast versus 2014 Forecast

Hydro Ottawa's forecast for 2015 shows a slight decrease in total compensation for the management and non-union groups compared to the 2014 forecast. For the 2016 forecast, the total compensation for these groups is slightly above the 2014 forecast. This trending demonstrates Hydro Ottawa's commitment to prudently managing the total compensation for the management and non-union groups.

The increase in the 2015 and 2016 forecasted total compensation for the union group is based on the negotiated collective agreement wage increases as per 2.3 above and the revitalization of the trades, via the redistribution of vacancies from support functions, to ensure a ready supply of trades talent to meet operational demand.

The increase in the 2016 forecasted total compensation costs for all groups is also attributable to forecasted increases in benefit and pension costs, given the above noted wage increases and as a result of the expiry of a rate guarantee for certain benefit premiums.

### 4.4 2017 to 2020 Forecast

Hydro Ottawa's approach to compensation and its plan to stabilize its workforce is anticipated to continue throughout the 2017 to 2020 period. However, Hydro Ottawa must contend during this period with the increasing effects of its aging workforce and the significant volume of forecasted retirement eligibility which must be effectively addressed to ensure operational capacity and continuity. In addition, Hydro Ottawa will be faced with the need to continue planning and responding to the ever-changing business landscape including the anticipated challenges arising from technological innovations and the evolving and dynamic labour market conditions.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | D |
| **Tab:** | 1 |
| **Schedule:** | 8 |
| **Page:** | 1 |
| **Date:** | ORIGINAL |

# Appendix 2-K
# Employee Costs

| | 2012 Actuals | 2013 Actuals | 2014 Forecast | 2015 Forecast | 2016 Forecast |
|---|---|---|---|---|---|
| **Number of Employees (FTEs including Temporary)[1]** | | | | | |
| Management, including executive | 131.1 | 126.4 | 131.0 | 137.5 | 137.5 |
| Non-Union | 43.1 | 48.8 | 51.6 | 47.7 | 47.7 |
| Union | 419.3 | 435.4 | 445.2 | 437.5 | 437.5 |
| Total | 593.5 | 610.6 | 627.8 | 622.7 | 622.7 |
| **Total Salary and Wages including overtime and incentive pay** | | | | | |
| Management, including executive | $ 14,165,529 | $ 14,222,153 | $ 15,582,458 | $ 15,241,053 | $ 15,648,115 |
| Non-Union | $ 3,365,144 | $ 3,830,997 | $ 4,080,266 | $ 3,660,815 | $ 3,868,504 |
| Union | $ 31,839,026 | $ 34,215,448 | $ 35,569,909 | $ 36,832,143 | $ 38,242,411 |
| Total | $ 49,369,699 | $ 52,268,598 | $ 55,232,633 | $ 55,734,011 | $ 57,759,030 |
| **Total Benefits (Current + Accrued)** | | | | | |
| Management, including executive | $ 3,241,396 | $ 3,414,421 | $ 3,569,243 | $ 3,745,892 | $ 3,954,359 |
| Non-Union | $ 779,896 | $ 947,624 | $ 893,708 | $ 867,682 | $ 925,815 |
| Union | $ 7,514,751 | $ 8,386,018 | $ 8,393,653 | $ 8,741,167 | $ 9,305,079 |
| Total | $ 11,536,043 | $ 12,748,063 | $ 12,856,605 | $ 13,354,741 | $ 14,185,253 |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | |
| Management, including executive | $ 17,406,925 | $ 17,636,573 | $ 19,151,701 | $ 18,986,945 | $ 19,602,474 |
| Non-Union | $ 4,145,040 | $ 4,778,621 | $ 4,973,974 | $ 4,528,497 | $ 4,794,319 |
| Union | $ 39,353,778 | $ 42,601,466 | $ 43,963,563 | $ 45,573,310 | $ 47,547,490 |
| Total | $ 60,905,742 | $ 65,016,660 | $ 68,089,238 | $ 69,088,752 | $ 71,944,283 |

**Note:**
**[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.**

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# POST-RETIREMENT BENEFITS FOR EMPLOYEES OF HYDRO OTTAWA GROUP OF COMPANIES

## ACTUARIAL VALUATION AS AT DECEMBER 31, 2014

Prepared in January 2014

# Table of Contents

# INTRODUCTION

## PURPOSE

Hydro Ottawa Group of Companies ("Hydro Ottawa") retained the services of Morneau Shepell Ltd. to perform a valuation of post-retirement benefits as at December 31, 2014.

This report was prepared for Hydro Ottawa and its auditors in accordance with CICA 3461 for the following purposes:

- To determine the accrued benefit obligation as at December 31, 2014;
- To determine the benefit cost to be recognized in the financial statements for the fiscal year ending December 31, 2014;
- To determine the accrued benefit liability for post-retirement benefits as at December 31, 2014;
- To provide the information and the actuarial opinion required by Hydro Ottawa's auditors.

This report was also prepared for Hydro Ottawa and its auditors in accordance with IAS 19 for the following purposes:

- To determine as at January 1, 2014 the impact of the transition to IFRS and the 2014 expense (income) that will be used for comparative purposes;
- To provide an estimate of the 2015 expense (income).

The post-retirement benefits covered by this report are:

- Post-retirement life insurance program
- Retirement grant program

## EVOLUTION OF THE ACCRUED BENEFIT OBLIGATION

The table below shows the evolution of the accrued benefit obligation from December 31, 2013 to December 31, 2014.

| | Life Insurance $ | Retirement Grant $ |
|---|---|---|
| Accrued benefit obligation as at December 31, 2013 | 8,414,200 | 983,900 |
| Interest cost | 399,800 | 45,800 |
| Service cost | 154,000 | 44,000 |
| Benefit payments | (463,200) | (107,300) |
| Actuarial loss (gain) | 1,365,400 | (67,600) |
| Accrued benefit obligation as at December 31, 2014 | 9,870,200 | 898,800 |

## ACTUARIAL LOSSES (GAINS) BREAKDOWN

The table below shows the breakdown of the above actuarial gain and loss.

| Actuarial Loss / (Gain) | Life Insurance $ | Retirement Grant $ |
|---|---|---|
| New membership data | 400,300 | (48,100) |
| New termination rates assumption | (118,100) | (57,200) |
| Updated mortality assumption | (5,300) | (3,700) |
| New administration fees for life insurance | (56,200) | — |
| New interest rate (from 4.8% to 4%) | 1,144,700 | 41,400 |
| Total Loss (Gain) | 1,365,400 | (67,600) |

# SECTION 1 – ACCOUNTING RESULTS UNDER CICA 3461

The following tables present the 2014 fiscal year benefit cost and the December 31, 2014 funded position and accrued benefit liability for reporting purposes under CICA 3461. Further details can be found in Appendix D.

## INCOME STATEMENT ITEMS – 2014 BENEFIT COST

| | Life Insurance<br>$ | Retirement Grant<br>$ |
|---|---|---|
| Current Service Cost | 154,000 | 44,000 |
| Interest Cost | 399,800 | 45,800 |
| Actuarial Loss (Gain) | 1,365,400 | (67,600) |
| Benefit Cost (Credit) | 1,919,200 | 22,200 |

## RECONCILIATION BETWEEN FUNDED POSITION AND BALANCE SHEET AS AT DECEMBER 31, 2014

| | Life Insurance<br>$ | Retirement Grant<br>$ |
|---|---|---|
| Accrued Benefit Obligation (“ABO”) | 9,870,200 | 898,800 |
| Assets | — | — |
| Funded Position | (9,870,200) | (898,800) |
| | | |
| Unamortized Amounts: | | |
| Transitional Obligation | — | — |
| Actuarial Losses (gains) | — | — |
| Past Service Costs | — | — |
| Accrued Benefit Liability (balance sheet item) | (9,870,200) | (898,800) |

# SECTION 2 – TRANSITION TO IAS 19

In February 2013, the AcSB decided to defer the mandatory IFRS changeover date for rate-regulated entities to January 1, 2015. It is our understanding that Hydro Ottawa has elected this extension and will be changing over to IFRS in 2015.

The following table compares results at transition date (i.e. January 1, 2014) under CICA 3461 and IAS19. They are presented in aggregate although our accounting calculations are performed by plan.

## IMPACT OF TRANSITION TO IAS 19

| | CICA 3461 Jan 1, 2014 | IAS 19 Jan 1, 2014 | Transition Impact |
|---|---|---|---|
| Accrued Benefit Obligation | 9,398,100 | 9,398,100 | — |
| Assets | — | — | — |
| Funded Position | (9,398,100) | (9,398,100) | — |
| | | | |
| Unamortized Amounts: | | | |
| Actuarial Losses (gains) | — | — | — |
| Past Service Costs | — | — | — |
| Accrued Benefit Liability | (9,398,100) | (9,398,100) | — |
| Pre-tax adjustment to retained earnings | | | — |

Since there were no unamortized amounts as at January 1, 2014, the transition from CICA 3461 to IAS 19 has no impact.

The following table shows the 2014 benefit cost under IAS 19 for comparative purposes.

## 2014 BENEFIT COST UNDER IAS 19

| | Life Insurance $ | Retirement Grant $ |
|---|---|---|
| Current Service Cost | 154,000 | 44,000 |
| Interest Cost | 399,800 | 45,800 |
| Expense recognized through P&L | 553,800 | 89,800 |
| Actuarial Loss (Gain) recognized through the OCI | 1,365,400 | (67,600) |
| Total Benefit Cost | 1,919,200 | 22,200 |

The following table shows the 2015 estimated benefit cost under IAS 19.

## 2015 ESTIMATED BENEFIT COST UNDER IAS 19

| | Life Insurance $ | Retirement Grant $ |
|---|---|---|
| Current Service Cost | 181,500 | 41,300 |
| Interest Cost | 391,600 | 34,600 |
| Expense recognized through P&L | 573,100 | 75,900 |
| Actuarial Loss (Gain) recognized through the OCI | — | — |
| Total Benefit Cost | 573,100 | 75,900 |

# SECTION 3 - ACTUARIAL OPINION

With respect to the Post-Retirement Benefits plan for Employees of Hydro Ottawa Group of Companies and its subsidiaries,

We certify, to the best of our knowledge, the following:

1) The Post-Retirement Benefits other than Pension for employees of Hydro Ottawa Group of Companies are defined benefits for purposes of CICA 3461 and IAS 19.
2) Our valuation and extrapolation were made in accordance with the standards of the Canadian Institute of Actuaries (CIA). The financial statement items resulting from our valuation and extrapolation thereof have been determined in accordance with our understanding of CICA 3461 and IAS 19. We are aware that Hydro Ottawa's auditors intend to take into account our work. Our actuarial valuation and extrapolation thereof were performed using best-estimate assumptions developed by Hydro Ottawa as provided for in the accounting standard. Since best-estimate assumptions were used, we understand that they do not include any margin for adverse deviations. The discount rate selected by Hydro Ottawa was determined based on Morneau Shepell's methodology which complies with the Educational Note published by the Canadian Institute of Actuaries in September 2011. We do not express any opinion on the assumptions. The main assumptions used are detailed in appendix A.
3) The projected unit credit method prorated on service was used for the accounting valuation and the determination of the expense (income). It was applied in a manner consistent with CICA 3461 and IAS 19.
4) We have confirmed with the plan administrator that the plans' provisions are up to date as at the date of our valuation report. We have compared the provisions with the previous actuarial valuation and have validated any amendment that occurred on the basis of the values produced on the membership data. We have not been informed of any event that has occurred thereafter and that would materially affect the results of the actuarial valuation, the extrapolation or the financial statements of the company.
5) We are members in good standing of the Canadian Institute of Actuaries (CIA). Among the signatories of this opinion, at least one actuary holds the title of Fellow. We have all the necessary qualifications to carry out the work required to prepare the results contained in this document.
6) We have been duly appointed by the plan sponsor to prepare the above actuarial details at December 31, 2014 in accordance with the standards of the Canadian Institute of Actuaries.
7) We have used a materiality of $100,000 for the accrued benefit obligation.

We hereby declare that, in our opinion:

- The data on which this valuation is based are sufficient and reliable for the purpose of the valuation;
- This report has been prepared and our opinion given in accordance with accepted actuarial practice in Canada;
- Emerging experience differing from the assumptions may result in gains or losses. These will be revealed in future actuarial valuations.

We are available, at your convenience, to provide you with any additional information that you may require.

Best regards,

Louis Bernatchez, FCIA
Partner

Philippe Grégoire, ACIA
Consultant

MORNEAU SHEPELL
350 Sparks Street, Suite 601
Ottawa, Ontario K1R 7S8

# APPENDIX A – ACTUARIAL ASSUMPTIONS AND METHODS

The following table summarizes the actuarial assumptions used for the valuations.

## ACTUARIAL ASSUMPTIONS

| | December 31, 2013 | | December 31, 2014 | |
|---|---|---|---|---|
| Discount Rate | 4.8% | | 4.0% | |
| Mortality | CPM2014 – Private Sector<br>CPM improvement scale A<br>(draft version) | | CPM2014 – Private Sector<br>CPM improvement scale B<br>(final version) | |
| Termination of employment | Age | | Age | |
| | 20 | 10.0% | 20 | 7.0% |
| | 25 | 7.5% | 25 | 5.0% |
| | 30 | 5.0% | 30 | 5.0% |
| | 35 | 3.4% | 35 | 5.0% |
| | 40 | 2.4% | 40 | 3.0% |
| | 45 | 1.5% | 45 | 2.0% |
| | 50 | 0.0% | 50 | 2.0% |
| | 55 | 0.0% | 55 | 0.0% |
| Retirement age | Upon attainment of Rule of 90; or | | Upon attainment of Rule of 90; or | |
| | Completion of 30 years of service subject to a minimum of 55, and a maximum of 71 | | Completion of 30 years of service subject to a minimum of 55, and a maximum of 71 | |
| Salary increases | 3.10% | | 3.10% | |
| Expenses and taxes | 17.95% | | 17.40% | |
| Age difference between spouses | Women are 3 years younger than men | | Women are 3 years younger than men | |

## ACTUARIAL COST METHOD

For all active employees, the accrued benefit obligation and the current service cost were calculated using the "projected benefit method pro rated on service". According to this method, the accrued benefit obligation is equal to the actuarial present value of all future benefits (net of retiree cost sharing), taking into account the assumptions described above, multiplied by the ratio of an employee's service at the valuation date to total service at the full eligibility date.

The current service cost for a period for each member who has not reached the full eligibility date is equal to the actuarial present value of benefits attributed to the employee divided by the total service at full eligibility date.

For each member who is at or past the full eligibility date and each retiree, the accrued benefit obligation is determined as the actuarial present value of all future post-retirement benefits which will be paid on their behalf. The current service cost for members at or past the full eligibility date and for retirees is zero.

# APPENDIX B – MEMBERSHIP DATA

The accrued benefit obligation as at December 31, 2014 is based on data supplied to us by Hydro Ottawa in December 2014.

We have performed tests to verify reasonableness and internal consistency and are satisfied that the data is sufficient and reliable for the purposes of this valuation.

Statistics on the data are shown in the tables below:

## LIFE INSURANCE PROGRAM

| Summary of Membership Data | December 2011 | December 2014 |
|---|---|---|
| **Active Employees** | | |
| Number | 623 | 639 |
| Average age | 44.3 | 43.8 |
| Average service | 14.1 | 13.9 |
| Average salary | $77,200 | $83,200 |

| | | |
|---|---|---|
| **Retirees** | | |
| Number | 304 | 336 |
| Average age | 70.9 | 71.2 |
| Average insurance in force | $33,700 | $33,600 |

## RETIREMENT GRANT PROGRAM

| Summary of Membership Data | December 2011 | December 2014 |
|---|---|---|
| **Active Employees** | | |
| Number | 423 | 425 |
| Average age | 43.1 | 42.4 |
| Average service | 14.9 | 14.5 |
| Average salary | $67,800 | $73,900 |

# APPENDIX C – SUMMARY OF PLAN PROVISIONS

The following is a summary of the main provisions of post-retirement benefits for Hydro Ottawa. This summary is based on information provided by Hydro Ottawa.

| | |
|---|---|
| **Cost sharing** | 100% employer paid |

| | |
|---|---|
| **Retired members** | |
| Dependant coverage | None |

| | |
|---|---|
| Upon termination other than retirement or disability | No coverage |

| | |
|---|---|
| Upon retirement | |
| • With less than 10 years of service | Flat coverage of $2,000 |
| • With more than 10 years of service, and | |
| – Hired before May 1, 1967 | 70% of the amount for which you were insured, prior to retirement. |
| – Hired after May 1, 1967 and | |
| > Elected coverage under Options 2, 3, or 4 at any time prior to retirement | 50% of final annual earnings reducing by 2.5% at the end of each year following retirement for ten years, to a minimum of 25% |
| > Elected coverage under Option 1 | 50% of final annual earnings |

| Active members | |
|---|---|
| Retirement Grant | |
| | Eligibility: If 25 years of service at retirement<br>• four week's pay or<br>• a retirement grant<br>The retirement grant is based on the employee's sick leave record and is calculated as follows;<br>The amount of the retirement grant is the years of service (to a maximum of 35 days) multiplied by the sick leave factor. Allowance will be made of exclude one three-month illness (sixty working days) from the calculation.<br><br>Average Sick Leave usage per year — Eligibility<br>4.0 days — 100%<br>4.5 days — 80%<br>5.0 days — 60%<br>5.5 days — 40%<br>6.0 days — 20%<br>Over 6.0 days — 0% |

# APPENDIX D – ACCOUNTING SCHEDULE – CICA 3461

# Hydro Ottawa
# Retirement Grant
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **Basic information** | | | |
| **Defined benefit portion (DB)** | | | |
| . Total accrued benefit obligation (before past service costs) | 981 800 | 983 900 | 898 800 |
| . Total past service costs (Beginning of year) | 0 | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 981 800 | 983 900 | 898 800 |
| . Fair value of plan assets | 0 | 0 | 0 |
| . Plan surplus (deficit) | -981 800 | -983 900 | -898 800 |
| . Current service cost (employer) | | | |
| - Life insurance | 0 | 0 | 0 |
| - Retirement gratuity | 46 800 | 44 000 | 41 300 |
| - Total | 46 800 | 44 000 | 41 300 |
| . Contributions by the company | | | |
| . Expected | 147 900 | 147 700 | 151 000 |
| . Actual | 21 300 | 107 300 | 151 000 |
| . Average remaining service period | | | |
| - past service costs amortization | 15,3 | 15,3 | 15,8 |
| . Benefit Payments | | | |
| - Total expected | 147 900 | 147 700 | 151 000 |
| - Total actual | 21 300 | 107 300 | 151 000 |
| **Significant assumptions** | | | |
| . Benefit cost (current year) | | | |
| - Discount rate | 3,80% | 4,80% | 4,00% |
| - Rate of salary escalation | 3,10% | 3,10% | 3,10% |
| **I- Interest cost on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 981 800 | 983 900 | 898 800 |
| . Current service cost | 46 800 | 44 000 | 41 300 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit payments (mid-year) | -74 000 | -73 900 | -75 500 |
| . Average expected value of accrued benefit obligation | 954 600 | 954 000 | 864 600 |
| . Interest cost on accrued benefit obligation | 36 300 | 45 800 | 34 600 |
| **II- Actuarial gain (loss) on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 981 800 | 983 900 | 898 800 |
| . Current service cost | 46 800 | 44 000 | 41 300 |
| . Past service costs | 0 | 0 | 0 |
| . Interest cost on accrued benefit obligation | 36 300 | 45 800 | 34 600 |
| . Benefit payments | -21 300 | -107 300 | -151 000 |
| . Expected value of accrued benefit obligation | 1 043 600 | 966 400 | 823 700 |
| . Actual value of accrued benefit obligation | 983 900 | 898 800 | 823 700 |
| . Experience gain (loss) | 59 700 | 67 600 | 0 |

# Hydro Ottawa
# Retirement Grant
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **III- Determination of benefit cost** | | | |
| . Current service cost | 46 800 | 44 000 | 41 300 |
| . Interest cost on accrued benefit obligation | 36 300 | 45 800 | 34 600 |
| . Actuarial loss (gain) on obligation | -59 700 | -67 600 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit cost | 23 400 | 22 200 | 75 900 |
| | | | |
| **IV- Accrued benefit liability (asset)** | | | |
| . Opening balance | 981 800 | 983 900 | 898 800 |
| . Benefit cost for the year | 23 400 | 22 200 | 75 900 |
| . Contributions by the company | -21 300 | -107 300 | -151 000 |
| . Closing Balance | 983 900 | 898 800 | 823 700 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Opening balance | 981 800 | 983 900 | 898 800 |
| . Current service cost | 46 800 | 44 000 | 41 300 |
| . Interest cost on accrued benefit obligation | 36 300 | 45 800 | 34 600 |
| . Benefit payments | -21 300 | -107 300 | -151 000 |
| . Past service costs | 0 | 0 | 0 |
| . Actuarial loss (gain) | -59 700 | -67 600 | 0 |
| . Special event | 0 | 0 | 0 |
| . Closing balance | 983 900 | 898 800 | 823 700 |

**Reconciliation of accrued benefit obligation**
**to accrued benefit asset (liability) at end of year**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Plan assets at fair value | 0 | 0 | 0 |
| . Accrued benefit obligation | 983 900 | 898 800 | 823 700 |
| . Plan surplus (deficit) | -983 900 | -898 800 | -823 700 |
| . Unamortized transitional obligation (asset) | 0 | 0 | 0 |
| . Unamortized past service costs | 0 | 0 | 0 |
| . Unamortized net actuarial loss (gain) | 0 | 0 | 0 |
| . Accrued benefit asset (liability) | -983 900 | -898 800 | -823 700 |

**Assumptions**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Benefit cost (current year) | | | |
| - discount rate | 3,80% | 4,80% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |
| | | | |
| . Accrued benefit obligation (end of year) | | | |
| - discount rate | 4,80% | 4,00% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |

# Hydro Ottawa
# Energy - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **Basic information** | | | |
| **Defined benefit portion (DB)** | | | |
| . Total accrued benefit obligation (before past service costs) | 71 200 | 58 700 | 95 600 |
| . Total past service costs (Beginning of year) | 0 | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 71 200 | 58 700 | 95 600 |
| . Fair value of plan assets | 0 | 0 | 0 |
| . Plan surplus (deficit) | -71 200 | -58 700 | -95 600 |
| . Current service cost (employer) | | | |
| - Life insurance | 3 700 | 2 700 | 3 700 |
| - Retirement gratuity | 0 | 0 | 0 |
| - Total | 3 700 | 2 700 | 3 700 |
| . Contributions by the company | | | |
| . Expected | 1 100 | 900 | 1 900 |
| . Actual | 0 | 0 | 1 900 |
| . Average remaining service period | | | |
| - past service costs amortization | 16,8 | 16,8 | 18,0 |
| . Benefit Payments | | | |
| - Total expected | 1 100 | 900 | 1 900 |
| - Total actual | 0 | 0 | 1 900 |
| **Significant assumptions** | | | |
| . Benefit cost (current year) | | | |
| - Discount rate | 3,80% | 4,80% | 4,00% |
| - Rate of salary escalation | 3,10% | 3,10% | 3,10% |
| **I- Interest cost on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 71 200 | 58 700 | 95 600 |
| . Current service cost | 3 700 | 2 700 | 3 700 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit payments (mid-year) | -600 | -500 | -1 000 |
| . Average expected value of accrued benefit obligation | 74 300 | 60 900 | 98 300 |
| . Interest cost on accrued benefit obligation | 2 800 | 2 900 | 3 900 |
| **II- Actuarial gain (loss) on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 71 200 | 58 700 | 95 600 |
| . Current service cost | 3 700 | 2 700 | 3 700 |
| . Past service costs | 0 | 0 | 0 |
| . Interest cost on accrued benefit obligation | 2 800 | 2 900 | 3 900 |
| . Benefit payments | 0 | 0 | -1 900 |
| . Expected value of accrued benefit obligation | 77 700 | 64 300 | 101 300 |
| . Actual value of accrued benefit obligation | 58 700 | 95 600 | 101 300 |
| . Experience gain (loss) | 19 000 | -31 300 | 0 |

# Hydro Ottawa
# Energy - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **III- Determination of benefit cost** | | | |
| . Current service cost | 3 700 | 2 700 | 3 700 |
| . Interest cost on accrued benefit obligation | 2 800 | 2 900 | 3 900 |
| . Actuarial loss (gain) on obligation | -19 000 | 31 300 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit cost | -12 500 | 36 900 | 7 600 |
| | | | |
| **IV- Accrued benefit liability (asset)** | | | |
| . Opening balance | 71 200 | 58 700 | 95 600 |
| . Benefit cost for the year | -12 500 | 36 900 | 7 600 |
| . Contributions by the company | 0 | 0 | -1 900 |
| . Closing Balance | 58 700 | 95 600 | 101 300 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Opening balance | 71 200 | 58 700 | 95 600 |
| . Current service cost | 3 700 | 2 700 | 3 700 |
| . Interest cost on accrued benefit obligation | 2 800 | 2 900 | 3 900 |
| . Benefit payments | 0 | 0 | -1 900 |
| . Past service costs | 0 | 0 | 0 |
| . Actuarial loss (gain) | -19 000 | 31 300 | 0 |
| . Special event | 0 | 0 | 0 |
| . Closing balance | 58 700 | 95 600 | 101 300 |

**Reconciliation of accrued benefit obligation**
**to accrued benefit asset (liability) at end of year**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Plan assets at fair value | 0 | 0 | 0 |
| . Accrued benefit obligation | 58 700 | 95 600 | 101 300 |
| . Plan surplus (deficit) | -58 700 | -95 600 | -101 300 |
| . Unamortized transitional obligation (asset) | 0 | 0 | 0 |
| . Unamortized past service costs | 0 | 0 | 0 |
| . Unamortized net actuarial loss (gain) | 0 | 0 | 0 |
| . Accrued benefit asset (liability) | -58 700 | -95 600 | -101 300 |

**Assumptions**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Benefit cost (current year) | | | |
| - discount rate | 3,80% | 4,80% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |
| . Accrued benefit obligation (end of year) | | | |
| - discount rate | 4,80% | 4,00% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |

# Hydro Ottawa
# Hold Co. - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **Basic information** | | | |
| **Defined benefit portion (DB)** | | | |
| . Total accrued benefit obligation (before past service costs) | 202 300 | 185 100 | 170 000 |
| . Total past service costs (Beginning of year) | 0 | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 202 300 | 185 100 | 170 000 |
| . Fair value of plan assets | 0 | 0 | 0 |
| . Plan surplus (deficit) | -202 300 | -185 100 | -170 000 |
| . Current service cost (employer) | | | |
| - Life insurance | 39 000 | 29 900 | 23 700 |
| - Retirement gratuity | 0 | 0 | |
| - Total | 39 000 | 29 900 | 23 700 |
| . Contributions by the company | | | |
| . Expected | 0 | 0 | 0 |
| . Actual | 0 | 0 | 0 |
| . Average remaining service period | | | |
| - past service costs amortization | 17,6 | 17,6 | 14,5 |
| . Benefit Payments | | | |
| - Total expected | 0 | 0 | 0 |
| - Total actual | 0 | 0 | 0 |
| **Significant assumptions** | | | |
| . Benefit cost (current year) | | | |
| - Discount rate | 3,80% | 4,80% | 4,00% |
| - Rate of salary escalation | 3,10% | 3,10% | 3,10% |
| **I- Interest cost on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 202 300 | 185 100 | 170 000 |
| . Current service cost | 39 000 | 29 900 | 23 700 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit payments (mid-year) | 0 | 0 | 0 |
| . Average expected value of accrued benefit obligation | 241 300 | 215 000 | 193 700 |
| . Interest cost on accrued benefit obligation | 9 200 | 10 300 | 7 700 |
| **II- Actuarial gain (loss) on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 202 300 | 185 100 | 170 000 |
| . Current service cost | 39 000 | 29 900 | 23 700 |
| . Past service costs | 0 | 0 | 0 |
| . Interest cost on accrued benefit obligation | 9 200 | 10 300 | 7 700 |
| . Benefit payments | 0 | 0 | 0 |
| . Expected value of accrued benefit obligation | 250 500 | 225 300 | 201 400 |
| . Actual value of accrued benefit obligation | 185 100 | 170 000 | 201 400 |
| . Experience gain (loss) | 65 400 | 55 300 | 0 |

# Hydro Ottawa
# Hold Co. - Post Retirement Life
# CICA 3461

| **January 1st** | **2013** | **2014** | **2015** |
|---|---|---|---|
| | | | **(estimate)** |
| **III- Determination of benefit cost** | | | |
| . Current service cost | 39 000 | 29 900 | 23 700 |
| . Interest cost on accrued benefit obligation | 9 200 | 10 300 | 7 700 |
| . Actuarial loss (gain) on obligation | -65 400 | -55 300 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit cost | -17 200 | -15 100 | 31 400 |
| | | | |
| **IV- Accrued benefit liability (asset)** | | | |
| . Opening balance | 202 300 | 185 100 | 170 000 |
| . Benefit cost for the year | -17 200 | -15 100 | 31 400 |
| . Contributions by the company | 0 | 0 | 0 |
| . Closing Balance | 185 100 | 170 000 | 201 400 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Opening balance | 202 300 | 185 100 | 170 000 |
| . Current service cost | 39 000 | 29 900 | 23 700 |
| . Interest cost on accrued benefit obligation | 9 200 | 10 300 | 7 700 |
| . Benefit payments | 0 | 0 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Actuarial loss (gain) | -65 400 | -55 300 | 0 |
| . Special event | 0 | 0 | 0 |
| . Closing balance | 185 100 | 170 000 | 201 400 |

**Reconciliation of accrued benefit obligation**
**to accrued benefit asset (liability) at end of year**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Plan assets at fair value | 0 | 0 | 0 |
| . Accrued benefit obligation | 185 100 | 170 000 | 201 400 |
| . Plan surplus (deficit) | -185 100 | -170 000 | -201 400 |
| . Unamortized transitional obligation (asset) | 0 | 0 | 0 |
| . Unamortized past service costs | 0 | 0 | 0 |
| . Unamortized net actuarial loss (gain) | 0 | 0 | 0 |
| . Accrued benefit asset (liability) | -185 100 | -170 000 | -201 400 |

**Assumptions**

| | 2013 | 2014 | 2015 |
|---|---|---|---|
| . Benefit cost (current year) | | | |
| - discount rate | 3,80% | 4,80% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |
| . Accrued benefit obligation (end of year) | | | |
| - discount rate | 4,80% | 4,00% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |

# Hydro Ottawa
# LDC - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **Basic information** | | | |
| **Defined benefit portion (DB)** | | | |
| . Total accrued benefit obligation (before past service costs) | 9 871 900 | 8 170 400 | 9 604 600 |
| . Total past service costs (Beginning of year) | 0 | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 9 871 900 | 8 170 400 | 9 604 600 |
| . Fair value of plan assets | 0 | 0 | 0 |
| . Plan surplus (deficit) | -9 871 900 | -8 170 400 | -9 604 600 |
| . Current service cost (employer) | | | |
| - Life insurance | 167 800 | 121 400 | 154 100 |
| - Retirement gratuity | 0 | 0 | |
| - Total | 167 800 | 121 400 | 154 100 |
| . Contributions by the company | | | |
| . Expected | 518 700 | 473 400 | 516 000 |
| . Actual | 433 600 | 463 200 | 516 000 |
| . Average remaining service period | | | |
| - past service costs amortization | 13,7 | 13,7 | 13,4 |
| . Benefit Payments | | | |
| - Total expected | 518 700 | 473 400 | 516 000 |
| - Total actual | 433 600 | 463 200 | 516 000 |
| **Significant assumptions** | | | |
| . Benefit cost (current year) | | | |
| - Discount rate | 3,80% | 4,80% | 4,00% |
| - Rate of salary escalation | 3,10% | 3,10% | 3,10% |
| **I- Interest cost on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 9 871 900 | 8 170 400 | 9 604 600 |
| . Current service cost | 167 800 | 121 400 | 154 100 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit payments (mid-year) | -259 400 | -236 700 | -258 000 |
| . Average expected value of accrued benefit obligation | 9 780 300 | 8 055 100 | 9 500 700 |
| . Interest cost on accrued benefit obligation | 371 700 | 386 600 | 380 000 |
| **II- Actuarial gain (loss) on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 9 871 900 | 8 170 400 | 9 604 600 |
| . Current service cost | 167 800 | 121 400 | 154 100 |
| . Past service costs | 0 | 0 | 0 |
| . Interest cost on accrued benefit obligation | 371 700 | 386 600 | 380 000 |
| . Benefit payments | -433 600 | -463 200 | -516 000 |
| . Expected value of accrued benefit obligation | 9 977 800 | 8 215 200 | 9 622 700 |
| . Actual value of accrued benefit obligation | 8 170 400 | 9 604 600 | 9 622 700 |
| . Experience gain (loss) | 1 807 400 | -1 389 400 | 0 |

# Hydro Ottawa
# LDC - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **III- Determination of benefit cost** | | | |
| . Current service cost | 167 800 | 121 400 | 154 100 |
| . Interest cost on accrued benefit obligation | 371 700 | 386 600 | 380 000 |
| . Actuarial loss (gain) on obligation | -1 807 400 | 1 389 400 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit cost | -1 267 900 | 1 897 400 | 534 100 |
| | | | |
| **IV- Accrued benefit liability (asset)** | | | |
| . Opening balance | 9 871 900 | 8 170 400 | 9 604 600 |
| . Benefit cost for the year | -1 267 900 | 1 897 400 | 534 100 |
| . Contributions by the company | -433 600 | -463 200 | -516 000 |
| . Closing Balance | 8 170 400 | 9 604 600 | 9 622 700 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| . Opening balance | 9 871 900 | 8 170 400 | 9 604 600 |
| . Current service cost | 167 800 | 121 400 | 154 100 |
| . Interest cost on accrued benefit obligation | 371 700 | 386 600 | 380 000 |
| . Benefit payments | -433 600 | -463 200 | -516 000 |
| . Past service costs | 0 | 0 | 0 |
| . Actuarial loss (gain) | -1 807 400 | 1 389 400 | 0 |
| . Special event | 0 | 0 | 0 |
| . Closing balance | 8 170 400 | 9 604 600 | 9 622 700 |

**Reconciliation of accrued benefit obligation**
**to accrued benefit asset (liability) at end of year**

| | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| . Plan assets at fair value | 0 | 0 | 0 |
| . Accrued benefit obligation | 8 170 400 | 9 604 600 | 9 622 700 |
| . Plan surplus (deficit) | -8 170 400 | -9 604 600 | -9 622 700 |
| . Unamortized transitional obligation (asset) | 0 | 0 | 0 |
| . Unamortized past service costs | 0 | 0 | 0 |
| . Unamortized net actuarial loss (gain) | 0 | 0 | 0 |
| . Accrued benefit asset (liability) | -8 170 400 | -9 604 600 | -9 622 700 |

**Assumptions**

| | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| . Benefit cost (current year) | | | |
| - discount rate | 3,80% | 4,80% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |
| . Accrued benefit obligation (end of year) | | | |
| - discount rate | 4,80% | 4,00% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |

# Hydro Ottawa
# Total - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **Basic information** | | | |
| **Defined benefit portion (DB)** | | | |
| . Total accrued benefit obligation (before past service costs) | 10 145 400 | 8 414 200 | 9 870 200 |
| . Total past service costs (Beginning of year) | 0 | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 10 145 400 | 8 414 200 | 9 870 200 |
| . Fair value of plan assets | 0 | 0 | 0 |
| . Plan surplus (deficit) | -10 145 400 | -8 414 200 | -9 870 200 |
| . Current service cost (employer) | | | |
| - Life insurance | 210 500 | 154 000 | 181 500 |
| - Retirement gratuity | 0 | 0 | 0 |
| - Total | 210 500 | 154 000 | 181 500 |
| . Contributions by the company | | | |
| . Expected | 519 800 | 474 300 | 517 900 |
| . Actual | 433 600 | 463 200 | 517 900 |
| . Average remaining service period | | | |
| - past service costs amortization | 14,0 | 14,0 | 13,5 |
| . Benefit Payments | | | |
| - Total expected | 519 800 | 474 300 | 517 900 |
| - Total actual | 433 600 | 463 200 | 517 900 |
| **Significant assumptions** | | | |
| . Benefit cost (current year) | | | |
| - Discount rate | 3,80% | 4,80% | 4,00% |
| - Rate of salary escalation | 3,10% | 3,10% | 3,10% |
| **I- Interest cost on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 10 145 400 | 8 414 200 | 9 870 200 |
| . Current service cost | 210 500 | 154 000 | 181 500 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit payments (mid-year) | -259 900 | -237 200 | -259 000 |
| . Average expected value of accrued benefit obligation | 10 096 000 | 8 331 000 | 9 792 700 |
| . Interest cost on accrued benefit obligation | 383 700 | 399 800 | 391 600 |
| **II- Actuarial gain (loss) on accrued benefit obligation** | | | |
| . Accrued benefit obligation | 10 145 400 | 8 414 200 | 9 870 200 |
| . Current service cost | 210 500 | 154 000 | 181 500 |
| . Past service costs | 0 | 0 | 0 |
| . Interest cost on accrued benefit obligation | 383 700 | 399 800 | 391 600 |
| . Benefit payments | -433 600 | -463 200 | -517 900 |
| . Expected value of accrued benefit obligation | 10 306 000 | 8 504 800 | 9 925 400 |
| . Actual value of accrued benefit obligation | 8 414 200 | 9 870 200 | 9 925 400 |
| . Experience gain (loss) | 1 891 800 | -1 365 400 | 0 |

# Hydro Ottawa
# Total - Post Retirement Life
# CICA 3461

| January 1st | 2013 | 2014 | 2015 (estimate) |
|---|---|---|---|
| **III- Determination of benefit cost** | | | |
| . Current service cost | 210 500 | 154 000 | 181 500 |
| . Interest cost on accrued benefit obligation | 383 700 | 399 800 | 391 600 |
| . Actuarial loss (gain) on obligation | -1 891 800 | 1 365 400 | 0 |
| . Past service costs | 0 | 0 | 0 |
| . Benefit cost | -1 297 600 | 1 919 200 | 573 100 |
| **IV- Accrued benefit liability (asset)** | | | |
| . Opening balance | 10 145 400 | 8 414 200 | 9 870 200 |
| . Benefit cost for the year | -1 297 600 | 1 919 200 | 573 100 |
| . Contributions by the company | -433 600 | -463 200 | -517 900 |
| . Closing Balance | 8 414 200 | 9 870 200 | 9 925 400 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | | | |
|---|---|---|---|
| . Opening balance | 10 145 400 | 8 414 200 | 9 870 200 |
| . Current service cost | 210 500 | 154 000 | 181 500 |
| . Interest cost on accrued benefit obligation | 383 700 | 399 800 | 391 600 |
| . Benefit payments | -433 600 | -463 200 | -517 900 |
| . Past service costs | 0 | 0 | 0 |
| . Actuarial loss (gain) | -1 891 800 | 1 365 400 | 0 |
| . Special event | 0 | 0 | 0 |
| . Closing balance | 8 414 200 | 9 870 200 | 9 925 400 |

**Reconciliation of accrued benefit obligation**
**to accrued benefit asset (liability) at end of year**

| | | | |
|---|---|---|---|
| . Plan assets at fair value | 0 | 0 | 0 |
| . Accrued benefit obligation | 8 414 200 | 9 870 200 | 9 925 400 |
| . Plan surplus (deficit) | -8 414 200 | -9 870 200 | -9 925 400 |
| . Unamortized transitional obligation (asset) | 0 | 0 | 0 |
| . Unamortized past service costs | 0 | 0 | 0 |
| . Unamortized net actuarial loss (gain) | 0 | 0 | 0 |
| . Accrued benefit asset (liability) | -8 414 200 | -9 870 200 | -9 925 400 |

**Assumptions**

| | | | |
|---|---|---|---|
| . Benefit cost (current year) | | | |
| - discount rate | 3,80% | 4,80% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |
| . Accrued benefit obligation (end of year) | | | |
| - discount rate | 4,80% | 4,00% | 4,00% |
| - rate of salary escalation | 3,10% | 3,10% | 3,10% |

# APPENDIX E – ACCOUNTING SCHEDULE – IAS 19

# Hydro Ottawa
# Retirement Grant
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| Basic information | | |
| Defined benefit portion (DB) | | |
| . Accrued benefit obligation (before past service costs) | 983 900 | 898 800 |
| . Past service costs (Beginning of year) | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 983 900 | 898 800 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -983 900 | -898 800 |
| . Current service cost (employer) | 44 000 | 41 300 |
| . Expected Benefit Payments | 147 700 | 151 000 |
| . Actual Benefit Payments | 107 300 | 151 000 |
| Significant assumptions | | |
| . Benefit cost (current year) | | |
| . Discount rate | 4,80% | 4,00% |
| **I-** Interest cost on accrued benefit obligation | | |
| . Accrued benefit obligation | 983 900 | 898 800 |
| . Current service cost and employee contributions | 44 000 | 41 300 |
| . Past service costs | 0 | 0 |
| . Expected Benefit payments (mid-year) | -73 900 | -75 500 |
| . Average expected value of accrued benefit obligation | 954 000 | 864 600 |
| . Interest cost on accrued benefit obligation | 45 800 | 34 600 |
| **II-** Actuarial gain (loss) on accrued benefit obligation | | |
| . Accrued benefit obligation | 983 900 | 898 800 |
| . Current service cost and employee contributions | 44 000 | 41 300 |
| . Past service costs | 0 | 0 |
| . Interest cost on accrued benefit obligation | 45 800 | 34 600 |
| . Actual Benefit payments | -107 300 | -151 000 |
| . Expected value of accrued benefit obligation | 966 400 | 823 700 |
| . Actual value of accrued benefit obligation | 898 800 | 823 700 |
| . Experience gain (loss) | 67 600 | 0 |

# Hydro Ottawa
# Retirement Grant
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| **III-** Expense (income) | | |
| . Current service cost | 44 000 | 41 300 |
| . Past service cost (including curtailment) | 0 | 0 |
| **. Service cost** | **44 000** | **41 300** |
| . Interest cost on the accrued benefit obligation | 45 800 | 34 600 |
| **. Net interest on the net accrued benefit liability (asset)** | **45 800** | **34 600** |
| **. Expense (income) recognized in profit or loss** | **89 800** | **75 900** |
| **IV-** Remeasurements of the net defined benefit liability (asset) | | |
| . Actuarial loss (gain) on the accrued benefit obligation | -67 600 | 0 |
| **. Loss (gain) recognized in other comprehensive income** | **-67 600** | **0** |
| **V-** Components of the defined benefit cost | | |
| . Service cost | 44 000 | 41 300 |
| . Net interest on the net accured benefit liability (asset) | 45 800 | 34 600 |
| . Remeasurements of the net accrued benefit liability (asset) | -67 600 | 0 |
| . Accrued benefit cost | 22 200 | 75 900 |
| **VI-** Net defined benefit asset (liability) recognized in the statement of financial position | | |
| . Present value of the accrued benefit obligation | 898 800 | 823 700 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -898 800 | -823 700 |
| . Net accrued benefit asset (liability) | -898 800 | -823 700 |
| **VII-** Net defined benefit asset (liability) reconciliation | | |
| . Opening balance | -983 900 | -898 800 |
| . (Expense) income for the reporting period | -89 800 | -75 900 |
| . (Loss) gain recognized in other comprehensive income | 67 600 | 0 |
| . Contributions by the company | 107 300 | 151 000 |
| . Closing Balance | -898 800 | -823 700 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2014 | 2015 |
|---|---|---|
| . Opening balance | 983 900 | 898 800 |
| . Current service cost | 44 000 | 41 300 |
| . Interest cost on accrued benefit obligation | 45 800 | 34 600 |
| . Actual Benefit payments | -107 300 | -151 000 |
| . Past service costs | 0 | 0 |
| . Actuarial loss (gain) arising from plan experience | -48 100 | 0 |
| . Actuarial loss (gain) arising from changes in demographic assumptions | -60 900 | 0 |
| . Actuarial loss (gain) arising from changes in financial assumptions | 41 400 | 0 |
| . Curtailment gain | 0 | 0 |
| . Closing balance | 898 800 | 823 700 |

**Assumptions**

| | 2014 | 2015 |
|---|---|---|
| . Accrued benefit obligation (end of year) | | |
| - discount rate | 4,00% | 4,00% |

# Hydro Ottawa
# Energy - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | (estimate) |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| Basic information | | |
| Defined benefit portion (DB) | | |
| . Accrued benefit obligation (before past service costs) | 58 700 | 95 600 |
| . Past service costs (Beginning of year) | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 58 700 | 95 600 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -58 700 | -95 600 |
| . Current service cost (employer) | 2 700 | 3 700 |
| . Expected Benefit Payments | 900 | 1 900 |
| . Actual Benefit Payments | 0 | 1 900 |
| Significant assumptions | | |
| . Benefit cost (current year) | | |
| . Discount rate | 4,80% | 4,00% |
| **I-** Interest cost on accrued benefit obligation | | |
| . Accrued benefit obligation | 58 700 | 95 600 |
| . Current service cost and employee contributions | 2 700 | 3 700 |
| . Past service costs | 0 | 0 |
| . Expected Benefit payments (mid-year) | -500 | -1 000 |
| . Average expected value of accrued benefit obligation | 60 900 | 98 300 |
| . Interest cost on accrued benefit obligation | 2 900 | 3 900 |
| **II-** Actuarial gain (loss) on accrued benefit obligation | | |
| . Accrued benefit obligation | 58 700 | 95 600 |
| . Current service cost and employee contributions | 2 700 | 3 700 |
| . Past service costs | 0 | 0 |
| . Interest cost on accrued benefit obligation | 2 900 | 3 900 |
| . Actual Benefit payments | 0 | -1 900 |
| . Expected value of accrued benefit obligation | 64 300 | 101 300 |
| . Actual value of accrued benefit obligation | 95 600 | 101 300 |
| . Experience gain (loss) | -31 300 | 0 |

# Hydro Ottawa
# Energy - Post Retirement Life
# IAS 19

| January 1st | **2014** | **2015** |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| **III-** Expense (income) | | |
| . Current service cost | 2 700 | 3 700 |
| . Past service cost (including curtailment) | 0 | 0 |
| **. Service cost** | **2 700** | **3 700** |
| . Interest cost on the accrued benefit obligation | 2 900 | 3 900 |
| **. Net interest on the net accrued benefit liability (asset)** | **2 900** | **3 900** |
| **. Expense (income) recognized in profit or loss** | **5 600** | **7 600** |
| **IV-** Remeasurements of the net defined benefit liability (asset) | | |
| . Actuarial loss (gain) on the accrued benefit obligation | 31 300 | 0 |
| **. Loss (gain) recognized in other comprehensive income** | **31 300** | **0** |
| **V-** Components of the defined benefit cost | | |
| . Service cost | 2 700 | 3 700 |
| . Net interest on the net accured benefit liability (asset) | 2 900 | 3 900 |
| . Remeasurements of the net accrued benefit liability (asset) | 31 300 | 0 |
| . Accrued benefit cost | 36 900 | 7 600 |
| **VI-** Net defined benefit asset (liability) recognized in the statement of financial position | | |
| . Present value of the accrued benefit obligation | 95 600 | 101 300 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -95 600 | -101 300 |
| . Net accrued benefit asset (liability) | -95 600 | -101 300 |
| **VII-** Net defined benefit asset (liability) reconciliation | | |
| . Opening balance | -58 700 | -95 600 |
| . (Expense) income for the reporting period | -5 600 | -7 600 |
| . (Loss) gain recognized in other comprehensive income | -31 300 | 0 |
| . Contributions by the company | 0 | 1 900 |
| . Closing Balance | -95 600 | -101 300 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2014 | 2015 |
|---|---|---|
| . Opening balance | 58 700 | 95 600 |
| . Current service cost | 2 700 | 3 700 |
| . Interest cost on accrued benefit obligation | 2 900 | 3 900 |
| . Actual Benefit payments | 0 | -1 900 |
| . Past service costs | 0 | 0 |
| . Actuarial loss (gain) arising from plan experience | 18 700 | 0 |
| . Actuarial loss (gain) arising from changes in demographic assumptions | -3 000 | 0 |
| . Actuarial loss (gain) arising from changes in financial assumptions | 15 600 | 0 |
| . Curtailment gain | 0 | 0 |
| . Closing balance | 95 600 | 101 300 |

**Assumptions**

| | 2014 | 2015 |
|---|---|---|
| . Accrued benefit obligation (end of year) | | |
| - discount rate | 4,00% | 4,00% |

# Hydro Ottawa
# Hold Co. - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 (estimate) |
|---|---|---|
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| Basic information | | |
| Defined benefit portion (DB) | | |
| . Accrued benefit obligation (before past service costs) | 185 100 | 170 000 |
| . Past service costs (Beginning of year) | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 185 100 | 170 000 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -185 100 | -170 000 |
| . Current service cost (employer) | 29 900 | 23 700 |
| . Expected Benefit Payments | 0 | 0 |
| . Actual Benefit Payments | 0 | 0 |
| Significant assumptions | | |
| . Benefit cost (current year) | | |
| . Discount rate | 4,80% | 4,00% |
| **I-** Interest cost on accrued benefit obligation | | |
| . Accrued benefit obligation | 185 100 | 170 000 |
| . Current service cost and employee contributions | 29 900 | 23 700 |
| . Past service costs | 0 | 0 |
| . Expected Benefit payments (mid-year) | 0 | 0 |
| . Average expected value of accrued benefit obligation | 215 000 | 193 700 |
| . Interest cost on accrued benefit obligation | 10 300 | 7 700 |
| **II-** Actuarial gain (loss) on accrued benefit obligation | | |
| . Accrued benefit obligation | 185 100 | 170 000 |
| . Current service cost and employee contributions | 29 900 | 23 700 |
| . Past service costs | 0 | 0 |
| . Interest cost on accrued benefit obligation | 10 300 | 7 700 |
| . Actual Benefit payments | 0 | 0 |
| . Expected value of accrued benefit obligation | 225 300 | 201 400 |
| . Actual value of accrued benefit obligation | 170 000 | 201 400 |
| . Experience gain (loss) | 55 300 | 0 |

# Hydro Ottawa
# Hold Co. - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 (estimate) |
|---|---|---|
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| **III-** Expense (income) | | |
| . Current service cost | 29 900 | 23 700 |
| . Past service cost (including curtailment) | 0 | 0 |
| **. Service cost** | **29 900** | **23 700** |
| . Interest cost on the accrued benefit obligation | 10 300 | 7 700 |
| **. Net interest on the net accrued benefit liability (asset)** | **10 300** | **7 700** |
| **. Expense (income) recognized in profit or loss** | **40 200** | **31 400** |
| **IV-** Remeasurements of the net defined benefit liability (asset) | | |
| . Actuarial loss (gain) on the accrued benefit obligation | -55 300 | 0 |
| **. Loss (gain) recognized in other comprehensive income** | **-55 300** | **0** |
| **V-** Components of the defined benefit cost | | |
| . Service cost | 29 900 | 23 700 |
| . Net interest on the net accured benefit liability (asset) | 10 300 | 7 700 |
| . Remeasurements of the net accrued benefit liability (asset) | -55 300 | 0 |
| . Accrued benefit cost | -15 100 | 31 400 |
| **VI-** Net defined benefit asset (liability) recognized in the statement of financial position | | |
| . Present value of the accrued benefit obligation | 170 000 | 201 400 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -170 000 | -201 400 |
| . Net accrued benefit asset (liability) | -170 000 | -201 400 |
| **VII-** Net defined benefit asset (liability) reconciliation | | |
| . Opening balance | -185 100 | -170 000 |
| . (Expense) income for the reporting period | -40 200 | -31 400 |
| . (Loss) gain recognized in other comprehensive income | 55 300 | 0 |
| . Contributions by the company | 0 | 0 |
| . Closing Balance | -170 000 | -201 400 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2014 | 2015 |
|---|---|---|
| . Opening balance | 185 100 | 170 000 |
| . Current service cost | 29 900 | 23 700 |
| . Interest cost on accrued benefit obligation | 10 300 | 7 700 |
| . Actual Benefit payments | 0 | 0 |
| . Past service costs | 0 | 0 |
| . Actuarial loss (gain) arising from plan experience | -80 400 | 0 |
| . Actuarial loss (gain) arising from changes in demographic assumptions | -6 000 | 0 |
| . Actuarial loss (gain) arising from changes in financial assumptions | 31 100 | 0 |
| . Curtailment gain | 0 | 0 |
| . Closing balance | 170 000 | 201 400 |

**Assumptions**

| | 2014 | 2015 |
|---|---|---|
| . Accrued benefit obligation (end of year) | | |
| - discount rate | 4,00% | 4,00% |

# Hydro Ottawa
# LDC - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| Basic information | | |
| Defined benefit portion (DB) | | |
| . Accrued benefit obligation (before past service costs) | 8 170 400 | 9 604 600 |
| . Past service costs (Beginning of year) | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 8 170 400 | 9 604 600 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -8 170 400 | -9 604 600 |
| . Current service cost (employer) | 121 400 | 154 100 |
| . Expected Benefit Payments | 473 400 | 516 000 |
| . Actual Benefit Payments | 463 200 | 516 000 |
| Significant assumptions | | |
| . Benefit cost (current year) | | |
| . Discount rate | 4,80% | 4,00% |
| **I-** Interest cost on accrued benefit obligation | | |
| . Accrued benefit obligation | 8 170 400 | 9 604 600 |
| . Current service cost and employee contributions | 121 400 | 154 100 |
| . Past service costs | 0 | 0 |
| . Expected Benefit payments (mid-year) | -236 700 | -258 000 |
| . Average expected value of accrued benefit obligation | 8 055 100 | 9 500 700 |
| . Interest cost on accrued benefit obligation | 386 600 | 380 000 |
| **II-** Actuarial gain (loss) on accrued benefit obligation | | |
| . Accrued benefit obligation | 8 170 400 | 9 604 600 |
| . Current service cost and employee contributions | 121 400 | 154 100 |
| . Past service costs | 0 | 0 |
| . Interest cost on accrued benefit obligation | 386 600 | 380 000 |
| . Actual Benefit payments | -463 200 | -516 000 |
| . Expected value of accrued benefit obligation | 8 215 200 | 9 622 700 |
| . Actual value of accrued benefit obligation | 9 604 600 | 9 622 700 |
| . Experience gain (loss) | -1 389 400 | 0 |

# Hydro Ottawa
# LDC - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| **III-** Expense (income) | | |
| . Current service cost | 121 400 | 154 100 |
| . Past service cost (including curtailment) | 0 | 0 |
| **. Service cost** | **121 400** | **154 100** |
| . Interest cost on the accrued benefit obligation | 386 600 | 380 000 |
| **. Net interest on the net accrued benefit liability (asset)** | **386 600** | **380 000** |
| **. Expense (income) recognized in profit or loss** | **508 000** | **534 100** |
| **IV-** Remeasurements of the net defined benefit liability (asset) | | |
| . Actuarial loss (gain) on the accrued benefit obligation | 1 389 400 | 0 |
| **. Loss (gain) recognized in other comprehensive income** | **1 389 400** | **0** |
| **V-** Components of the defined benefit cost | | |
| . Service cost | 121 400 | 154 100 |
| . Net interest on the net accured benefit liability (asset) | 386 600 | 380 000 |
| . Remeasurements of the net accrued benefit liability (asset) | 1 389 400 | 0 |
| . Accrued benefit cost | 1 897 400 | 534 100 |
| **VI-** Net defined benefit asset (liability) recognized in the statement of financial position | | |
| . Present value of the accrued benefit obligation | 9 604 600 | 9 622 700 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -9 604 600 | -9 622 700 |
| . Net accrued benefit asset (liability) | -9 604 600 | -9 622 700 |
| **VII-** Net defined benefit asset (liability) reconciliation | | |
| . Opening balance | -8 170 400 | -9 604 600 |
| . (Expense) income for the reporting period | -508 000 | -534 100 |
| . (Loss) gain recognized in other comprehensive income | -1 389 400 | 0 |
| . Contributions by the company | 463 200 | 516 000 |
| . Closing Balance | -9 604 600 | -9 622 700 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2014 | 2015 |
|---|---|---|
| . Opening balance | 8 170 400 | 9 604 600 |
| . Current service cost | 121 400 | 154 100 |
| . Interest cost on accrued benefit obligation | 386 600 | 380 000 |
| . Actual Benefit payments | -463 200 | -516 000 |
| . Past service costs | 0 | 0 |
| . Actuarial loss (gain) arising from plan experience | 462 000 | 0 |
| . Actuarial loss (gain) arising from changes in demographic assumptions | -114 400 | 0 |
| . Actuarial loss (gain) arising from changes in financial assumptions | 1 041 800 | 0 |
| . Curtailment gain | 0 | 0 |
| . Closing balance | 9 604 600 | 9 622 700 |

**Assumptions**

| | 2014 | 2015 |
|---|---|---|
| . Accrued benefit obligation (end of year) | | |
| - discount rate | 4,00% | 4,00% |

# Hydro Ottawa
# Total - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 |
|---|---|---|
| | | **(estimate)** |
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| Basic information | | |
| Defined benefit portion (DB) | | |
| . Accrued benefit obligation (before past service costs) | 8 414 200 | 9 870 200 |
| . Past service costs (Beginning of year) | 0 | 0 |
| . Total accrued benefit obligation (after past service costs) | 8 414 200 | 9 870 200 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -8 414 200 | -9 870 200 |
| . Current service cost (employer) | 154 000 | 181 500 |
| . Expected Benefit Payments | 474 300 | 517 900 |
| . Actual Benefit Payments | 463 200 | 517 900 |
| Significant assumptions | | |
| . Benefit cost (current year) | | |
| . Discount rate | 4,80% | 4,00% |
| **I-** Interest cost on accrued benefit obligation | | |
| . Accrued benefit obligation | 8 414 200 | 9 870 200 |
| . Current service cost and employee contributions | 154 000 | 181 500 |
| . Past service costs | 0 | 0 |
| . Expected Benefit payments (mid-year) | -237 200 | -259 000 |
| . Average expected value of accrued benefit obligation | 8 331 000 | 9 792 700 |
| . Interest cost on accrued benefit obligation | 399 800 | 391 600 |
| **II-** Actuarial gain (loss) on accrued benefit obligation | | |
| . Accrued benefit obligation | 8 414 200 | 9 870 200 |
| . Current service cost and employee contributions | 154 000 | 181 500 |
| . Past service costs | 0 | 0 |
| . Interest cost on accrued benefit obligation | 399 800 | 391 600 |
| . Actual Benefit payments | -463 200 | -517 900 |
| . Expected value of accrued benefit obligation | 8 504 800 | 9 925 400 |
| . Actual value of accrued benefit obligation | 9 870 200 | 9 925 400 |
| . Experience gain (loss) | -1 365 400 | 0 |

# Hydro Ottawa
# Total - Post Retirement Life
# IAS 19

| January 1st | 2014 | 2015 (estimate) |
|---|---|---|
| | 2014-01-01 | 2015-01-01 |
| | 2014-12-31 | 2015-12-31 |
| **III-** Expense (income) | | |
| . Current service cost | 154 000 | 181 500 |
| . Past service cost (including curtailment) | 0 | 0 |
| **. Service cost** | **154 000** | **181 500** |
| . Interest cost on the accrued benefit obligation | 399 800 | 391 600 |
| **. Net interest on the net accrued benefit liability (asset)** | **399 800** | **391 600** |
| **. Expense (income) recognized in profit or loss** | **553 800** | **573 100** |
| **IV-** Remeasurements of the net defined benefit liability (asset) | | |
| . Actuarial loss (gain) on the accrued benefit obligation | 1 365 400 | 0 |
| **. Loss (gain) recognized in other comprehensive income** | **1 365 400** | **0** |
| **V-** Components of the defined benefit cost | | |
| . Service cost | 154 000 | 181 500 |
| . Net interest on the net accured benefit liability (asset) | 399 800 | 391 600 |
| . Remeasurements of the net accrued benefit liability (asset) | 1 365 400 | 0 |
| . Accrued benefit cost | 1 919 200 | 573 100 |
| **VI-** Net defined benefit asset (liability) recognized in the statement of financial position | | |
| . Present value of the accrued benefit obligation | 9 870 200 | 9 925 400 |
| . Fair value of plan assets | 0 | 0 |
| . Plan surplus (deficit) | -9 870 200 | -9 925 400 |
| . Net accrued benefit asset (liability) | -9 870 200 | -9 925 400 |
| **VII-** Net defined benefit asset (liability) reconciliation | | |
| . Opening balance | -8 414 200 | -9 870 200 |
| . (Expense) income for the reporting period | -553 800 | -573 100 |
| . (Loss) gain recognized in other comprehensive income | -1 365 400 | 0 |
| . Contributions by the company | 463 200 | 517 900 |
| . Closing Balance | -9 870 200 | -9 925 400 |

**ADDITIONAL DISCLOSURE ITEMS REQUIRED**

**Reconciliation of Accrued Benefit Obligation**

| | 2014 | 2015 |
|---|---|---|
| . Opening balance | 8 414 200 | 9 870 200 |
| . Current service cost | 154 000 | 181 500 |
| . Interest cost on accrued benefit obligation | 399 800 | 391 600 |
| . Actual Benefit payments | -463 200 | -517 900 |
| . Past service costs | 0 | 0 |
| . Actuarial loss (gain) arising from plan experience | 400 300 | 0 |
| . Actuarial loss (gain) arising from changes in demographic assumptions | -123 400 | 0 |
| . Actuarial loss (gain) arising from changes in financial assumptions | 1 088 500 | 0 |
| . Curtailment gain | 0 | 0 |
| . Closing balance | 9 870 200 | 9 925 400 |

**Assumptions**

| | 2014 | 2015 |
|---|---|---|
| . Accrued benefit obligation (end of year) | | |
| - discount rate | 4,00% | 4,00% |

# HEALTH, SAFETY AND ENVIRONMENT

## 1.0 INTRODUCTION

As a company with deep roots in the community, established through more than 100 years of providing an essential service to homes and businesses, Hydro Ottawa Limited's ("Hydro Ottawa") customers expect the company to safely, responsibly and efficiently deliver electricity in a manner that protects the health and safety of employees, contracted partners, customers, and the broader community while also being a good steward of the environment we all share. Hydro Ottawa is fully committed to meeting that expectation.

Hydro Ottawa has adopted a best practice, continual improvement approach to meet legislative and regulatory requirements in the areas of health, safety and environment; and to maintain standards of performance relative to risks associated with its ongoing business activities. In 2014, Hydro Ottawa successfully obtained re-registration of its integrated health, safety and environmental management system certified to the International Organization for Standardization (ISO) 14001:2004 and the Occupational Health and Safety Assessment Series (OHSAS) 18001:2007. This registration has been consistently maintained since 2008.

## 2.0 EMPLOYEE SAFETY

At the core of Hydro Ottawa's business is the fundamental commitment to protecting the health and safety of employees. The foundation of occupational health and safety in Ontario, and at Hydro Ottawa is the internal responsibility system. This model has roles and responsibilities for all parties in the workplace, and for those associated with the workplace that have decision making or financial authority for the organization.

### 2.1 Internal Responsibility System

Hydro Ottawa has entrenched the internal responsibility system in the organization as both a general philosophy of shared accountability and as a direct reflection of the specific roles and responsibilities required by legislation and regulations. Building upon this basic model, Hydro Ottawa has a corporate Occupational Health, Safety and Environmental (OHSE) Accountability Program which details a number of specific OHSE activities required by each party in the workplace, in addition to their job-specific duties.

Further strengthening the internal responsibility and accountability model is the OHSE Management Framework, a structured system of management review, discussion and recommendation involving employees from the Supervisor to the Executive level. In addition to oversight at each level of management, Hydro Ottawa has a multi-workplace Joint Health and Safety Committee (JHSC) which functions within a mandate established by Terms of Reference approved by the Ministry of Labour. This mandate includes inspection, recommendation and worker representation functions for the various occupations and workplaces at Hydro Ottawa.

As part of the OHSE Management Framework, Hydro Ottawa exercises appropriate due diligence, and complies with legislative and regulatory requirements, by:

- establishing instruction, training and orientation programs for operational areas;
- auditing or reviewing the workplace for foreseeable health, safety and environmental risks;
- having policies, programs, procedures, processes and work instructions in place to protect workers and the environment against risks;
- actively demonstrating a strong, sustainable level of commitment to the health and safety of workers and to minimizing harm to the environment by reviewing regular reports on the operation of the occupational health, safety and environmental programs, particularly incidents and cases of non-compliance with legislation and regulations; and
- maintaining documents and records via a formal document/records management system.

### 2.2 Integrated Occupational Health, Safety and Environmental (OHSE) Management System

To ensure that the company's OHSE programs are current, effective and well-managed, Hydro Ottawa utilizes a structured focus on compliance together with a formal, documented approach to continual improvement.

This approach has been applied through the adoption of an integrated OHSE management system registered to the international ISO 14001 environmental standard and the OHSAS 18001 health and safety specification. These standards are based on the principles of planning, implementing, monitoring, measuring and pursuing continual improvement in Hydro Ottawa's OHSE programs and performance. Hydro Ottawa's integrated OHSE management system includes program elements on risk management, legal requirements, roles and responsibilities, competence and training, communication and consultation, document and record management, emergency preparedness and response, compliance evaluation, investigation and corrective action processes, audit and management review processes.

### 2.3 Safety Training

Training is not only a legislative requirement under the *Occupational Health and Safety Act* and other key statues and codes that govern Hydro Ottawa, but it also contributes to higher employee efficiency and safer operations. As depicted in Figure 1, Hydro Ottawa provides an average of over 40 hours of safe work practices training annually for all trades employees whose work is carried out in higher hazard environments, and an average of over 20 hours for all employees.

**Figure 1 – Safe Work Practices Training**


In addition to the increasing training needs that accompany apprenticeship programs, an emerging pressure that Hydro Ottawa is experiencing is the substantial increase in legislated health and safety related education and training in the province of Ontario. Recent initiatives related to worker and supervisor knowledge of the *Occupational Health and Safety Act* (Bill 160), the new Working at Heights training standard, and pending changes resulting from the Globally Harmonized System (replacement for Workplace Hazardous Materials Information System) will result in additional cost pressures for the company in both direct training development and delivery, and loss of productive time. This pressure will continue to grow as the Ministry of Labour develops and mandates additional training standards over the next five years.

Integral to Hydro Ottawa's OHSE management system, and its OHSE Accountability Program, all supervisors at Hydro Ottawa share a common performance deliverable tied to workplace safety. In 2010, Hydro Ottawa recognized an opportunity to position new operational supervisors for accelerated proficiency through the development of a Safe Supervisor Program. Implemented in 2011, this program provides new operational supervisors with the critical and substantial safety knowledge and skills needed for performance in their roles through intensive training and development that includes practical learning in the areas of audits, field inspections, incident investigations, equipment inspections, leading safety meetings and other activities. Partnered with a Safety Specialist who oversees their development as a mentor, operational supervisors receive development progress reports that formally assess their learning against expectations tied to the key OHSE knowledge and skills required to undertake their supervisory responsibilities.

### 2.4 Contractor Management

The importance of safety in Hydro Ottawa's operations extends beyond its own employees to include contractors who perform work on the company's behalf. Continued use of contractors is required to meet Hydro Ottawa's peak construction and maintenance needs, and safe, efficient and high quality performance from contractors is essential to the delivery of electricity to Hydro Ottawa's customers. To effectively manage projects involving contractors, Hydro Ottawa utilizes a project management methodology and a contractor OHSE management program, which align project planning and implementation activities as they relate to contractors and sub-contractors.

In 2014, Hydro Ottawa expanded and enhanced its contractor management program by partnering with a contractor management firm to implement more comprehensive and cost effective contractor pre-qualification and compliance monitoring processes. This partnership has resulted in the automation of previously manual processes; the provision of contractor performance scorecarding, benchmarking and trending capabilities; and the ability to do more in-depth review and tracking of contractor safety programs, worker training and competencies, and work performance.

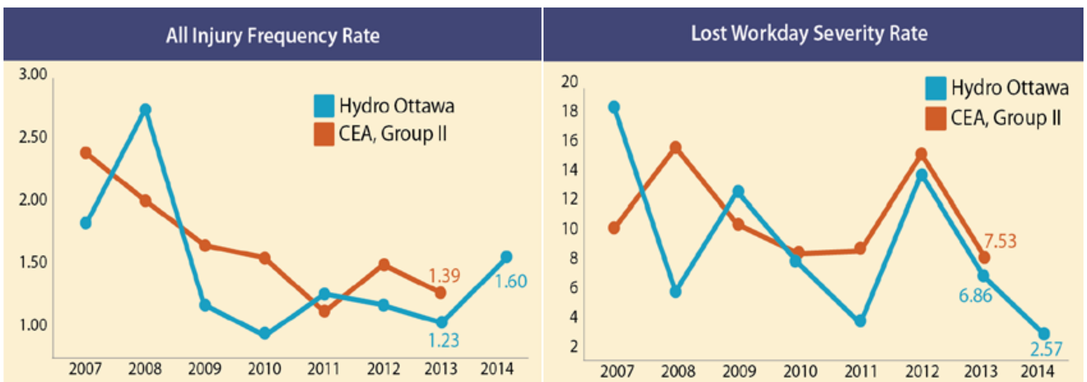
### 2.5 Safety Inspections

The number of safety inspections of Hydro Ottawa and contractor crews has doubled over recent years as part of efforts to more proactively manage safety risks. Over the 2016 to 2020 period, Hydro Ottawa is planning to leverage mobile tools and technology to enable more flexible and efficient completion, recording and reporting of health and safety related planning and monitoring activities such as Supervisor, and JHSC workplace inspections, Supervisor and Safety Specialist site visits and incident investigations, and tailboards. These tools and technologies will eliminate paper-based recording in the field, and enable Hydro Ottawa to more effectively and efficiently report on the findings and follow up actions resulting from these activities through enhanced analytics and reporting functionality.

### 2.6 Performance and Results

Hydro Ottawa's safety programs continue to show positive performance results with rates at or below the Canadian Electricity Association (CEA) Group II[1] average, Figure 2, from 2010 to 2013 for lost workday severity rate, and similar trending in the last two years for all injury frequency rate.

**Figure 2 – Comparison: All Injury Frequency and Lost Workday Severity Rates**

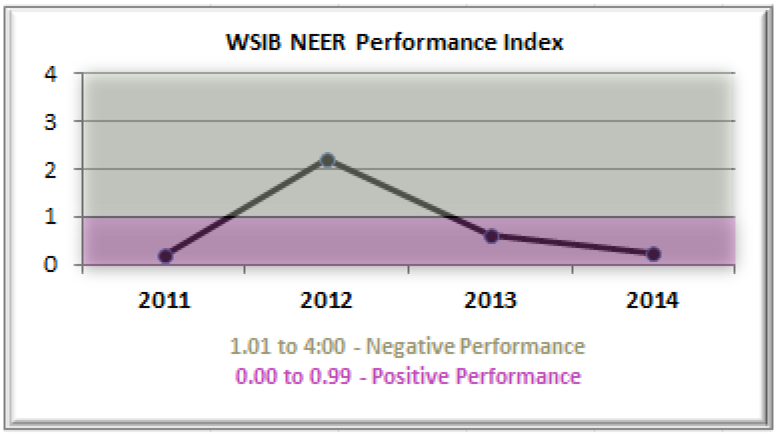



*CEA 2014 rates are not yet available.

The Workplace Safety and Insurance Board (WSIB) classify firms into rate groups based on their activities. Hydro Ottawa is in the oil, power and water distribution rate group which pays a premium that is one of the lowest rates that the WSIB charges employers. Hydro Ottawa's WSIB New Experimental Experience Rating (NEER) costs and performance index, Figure 3, shows positive performance in the last two years as a result of effective accident prevention programs and diligent case management.

[1] CEA member organizations with 301 to 1,500 employees.

**Figure 3 – WSIB NEER Performance Index**




Hydro Ottawa's continued focus on working safely has also resulted in the Infrastructure Health and Safety Association's (IHSA) President's Award in 2013 for completing one million person hours of work without experiencing a lost time injury, and Outstanding Achievement Awards from the Canadian Society of Safety Engineering (CSSE), at both the local and national levels, in 2013 for the Safe Supervisor Program.

## 3.0 EMPLOYEE HEALTH AND WELLNESS

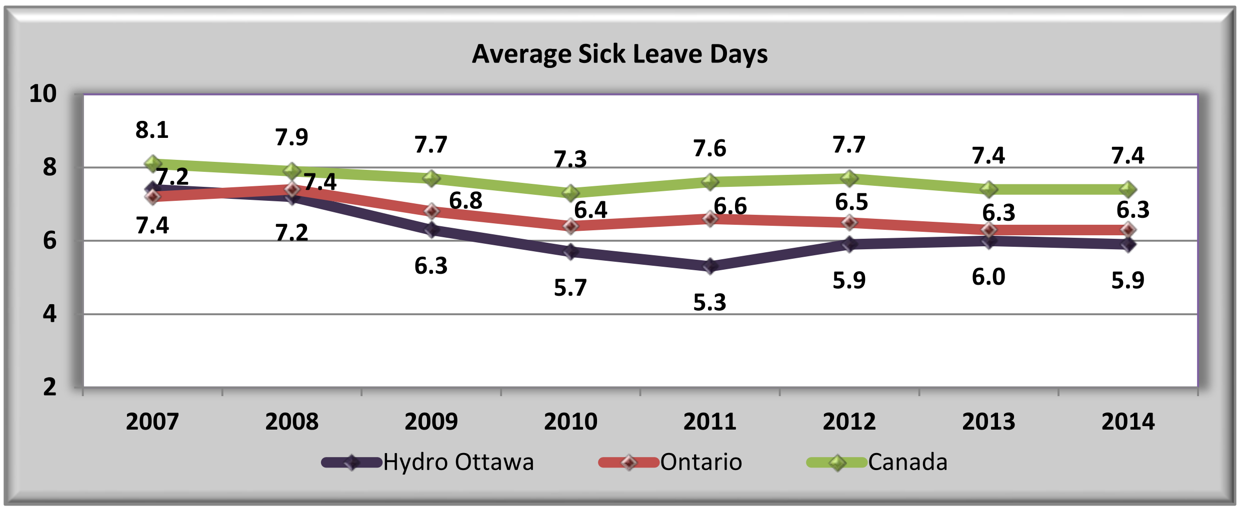
Along with an emphasis on safety, healthy and well employees lead to a more productive workforce. Hydro Ottawa has programs and strategies in place to help prevent illness and injury and reduce the associated lost time. This includes programs to alleviate soft tissue injuries given that half of the employees perform physically demanding jobs, occupational and non-occupational illness/injury work re-integration programs to ensure employees return to work early and safe and perform in a meaningful way, and other supports to promote employee health and wellness over the long term.

### 3.1 Attendance Management Program

Hydro Ottawa's Attendance Management Program monitors employee attendance, recognizes positive attendance and provides the framework for addressing excessive absenteeism. Hydro Ottawa's average number of sick days per employee in 2013 was 6.

This was below the Ontario and Canada benchmarks of 6.3 days and 7.4 days per employee respectively. In 2014, Hydro Ottawa's average number of sick days per employee decreased slightly to 5.9 and continues to be lower than the Ontario and Canada benchmarks as indicated in Figure 4.

**Figure 4 – Comparison: Average Sick Leave Days**




Ontario and Canada Data Source: Statistics Canada – Days Lost per Worker – Illness or Disability (Full time paid workers)

## 4.0 PUBLIC SAFETY

### 4.1 Compliance

Hydro Ottawa takes the health and safety of the public as seriously as it does the health and safety of its employees. Public safety is considered in all phases of Hydro Ottawa's operations from facility and equipment design, through construction to operations and maintenance. All job planning activities take into account public safety, so that the public is not adversely affected by construction and maintenance activities conducted on Hydro Ottawa property, on customer property and along the many city roadways where infrastructure is located. To ensure compliance under Regulation 22/04 which requires electrical utilities to design, build and maintain their distribution infrastructure to recognized standards, Hydro Ottawa participates in multiple Electrical Safety Authority (ESA) due diligence inspections per year, as well as two ESA compliance audits.

### 4.2 Public Education

The other major component of public safety is that of education. Hydro Ottawa provides highly visible signage warning of hazards on all of its distribution substations and ground level transformers. Hydro Ottawa works to foster a culture of safety and energy conservation in the community through a number of education campaigns. Since 2005, more than 1,300 presentations in 197 elementary schools across the Ottawa community have been delivered, training more than 161,000 students. Additional information on electrical safety and conservation is provided on the company's website.

## 5.0 ENVIRONMENT

### 5.1 Environmental Compliance

Hydro Ottawa is subject to federal, provincial and municipal environmental legislation and regulations, and in order to ensure compliance, Hydro Ottawa continually monitors for legislative and regulatory changes that may impose additional duties, requirements or costs on the organization. If any changes are identified, Hydro Ottawa revises its practices and procedures if and as required. Hydro Ottawa also regularly monitors its current regulatory approvals and permits to ensure they are complied with and renewed as required. Hydro Ottawa's operations require that a variety of environmental reports be submitted at scheduled and ad-hoc intervals throughout a year to ensure compliance, such as the Ontario Ministry of Environment's Director's Instructions related to the storage and destruction of polychlorinated biphenyls (PCBs), the National Pollutant Release Inventory and the Ontario Hazardous Waste Inventory Network. In addition, Hydro Ottawa performs quarterly chemical and waste storage inspections and provides ad-hoc spill reports to the Ontario Ministry of Environment.

Throughout any year, Hydro Ottawa can experience a number of unexpected releases of substances into the environment, with the majority of these releases coming from oil filled transformers that fail due to age or because they are damaged. Hydro Ottawa has a 24-hour response system, with employees trained to promptly report releases to the Ministry of Environment and to organize immediate response through an on-call spill remediation contractor. Field employees receive training in spill reporting and containment, with large vehicles carrying spill response kits to provide basic containment. The spill kits contain protective equipment for employees, absorbent materials and mats to prevent spill entry into sensitive areas.

Hydro Ottawa is working to actively eliminate PCBs from its electrical distribution system. Federal regulations introduced in 2008 established end of use dates for all PCBs from 2009 to 2025, depending upon the location and concentration of PCBs. Hydro Ottawa has fulfilled all requirements to date and to ensure compliance with the 2025 end of use deadlines. Hydro Ottawa is continuing the removal of the remaining PCBs from its system in accordance with its Asset Management Plan.

### 5.2 Environmental Sustainability

Hydro Ottawa's continuing focus in the area of environmental sustainability has resulted in it being recognized, for the last four years, as one of Canada's Greenest Employers, as a Delta Management Clean 16 and Clean 50 in 2013, and by the industry with a CEA Environmental Commitment Award in 2014.

Hydro Ottawa's environmental sustainability efforts have been focussed in three priority areas since 2010:

- Reducing the company's carbon footprint through improvements in fleet, facilities, technology infrastructure, and non-hazardous waste management and recycling;
- Greening procurement and the supply chain; and
- Building a culture of environmental sustainability in Hydro Ottawa's business practices and workforce.

The priority areas cover many aspects of the company's operations and address matters of importance to customers, governments and the sector as a whole. The three priority areas provide the company with the best options for reducing its environmental impacts, and improving its environmental performance, while considering costs and return on investment.

#### *5.2.1 Reducing the Company's Carbon Footprint*

A key area of attention continues to be the energy efficiency of facilities to contribute to an overall reduction in the company's energy consumption and greenhouse gas emissions. In this regard, between 2011 and 2014 Hydro Ottawa made improvements to offices and work centres following energy audits, and installed building automation systems, and lighting, insulation and window upgrades in its distribution substation buildings to more efficiently manage lighting and heating, ventilation and air conditioning (HVAC) operations.

A pilot study has been initiated at one facility to help reduce energy and water usage, optimize performance of renewable energy systems, and increase Hydro Ottawa's green footprint. Technology has been installed which allows for energy and water consumption and savings to be displayed in real time in a graphical manner, reporting on consumption and costing, and the setting of user defined email alerts to notify of outages or deviations from baseline usage. This initiative will be refined over the next year and expanded to other Hydro Ottawa facilities.

Hydro Ottawa is currently planning for the construction of a more efficient and strategically located Eastern Operations and Administrative Campus, as well as a Southern Operations and Warehouse facility. These facilities will be certified to the Leadership in Energy and Environmental Design (LEED) standards. Construction of these facilities, and the sale of some of the existing facilities, will provide a significant reduction in energy consumption and greenhouse gas emissions.

Hydro Ottawa also continues to invest in green fleet vehicles and technology where it is available for commercial fleets. Fleet initiatives in support of this approach along with additional initiatives related to technology, are planned from 2016 – 2020, such as:

- continuing to replace vehicles, as per the established fleet replacement schedule, with hybrid or more energy efficient vehicles in each class where available;

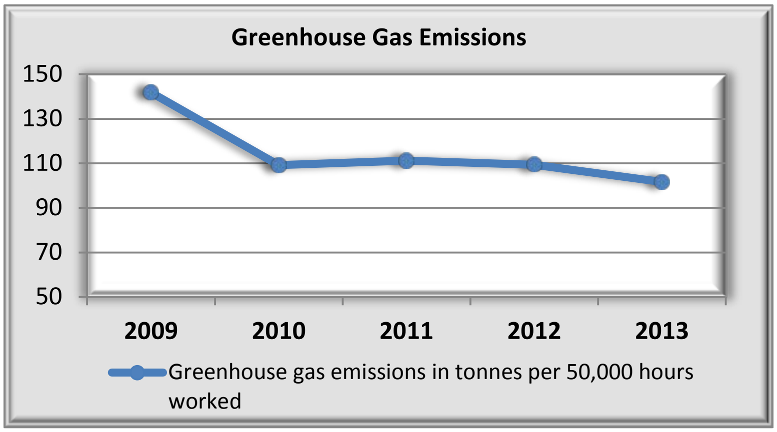
- incorporating hybrid technology to operate hydraulics for aerial devices (“buckets”) and battery technology in the entire fleet of vans to eliminate idling for heating and lighting while servicing underground cabling;
- piloting electric vehicles as appropriate;
- introducing biofuels such as ethanol and biodiesel;
- continuing to convert aerial devices to Biopure biodegradable oil, which is non-toxic, metal-free and inherently biodegradable;
- continuing efforts to optimize the fleet size; and
- leveraging vehicle Global Positioning System (GPS) technology and a new fleet management software to reduce operating costs through maintenance efficiencies, reduced fuel demand and greenhouse gas emissions.

Reducing the environmental impact of information technology platforms continues to be another approach Hydro Ottawa is utilizing to reduce the company’s carbon footprint. Some of the completed initiatives and those underway over the next few years include:

- implementing a server virtualization and consolidation program which has been decommissioning servers;
- establishing power management settings and double-sided printing defaults for all devices;
- establishing a Storage Area Network Program that has the capability to store a higher density of information on one server which means fewer servers are required for the same amount of information;
- initiating a virtual workstation pilot that provides the same service virtually for multiple users versus the typical arrangement of one physical workstation per user;
- establishing a new managed print services agreement with an external provider to standardize on a single brand of printers and eliminate all local and personal printers; and
- continuing to equip Hydro Ottawa facilities with video and teleconferencing capability in an effort to reduce travel between sites.

As outlined in Figure 5, Hydro Ottawa's greenhouse gas emissions (vehicle fuel combustion emissions, buildings combustion emissions and SF6 gas emissions) based on hours worked, have decreased steadily as a result of the increased focus placed on environmental sustainability.

**Figure 5 – Greenhouse Gas Emissions**




Reducing the amount of non-hazardous waste that is generated and diverting more away from landfill are also important elements of reducing the company's carbon footprint. Hydro Ottawa tracks all solid and liquid wastes, including operational waste streams, and has systems in place to ensure high diversion rates are maintained. Hydro Ottawa recycles many items including cans, glass, cardboard, paper, plastic, wood, tree trimmings, transformers and electrical equipment, tires, meters, e-waste (laptops, servers, desktops, printers, and cell phones) and metals.

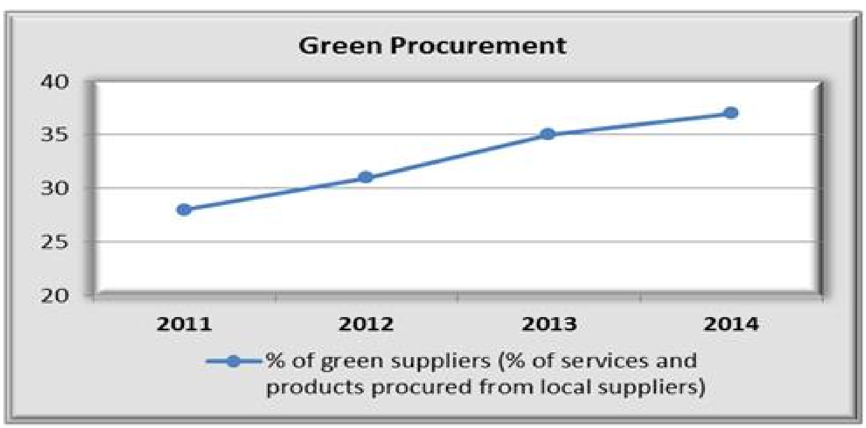
Hydro Ottawa's non-hazardous waste diversion rate was 91 percent for 2013, and 89 percent for 2014. While the company's diversion rate varies slightly from year to year, depending on the type and volume of materials being removed from service, and the availability of recycling options for the resulting waste, the non-hazardous waste diversion rate has consistently been above 90 percent from 2009 to 2013. Hydro Ottawa's LEED certified facilities will provide an opportunity for improvement in non-hazardous waste source separation and overall non-hazardous waste diversion rates by providing for a more centralized recycling model.

### *5.2.2 Greening Procurement and the Supply Chain*

Hydro Ottawa's approach to green procurement ensures that environmentally friendly purchasing decisions are made, where opportunities exist, while still ensuring that the procurement process delivers value for money.

Hydro Ottawa has put in place a point system for evaluating supplier proposals using environmental designations and practices as a "tie-breaker" for differentiating close competitive bidders. Hydro Ottawa also sources goods and services locally where it is cost-effective to do so, in order to minimize transportation and associated impacts on the environment. To that end, as represented in Figure 6, Hydro Ottawa tracks the relative proportion of purchase orders placed with firms in and surrounding the National Capital Region. Thirty-five percent of goods and services were purchased from local suppliers within a 100 km radius of the National Capital Region in 2013, measured in terms of dollars spent, and in 2014, 37% of goods and services were purchased locally, which represents a 6% increase over 2013.

**Figure 6 – Green Procurement**




### *5.2.3 Building a Culture of Environmental Sustainability*

By fostering a culture of environmental stewardship within the company, employees become champions for the greening of Hydro Ottawa's operations, and a key source of ideas for how to further reduce environmental impacts.

As measured through an engagement survey, employees have a strong level of awareness of the company's commitment and actions regarding environmental sustainability, as well as their role in this regard. Hydro Ottawa works to ensure employees have the tools they need to reduce waste and conserve energy, whether through the default settings on their electronic devices, the availability of recycling and waste separation stations in the workplace, or mechanisms for electronic collaboration and communication.

Hydro Ottawa is also greening its customer service practices by providing more online services through *MyHydroLink,* and working to grow the number of customers opting for paperless billing, in an effort to work with customers to reduce environmental impacts.

Hydro Ottawa plans to continue to engage employees in further greening its business operations and practices so as to increase the company's environmental performance and reduce environmental impacts.

# SHARED SERVICES AND CORPORATE COST ALLOCATION

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") provides and receives services to/from its affiliated companies Energy Ottawa Inc. ("Energy Ottawa") and Hydro Ottawa Holding Inc. (the "Holding Company"), in order to realize economies of scale, manage costs and maintain service levels.

Hydro Ottawa is the largest entity within the Hydro Ottawa Group of Companies, contributing approximately 90 percent of the revenues and assets. With the exception of strategic Management Services, Internal Audit, Legal, Treasury and Enterprise Risk Management services from the Holding Company, Hydro Ottawa maintains its own resources for the shared corporate services of Human Resources ("HR"), Information Technology ("IT"), Facilities, Supply Chain, Building and Facilities Support, Fleet, Communications, Conservation, Regulatory and Finance services. While the affiliates also have some resources of their own, Hydro Ottawa does provide certain shared corporate services to Energy Ottawa and the Holding Company.

The Holding Company provides shared corporate services such as strategic direction and oversight to Hydro Ottawa in the areas of Finance, Treasury, Internal Audit, Risk Management, Legal, Regulatory, Corporate Administration, Human Resources, Safety & Environment, Information Technology, Corporate Communications and Management Services. Some Board of Directors related costs are also included in the cost allocation to Hydro Ottawa following corporate governance reforms implemented on December 1, 2014, described later in this exhibit.

Furthermore, both Hydro Ottawa and the Holding Company allocate the cost of shared corporate services to Conservation Demand Management ("CDM"), according the fully-allocated costing methodology for non-rate-regulated activities described in the

*Conservation and Demand Management Code for Electricity Distributors, September 16, 2010*.

## 2.0 SHARED SERVICE MODEL

Hydro Ottawa's shared service methodology has not changed since the last rate application in 2012, except for the inclusion of Treasury Services and Board of Directors related costs described later in this section.

In accordance with the *Affiliate Relationships Code for Electrical Distributors and Transmitters*, the prices for the shared corporate services are determined by fully-allocated cost-based pricing, with the exception of Meter Data Service Provider costs which are based on market pricing. The pricing models and methodology were developed internally and the services are provided under the terms of Service Level Agreements ("SLA").

Table 1 below identifies the functional services provided by Hydro Ottawa to its affiliates and describes the pricing methodology used for each functional service.

**Table 1: Pricing Methodology for services provided by Hydro Ottawa**

| Functional Service | Pricing Methodology |
|---|---|
| Human Resources | Cost per employee |
| Facilities | Market rate for rent, proportionate share of cost for operations and maintenance, property taxes, and furnishings |
| IT Services | Cost per employee |
| Finance | Proportionate share of cost factored by time spent |
| Communications | Proportionate share of cost factored by time spent |
| Metering, Meter Data Services | Market based |
| Mechanic Services | Internal labour rate factored by time spent |

Table 2 identifies the management services received by Hydro Ottawa from the Holding Company and describes the pricing methodology used for each Management service.

**Table 2: Pricing Methodology for services received from the Holding Company**

| Management Service | Pricing Methodology |
|---|---|
| Legal, Corporate Administration & Regulatory | Proportionate share of cost factored by time spent |
| Finance, Internal Audit & Enterprise Risk Management | |
| HR, Safety & Environment | |
| Corporate Communications | |
| Information Management & Technology Services | |
| Management Services | |
| Conservation | |
| Treasury Services | Proportionate share of cost based on borrowing activity |
| Board of Directors | Proportionate share of cost |

The Holding Company costs are allocated to all affiliates based on an assessment of the budgeted costs in relation to activity level within each affiliate and the proportionate share of time spent. This assessment is completed annually to determine the appropriate allocation of costs. At year end, the allocations are reviewed and any material differences between actuals and budget are adjusted through a true up process to ensure costs are properly allocated to affiliates and to non-rate regulated activities.

The range of services provided and received by Hydro Ottawa to and from its affiliates is reviewed annually and adjusted to take into account changing circumstances. Since the 2012 rate application, the following new services have been added to the Service Level Agreements.

- Treasury administration services provided by the Holding Company were consolidated under the umbrella of the SLAs starting in 2012 in order to improve efficiency and transparency around the costs related to borrowing activities and maintaining credit ratings/credit facilities. The costs related to treasury administration services are allocated to affiliates based on their level of borrowing activity.
- Communications services provided by Hydro Ottawa to Energy Ottawa and to CDM were added to the allocations starting in 2013.
- Fleet costs associated with the CDM van provided by Hydro Ottawa were also added to the allocations starting in 2013.

- Certain governance reforms were implemented effective December 1, 2014 in order to achieve a more efficient and cost effective governance structure. The Boards of Directors of the Holding Company and Hydro Ottawa were reconfigured to reduce the duplication and redundancy that existed with the two boards. The Hydro Ottawa Board was reduced from its previous size of seven members to a board of three members, composed of the Chair of the Holding Company Board, the President and Chief Executive Officer of the Holding Company, and one member of management of Hydro Ottawa who is not employed by an affiliate. The Chair of the Holding Company Board and the President and Chief Executive Officer of the Holding Company also serve on the reconfigured eleven-member Holding Company Board. As a consequence of these reforms, all costs related to the Board of Directors are now budgeted under the Holding Company and a proportion of the cost is allocated to Hydro Ottawa through the SLAs starting in 2015. This has resulted in a net reduction of cost to Hydro Ottawa of approximately $40,000 annually.

**Table 3: Board of Directors-Related Costs before and After Governance Reform**

| | Annual Cost |
|---|---|
| Board of Directors cost before | $160,000 |
| Board of Directors cost after | $120,000 |
| Reduction in Cost due to Governance Reform | ($40,000) |

## 3.0 SERVICES PROVIDED TO AND FROM AFFILIATES

A copy of OEB Appendix 2-N is reproduced at the end of this Exhibit for reference. This appendix provides cost information and allocation details relating to each shared service provided or received by Hydro Ottawa in the historical years (2012 to 2014), the bridge year (2015) and the test year (2016). The amount of Board of Directors related costs included in the Holding Company's allocation to Hydro Ottawa in the years 2015 and 2016 is also provided in this appendix.

Table 4 provides a summary of the services provided by Hydro Ottawa to its affiliates and to non-rate regulated CDM activities.

**Table 4: Summary of Shared Corporate Services provided by Hydro Ottawa**

| Provided By | Provided To | 2012 Actual | 2013 Actual | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| Hydro Ottawa | Holding Company[1] | $743,921 | $771,477 | $785,029 | $818,932 | $835,388 |
| Hydro Ottawa | Energy Ottawa[1] | $532,668 | $983,140 | $989,715 | $1,043,155 | $1,061,482 |
| Hydro Ottawa | CDM[2] | $292,962 | $433,950 | $437,837 | $455,664 | $464,836 |
| **Total** | | **$1,569,551** | **$2,188,567** | **$2,212,581** | **$2,317,751** | **$2,361,706** |

[1] Represents the costs allocated to the Holding Company and Energy Ottawa, which are reflected as Other Revenue in Exhibit C-2-1.

[2] The costs allocated to CDM are treated as an offset to OM&A.

Table 5 provides a summary of the services received by Hydro Ottawa from its parent Holding Company.

**Table 5: Summary of Shared Corporate Services received by Hydro Ottawa**

| Provided By | Provided To | 2012 Actual | 2013 Actual | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| Holding Company | Hydro Ottawa | $3,501,812 | $3,454,602 | $3,626,081 | $3,646,744 | $3,720,040 |
| Holding Company | CDM | $156,200 | $155,398 | $173,917 | $173,256 | $176,736 |
| **Total** | | **$3,658,012** | **$3,610,000** | **$3,799,998** | **$3,820,000** | **$3,896,776** |

## 4.0 VARIANCE ANALYSIS

Table 6 and Table 7 below identify the variances for the following:

- 2016 Test Year vs 2012 Actual
- 2016 Test Year vs 2013 Actual

Explanations for significant variances are provided after the tables.

**Table 6: 2016 Test Year vs 2012 Actual**

| Provided By | Provided To | 2012 Actual | 2016 Test Year | $ Variance | % Variance |
|---|---|---|---|---|---|
| Hydro Ottawa | Holding Company | $743,921 | $835,388 | $91,467 | 12% |
| Hydro Ottawa | Energy Ottawa | $532,668 | $1,061,482 | $528,814 | 99% |
| Hydro Ottawa | CDM | $292,962 | $464,836 | $171,874 | 59% |
| Holding Company | Hydro Ottawa | $3,501,812 | $3,720,040 | $218,228 | 6% |
| Holding Company | CDM | $156,200 | $176,736 | $20,536 | 13% |

The $528,814 variance between 2012 Actual and 2016 Test Year for services provided by Hydro Ottawa to Energy Ottawa is due to an increase in the activities of the affiliate. In late 2012, Energy Ottawa acquired three additional hydroelectric plants and additional interest in the Ring Dam and remaining water rights at Chaudière Falls, increasing its number of employees from 14 before the acquisition to 36 after the acquisition. The cost of the various corporate services provided by Hydro Ottawa was reassessed in 2013 to take into account the additional volume of work and time spent in support of Energy Ottawa. The allocations for HR and IT services were both impacted significantly as they are based on cost per employee.

The $171,874 variance between 2012 Actual and 2016 Test Year for services provided by Hydro Ottawa to CDM is primarily due to increase in HR and IT services required to support additional CDM employees and new cost allocations for Communications Services and Fleet introduced in 2013, as described earlier in this Exhibit.

The $218,228 variance between 2012 Actual and 2016 Test Year for services provided by the Holding Company to Hydro Ottawa include inflationary increases and the new allocation for Board of Directors-related costs starting in 2015 as described earlier. These increases are partially offset by a reduction in proportionate share of Treasury services to 67% as greater effort will be focused on borrowing activities for Energy Ottawa capital works planned.

**Table 7: 2016 Test Year vs 2013 Actual**

| Provided By | Provided To | 2013 Actual | 2016 Test Year | $ Variance | % Variance |
|---|---|---|---|---|---|
| Hydro Ottawa | Holding Company | $771,477 | $835,388 | $63,911 | 8% |
| Hydro Ottawa | Energy Ottawa | $983,140 | $1,061,482 | $78,342 | 8% |
| Hydro Ottawa | CDM | $433,950 | $464,836 | $30,886 | 7% |
| Holding Company | Hydro Ottawa | $3,454,602 | $3,720,040 | $265,438 | 8% |
| Holding Company | CDM | $155,398 | $176,736 | $21,338 | 14% |

All of the variances between 2013 Actual and 2016 Test Year are consistent with previous explanations and general inflationary cost increases.

## 5.0 RECONCILIATION OF REVENUE IN APPENDIX 2-N

The Board's Filing Requirements require applicants to provide a reconciliation of the revenue in Appendix 2-N to the amounts included in Other Revenue in Exhibit C-2-1.

Table 8 summarizes the costs allocated by Hydro Ottawa to the Holding Company and Energy Ottawa which are included in Other Revenue.

**Table 8: Revenues from Affiliates Included in Other Revenue**

| Provided By | Provided To | 2012 Actual | 2013 Actual | 2014 Q2 Forecast | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|---|
| Hydro Ottawa | Holding Company | $743,921 | $771,477 | $785,029 | $818,932 | $835,388 |
| Hydro Ottawa | Energy Ottawa | $532,668 | $983,140 | $989,715 | $1,043,155 | $1,061,482 |
| **Total** | | **$1,276,589** | **$1,754,617** | **$1,774,744** | **$1,862,087** | **$1,896,870** |

## 6.0 BOARD OF DIRECTORS COSTS

The Board's Filing Requirements also require applicants to identify any Board of Director-related costs for affiliates that are included in its own costs. Hydro Ottawa confirms that there are no Board of Directors costs for affiliated entities included in its costs.

# Appendix 2-N
# Shared Services and Corporate Cost Allocation

**Year:** 2012 Actual

## Shared Services

| Name of Company | | Service Offered | Pricing Methodology | Price for the Service | Cost for the Service |
|---|---|---|---|---|---|
| From | To | | | $ | $ |
| HOL | HOHI | Human Resources | Cost | 101,512 | 101,512 |
| HOL | HOHI | Facilities | Market/Cost | 236,441 | 151,683 |
| HOL | HOHI | IT Services | Cost | 187,005 | 187,005 |
| HOL | HOHI | Finance | Cost | 136,951 | 136,951 |
| HOL | HOHI | Communications | Cost | 82,012 | 82,012 |
| **Total Charged from HOL to HOHI** | | | | **743,921** | **659,163** |
| HOL | Energy Ottawa | Human Resources | Cost | 58,889 | 58,889 |
| HOL | Energy Ottawa | Facilities | Market/Cost | 64,649 | 49,248 |
| HOL | Energy Ottawa | IT Services | Cost | 112,972 | 112,972 |
| HOL | Energy Ottawa | Finance | Cost | 111,894 | 111,894 |
| HOL | Energy Ottawa | Metering, Meter Data Services | Market | 81,720 | * |
| HOL | Energy Ottawa | Mechanic Services | Cost | 102,544 | 102,544 |
| **Total Charged from HOL to Energy Ottawa** | | | | **532,668** | **435,547** |
| HOL | CDM | Human Resources | Cost | 59,058 | 59,058 |
| HOL | CDM | Facilities | Market/Cost | 40,104 | 28,375 |
| HOL | CDM | IT Services | Cost | 119,853 | 119,853 |
| HOL | CDM | Finance | Cost | 73,947 | 73,947 |
| **Total Charged from HOL to CDM** | | | | **292,962** | **281,233** |
| | | | | | |

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

## Corporate Cost Allocation

| Name of Company | | Service Offered | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|
| From | To | | | % | $ |
| *HOHI* | *HOL* | Legal, Corporate Admin & Regulatory | Cost | 50% | 219,461 |
| HOHI | HOL | Finance, Internal Audit & Enterprise Risk Mgmt | Cost | 65% | 1,587,467 |
| HOHI | HOL | Treasury | Cost | 100% | 348,000 |
| HOHI | HOL | HR, Safety & Environment | Cost | 95% | 541,666 |
| HOHI | HOL | Corporate Communications | Cost | 20% | 152,095 |
| HOHI | HOL | Information Management & Technology Services | Cost | 45% | 189,041 |
| HOHI | HOL | Management Services | Cost | 46% | 464,082 |
| **Total Charged from HOHI to HOL** | | | | | **3,501,812** |
| HOHI | CDM | Management Services | Cost | 50% | 156,200 |
| **Total Charged from HOHI to CDM** | | | | | **156,200** |
| | | | | | |

**Note:**

**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***
**Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

· ***Pricing Methodology:***

**Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

· ***% Allocation:***

**The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

## Appendix 2-N
## Shared Services and Corporate Cost Allocation

**Year:** 2013 Actual

### Shared Services

| Name of Company | | Service Offered | Pricing Methodology | Price for the Service | Cost for the Service |
|---|---|---|---|---|---|
| From | To | | | $ | $ |
| HOL | HOHI | Human Resources | Cost | 110,004 | 110,004 |
| HOL | HOHI | Facilities | Market/Cost | 226,576 | 142,272 |
| HOL | HOHI | IT Services | Cost | 189,949 | 189,949 |
| HOL | HOHI | Finance | Cost | 162,933 | 162,933 |
| HOL | HOHI | Communications | Cost | 82,015 | 82,015 |
| **Total Charged from HOL to HOHI** | | | | **771,477** | **687,173** |
| HOL | Energy Ottawa | Human Resources | Cost | 171,068 | 171,068 |
| HOL | Energy Ottawa | Facilities | Market/Cost | 74,745 | 56,217 |
| HOL | Energy Ottawa | IT Services | Cost | 303,040 | 303,040 |
| HOL | Energy Ottawa | Finance | Cost | 182,455 | 182,455 |
| HOL | Energy Ottawa | Communications | Cost | 33,771 | 33,771 |
| HOL | Energy Ottawa | Metering, Meter Data Services | Market | 79,760 | * |
| HOL | Energy Ottawa | Mechanic Services | Cost | 138,301 | 138,301 |
| **Total Charged from HOL to Energy Ottawa** | | | | **983,140** | **884,852** |
| HOL | CDM | Human Resources | Cost | 88,304 | 88,304 |
| HOL | CDM | Facilities | Market/Cost | 49,224 | 34,008 |
| HOL | CDM | IT Services | Cost | 152,476 | 152,476 |
| HOL | CDM | Finance | Cost | 111,602 | 111,602 |
| HOL | CDM | Communications | Cost | 24,144 | 24,144 |
| HOL | CDM | Fleet | Cost | 8,200 | 8,200 |
| **Total Charged from HOL to CDM** | | | | **433,950** | **418,734** |
| | | | | | |

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

### Corporate Cost Allocation

| Name of Company | | Service Offered | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|
| From | To | | | % | $ |
| HOHI | HOL | Legal, Corporate Admin & Regulatory | Cost | 50% | 178,863 |
| HOHI | HOL | Finance, Internal Audit & Enterprise Risk Mgmt | Cost | 69% | 1,551,912 |
| HOHI | HOL | Treasury | Cost | 88% | 311,000 |
| HOHI | HOL | HR, Safety & Environment | Cost | 95% | 564,055 |
| HOHI | HOL | Corporate Communications | Cost | 20% | 162,196 |
| HOHI | HOL | Information Management & Technology Services | Cost | 45% | 164,980 |
| HOHI | HOL | Management Services | Cost | 46% | 521,596 |
| **Total Charged from HOHI to HOL** | | | | | **3,454,602** |
| HOHI | CDM | Management Services | Cost | 50% | 155,398 |
| **Total Charged from HOHI to CDM** | | | | | **155,398** |
| | | | | | |

**Note:**

**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***

**Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

· ***Pricing Methodology:***

**Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

· ***% Allocation:***

**The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

# Appendix 2-N
# Shared Services and Corporate Cost Allocation

**Year:** 2014 Forecast

## Shared Services

| Name of Company | | Service Offered | Pricing Methodology | Price for the Service | Cost for the Service |
|---|---|---|---|---|---|
| From | To | | | $ | $ |
| HOL | HOHI | Human Resources | Cost | 115,441 | 115,441 |
| HOL | HOHI | Facilities | Market/Cost | 227,148 | 147,367 |
| HOL | HOHI | IT Services | Cost | 192,840 | 192,840 |
| HOL | HOHI | Finance | Cost | 164,126 | 164,126 |
| HOL | HOHI | Communications | Cost | 85,474 | 85,474 |
| **Total Charged from HOL to HOHI** | | | | **785,029** | **705,248** |
| HOL | Energy Ottawa | Human Resources | Cost | 175,856 | 175,856 |
| HOL | Energy Ottawa | Facilities | Market/Cost | 74,437 | 57,463 |
| HOL | Energy Ottawa | IT Services | Cost | 299,972 | 299,972 |
| HOL | Energy Ottawa | Finance | Cost | 190,621 | 190,621 |
| HOL | Energy Ottawa | Communications | Cost | 35,195 | 35,195 |
| HOL | Energy Ottawa | Metering, Meter Data Services | Market | 80,680 | * |
| HOL | Energy Ottawa | Mechanic Services | Cost | 132,954 | 132,954 |
| **Total Charged from HOL to Energy Ottawa** | | | | **989,715** | **892,061** |
| HOL | CDM | Human Resources | Cost | 93,394 | 93,394 |
| HOL | CDM | Facilities | Market/Cost | 47,508 | 33,097 |
| HOL | CDM | IT Services | Cost | 156,011 | 156,011 |
| HOL | CDM | Finance | Cost | 111,684 | 111,684 |
| HOL | CDM | Communications | Cost | 25,140 | 25,140 |
| HOL | CDM | Fleet | Cost | 4,100 | 4,100 |
| **Total Charged from HOL to CDM** | | | | **437,837** | **423,426** |
| | | | | | |

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

## Corporate Cost Allocation

| Name of Company | | Service Offered | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|
| From | To | | | % | $ |
| HOHI | HOL | Legal, Corporate Admin & Regulatory | Cost | 50% | 218,307 |
| HOHI | HOL | Finance, Internal Audit & Enterprise Risk Mgmt | Cost | 66% | 1,510,480 |
| HOHI | HOL | Treasury | Cost | 88% | 330,000 |
| HOHI | HOL | HR, Safety & Environment | Cost | 92% | 567,892 |
| HOHI | HOL | Corporate Communications | Cost | 20% | 188,479 |
| HOHI | HOL | Information Management & Technology Services | Cost | 45% | 193,573 |
| HOHI | HOL | Management Services | Cost | 46% | 617,350 |
| **Total Charged from HOHI to HOL** | | | | | **3,626,081** |
| HOHI | CDM | Management Services | Cost | 50% | 173,917 |
| **Total Charged from HOHI to CDM** | | | | | **173,917** |
| | | | | | |

**Note:**

**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***
**Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

· ***Pricing Methodology:***

**Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

· ***% Allocation:***

**The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

# Appendix 2-N
# Shared Services and Corporate Cost Allocation

**Year:** 2015 Bridge Year

## Shared Services

| Name of Company | | Service Offered | Pricing Methodology | Price for the Service | Cost for the Service |
|---|---|---|---|---|---|
| **From** | **To** | | | **$** | **$** |
| HOL | HOHI | Human Resources | Cost | 124,792 | 124,792 |
| HOL | HOHI | Facilities | Market/Cost | 229,224 | 148,721 |
| HOL | HOHI | IT Services | Cost | 214,752 | 214,752 |
| HOL | HOHI | Finance | Cost | 169,500 | 169,500 |
| HOL | HOHI | Communications | Cost | 80,664 | 80,664 |
| **Total Charged from HOL to HOHI** | | | | **818,932** | **738,429** |
| HOL | Energy Ottawa | Human Resources | Cost | 186,948 | 186,948 |
| HOL | Energy Ottawa | Facilities | Market/Cost | 75,299 | 58,834 |
| HOL | Energy Ottawa | IT Services | Cost | 329,096 | 329,096 |
| HOL | Energy Ottawa | Finance | Cost | 194,575 | 194,575 |
| HOL | Energy Ottawa | Communications | Cost | 33,216 | 33,216 |
| HOL | Energy Ottawa | Metering, Meter Data Services | Market | 79,920 | * |
| HOL | Energy Ottawa | Mechanic Services | Cost | 144,101 | 144,101 |
| **Total Charged from HOL to Energy Ottawa** | | | | **1,043,155** | **946,770** |
| HOL | CDM | Human Resources | Cost | 94,000 | 94,000 |
| HOL | CDM | Facilities | Market/Cost | 49,260 | 34,784 |
| HOL | CDM | IT Services | Cost | 161,768 | 161,768 |
| HOL | CDM | Finance | Cost | 118,536 | 118,536 |
| HOL | CDM | Communications | Cost | 23,724 | 23,724 |
| HOL | CDM | Fleet | Cost | 8,376 | 8,376 |
| **Total Charged from HOL to CDM** | | | | **455,664** | **441,188** |
| | | | | | |

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

## Corporate Cost Allocation

| Name of Company | | Service Offered | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|
| **From** | **To** | | | **%** | **$** |
| HOHI | HOL | Legal, Corporate Admin & Regulatory | Cost | 50% | 210,793 |
| HOHI | HOL | Finance, Internal Audit & Enterprise Risk Mgmt | Cost | 64% | 1,439,594 |
| HOHI | HOL | Treasury | Cost | 67% | 253,000 |
| HOHI | HOL | HR, Safety & Environment | Cost | 92% | 577,187 |
| HOHI | HOL | Corporate Communications | Cost | 20% | 185,806 |
| HOHI | HOL | Information Management & Technology Services | Cost | 45% | 244,523 |
| HOHI | HOL | Management Services | Cost | 46% | 615,503 |
| HOHI | HOL | Board of Directors | Cost | 27% | 120,338 |
| **Total Charged from HOHI to HOL** | | | | | **3,646,744** |
| HOHI | CDM | Management Services | Cost | 50% | 173,256 |
| **Total Charged from HOHI to CDM** | | | | | **173,256** |
| | | | | | |

**Note:**

**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***
**Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

· ***Pricing Methodology:***

**Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

· ***% Allocation:***

**The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

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| **File Number:** | EB-2015-0004 |
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| **Date:** | ORIGINAL |

## Appendix 2-N
## Shared Services and Corporate Cost Allocation

**Year:** 2016 Test Year

### Shared Services

| Name of Company | | Service Offered | Pricing Methodology | Price for the Service | Cost for the Service |
|---|---|---|---|---|---|
| From | To | | | $ | $ |
| HOL | HOHI | Human Resources | Cost | 127,304 | 127,304 |
| HOL | HOHI | Facilities | Market/Cost | 233,828 | 151,710 |
| HOL | HOHI | IT Services | Cost | 219,064 | 219,064 |
| HOL | HOHI | Finance | Cost | 172,908 | 172,908 |
| HOL | HOHI | Communications | Cost | 82,284 | 82,284 |
| **Total Charged from HOL to HOHI** | | | | **835,388** | **753,270** |
| HOL | Energy Ottawa | Human Resources | Cost | 190,704 | 190,704 |
| HOL | Energy Ottawa | Facilities | Market/Cost | 76,811 | 60,017 |
| HOL | Energy Ottawa | IT Services | Cost | 335,716 | 335,716 |
| HOL | Energy Ottawa | Finance | Cost | 198,487 | 198,487 |
| HOL | Energy Ottawa | Communications | Cost | 33,888 | 33,888 |
| HOL | Energy Ottawa | Metering, Meter Data Services | Market | 79,800 | * |
| HOL | Energy Ottawa | Mechanic Services | Cost | 146,076 | 146,076 |
| **Total Charged from HOL to Energy Ottawa** | | | | **1,061,482** | **964,888** |
| HOL | CDM | Human Resources | Cost | 95,892 | 95,892 |
| HOL | CDM | Facilities | Market/Cost | 50,256 | 35,483 |
| HOL | CDM | IT Services | Cost | 165,016 | 165,016 |
| HOL | CDM | Finance | Cost | 120,924 | 120,924 |
| HOL | CDM | Communications | Cost | 24,204 | 24,204 |
| HOL | CDM | Fleet | Cost | 8,544 | 8,544 |
| **Total Charged from HOL to CDM** | | | | **464,836** | **450,063** |
| | | | | | |

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

### Corporate Cost Allocation

| Name of Company | | Service Offered | Pricing Methodology | % of Corporate Costs Allocated | Amount Allocated |
|---|---|---|---|---|---|
| From | To | | | % | $ |
| HOHI | HOL | Legal, Corporate Admin & Regulatory | Cost | 50% | 215,030 |
| HOHI | HOL | Finance, Internal Audit & Enterprise Risk Mgmt | Cost | 64% | 1,468,530 |
| HOHI | HOL | Treasury | Cost | 67% | 258,085 |
| HOHI | HOL | HR, Safety & Environment | Cost | 92% | 588,788 |
| HOHI | HOL | Corporate Communications | Cost | 20% | 189,541 |
| HOHI | HOL | Information Management & Technology Services | Cost | 45% | 249,438 |
| HOHI | HOL | Management Services | Cost | 46% | 627,871 |
| HOHI | HOL | Board of Directors | Cost | 27% | 122,757 |
| **Total Charged from HOHI to HOL** | | | | | **3,720,040** |
| HOHI | CDM | Management Services | Cost | 50% | 176,736 |
| **Total Charged from HOHI to CDM** | | | | | **176,736** |
| | | | | | |

**Note:**

**1** **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***
**Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.**

· ***Pricing Methodology:***

**Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.**

· ***% Allocation:***

**The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.**

# PURCHASE OF NON-AFFILIATE SERVICES

## 1.0 PROCUREMENT PROCESS

The Hydro Ottawa Procurement Policy, Attachment D-2(A), stipulates that all acquisitions shall be covered by purchase orders, with noted exceptions, such as utilities and taxes, as defined by policy. Spending authority is set out in the Approval Authority for Procurements and Disbursements, Attachment POL-En-006.00 and controlled by electronic workflow embedded in the business system (JD Edwards – EnterpriseOne).

In 2014, Hydro Ottawa moved to improve control and consistency in the procurement of major contracts s by implementing a new Contract Procurement Process. See D-2, Attachment C) for further details.

Hydro Ottawa also has long standing alliances with seven key suppliers. Monthly forecast sessions enable the supplier to work their supply channels to pipeline material to meet projected need dates with minimal commitment on Hydro Ottawa's part. The alliance partnerships position Hydro Ottawa to take delivery only when ready to proceed with the relevant job. The supplier holds the inventory. All residential transformers and underground cable are delivered in this manner in addition to some commercial transformers and poles for new or replacement pole lines.

All non-affiliate purchases are in compliance with the above-noted policies.

## 2.0 HISTORIC EXPENDITURES

The following tables contain information on the purchases of non-affiliate services for 2012 through 2014 by Hydro Ottawa Limited ("Hydro Ottawa"). The total costs are those costs paid to the Suppliers each year, excluding tax. The dollar amounts have been redacted for confidentiality purposes. If parties feel that the information is required, Hydro Ottawa will follow the Ontario Energy Board's (the "Board") Practice Direction on

Confidential Filings in order to provide the information. Suppliers have been included in the list if the total purchases exceeded $750k.

Beside each supplier reference in the table below is an indication of the type(s) of procurement methodology employed.

**Table 1: 2012 Suppliers**

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Request for Proposal | Altec Industries | Line Trucks |
| Request for Proposal | B.G. High Voltage Systems | Civil/Electrical Construction |
| Request for Proposal | Black & McDonald | General OH & UG Line Work |
| Request for Proposal | Elster Metering | Metering |
| Request for Proposal | General Switchgear and Controls Ltd. | Station Switchgear |
| Request for Proposal | IBM Canada | CIS Software Upgrade |
| Request for Proposal | Intergraph | GIS Software |
| Request for Proposal | J.W. Leslie Utilities | Light Underground Electrical Servicing |
| Request for Proposal | K-Line Maintenance | General OH & UG Line Work |
| Request for Proposal | Tamarack Tree Care LTD | Vegetation Management |
| Request for Proposal | Tetra Tech WEI Inc. (Formerly Wardrop) | Engineering Consulting |
| Request for Quote | Stoneworks Technologies Inc. | Computer Network Hardware & Support |
| Request for Standing Offer | Bradley Kelly Construction Ltd. | Civil Construction & Maintenance |
| Request for Standing Offer | Drain-All | Waste/Recycling |
| Request for Standing Offer | Greely Construction Ltd. | Civil Construction & Maintenance |
| Request for Standing Offer | Sproule Powerline Construction | General OH & UG Line Work |
| Request for Standing Offer | Teraflex | Civil Construction & Maintenance |

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Sole/Directed Source | Hydro One Accounts Receivable Unit | CCRAs/LTLTs/Line Work |
| Sole/Directed Source | IBM Canada | CIS Managed Services/Call-Centre |
| Sole/Directed Source | Oracle | Software Support and Enhancements |
| Sole/Directed Source | Promark Telecon | U/G Cable Locations |
| Sole/Directed Source | Syntax | Software Consulting Services |
| Strategic Alliance | Bel Volt Sales | Pole Line Hardware |
| Strategic Alliance | Guelph Utility Pole | Wood Poles |
| Strategic Alliance | HD Supply Utilities (Formerly Grafton) | Pole Line Hardware/Dist Transformers |
| Strategic Alliance | Pioneer Transformers Ltd. | Vault Transformers |
| Strategic Alliance | Prysmian Power Cables & Systems Can. Ltd. | U/G Cable |
| Strategic Alliance | S&C Electric (Toronto) | Distribution Switchgear |

1 **Table 2: 2013 Suppliers**

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Request for Proposal | Arno Electrique Ltée | Civil/Electrical Construction |
| Request for Proposal | B.G. High Voltage Systems | Civil/Electrical Construction |
| Request for Proposal | Black & McDonald | General OH & UG Line Work |
| Request for Proposal | CG Power Systems USA Inc. | Station Transformers |
| Request for Proposal | Custom Control Panels Inc. | Station Switchgear |
| Request for Proposal | Dual Ade Inc. | Station Switchgear |
| Request for Proposal | Elster Metering | Metering |
| Request for Proposal | IBM Canada Ltd. | CIS Software Upgrade |
| Request for Proposal | J.W. Leslie Utilities | Light Underground Electrical Servicing |
| Request for Proposal | K-Line Maintenance | General OH & UG Line Work/Civil Construction |
| Request for Proposal | Posi-Plus Technologies Inc. | Line Trucks |
| Request for Proposal | Tamarack Tree Care LTD | Vegetation Management |
| Request for Proposal | Tetra Tech WEI Inc. (Formerly Wardrop) | Engineering Consulting |
| Request for Standing Offer | Bradley Kelly Construction Ltd. | Civil Construction & Maintenance |
| Request for Standing Offer | Drain-All | Waste/Recycling |
| Request for Standing Offer | Greely Construction Inc. | Civil Construction & Maintenance |
| Request for Standing Offer | Sproule Powerline Construction | General OH & UG Line Work |

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Request for Standing Offer | Teraflex | Civil Construction & Maintenance |
| Sole/Directed Source | Hydro One Accounts Receivable Unit | CCRAs/LTLTs/Line Work |
| Sole/Directed Source | IBM Canada | CIS Managed Services/Call-Centre |
| Sole/Directed Source | Oracle | Software Support and Enhancements |
| Sole/Directed Source | Promark Telecon | U/G Cable Locations |
| Strategic Alliance | Guelph Utility Pole | Wood Poles |
| Strategic Alliance | HD Supply Utilities (Formerly Grafton) | Pole Line Hardware/Dist Transformers |
| Strategic Alliance | LaPrairie Inc. | Pole Line Hardware |
| Strategic Alliance | Prysmian Power Cables & Systems Can. Ltd. | U/G Cable |
| Strategic Alliance | S&C Electric (Toronto) | Distribution Switchgear |

**Table 3: 2014 Suppliers**

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Request for Proposal | AZZ Incorporated | Station Switchgear |
| Request for Proposal | Black & McDonald | General OH & UG Line Work |
| Request for Proposal | Dual Ade Inc. | Station Switchgear |
| Request for Proposal | Elster Solutions Canada | Metering |
| Request for Proposal | IBM Canada Ltd. | CC&B Hosting Services |
| Request for Proposal | Intergraph | GIS Software |
| Request for Proposal | J.W. Leslie Utilities | Light Underground Electrical Servicing |
| Request for Proposal | K-Line Maintenance | General OH & UG Line Work |
| Request for Proposal | Nova Networks Inc. | Computer Hardware & Software |
| Request for Proposal | Posi-Plus Technologies Inc. | Line Trucks |
| Request for Proposal | Riggs Distler Inc. | Civil/Electrical Construction |
| Request for Proposal | Tamarack Tree Care Ltd. | Vegetation Management |
| Request for Proposal | Virginia Transformer Corporation | Station Transformers |
| Request for Standing Offer | Bradley Kelly Construction Ltd. | Civil Construction & Maintenance |
| Request for Standing Offer | Sproule Powerline Construction | General OH & UG Line Work |
| Request for Standing Offer | Teraflex | Civil Construction & Maintenance |

| Procurement Method | Supplier | Service / Product |
|---|---|---|
| Sole/Directed Source | Concentrix Services (Canada) Ltd. | Call-Centre Services |
| Sole/Directed Source | Copperleaf Technologies | Asset Management Software |
| Sole/Directed Source | Custom Control Panels Inc. | Station P&C Houses |
| Sole/Directed Source | Hydro One Accounts Receivable Unit | CCRA & Line Transfers |
| Sole/Directed Source | IBM Canada Ltd. | CIS Managed Services/Call-Centre |
| Sole/Directed Source | Promark Telecon | U/G Cable Locations |
| Strategic Alliance | Dell | Computer Hardware & Software |
| Strategic Alliance | Guelph Utility Pole | Wood Poles |
| Strategic Alliance | HD Supply Utilities (Formerly Grafton) | Pole Line Hardware/Dist Transformers |
| Strategic Alliance | Pioneer Transformers Ltd. | Vault Transformers |
| Strategic Alliance | Prysmian Power Cables & Systems Can. Ltd. | U/G Cable |
| Strategic Alliance | S&C Electric (Toronto) | Distribution Switchgear |

# HYDRO OTTAWA CORPORATE POLICIES

| **Subject**: Procurement | | |
|---|---|---|
| **Category**: Finance | **Policy Number**: POL-Fi-003.00 | |
| **Administrator:** Director of Finance | **Owner:** Chief Financial Officer | **Approver:** President and CEO |

1. **PURPOSE**

The purpose of this policy is to document the principles that govern the acquisition of goods and services by Hydro Ottawa.

The objectives of the Procurement Policy are to:
- Establish an efficient process for the purchase of quality goods and services
- Ensure favourable prices are obtained to maximize the value of all purchases for Hydro Ottawa stake-holders
- Ensure Hydro Ottawa procures all goods and services from reputable/ethical vendors.
- Support the protection of the environment
- Ensure fair, open, transparent and accountable competitive processes are followed in the acquisition of goods and services
- Ensure compliance with all applicable laws and regulations.

2. **SCOPE**

All employees of Hydro Ottawa.

3. **DEFINITIONS**

***Call-Ups*** are requests to purchase goods and services available for sale under a Standing Offer.
***Hydro Ottawa*** refers to the Hydro Ottawa Group of Companies.
***Emergency*** is defined as a sudden, urgent, unexpected occurrence or occasion requiring immediate action.
***Low Dollar Value*** is defined as ≤ $2000.
***Inventory Items*** are materials that are routinely ordered/tracked by Procurement and issued to field operations for construction and maintenance activities.
***Invoices without Reference*** are invoices for goods and services that have not been pre-authorized by a purchase order and/or vendor contract.
A ***Non-Competitive Procurement***, in the context of this policy, refers to an acquisition from a:

i. Sole Source, where there is only one identifiable source for a given good or service, or a
ii. Directed Source, where there is more than one identifiable source for a given good or service, but there are compelling reasons why the selected vendor is not determined by an open competition.

***Non-Inventory Items*** are goods and services Hydro Ottawa business entities purchase either directly from a vendor or through the assistance of the Procurement function.
***Personal Payments*** refer to "out of pocket" business expenditures paid for by employees through cash, personal debit/credit card or personal cheque transactions.
***Procurement*** (Unit) is defined as the individual or team of individuals responsible for the Procurement function within Hydro Ottawa.
A ***Standing Offer*** agreement is an offer from a vendor to supply "on demand" goods and services at pre-arranged prices under negotiated terms and conditions.

## 4. POLICY DIRECTIVES

a. Purchases of goods and services are categorized as follows:

**Inventory Items:**

Construction materials that are purchased solely by Procurement working in conjunction with Hydro Ottawa field operations.

**Non-Inventory Items:**

i. Goods and services acquired by Procurement on behalf of Hydro Ottawa Business entities using the following purchasing vehicles:
- Standing Offers
  - Where Standing Offers are in place, they are the preferred procurement vehicle for the purchase of related goods and services
  - A good and/or service to a maximum of $100,000 can be procured by a Call-Up under a specific Standing Offer
  - Any Call-Up for a good and/or service over $100,000 requires competitive bids from existing Standing Offer suppliers

  Note: Where only one Standing Offer supplier exists the Requisitioner has the option of initiating a Directed Source procurement or requesting that a new competitive bid procurement process takes place
- Request for Proposal, Quotation and/or Tender
  - For values greater than $2000 to a maximum of $25,000, Procurement will obtain a minimum of two oral or written competitive quotations
  - For values over $25,000 Procurement will obtain a minimum of three written competitive quotations

  Note: Following the selection of the winning supplier a Purchase Order and/or vendor contract will be issued by Procurement.

ii. Goods and services > $2000 that can be acquired without the requirement of a Purchase Order and/or vendor contract (Reference Annex 1 – Schedule 6 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements)

iii. Low Dollar Value goods and services that Hydro Ottawa business entities purchase directly from vendors using the following purchase vehicles:
- Petty Cash (To a maximum of $100)
- Hydro Ottawa Credit Card
- Personal Payment

Note: Low Dollar Value purchases do not require Purchase Orders/competitive bids.

b. Procurement is responsible for ensuring that goods and services are acquired using the appropriate procurement method.

c. Approvals for the purchase of all goods and services will be in accordance with Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements.

d. With the exception of Standing Offers and emergency purchases, PO's initiated after the provision of goods or services and/or the receipt of supplier invoices are a serious violation of this policy and will:

   i. Require the approval of two management levels above the Requisitioner

   ii. Be reported on a quarterly basis to senior Divisional management

e. Vendor bids for the provision of goods will be assessed using a 50% weighting factor for price.

f. Vendor bids for the provision of services will be assessed using a 30% weighting factor for price.

g. When appropriate, bid evaluations will include environmental impact as part of the assessment criteria.

h. Non-financial bid evaluation criteria will be jointly set by Procurement and the Requisitioner.

i. The use of any non-standard terms and conditions relating to Hydro Ottawa procurement documentation requires prior approval by the Legal group.

j. The splitting of purchase requests into multiple Purchase Orders is a serious violation of this policy.

k. The following three conditions must be met before amendments to released Purchase Orders will be actioned by Procurement:
    i. Requested cost increases do not exceed 50% of the original Purchase Order/contract value, and
    ii. There are no material changes in scope as defined in the original Purchase Order, and
    iii. A revised requisition, with details on the reasons for the required changes, has been resubmitted/re-approved per Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements.

    Note: The absence of any of the above would result in a requirement for a new procurement process.

l. A vendor contract, relating to either a competitive or non-competitive procurement of goods and services, can be extended by up to one year (under the original or more favourable terms and conditions) with the joint approval of the sponsoring EMT member and Manager of Supply Chain.

   Note: The maximum term of a vendor contract (including extensions) is limited to 3 years.

m. Employees involved in both competitive and non-competitive procurements must comply with Hydro Ottawa's conflict of interest guidelines as defined in Hydro Ottawa's Code of Business Conduct.

n. The dollar limits referenced in this policy are in Canadian currency and are exclusive of taxes and duties.

## 5. RELATED POLICIES, PROCEDURES and REFERENCE DOCUMENTS

Approval Authority for Procurements and Disbursements Policy (POL-En-006.00)
Hydro Ottawa Corporate Credit Card Policy (POL-Fi-001.00)
Petty Cash Policy (POL-Fi-004.00)
Business Expense Reimbursement Policy (POL-Fi-005.00)
Discipline and Discharge Policy (POL-Hr-005.00).
Request to Direct Source Goods and Services Form
Hydro Ottawa's Code of Business Conduct
Contractor OHSE Requirements (WI-MS-002.00)

## 6. EXCLUSIONS

**Non-Competitive Procurements**

Examples of when the competitive procurement process may be waived are as follows:

i. The need is one of pressing urgency and must be addressed quickly to alleviate a threat to:
    - the health, safety or welfare of Hydro Ottawa employees and/or the public
    - Hydro Ottawa and/or public property
    - essential services

    Note: During emergency situations it is understood urgently needed goods and services may be services may be procured without the issuance of a purchase order.

ii. The time, effort and expense of a competitive procurement are not justified given the nature of the goods or services being acquired.
    Example: The provision of price competitive professional services from an embedded vendor who, through a long standing relationship with Hydro Ottawa, has an in-depth understanding of the corporation's business needs/requirements

iii. There is only one qualified supplier capable of supplying the required good or service

iv. There are pre-requisites to bidding that can only be satisfied by one supplier

v. The need is a follow-on to a previously acquired good or service and, if price competitive, is most appropriately provided by the original contractor

vi. The value of the good or service being acquired does not exceed $2000

**Non-Competitive Procurement Approval Requirements**

i. SOLE SOURCE procurements require prior authorization in accordance with Annex 1 – Schedule 1 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements

ii. DIRECTED SOURCE procurements require authorization in accordance with Annex 1 – Schedule 4 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements

Note:
1. The cost of known follow-on support activity (to a maximum of 3 years) associated with a Directed Source procurement should be included in the initial total purchase value to avoid duplication in approval requests (e.g. annual hardware/software maintenance, ongoing software support, quarterly/yearly audits etc.). After 3 years a decision to continue with the follow-on support requires re-approval in accordance with Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements.

2. A Request To Direct Source Goods and Services Form must be completed to justify all Directed Source acquisitions of goods or services in excess of $2,000.
Note: Hydro Ottawa management approvals are not required when the non-competitive procurement has been authorized by Hydro Ottawa's Board of Directors and/or its committees.

## 7. ADDITIONAL POLICY ELEMENTS

**Requisitioner's Responsibilities:**

i. Provide sufficient lead time for the processing of procurement documentation
ii. Initiate a Purchase Requisition in JDE and, through the imbedded workflow, secure approval to purchase
iii. Develop the Statement of Requirements or detailed Specification as applicable to the requirement and the acquisition method
iv. Work collaboratively with Procurement to define the non-financial bid evaluation criteria/weighting and the selection process as appropriate to the acquisition method
v. In conjunction with Procurement, evaluate suppliers' bids in accordance with the pre-determined evaluation criteria/weighting

**Procurement's Responsibilities:**

i. Act as custodian of the Procurement Policy and all associated procurement procedures and in so doing:
    - Monitor conformance with the policy and procedures
    - Reject any Purchase Requisitions which, in the opinion of Procurement, do not comply with this policy and supporting procedures
    - Raise any incidents of non-compliance through the Procurement management hierarchy for resolution
ii. Provide advice and guidance to internal customers and work collaboratively with them during the procurement process to:
    - Determine the most appropriate acquisition method
    - Establish the non-financial bid evaluation criteria/weighting and the selection process as appropriate to the procurement method
    - Prepare the solicitation documents including the Statement of Requirements or detailed Specifications
    - Evaluate supplier submissions including the completion of a vendor risk assessment and validation of compliance with Hydro Ottawa's Contractor OHSE Management Program (Reference Contractor OHSE Requirements – WI-MS-002.00)
    - Ensure bidding prerequisites are fair and objective
iii. Identify/validate Sole Source (vs. Directed Source) procurements
iv. Work collaboratively with internal customers to determine opportunities to aggregate purchases and establish vehicles for the acquisition of common buys
v. Routinely inform internal customers about the availability of Standing Offers, supply arrangements and supplier source lists for the acquisition of goods or services
vi. Assess the complexity and risk of purchases to determine when vendor contracts are required and interface with Legal accordingly
vii. Debrief unsuccessful suppliers, in consultation with internal customers if requested by a supplier

viii. Work collaboratively with internal customers to evaluate supplier performance ensuring compliance with contract deliverables/service level commitments
Note: In the case of long term agreements performance assessments should be completed annually and/or in advance of any contract renewals and/or extensions
ix. Provide management with requested reports on procurement activity
x. Ensure all likely follow-on activity is identified and included in the initial approval request for Directed Source acquisitions

**Management's Responsibilities:**
i. Communicate details of the Procurement Policy to employees
ii. Ensure all procurements comply with this policy
iii. Ensure the availability of current year (and, when required, future years') budget funding to support the acquisition
iv. Collaborate with Procurement in the
- aggregation of Hydro Ottawa common purchases
- evaluation of supplier submissions
- assessment of supplier performance

v. Address minor policy non-compliance issues with the responsible employee and escalate serious policy violations to the Policy Owner

## 8. COMPLIANCE

Serious policy infractions will be addressed in accordance with Hydro Ottawa's Code of Business Conduct and policy on Discipline and Discharge (POL-Hr-005.00).

## 9. APPROVAL HISTORY

| Revision | Release Date: | Policy Owner Sign-off: | Approved By: | Effective Date: |
|---|---|---|---|---|
| .00 | January 1, 2013 | Chief Financial Officer | President and CEO | January 1, 2013 |
| Revision .NN | Revision Date Month/Day/Year | Policy Owner Sign-off: Chief Financial Officer | Approved By: President and CEO | Effective Date: Month/Day/Year |
| Revision .NN | Revision Date Month/Day/Year | Policy Owner Sign-off: Chief Financial Officer | Approved By: President and CEO | Effective Date: Month/Day/Year |

| Scheduled Re-affirmation Date: **January 1, 2016** | Responsibility: **Chief Financial Officer** |
|---|---|

## 10. POLICY EXCEPTIONS

Exceptions to the above directives and/or changes to this policy must receive written pre-authorization from the President and CEO. For clarification on any aspect of this policy contact the Director of Finance.

# HYDRO OTTAWA CORPORATE POLICIES

| **Subject**: Approval Authority for Procurements and Disbursements | | |
|---|---|---|
| **Category**: Enterprise | **Policy Number**: POL-En-006.00 | |
| **Administrator:** Director Finance | **Owner:** Chief Financial Officer | **Approver:** President and CEO |

1. **PURPOSE**
The purpose of this policy is to define the limits of procurement and disbursements approval authority delegated to specified positions within Hydro Ottawa.

2. **SCOPE**
The Hydro Ottawa Group of Companies.

3. **DEFINITIONS**
***Temporary***, in the context of this policy, is defined as ≤ 30 consecutive calendar days.
***Delegation of Approval Authority*** refers to the long term assignment of financial decision making authority by the President and CEO to various positions within Hydro Ottawa.
***Temporary Sub-delegation of Approval Authority*** refers to the short term reassignment of financial decision making authority during management/supervisor absences.
A ***Sole Source Procurement*** is when there is only one identifiable source for a given good or service.
A ***Directed Source Procurement*** is when there is more than one identifiable source for a given good or service, but there are compelling reasons why the selected vendor is not determined by an open competition.
***EA*** refers to Executive Assistant.
***AA*** refers to Administrative Assistant.

4. **POLICY DIRECTIVES**
   a. The President and CEO has been granted, by the Boards of Directors of the Hydro Ottawa Group of Companies, full decision making authority on all Hydro Ottawa day-to-day financial matters.
   b. This authority has been delegated by the President and CEO to various employees within the Hydro Ottawa Group of Companies based on their position and business mandate.
   c. Details on the delegation and temporary sub-delegation of approval authority for procurements and disbursements are provided in Annex 1 of this policy, which is structured as follows:

| | |
|---|---|
| Schedule 1 | Delegation of Approval Authority for Purchase Requisitions |
| Schedule 2 | Temporary Sub-Delegation of Approval Authority for Purchase Requisitions |
| Schedule 3 | Approval of Purchase Orders |
| Schedule 4 | Approval of Directed Source Procurements |
| Schedule 5 | Approval of Expense Reports |
| Schedule 6 | Approval of Payments That Do Not Require Purchase Orders |

   d. All values in Annex 1 are expressed in Canadian currency and are exclusive of taxes and duties.
   e. Responsibility rests with the approver to ensure there are current year (and if necessary future years') budget funds to pay for goods and services procured through purchase orders and/or procurement contracts.
   f. The procurement of /discretionary spending on the following specialized categories of goods and services must have co-approval from the appropriate Hydro Ottawa "functional" division before action is taken:

| Category | Functional Division Co-Approval |
|---|---|
| IM & IT Products and Services | IM & IT |
| Advertising | Communications |
| Legal Services | CFO (Legal) |
| Commercial Insurance | CFO (Treasury) |
| Sponsorships/Donations | Communications |
| Leases | CFO (Treasury) |
| Recruitment Services | HR |

Note:

- CFO (Legal) approval is not required when:
  - there is an established relationship between the legal service provider and Hydro Ottawa, and
  - CFO (Legal) initially approved the vendor.
- Commercial Insurance excludes HR employee benefit insurance programs such as life insurance, health and dental plans, the Worker Safety Insurance Board etc.

g. Individuals are responsible for sub-delegating their approval authority *before departing on planned absences* by documenting the sub-delegate's name and the duration the of the authority reassignment in an email which, at a minimum, should be sent to:

To: Director Human Resources
Supervisor Procurement
Supervisor Accounts Payable

Copy: Name of sub-delegated signing authority
The manager of the individual sub-delegating their signing authority
Supporting Executive/Administrative Assistant

Note: The above email can be sent by the appropriate EA/AA copying the individual who is sub-delegating their approval authority.

h. Approval authority can be sub-delegated to a peer within the employee's division or to a subordinate as detailed in Annex 1 - Schedule 2 of this policy.

i. Chiefs must sub-delegate their approval authority to a direct report within their division (i.e. lateral assignments are not permitted).

j. When approval authority has been sub-delegated to a subordinate, all financial transactions must be co-approved by the CFO Division per Annex 1 - Schedule 2 of this policy.

k. In the case of absences where a sub-delegate has not been named, approval authority will revert to the individual's direct manager who can either retain the signing authority responsibilities until the individual returns or initiate the assignment of temporary signing authority as described in 4 g. above.

l. The sub-delegation of signing authority for periods > 30 consecutive days requires the approval of the individual's direct manager (e.g. sub-delegation of a Director's signing authority for a 31 day period would require approval of the Division Chief.)

m. Individuals who are appointed to a management position as a result of Hydro Ottawa's Emergency Succession Plan will assume full approval authority of the appointed position.

## 5. RELATED POLICIES, PROCEDURES and REFERENCE DOCUMENTS

Approval Authority for Procurements and Disbursements Policy – Annex 1.
Hydro Ottawa Credit Card Policy (POL-Fi-001.00)
Business Expense Reimbursement Policy (POL-Fi-005.00)
Travel Expense Reimbursement Policy (POL-Fi-002.00)
Procurement Policy (POL-Fi-003.00)
Insurance Policy (POL-Fi-006.00)
Discipline and Discharge Policy (POL-Hr-005.00).
Recruiting and Staffing – Management Group Positions (POL-Hr-006.00).

## 6. EXCLUSIONS

There are no exclusions

## 7. ADDITIONAL POLICY ELEMENTS

There are no additional policy elements

## 8. COMPLIANCE

Policy violations will be addressed in accordance with Hydro Ottawa's Code of Business Conduct and policy on Discipline and Discharge (POL-Hr-005.00).

## 9. APPROVAL HISTORY

| Revision | Release Date: | Policy Owner Sign-off: | Approved By: | Effective Date: |
|---|---|---|---|---|
| .00 | January 1, 2013 | Chief Financial Officer | President and CEO | January 1, 2013 |
| Revision .NN | Revision Date Month/Day/Year | Policy Owner Sign-off: Chief Financial Officer | Approved By: President and CEO | Effective Date: Month/Day/Year |

| | |
|---|---|
| Scheduled Re-affirmation Date: **January 1, 2016** | Responsibility: CFO |

## 10. POLICY EXCEPTIONS

Exceptions to the above directives and/or changes to this policy must receive written pre-authorization from the President and CEO. For clarification on any aspect of this policy contact the Director, Finance.

# Approval Authority for Procurements and Disbursements

## ANNEX 1 – AUTHORITY LEVELS

Schedule 1

**Delegation of Approval Authority**
**Purchase Requisitions**

| Approver | Mandate | Limit |
|---|---|---|
| President & CEO | Enterprise | > $1,000,000 |
| Chief | Division | To $1,000,000 |
| Director | Group | To $500,000 |
| Manager | Section | To $100,000 |
| Supervisor | Unit | To $5,000 |
| Executive Assistant | N/A | To $1,000 |

**NOTES:**

1. The above authorization limits relate to purchase requisitions for both competitive and sole source procurements.
2. Directed source procurement approval requirements are provided in Schedule 4.
3. Approval to purchase goods and services must be obtained from the division that will be paying the associated invoices/incurring the expenses.
4. Responsibility rests with the approver to ensure there are current year (and if necessary future years') budget funds to pay for goods and services procured through purchase orders and/or third party contracts.
5. Requisitions (and purchase orders) are *not* required for procurements:
   - ≤ $2000 (unless stipulated by the supplier)
   - listed in Schedule 6
6. All purchases must comply with Hydro Ottawa's Procurement Policy (POL-Fi-003.00).
7. Higher approval limits for specific operational positions (based on job function) require authorization from the President & CEO.

# Approval Authority for Procurements and Disbursements

## ANNEX 1 – AUTHORITY LEVELS

Schedule 2

**Temporary Sub-delegation of Approval Authority**
**Purchase Requisitions**

| Original Signing Authority | Limit | Temporary Sub-delegated Signing Authority | CFO Division Co-Approval |
|---|---|---|---|
| President & CEO | > $1,000,000 | Chief | Chief Financial Officer |
| Chief | To $1,000,000 | Director | Director Finance |
| Director | To $500,000 | Manager | Controller |
| Manager | To $100,000 | Supervisor | Manager Accounting |
| Supervisor | To $5,000 | N/A | N/A |
| Executive Assistant | To $1,000 | N/A | N/A |

**NOTES:**

1. Temporary is defined as ≤ 30 consecutive calendar days.
2. In the absence of Director positions within a Division, Chiefs would sub-delegate signing authority to a Manager.
   Note: The Manager's sub-delegated approval limit would be $500,000.
3. Sub-delegation of a signing authority for any period in excess of 30 consecutive days requires approval of the individual's manager.
4. CFO Division co-approval is required when approval authority has been sub-delegated to a subordinate.
   Note: CFO Division co-approval is *not required* when approval authority has been sub-delegated to a peer within the division.
5. When a CFO Division employee is named as the temporary sub-delegated signing authority, co-approval must be obtained from one of the Director Finance, Treasurer, General Counsel or Director of Regulatory Affairs.
6. Supervisors and EAs cannot sub-delegate their approval authority.
7. All NOTES in Schedule 1 apply to Schedule 2.

## Approval Authority for Procurements and Disbursements

### ANNEX 1 – AUTHORITY LEVELS

Schedule 3

| Approval of Purchase Orders | | |
|---|---|---|
| **Approver** | **Mandate** | **Limit** |
| President & CEO | Enterprise | > $1,000,000 |
| Chief Financial Officer | Enterprise | > $1,000,000 |
| Director Finance | Enterprise | To $1,000,000 |
| Manager Supply Chain | Enterprise | To $500,000 |
| Supervisor Procurement | Enterprise | To $100,000 |
| Procurement Agent | Enterprise | To $5,000 |

**NOTES:**

1. The above relates to approval to make a commitment to a 3rd party supplier through the execution of Purchase Orders by the CFO division.
2. If a contract is required, in addition to the Purchase Order, Procurement will consult with Legal, as appropriate.
3. The Purchase Order approver cannot be the same individual as the Requisition approver.
4. Invoices will be paid to a maximum of 105% of the Purchase Order value.
5. Purchase Orders are *not* required for procurements:
    - ≤ $2000 (unless stipulated by the supplier)
    - Listed in Schedule 6

## Approval Authority for Procurements and Disbursements

### ANNEX 1 – AUTHORITY LEVELS

Schedule 4

| Approval of Directed Source Procurements | | |
|---|---|---|
| **Approver** | **Mandate** | **Limit** |
| Sponsoring EMT Member + CFO + President & CEO | Enterprise | > $100,000 |
| Sponsoring EMT Member + Director Finance | Division | $50,000 - $100,000 |
| Sponsoring Director + Manager Supply Chain | Group | < $50,000 |

**NOTES:**

1. A Directed Source Procurement is when there is more than one identifiable source for a given good or service, but there are compelling reasons why the selected vendor is not determined by an open competition. (Refer to Hydro Ottawa's Procurement Policy – POL-Fi-003.00 for additional details on Directed Source Procurements)
2. Hydro Ottawa management approvals are not required for Directed Source Procurements authorized by Hydro Ottawa's Board of Directors and/or its committees.

## Approval Authority for Procurements and Disbursements

### ANNEX 1 – AUTHORITY LEVELS

Schedule 5

| Approval of Expense Reports | | |
|---|---|---|
| **Approver** | **Mandate** | **Limit** |
| President & CEO | Enterprise | > $10,000 |
| Chiefs | Division | To $10,000 |
| Directors | Group | To $5,000 |
| Managers | Section | To $2,000 |
| Supervisor | Unit | To $500 |

**NOTES:**

1. Individuals cannot approve their own expense reports.
2. The Temporary Sub-delegation of Approval Authority listed in Schedule 2 includes authority to approve expense reports per the above limits. (CFO co-approval is not required for sub-delegate approved expense reports.)

## Approval Authority for Procurements and Disbursements

### ANNEX 1 – AUTHORITY LEVELS

Schedule 6

| Approval of Payments that do not Require Purchase Orders (Invoices Without Reference) | |
|---|---|
| **1. Approval limits same as Schedule 1** | |
| **Expense Item** | **Responsible Division** |
| Freight & forwarding | CFO |
| Courier | |
| * Commercial Insurance premiums | |
| Corporate income tax | |
| Licenses and registrations | |
| Legal Costs (Non HR related) | |
| Legal Costs (HR related) | HR |
| Planning permits, access fees, development fees, easements | Distribution & Customer Service |
| Hot water tank rentals | |
| Sponsorships, market promotions, donations | Communications & Marketing |
| Conferences | All |
| Subscriptions and Publications | All |
| Emergency related purchases of goods and services | All |
| **2. Specified Approvers** | |
| **Expense Item** | **One of:** |
| Property taxes | Manager Supply Chain/Director Finance |
| Utilities | |
| Interest and financing charges | Treasurer/Chief Financial Officer |
| HST | Controller/Director Finance |
| Other taxes and duties | |
| IESO Monthly Settlement | |
| Embedded Generators (FIT, MicroFIT, HCI, RESOP) | |
| Bank charges | |
| Payments to Retailers | |
| Payroll-related remittances | Director Human Resources Services/Chief Human Resources Officer |
| Telecommunication services | Manager IT Operations/Chief Information Officer |

* Note: Excludes HR employee benefit insurance programs such as life insurance, health and dental plans, Worker Safety Insurance Board etc.

## ANNEX 1 – AUTHORITY LEVELS

Schedule 6 (continued)

| **Approval of Payments that do not Require Purchase Orders**<br>**(Invoices Without Reference)** |
|---|
| **Notes:**<br>1. Schedule 6 identifies invoices for goods and services > \$2000 that are payable without a requirement for/reference to a purchase order.<br>2. Invoices for any goods or services ≤ \$2000 do not require a purchase order.<br>3. Emergency is defined as a sudden, urgent, unexpected occurrence or occasion requiring immediate action.<br>4. Changes to the expense item listing and related authorizations in Schedule 6 require the approval of the Chief Financial Officer.<br>5. **Section 2 - Specified Approvers** are invoices where payment is time sensitive and authorization requires specialized knowledge/insights to validate the invoice amount.<br>6. There are no dollar limits associated with the expense items listed in **Section 2 - Specified Approvers**.<br>7. Individuals indentified in **Section 2 - Specified Approvers** must determine supporting documentation requirements for invoice approval with concurrence from Director Finance. |

# CORPORATE PROCEDURE

| Subject: Contract Procurement Process | | |
|---|---|---|
| **Category**: Finance | | **Procedure Number**: PRO-Fi-013.00 |
| **Policy Ref:** POL-Fi-003.00<br>Procurement | **Administrator**<br>Director of Finance | **Owner**<br>Chief Financial Officer |

**1. PURPOSE**
To ensure consistency and accountability in the contract procurement process.

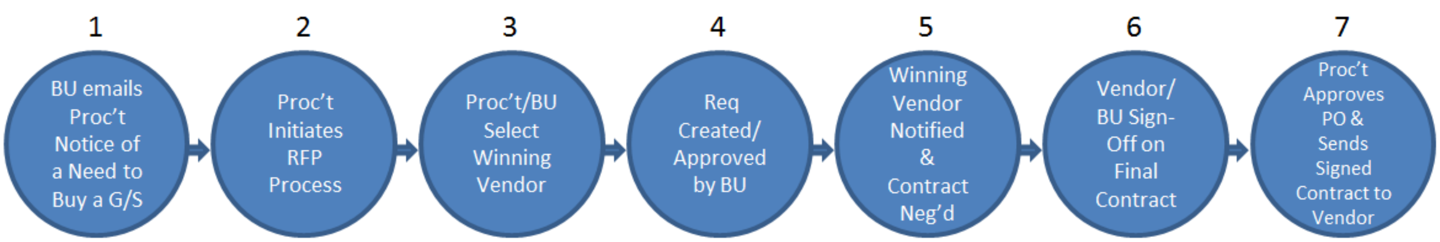
**2. SCOPE**
All Hydro Ottawa employees involved in contract procurements.

**3. DEFINITIONS**
**BU** refers to a Hydro Ottawa business unit
**G/S** refers to a good or service
**Hydro Ottawa** refers to Hydro Ottawa Holding Inc. and its affiliates
**Legal** refers to Hydro Ottawa's Legal Group
**PO** refers the Hydro Ottawa Purchase Order module within JDE
**Procurement or Proc't** refers to the Procurement Unit within Hydro Ottawa's Supply Chain Section
**Pro Forma Contract** refers to any Hydro Ottawa contract that has been prepared by Legal and contains standard terms and conditions
**Req** refers to the Requisition module within JDE
**RFP** refers to Request for Proposal
**RFQ** refers to Request for Quote

**All** references to dollar amounts shall be in Canadian currency and exclusive of taxes

**4. PROCEDURE DESCRIPTION**

**Contract Procurement Process Overview**




| Responsibility | Ref | Instructions |
|---|---|---|
| BU – Requisitioner | 4.1 | When it is anticipated a pending purchase will require a procurement contract, the BU shall email the details to the Supervisor, Procurement providing a description of the G/S involved, an estimate of the total cost (excluding taxes/duties), specifics on the timing of the purchase and confirmation of budget funding.<br>Note:<br>a. The email should be copied to the appropriate BU signing level (per Annex 1 Schedule 1 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements (POL-En-006.00)<br>b. The final decision to proceed with an RFP/Contract procurement (vs. an alternate procurement vehicle such as an RFQ or PO) rests solely with Procurement<br>c. The need to send a Request For Information (RFI) to prospective vendors shall be jointly determined by the BU and Procurement<br>d. A non-competitive procurement process begins with step 4.4 above once the required Sole/Directed Source approvals are obtained per Hydro Ottawa's Procurement Policy (POL-Fi-003.00) |

| Responsibility | Ref | Instructions |
|---|---|---|
| Procurement | 4.2 | Per the Procurement Policy, an RFP is issued containing a detailed Statement of Work (written by the BU) and the requirement that vendors accept Hydro Ottawa's pro-forma contract terms and conditions. |
| Procurement/BU | 4.3 | The winning vendor is selected based on pre-set evaluation criteria.<br>Note: The winning vendor selection shall remain Hydro Ottawa confidential until the Req is created/approved. |
| BU | 4.4 | The Req is created in JDE and approved per Annex 1 Schedule 1 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements (POL-En-006.00). Note: Electronic attachments to the Requisition shall include:<br>a. The Statement of Work<br>b. The winning vendor's proposed solution<br>c. Solution pricing<br>d. The pro-forma contract and, if known, any potential non-standard contract terms and conditions<br>e. Summary comments on open issues i.e. potential risk areas including recommendations on contingency funding to address risk issues |
| Procurement/BU | 4.5 | The winning vendor is notified and the contract is negotiated.<br>Note:<br>a. The winning vendor is advised that any commitments made by Hydro Ottawa during negotiations are subject to the BU sign-off on the final contract and the execution of the PO within JDE by Procurement<br>b. Procurement (not the BU) shall engage Legal as/when required in the event changes are required to Hydro Ottawa's pro-forma contract wording<br>c. Material changes (in the judgement of Procurement) between the winning vendor's RFP response and the negotiated contract (such as changes in contract terms and conditions, price, risks, key elements of the deliverables etc.) require an update to/re-approval of the Req within JDE<br>d. In the event of material changes per 4.5 (c.) above, Procurement shall consult with Legal to determine if the RFP needs to be re-issued<br>e. Procurement creates a PO within JDE and registers the PO number as the contract number on the duplicate originals of the final agreement<br>f. The PO shall identify any contingency funding required to address risk issues that are contained in the final contract<br>g. Contingency funding shall remain Hydro Ottawa confidential and excluded from the financial information detailed in the contract<br>h. Procurement shall provide a scanned copy of the final agreement to both the contract and procurement signing authorities for their review. |
| Procurement/BU | 4.6 | The Vendor/BU sign-off on the final contract.<br>Note:<br>a. Duplicate originals of the final contract are presented to the vendor for their sign-off<br>b. Following vendor approval, the contracts are returned to Hydro Ottawa and signed off by the BU per the following: |

**Hydro Ottawa Contract Procurement Signing Limits**

| Approver | Mandate | Limit |
|---|---|---|
| President & CEO | Enterprise | > $5,000,000 |
| Chief | Division | To $5,000,000 |
| Director | Group | To $500,000 |
| Manager | Section | To $100,000 |
| Supervisor | Unit | To $5,000 |

c. Chiefs shall provide the President & CEO with email notifications of contract sign-offs valued from $1,000,000 to $5,000,000.

| Responsibility | Ref | Instructions |
|---|---|---|
| Procurement | 4.7 | Once both parties have signed off on the contract, the PO is approved within JDE.<br>Note:<br>a. Approvals shall be in accordance with Annex 1 Schedule 3 of Hydro Ottawa's policy on Approval Authority for Procurements and Disbursements (POL-En-006.00)<br>b. A duplicate contract original is returned to the vendor<br>c. Procurement attaches a scanned copy of the second duplicate original to the PO within JDE and files the hard copy for their records |

5. **RELATED POLICIES, PROCEDURES & REFERENCE DOCUMENTS**
   Procurement Policy (POL-Fi-003.00)
   Approval Authority for Procurements and Disbursements Policy (POL-En-006.00)
   Discipline and Discharge Policy (POL-Hr-005.00)

6. **COMPLIANCE**
   Periodic audits will be carried out by the Internal Audit & Risk Management group to assess compliancy with the procedures detailed above. Non-compliant behaviour will be escalated to the Chief Financial Officer who will determine the appropriate disciplinary action.

7. **APPROVAL HISTORY**

| Revision | Release Date | | Procedure Admin Sign-off: | Procedure Owner Approval: |
|---|---|---|---|---|
| .00 | July 1, 2014 | | Director of Finance | Chief Financial Officer |
| Revision | Revision Date: | Description of Changes | Procedure Admin Sign-off: | Procedure Owner Approval: |
| .NN | Month/Day/Year | | Director of Finance | Chief Financial Officer |

| Scheduled Re-affirmation Date | Responsibility |
|---|---|
| July 1, 2016 | Director of Finance |

**Exceptions** and/or **changes** to this procedure must receive written authorization from the Chief Financial Officer. For **clarification** on any aspect of this policy contact the Director of Finance.

# ONE-TIME COSTS

## 1.0 INTRODUCTION

Hydro Ottawa Limited confirms there are no one-time costs in 2016 as part of this application.

# REGULATORY COSTS

## 1.0 INTRODUCTION

Regulatory costs for Hydro Ottawa Limited ("Hydro Ottawa") are included in the Uniform System of Accounts ("USoA") 5655, 5630 and 5620 – a summary of Regulatory Expenses are shown in Table 1. Please refer to Appendix 2-M - Regulatory Cost Schedule for further details. This includes Ontario Energy Board (the "Board") cost assessments and licence fees, Electrical Safety Authority ("ESA") cost assessments, intervenor and other cost awards, professional services (legal and consulting) and costs to publish public notices, all of which are considered on-going costs. Annual assessment fees paid to the Board is the largest expenditure in this category. Hydro Ottawa has seen increases in total Regulatory Costs, the budget for the test year, 2016 is $1.4M. The volume of proceedings at the Board continues to increase, resulting in higher annual cost awards. Furthermore, the continual changes within the electricity industry, including aging infrastructure and an aging workforce as well as a number of issues specific to Hydro Ottawa means that this application is for the 2016 test year only and is not considered a base year for a subsequent IRM process.

Hydro Ottawa's costs of regulatory staff have not been included in USoA Accounts 5655, 5630 or 5620. These costs are contained within the general OM&A budgets. Personnel from other departments who work on the preparation of the rate case (such as finance, distribution asset management, treasury, human resources, customer service, information technology, etc.) are not included in Accounts 5655, 5630 or 5620. These costs are contained within their departmental budgets.

**Table 1 – Regulatory Cost Schedule (Summary)**

| Last Rebasing Year (2012 Board Approved) | Most Current Actuals Year 2014 | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|
| $1,298,157 | $1,173,303 | $1,338,863 | $1,365,775 |

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | D |
| **Tab:** | 2 |
| **Schedule:** | 4 |
| **Page:** | 1 |
| | |
| **Date:** | ORIGINAL |

# Appendix 2-M
## Regulatory Cost Schedule

| | **Regulatory Cost Category** | **USoA Account** | **USoA Account Balance** | **Ongoing or One-time Cost?** [2] | **Last Rebasing Year (2012 Board Approved)** | **Most Current Actuals Year 2014** | **2015 Bridge Year** | **Annual % Change** | **2016 Test Year** | **Annual % Change** |
|---|---|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C ) | (D) | (E) | (F) | (G) | (H) = [(G)-(F)]/(F) | (I) | (J) = [(I)-(G)]/(G) |
| **1** | OEB Annual Assessment | 5655 | | On-Going | $ 775,196 | $ 880,729 | $ 898,344 | 2.00% | $ 916,311 | 2.00% |
| **2** | OEB Section 30 Costs (Applicant-originated) | | | | | | | | | |
| **3** | OEB Section 30 Costs (OEB-initiated) | | | | | | | | | |
| **4** | Expert Witness costs for regulatory matters | | | | | | | | | |
| **5** | Legal costs for regulatory matters | 5655 | | On-Going | $ 208,829 | $ 55,955 | $ 157,547 | 181.56% | $ 160,711 | 2.01% |
| **6** | Consultants' costs for regulatory matters | 5630 | | On-Going | $ 20,000 | $ 64,773 | $ 66,069 | 2.00% | $ 16,188 | -75.50% |
| **7** | Operating expenses associated with staff resources allocated to regulatory matters | | | | | | | | | |
| **8** | Operating expenses associated with other resources allocated to regulatory matters [1] | | | | | | | | | |
| **9** | Other regulatory agency fees or assessments | 5655 | | On-Going | $ 127,044 | $ 135,374 | $ 138,081 | 2.00% | $ 140,843 | 2.00% |
| **10** | Any other costs for regulatory matters (please define) | 5655 | | On-Going | $ 5,208 | | | | | |
| **11** | Intervenor costs | 5620 | | On-Going | $ 161,880 | $ 36,472 | $ 78,822 | 116.12% | $ 131,722 | 67.11% |
| **12** | Sub-total - Ongoing Costs [3] | | $ - | | $ 1,298,157 | $ 1,173,303 | $ 1,338,863 | 14.11% | $ 1,365,775 | 2.01% |
| **13** | Sub-total - One-time Costs [4] | | $ - | | $ - | $ - | $ - | | $ - | |
| **14** | Total | | $ - | | $ 1,298,157 | $ 1,173,303 | $ 1,338,863 | 14.11% | $ 1,365,775 | 2.01% |

**Please fill out the following table for all <u>one-time</u> costs related to this cost of service application to be amortized over the test year plus the IRM period.**

| | | **Historical Year(s)** | **2015 Bridge Year** | **2016 Test Year** |
|---|---|---|---|---|
| **4** | Expert Witness costs | | | |
| **5** | Legal costs | | | |
| **6** | Consultants' costs | | | |
| **7** | Incremental operating expenses associated with staff resources allocated to this application. | | | |
| **8** | Incremental operating expenses associated with other resources allocated to this application. [1] | | | |
| **11** | Intervenor costs | | | |

# LOW-INCOME ENERGY ASSISTANCE PROGRAM

## 1.0 INTRODUCTION

In accordance with the LEAP Report, since 2011, Hydro Ottawa has allocated 0.12 percent of its total distribution revenue requirement towards the LEAP Emergency Financial Assistance program.

Table 1 below shows Hydro Ottawa's annual LEAP contributions, and the number of customers assisted for 2012-2015:

**Table 1 – LEAP Contributions and Number of Customers Assisted**

| | Actual 2012 | Actual 2013 | Actual 2014 | Bridge 2015 |
|---|---|---|---|---|
| Annual Contribution | $185,000.00 | $187,000.00 | $187,300.00 | $190,984.00 |
| Carryover from prior years | 6,465.47 | 9,483.02 | 0.00 | 46,341.83 |
| Administration Fees | 27,750.00 | 28,050.00 | 28,095.00 | 28,647.60 |
| Total Available | 163,715.47 | 168,433.47 | 159,205 | 162,336.40 |
| | | | | |
| Total Number of Applicants | 530 | 663 | 435 | N/A |
| Number of Applicants Assisted | 435 | 487 | 329 | N/A |

Currently, Hydro Ottawa continues to work with the United Way as its Lead Agency, with the Salvation Army administering the various Intake Agencies throughout the City of Ottawa.

As prescribed by the Board, Hydro Ottawa contributes 0.12% of its Board-Approved distribution revenue requirement annually to LEAP, and will continue to do so from 2016 through 2020.

Prior to 2011, Hydro Ottawa participated and supported the Winter Warmth program, which provided assistance to low-income residents in Ottawa with winter heating bills. Hydro Ottawa confirms that there are no amounts included in the revenue requirement for the Test Years for Winter Warmth or any other such legacy assistance program.

# CHARITABLE AND POLITICAL DONATIONS

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") follows the OEB's Accounting Procedures Handbook ("APH") with respect to charitable and political donations. As per the APH, Donations are tracked in the Uniform System of Accounts ("USoA") 6205 Donations and are not included in the revenue requirement for the Test Years.

Only donations specifically for the Low-Income Energy Assistance Program ("LEAP") as tracked in the USoA Sub-account 6205 Donations, sub-account LEAP Funding are included in the revenue requirement for the Test Years. The Board has prescribed the LEAP program to provide assistance to low-income consumers in paying their electricity bills. Please refer to Exhibit D-2-5 for further details on the LEAP program.

The following Table 1 summarizes charitable and political donations that are both recoverable and non-recoverable for revenue requirement from 2012 to 2016 Test Year.

**Table 1– Charitable and Political Donations Summary**

| Category | 2012 Actual | 2013 Actual | Most Current Actuals Year 2014 | 2015 Bridge Year | 2016 Test Year |
|---|---|---|---|---|---|
| Rate Recoverable | $185,000 | $187,000 | $187,152 | $190,984 | $210,088 |
| Non-Rate Recoverable | $190,124 | 190,536 | 190,214 | 154,750 | 156,275 |
| TOTAL | **$375,124** | **$377,536** | **$377,366** | **$345,734** | **$366,363** |

Hydro Ottawa will also adhere to any requirements for the recording of charitable and political donations for any new Board-Approved programs to assist low-income customers, such as the Low-Income Strategy Review (EB-2014-0227), that are regulated by the Board.

# NON-RECOVERABLE CONTRIBUTIONS

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") confirms that no political contributions have been included in the revenue requirement for the Test Years. Please refer to Exhibit D-2-6 for a summary of non-rate recoverable charitable and political donations.

# DEPRECIATION/AMORTIZATION/DISPOSAL SCHEDULE

Hydro Ottawa Limited ("Hydro Ottawa") is not proposing to make any changes from the amortization rates that were previously accepted in the 2012 Electricity Distribution Rate Application (EB-2011-0054) therefore an amortization study is not included with this application. Hydro Ottawa's useful lives are provided in Table 4 and are consistent with the 2012 lives.

Hydro Ottawa uses the half-year rule for calculating depreciation/amortization in the year that capital additions are added to the rate base for both actual and budgeted pooled assets, except in the case of discrete material assets, such as a station. In those specific cases, that actual or forecasted in-service month would be used to calculate the depreciation/amortization.

The following tables (Table 1 and Table 2) detail the amortization expenses for 2012 Actual, 2013 Actual, 2014 Forecast, and 2015 to 2020 Budget, by asset group. As noted in the 2012 Electricity Distribution Rate Application (EB-2011-0054), Hydro Ottawa received approval to recover the cost of meters stranded as a result of the installation of Smart Meters over a six year period; $2,987k has been included in the amortization expense for years 2012 and 2013, which are the fifth and last year period.

Also included in the Tables is the effect on amortization from disposals in 2012 and 2013 and 2014 forecast and budgeted disposals for 2015 to 2020.

Hydro Ottawa has not provided Chapter 2 MIFRS Appendices (2-CA to 2-CI) of the Board's Chapter 2 2.7.4 Depreciation, Amortization and Depletion of the Filing Requirements for Transmission and Distribution Applications as it is a simplified approach to the calculation of depreciation expense and the requested information is already provided in Chapter 2 Appendix 2 – BA.

**Table 1: Amortization Expense 2012 to 2016 (In $000's)**

| **Asset Group** | **2012 Amortization Expense** | **2012 Disposal** | **2013 Amortization Expense** | **2013 Disposal** | **2014 Amortization Expense** | **2014 Disposal** | **2015 Amortization Expense** | **2015 Disposal** | **2016 Amortization Expense** | **2016 Disposal** |
|---|---|---|---|---|---|---|---|---|---|---|
| Land and Buildings | (593) | 0 | (721) | 0 | (794) | 0 | (858) | 0 | (891) | 0 |
| TS Primary Above 50 | (2,202) | 0 | (2,328) | 0 | (2,854) | 3 | (3,144) | 0 | (3,158) | 0 |
| DS | (3,697) | 0 | (3,634) | 644 | (3,704) | 32 | (3,566) | 92 | (3,364) | 92 |
| Pole, Wires | (8,982) | 28 | (10,000) | 182 | (10,820) | 424 | (13,615) | 714 | (15,002) | 714 |
| Line Transformers | (1,973) | 12 | (2,241) | 23 | (2,305) | 2 | (3,608) | 118 | (3,993) | 118 |
| Services and Meters | (7,979) | 3 | (8,119) | 289 | (5,325) | 6 | (6,595) | 52 | (6,918) | 52 |
| General Plant | (1,971) | 0 | (1,880) | 0 | (1,744) | 2 | (1,821) | 0 | (1,855) | 0 |
| Equipment | (2,139) | 2 | (2,288) | 0 | (2,699) | 33 | (2,528) | 38 | (2,669) | 38 |
| IT Assets | (9,064) | 0 | (9,181) | 0 | (7,899) | 92 | (8,317) | 0 | (9,071) | 0 |
| Other Distribution Assets[1] | 4 | 0 | 593 | 0 | 1,628 | 4 | 5,494 | 0 | 6,093 | 0 |
| **Total** | **$ (38,595)** | **$ 44** | **$ (39,798)** | **$ 1,138** | **$ (36,517)** | **$ 598** | **$ (38,558)** | **$ 1,013** | **$ (40,826)** | **$ 1,013** |

| Asset Group | 2012 Amortization Expense | 2012 Disposal | 2013 Amortization Expense | 2013 Disposal | 2014 Amortization Expense | 2014 Disposal | 2015 Amortization Expense | 2015 Disposal | 2016 Amortization Expense | 201 Dispos |
|---|---|---|---|---|---|---|---|---|---|---|
| Land and Buildings | (593) | 0 | (721) | 0 | (794) | 0 | (858) | 0 | (891) | |
| TS Primary Above 50 | (2,202) | 0 | (2,328) | 0 | (2,854) | 3 | (3,144) | 0 | (3,158) | |
| DS | (3,697) | 0 | (3,634) | 644 | (3,704) | 32 | (3,566) | 92 | (3,364) | |
| Poles, Wires | (8,982) | 28 | (10,000) | 182 | (10,820) | 424 | (13,615) | 714 | (15,002) | 7 |
| Line Transformers | (1,973) | 12 | (2,241) | 23 | (2,305) | 2 | (3,608) | 118 | (3,993) | 1 |
| Services and Meters | (7,979) | 3 | (8,119) | 289 | (5,325) | 6 | (6,595) | 52 | (6,918) | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| General Plant | (1,971) | 0 | (1,880) | 0 | (1,744) | 2 | (1,821) | 0 | (1,855) | |
| Equipment | (2,139) | 2 | (2,288) | 0 | (2,699) | 33 | (2,528) | 38 | (2,669) | |
| IT Assets | (9,064) | 0 | (9,181) | 0 | (7,899) | 92 | (8,317) | 0 | (9,071) | |
| Capital Contributions Paid | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| Other Distribution Assets [1] | 4 | 0 | 593 | 0 | 1,628 | 4 | 5,494 | 0 | 6,093 | |
| **Total** | **$ (38,595)** | **$ 44** | **$ (39,798)** | **$ 1,138** | **$ (36,517)** | **$ 598** | **$ (38,558)** | **$ 1,013** | **$ (40,826)** | **$ 1,013** |

Note 1: Other Distribution Assets include Deferred Revenue

**Table 2: Amortization Expense 2017 to 2020 (In $000's)**

| Asset Group | 2017 Amortization Expense | 2017 Disposal | 2018 Amortization Expense | 2018 Disposal | 2019 Amortization Expense | 2019 Disposal | 2020 Amortization Expense | 2020 Disposal |
|---|---|---|---|---|---|---|---|---|
| Land and Buildings | (905) | 0 | (940) | 0 | (976) | 0 | (1,017) | 0 |
| TS Primary Above 50 | (3,176) | 0 | (3,249) | 0 | (3,277) | 0 | (3,261) | 0 |
| DS | (3,427) | 92 | (3,804) | 92 | (4,112) | 92 | (4,283) | 92 |
| Pole, Wires | (16,282) | 714 | (17,610) | 714 | (18,872) | 714 | (20,119) | 714 |
| Line Transformers | (4,340) | 118 | (4,715) | 118 | (5,093) | 118 | (5,481) | 118 |
| Services and Meters | (7,244) | 52 | (7,621) | 52 | (7,977) | 52 | (8,360) | 52 |
| General Plant | (1,832) | 0 | (1,762) | 0 | (1,715) | 0 | (1,721) | 0 |
| Equipment | (2,819) | 38 | (3,115) | 38 | (3,284) | 38 | (3,385) | 38 |
| IT Assets | (10,805) | 0 | (11,430) | 0 | (11,332) | 0 | (10,986) | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Distribution Assets[1] | 6,684 | 0 | 7,200 | 0 | 7,689 | 0 | 8,319 | 0 |
| **Total** | **$ (44,145)** | **$ 1,013** | **$ (47,047)** | **$ 1,013** | **$ (48,949)** | **$ 1,013** | **$ (50,295)** | **$ 1,013** |

| Asset Group | 2017 Amortization Expense | 2017 Disposal | 2018 Amortization Expense | 2018 Disposal | 2019 Amortization Expense | 2019 Disposal | 2020 Amortization Expense | 2020 Disposal |
|---|---|---|---|---|---|---|---|---|
| Land and Buildings | (905) | 0 | (940) | 0 | (976) | 0 | (1,017) | 0 |
| TS Primary Above 50 | (3,176) | 0 | (3,249) | 0 | (3,277) | 0 | (3,261) | 0 |
| DS | (3,427) | 92 | (3,804) | 92 | (4,112) | 92 | (4,283) | 92 |
| Poles, Wires | (16,282) | 714 | (17,610) | 714 | (18,872) | 714 | (20,119) | 714 |
| Line Transformers | (4,340) | 118 | (4,715) | 118 | (5,093) | 118 | (5,481) | 118 |
| Services and Meters | (7,244) | 52 | (7,621) | 52 | (7,977) | 52 | (8,360) | 52 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| General Plant | (1,832) | 0 | (1,762) | 0 | (1,715) | 0 | (1,721) | 0 |
| Equipment | (2,819) | 38 | (3,115) | 38 | (3,284) | 38 | (3,385) | 38 |
| IT Assets | (10,805) | 0 | (11,430) | 0 | (11,332) | 0 | (10,986) | 0 |
| Capital Contributions Paid | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Distribution Assets[1] | 6,684 | 0 | 7,200 | 0 | 7,689 | 0 | 8,319 | 0 |
| **Total** | **$ (44,145)** | **$ 1,013** | **$ (47,047)** | **$ 1,013** | **$ (48,949)** | **$ 1,013** | **$ (50,295)** | **$ 1,013** |

**Table 3: Asset Retirement Obligations ("ARO")**

| Asset Retirement Obligation | USofA | Net Book Value 2012 | 2013 Amortization Expense | Net Book Value 2013 |
|---|---|---|---|---|
| Station Equipment (Below 50kV) | 1820 | $2,410 | ($2,410) | 0 |
| Line Transformers | 1815 | $232,294 | ($232,294) | 0 |
| **Total** | | **$234,704** | **($234,704)** | **0** |

**Table 4 – Useful Lives**

| USofA Account Number | Description | Useful life (years) |
|---|---|---|
| 1805 | Land | NA |
| 1806 | Land Rights | 50 |
| 1808 | Buildings and Fixtures | 30 - 75 |
| 1815 | Station Equipment (Above 50kV) | 15 - 45 |
| 1820 | Station Equipment (Below 50kV) | 15 - 45 |
| 1830 | Poles, Towers, Fixtures | 45 |
| 1835 | Overhead Conductors and Devices | 25 - 45 |
| 1840 | Underground Conduit | 40 |
| 1845 | Underground Conductors and Devices | 25 - 60 |
| 1850 | Line Transformers | 35 |
| 1855 | Services | 45 |
| 1860 | Meters | 15 – 25 |
| 1860 | Smart Meters | 15 |
| 1905 | Land | NA |
| 1612 (formerly 1906) | Land Rights | 50 |
| 1908 | Buildings and Fixtures | 20 - 75 |
| 1915 | Office Furniture & Equipment | 10 |
| 1920 | Computer Equipment – Hardware | 5 |
| 1611 (formerly 1925) | Computer Software | 5 -10 |
| 1930 | Automobiles | 7 |
| 1930 | Trucks Less Than 3 tonnes | 8 |
| 1930 | Trucks Greater Than 3 tonnes | 12 |
| 1930 | Powered Equip & Trailers | 15 |
| 1935 | Stores Equipment | 10 |
| 1940 | Tools, Shop & Garage Equipment | 10 |
| 1945 | Measurement & Testing Equipment | 10 |
| 1955 | Communication Equipment | 8 |
| 1960 | Equipment - Miscellaneous | 10 |
| 1970 | Load Mgmt Contrls Cust Prem | 10 |
| 1975 | Load Mgmt Contrls Utility Prem | 10 |
| 1980 | System Supervisory Equipment | 15 |

# TAXES, OR PAYMENTS IN LIEU OF TAXES

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") is required to make Payments in Lieu of Taxes ("PILS") based on its taxable income. Hydro Ottawa has used the PILS Workform Model (the "PILS Tax Model") supplied by the Board for 2015 Cost of Service Applications Filers to calculate the PILS payable for each of the Test Years (2016 to 2020).

The amount for PILs included in the revenue requirements for each of the 2016 to 2020 Test Years is summarized in Table 1.1 below. The PILS Tax Models for the 2016 to 2020 Test Years are included as Attachments D-4(C), (D), (E), (F) and (G) and in both PDF and Excel.

**Table 1.1 Corporate PILS for Test Years 2016 to 2020**

| Test Year | Income Tax/PILS ($000) |
|---|---|
| 2016 | $4,958 |
| 2017 | $4,799 |
| 2018 | $6,074 |
| 2019 | $8,473 |
| 2020 | $7,587 |

No modifications have been made to the general principles and methodologies of the PILS Tax Model. However, the PILS Tax Model supplied by the Board for 2015 Cost of Service Applications Filers incorrectly includes the Ontario Small Business Deduction, which was eliminated in Ontario's 2014 budget for tax years ending after May 1, 2014 for large companies with taxable capital employed in Canada greater than $15 million. The effect of this is an underestimate of PILS of $64,000 per Test Year, which has not been reflected in the PILS summarized in Table 1.1, but will be updated when the PILS Tax Model is issued by the Board for 2016 Filers.

## 2.0 GENERAL METHODOLOGY

For 2016 to 2020 PILS, Hydro Ottawa has used a combined Federal and Ontario tax rate of 26.50%. This rate is applied to Hydro Ottawa's regulatory taxable income determined through the PILS Tax Model to calculate income taxes payable before the deduction of tax credits. This amount is then grossed up by the 1 – tax rate formula to determine the tax provision component of the revenue requirement for each Test Year.

The regulatory taxable income in each Test Year includes forecasted Capital Cost Allowances ("CCA"). These forecasts use the estimated ending Undepreciated Capital Cost ("UCC") balance from the previous year as the opening balance and then adds net capital additions (applying the half-year rule) to determine the UCC balance available for the year.

For example, the 2016 Test Year uses the forecasted 2015 ending balance and then adds the net capital additions for 2016 to provide the UCC balance available for the 2016 CCA deduction. The Cumulative Eligible Capital ("CEC") deductions for 2016 to 2020 were also determined in the same manner based on the 2016 to 2020 forecasts for Eligible Capital Expenditures.

## 3.0 PRINCIPLES & INTEGRITY CHECKS

Hydro Ottawa has followed the same principles as it has for its previous rate applications. These principles include the integrity checks required as per section 2.7.5.2 of the filing requirements and are summarized below:

### 3.1 Taxable Additions

The depreciation and amortization added back agrees with the numbers disclosed in the rate base section of the application.

The accounting Other Post-Employment Benefits (OPEB) and pension amounts added back agree with the Operating Management and Expenses ("OM&A") analysis for compensation. The amounts deducted are reasonable.

### 3.2 Undepreciated Capital Cost and Capital Cost Allowances

Schedule 8 of the most recent federal T2 tax return filed with the application agrees with the PILS Tax Models filed.

The capital additions and deductions agree with the rate base section for the 2014 Historical Year, 2015 Bridge Year and 2016 to 2020 Test Years.

The CCA deductions in the 2014 Historical Year, 2015 Bridge Year and 2016 to 2020 Test Years agree with the UCC schedules filed.

The capital cost allowance and eligible capital expenditure deductions are fully maximized in each year.

### 3.3 Loss Carry-Forwards

Hydro Ottawa is forecasted not to have any non-capital or capital loss carryforwards available at the end of 2015 and does not expect to have any such losses available for the 2016 to 2020 Test Years.

### 3.4 Tax Rates

The corporate income tax rate used to calculate PILS in the PILS Tax Model is consistent with the current legislated rates.

### 3.5 Non-Distribution and Non-Recoverable Eliminations

Hydro Ottawa has excluded all non-distribution costs and non-recoverable revenue and costs in the tax calculations.

## 4.0 TAX CREDITS

As in previous years, Hydro Ottawa continues to claim the Federal Apprenticeship Job Creation Tax Credit, the Ontario Apprenticeship Training Credit, and the Ontario Co-op Education Tax Credit.

The Federal Apprenticeship Job Creation Tax Credit is 10% of salaries and wages paid to eligible apprentices, up to a maximum of $2,000 per year per apprentice for the first two years of the apprenticeship contract.

The Ontario Apprenticeship Training Credit is 35% of eligible expenditures (such as salaries and wages), up to a maximum of $10,000 per apprentice during the first 48 months of the apprenticeship program for expenditures incurred after March 26, 2009.

The Ontario Co-operative Education Tax Credit is 25% of eligible expenditures up to a maximum of $3,000 per student per year.

Hydro Ottawa has forecasted the tax credits available and has deducted the available tax credits for the 2016 to 2020 Test Years as outlined in the tables below.

**Table 4.1 Total Apprenticeship & Coop Tax Credits Claimed for Test Years 2016 to 2020**

| Year | Federal Apprenticeship Tax Credit | Ontario Apprenticeship Tax Credit | Ontario Coop Education Tax Credit | Total Tax Credits Claimed |
|---|---|---|---|---|
| 2016 Test Year | $20,000 | $160,000 | $37,500 | $217,500 |
| 2017 Test Year | $20,000 | $210,000 | $37,500 | $267,500 |
| 2018 Test Year | $20,000 | $200,000 | $37,500 | $257,500 |
| 2019 Test Year | $18,000 | $190,000 | $37,500 | $245,500 |
| 2020 Test Year | $16,000 | $180,000 | $37,500 | $233,500 |

**Table 4.2 Federal Apprenticeship Tax Credits Calculation for Test Years 2016 to 2020**

| Year | Number Eligible | Test Year 2016 | Test Year 2017 | Test Year 2018 | Test Year 2019 | Test Year 2020 |
|---|---|---|---|---|---|---|
| 2013 | 0 | | | | | |
| 2014 | 6 | | | | | |
| 2015 | 5 | 5 | | | | |
| 2016 | 5 | 5 | 5 | | | |
| 2017 | 5 | | 5 | 5 | | |
| 2018 | 5 | | | 5 | 5 | |
| 2019 | 4 | | | | 4 | 4 |
| 2020 | 4 | | | | | 4 |
| | | | | | | |
| Total/yr | | 10 | 10 | 10 | 9 | 8 |
| Credit/yr | | $20,000 | $20,000 | $20,000 | $18,000 | $16,000 |

**Table 4.3 Ontario Apprenticeship Tax Credits Calculation for Test Years 2016 to 2020**

| Year | Number Eligible | Test Year 2016 | Test Year 2017 | Test Year 2018 | Test Year 2019 | Test Year 2020 |
|---|---|---|---|---|---|---|
| 2013 | 0 | 0 | | | | |
| 2014 | 6 | 6 | 6 | | | |
| 2015 | 5 | 5 | 5 | 5 | | |
| 2016 | 5 | 5 | 5 | 5 | 5 | |
| 2017 | 5 | | 5 | 5 | 5 | 5 |
| 2018 | 5 | | | 5 | 5 | 5 |
| 2019 | 4 | | | | 4 | 4 |
| 2020 | 4 | | | | | 4 |
| | | | | | | |
| Total/yr | | 16 | 21 | 20 | 19 | 18 |
| Credit/yr | | $160,000 | $210,000 | $200,000 | $190,000 | $180,000 |

The Ontario Co-op Education Tax Credit for each of the Test Years 2016 to 2020 has been calculated by assuming 15 eligible co-op students are hired per Test Year, with an average tax credit per student of $2,500, or total credits of $37,500 per Test Year. This is based on Hydro Ottawa's historical annual expenditure per Co-op student.

## 5.0 PILS VARIANCES

Table 5.1 summarizes the PILs for the 2012 Approved and Actual, 2013 Actual and 2014 Forecast. Table 5.2 summarizes the PILs for the 2015 Bridge Year and 2016 to 2020 Test Years. The PILs include amounts relating to corporate income taxes only. Ontario capital taxes have been eliminated as of July 1, 2010. The Ontario Small Business Deduction was eliminated May 1, 2014 for large companies with taxable capital employed in Canada greater than $15 million.

**Table 5.1 – Corporate PILs by Year (2012 to 2014)**
**($000)**

| | 2012 Approved $000 | 2012 Actual $000 | 2013 Actual $000 | 2014 Forecast $000 |
|---|---|---|---|---|
| Income Taxes | $6,003 | $6,857 | $6,806 | $3,000 |

**Table 5.2 – Corporate PILs by Year (2015 to 2020)**
**($000)**

| | 2015 Forecast $000 | 2016 Forecast $000 | 2017 Forecast $000 | 2018 Forecast $000 | 2019 Forecast $000 | 2020 Forecast $000 |
|---|---|---|---|---|---|---|
| Income Taxes | NIL | $4,958 | $4,799 | $6,074 | $8,473 | $7,587 |

### 5.1 2012 Actual to 2012 Approved

2012 actual PILS was slightly higher than the 2012 approved PILS mainly due to a higher pre-tax income and differences between the depreciation add back and CCA deduction. Hydro Ottawa Limited's 2012 Tax Return is provided as Attachment D-4(A).

### 5.2 2013 Actual to 2012 Actual

2013 PILS was not significantly different from 2012 PILS and Hydro Ottawa Limited's 2013 Tax Return is provided as Attachment D-4(B).

### 5.2 2014 Forecast to 2013 Actual

2014 PILS is forecasted to decrease from 2013 PILS due to higher CCA deductions from computer software (class 12) additions available in 2014.

### 5.3 2015 Forecast to 2014 Forecast

2015 PILS is forecasted to decrease from 2014 PILS due to higher CCA deductions from computer software (class 12) additions available in 2015.

### 5.4 2016 Forecast to 2015 Forecast

2016 PILS is forecasted to increase due to higher net income in 2016 and significantly less CCA deductions being available in 2016 as compared to 2015. The CCA was reduced as the majority of Class 12 UCC had been utilized in previous years.

### 5.5 2017 Forecast to 2016 Forecast

2017 PILS is forecasted not to be significantly different from 2016 PILS as higher regulatory net income is offset by an increase in CCA deductions.

### 5.6 2018 Forecast to 2017 Forecast

2018 PILS is forecasted to increase due to higher net income in 2018 and a large increase in the accounting amortization add back.

### 5.7 2019 Forecast to 2018 Forecast

2019 PILS is forecasted to increase due to a slight increase in net income and amortization add back in 2018 and approximately $4 million less in CCA deductions available in 2019 as compared to 2018.

### 5.8 2020 Forecast to 2019 Forecast

2020 PILS is forecasted to decrease due to $5.3 million in additional CCA deductions being available in 2020 as compared to 2019.

200

Canada Revenue Agency / Agence du revenu du Canada

PIL FILING

# T2 Corporation Income Tax Return

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . 001 86339 1363 RC0001

**Corporation's name**

002 Hydro Ottawa Limited

**Address of head office**

Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 3025 Albion Road North

012 P.O. Box 8700

City: 015 Ottawa — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 K1G 3S4

**Mailing address** (if different from head office address)

Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City: 025 — Province, territory, or state: 026

Country (other than Canada): 027 — Postal code/Zip code: 028

**Location of books and records**

Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 3025 Albion Road North

032 P.O. Box 8700

City: 035 Ottawa — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 K1G 3S4

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . 043 ______ YYYY MM DD

**To which tax year does this return apply?**

Tax year start 060 2012-01-01 (YYYY MM DD) — Tax year-end 061 2012-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . . . . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . . . . . . . . . 065 ______ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to:**

subparagraph 88(2)(a)(iv)? . . . . . . . . 064 1 Yes [ ] 2 No [X]

subsection 249(3.1)? . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . 067 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**

Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079

**Is the corporation a resident of Canada?**

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**

095 096

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation have any foreign affiliates during the year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Has the corporation had any non-arm's length transactions with a non-resident? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | X | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | X | 3 |
| Is the corporation claiming any type of losses? | 204 | | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | X | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | ——— |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | ——— |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates that are not controlled foreign affiliates? | 256 | | T1134 |
| Did the corporation have any controlled foreign affiliates? | 258 | | T1134 |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | X | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| Line | Product or service | Line | % |
|---|---|---|---|
| 284 | DIST. OF ELECTRICITY | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

## Taxable income

| | Description | Line | Amount | | Total | |
|---|---|---|---|---|---|---|
| | Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | 300 | | | 27,004,004 | A |
| **Deduct:** | Charitable donations from Schedule 2 | 311 | 103,185 | | | |
| | Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | | |
| | Cultural gifts from Schedule 2 | 313 | | | | |
| | Ecological gifts from Schedule 2 | 314 | | | | |
| | Gifts of medicine from Schedule 2 | 315 | | | | |
| | Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | | |
| | Part VI.1 tax deduction* | 325 | | | | |
| | Non-capital losses of previous tax years from Schedule 4 | 331 | | | | |
| | Net capital losses of previous tax years from Schedule 4 | 332 | | | | |
| | Restricted farm losses of previous tax years from Schedule 4 | 333 | | | | |
| | Farm losses of previous tax years from Schedule 4 | 334 | | | | |
| | Limited partnership losses of previous tax years from Schedule 4 | 335 | | | | |
| | Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | | |
| | Prospector's and grubstaker's shares | 350 | | | | |
| | Subtotal | | 103,185 | ▶ | 103,185 | B |
| | Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | 26,900,819 | C |
| **Add:** | Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | | D |
| | **Taxable income** (amount C **plus** amount D) | 360 | | | 26,900,819 | |
| | Income exempt under paragraph 149(1)(t) | 370 | | | | |
| | **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | 26,900,819 | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

| | | | |
|---|---|---|---|
| Income from active business carried on in Canada from Schedule 7 | **400** | 27,004,004 | A |
| Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax | **405** | 26,900,819 | B |
| Business limit (see notes 1 and 2 below) | **410** | 500,000 | C |

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C 500,000 x **415** ***** 1,458,453 D / 11,250 = 64,820,133 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") **425** F

**Small business deduction**

Amount A, B, C, or F, whichever is the least x 17 % = **430** G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from line 360 on page 3* | | | 26,900,819 | A |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | B | | |
| Amount QQ from Part 13 of Schedule 27 | | C | | |
| Personal service business income** | 432 | D | | |
| Amount used to calculate the credit union deduction from Schedule 17 | | E | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | F | | |
| Aggregate investment income from line 440 on page 6*** | | G | | |
| Total of amounts B to G | | ▶ | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | 26,900,819 | I |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Amount I | 26,900,819 x | Number of days in the tax year before January 1, 2011 / Number of days in the tax year | / 366 | x | 10 % = | | J |
| Amount I | 26,900,819 x | Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year | / 366 | x | 11.5 % = | | K |
| Amount I | 26,900,819 x | Number of days in the tax year after December 31, 2011 / Number of days in the tax year | 366 / 366 | x | 13 % = | 3,497,106 | L |

**General tax reduction for Canadian-controlled private corporations** – Total of amounts J to L 3,497,106 M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | N |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | O | | |
| Amount QQ from Part 13 of Schedule 27 | | P | | |
| Personal service business income* | 434 | Q | | |
| Amount used to calculate the credit union deduction from Schedule 17 | | R | | |
| Total of amounts O to R | | ▶ | | S |
| Amount N **minus** amount S (if negative, enter "0") | | | | T |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Amount T | x | Number of days in the tax year before January 1, 2011 / Number of days in the tax year | / 366 | x | 10 % = | | U |
| Amount T | x | Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year | / 366 | x | 11.5 % = | | V |
| Amount T | x | Number of days in the tax year after December 31, 2011 / Number of days in the tax year | 366 / 366 | x | 13 % = | | W |

**General tax reduction** – Total of amounts U to W X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

Aggregate investment income from Schedule 7 . . . . . . . . **440** ________ x 26 2 / 3 % = . . . . . . . . . . . . . . . . ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . . . . . . . . . . . . . . . . . . ________

**Deduct:**
Foreign investment income from Schedule 7 . . . . . . . . . . **445** ________ x 9 1 / 3 % = ________
(if negative, enter "0") ________ ▶ ________ B

Amount A **minus** amount B (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ C

Taxable income from line 360 on page 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 26,900,819

**Deduct:**
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 25/9* 100 / 35 = ________

Foreign business income tax credit from line 636 on page 7 . . . . . . . . . . . . . ________ x 1(0.38 - X**) / 4 = ________

________ ▶ ________

26,900,819
x 26 2 / 3 % = 7,173,552 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . . . . . . . . . . . . . . . . . . . 4,021,123 E

**Refundable portion of Part I tax** – Amount C, D, or E, whichever is the least . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **450** ________ F

* 100/35 for tax years beginning after October 31, 2011.
** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

## Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . . . . . . . . . . . . . **460** ________
**Deduct:** Dividend refund for the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . **465** ________
________ ▶ ________ G

**Add** the total of:
Refundable portion of Part I tax from line 450 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Total Part IV tax payable from Schedule 3 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . . . . . . . . . . . . . . . . . . **480** ________
________ ▶ ________ H

**Refundable dividend tax on hand at the end of the tax year** – Amount G **plus** amount H . . . . . . . . . . . . . . . . . . . . **485** ________

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . . . . . . . . 15,000,000 x 1 / 3 5,000,000 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ J

**Dividend refund** – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . . . . . . . . . . . . . . . . . . . . . ________

## Part I tax

| | | | | | |
|---|---|---|---|---|---|
| **Base amount of Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % | | | 550 | 10,222,311 | A |
| **Recapture of investment tax credit from Schedule 31** | | | 602 | | B |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | |
|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | | i |
| Taxable income from line 360 on page 3 | 26,900,819 | | |
| **Deduct:** | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | | |
| Net amount | 26,900,819 ► | 26,900,819 | ii |

| | | | |
|---|---|---|---|
| **Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount i or ii | 604 | | C |
| Subtotal (**add** amounts A to C) | | 10,222,311 | D |

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | 1 | | |
| Federal tax abatement | 608 | 2,690,082 | | | |
| Manufacturing and processing profits deduction from Schedule 27 | 616 | | | | |
| Investment corporation deduction | 620 | | | | |
| Taxed capital gains 624 | | | | | |
| Additional deduction – credit unions from Schedule 17 | 628 | | | | |
| Federal foreign non-business income tax credit from Schedule 21 | 632 | | | | |
| Federal foreign business income tax credit from Schedule 21 | 636 | | | | |
| General tax reduction for CCPCs from amount M on page 5 | 638 | 3,497,106 | | | |
| General tax reduction from amount X on page 5 | 639 | | | | |
| Federal logging tax credit from Schedule 21 | 640 | | | | |
| Federal qualifying environmental trust tax credit | 648 | | | | |
| Investment tax credit from Schedule 31 | 652 | 14,000 | | | |
| Subtotal | | 6,201,188 | ► | 6,201,188 | E |

| | | |
|---|---|---|
| **Part I tax payable** – Amount D **minus** amount E | 4,021,123 | F |

Enter amount F on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from page 7 | 700 | 4,021,123 |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | 4,021,123 |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | | |
|---|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | 2,835,814 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | | |
| (The Nova Scotia tax on large corporations is eliminated effective July 2012.) | | 2,835,814 ▶ | 2,835,814 |
| Total tax payable | 770 | | 6,856,937 A |

**Deduct other credits:**

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | |
| Tax instalments paid | 840 | 7,860,010 |
| Total credits | 890 | 7,860,010 ▶ 7,860,010 B |

Refund code 894 1    Overpayment 1,003,073

Balance (amount A **minus** amount B) -1,003,073

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . . . . .

Enclosed payment 898

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start    ☐ Change information

910 ______ Branch number

914 ______ Institution number    918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

## Certification

I, 950 Hoverd (Last name (print)) 951 Alan (First name (print)) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-06-24 Date (yyyy/mm/dd)    Signature of the authorized signing officer of the corporation    956 (613) 738-5499 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 Mike Grue Name (print)    959 (613) 738-5499 Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.    990 1

*Privacy Act*, Personal Information Bank number CRA PPU 047

# Schedule of Instalment Remittances

Name of corporation contact: Mike Grue
Telephone number: (613) 738-5499

| Effective interest date | Description (instalment remittance, split payment, assessed credit) | Amount of credit |
|---|---|---|
| | 2012 INSTALLMENTS | 7,860,010 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

| | | |
|---|---|---|
| Total amount of instalments claimed (carry the result to line 840 of the T2 Return) | 7,860,010 | A |
| Total instalments credited to the taxation year per T9 | 7,860,010 | B |

## Transfer

| | Account number | Taxation year end | Amount | Effective interest date | Description |
|---|---|---|---|---|---|
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

### Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 168,080,000 | 165,667,000 |
| | Total tangible capital assets | 2008 | + | 1,016,871,000 | 942,397,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 421,239,000 | 392,419,000 |
| | Total intangible capital assets | 2178 | + | 83,000,000 | 70,521,000 |
| | Total accumulated amortization of intangible capital assets | 2179 | – | 53,317,000 | 46,737,000 |
| | Total long-term assets | 2589 | + | 31,768,000 | 33,732,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 825,163,000 | 773,161,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 172,048,000 | 127,879,000 |
| | Total long-term liabilities | 3450 | + | 393,960,000 | 397,540,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 566,008,000 | 525,419,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | 259,155,000 | 247,742,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 825,163,000 | 773,161,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | 92,074,000 | 80,661,000 |

* Generic item

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**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 886,094,000 | 828,183,000 |
| | Cost of sales | 8518 | – | 709,935,000 | 663,855,000 |
| | **Gross profit/loss** | 8519 | = | 176,159,000 | 164,328,000 |
| | Cost of sales | 8518 | + | 709,935,000 | 663,855,000 |
| | Total operating expenses | 9367 | + | 143,111,000 | 133,532,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 853,046,000 | 797,387,000 |
| | Total revenue (mandatory field) | 8299 | + | 886,094,000 | 828,183,000 |
| | Total expenses (mandatory field) | 9368 | – | 853,046,000 | 797,387,000 |
| | **Net non-farming income** | 9369 | = | 33,048,000 | 30,796,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 33,048,000 | 30,796,000 |
| | **Total other comprehensive income** | 9998 | = | | |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | 6,635,000 | 8,312,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | | |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 26,413,000 | 22,484,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Does the accountant have a professional designation? | 095 | X | |
| Is the accountant connected* with the corporation? | 097 | | X |

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

| | | |
|---|---|---|
| Completed an auditor's report | 1 | X |
| Completed a review engagement report | 2 | |
| Conducted a compilation engagement | 3 | |

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Has the accountant expressed a reservation? | 099 | | X |

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

| | | |
|---|---|---|
| Prepared the tax return (financial statements prepared by client) | 1 | |
| Prepared the tax return and the financial information contained therein (financial statements have not been prepared) | 2 | |

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Were notes to the financial statements prepared? | 101 | X | |

If **yes**, complete lines 104 to 107 below:

| | Line | 1 Yes | 2 No |
|---|---|---|---|
| Are subsequent events mentioned in the notes? | 104 | | X |
| Is re-evaluation of asset information mentioned in the notes? | 105 | | X |
| Is contingent liability information mentioned in the notes? | 106 | X | |
| Is information regarding commitments mentioned in the notes? | 107 | X | |
| Does the corporation have investments in joint venture(s) or partnership(s)? | 108 | | X |

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income<br>Increase (decrease) | | In OCI<br>Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [X] 2 No [ ]

If **yes**, you have to maintain a separate reconciliation.

**SCHEDULE 100**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

## Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1000 | 1,639,000 | 1060 | 160,158,000 | 1480 | 1,969,000 |
| 1481 | 628,000 | 1483 | 1,211,000 | 1484 | 2,475,000 |
| 1599 | 168,080,000 | 1600 | 5,381,000 | 1680 | 72,336,000 |
| 1681 | -19,604,000 | 1740 | 20,820,000 | 1741 | -15,030,000 |
| 1900 | 856,760,000 | 1901 | -386,605,000 | 1920 | 61,574,000 |
| 2008 | 1,016,871,000 | 2009 | -421,239,000 | 2010 | 83,000,000 |
| 2011 | -53,317,000 | 2178 | 83,000,000 | 2179 | -53,317,000 |
| 2420 | 7,603,000 | 2421 | 24,165,000 | 2589 | 31,768,000 |
| 2599 | 825,163,000 | | | | |

## Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 149,323,000 | 2960 | 22,097,000 | 2963 | 628,000 |
| 3139 | 172,048,000 | 3140 | 327,185,000 | 3240 | 24,165,000 |
| 3270 | 10,246,000 | 3320 | 32,364,000 | 3450 | 393,960,000 |
| 3499 | 566,008,000 | | | | |

## Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 167,081,000 | 3600 | 92,074,000 | 3620 | 259,155,000 |
| 3640 | 825,163,000 | | | | |

## Retained earnings – lines 3660 to 3849

| | | | | | |
|---|---|---|---|---|---|
| 3660 | 80,661,000 | 3680 | 26,413,000 | 3700 | -15,000,000 |
| 3849 | 92,074,000 | | | | |

**SCHEDULE 125**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

## Description

Sequence number . . . . . . . 0003 01

## Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 886,094,000 | 8089 | 886,094,000 | 8299 | 886,094,000 |

## Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8320 | 709,935,000 | 8518 | 709,935,000 | 8519 | 176,159,000 |

## Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8570 | 6,580,000 | 8670 | 28,939,000 | 8740 | 15,626,000 |
| 9270 | 91,966,000 | 9367 | 143,111,000 | 9368 | 853,046,000 |
| 9369 | 33,048,000 | | | | |

## Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| 9970 | 33,048,000 | 9990 | 6,635,000 | 9999 | 26,413,000 |

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# Net Income (Loss) for Income Tax Purposes

**SCHEDULE 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | |
|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | | 26,413,000 A |
| **Add:** | | | | |
| Provision for income taxes – current | | 101 | 6,635,000 | |
| Interest and penalties on taxes | | 103 | 8,118 | |
| Amortization of tangible assets | | 104 | 28,939,000 | |
| Amortization of intangible assets | | 106 | 6,580,000 | |
| Loss on disposal of assets | | 111 | 1,154,794 | |
| Charitable donations and gifts from Schedule 2 | | 112 | 103,185 | |
| Non-deductible meals and entertainment expenses | | 121 | 62,955 | |
| Other reserves on lines 270 and 275 from Schedule 13 | | 125 | 649,697 | |
| Reserves from financial statements – balance at the end of the year | | 126 | 1,620,141 | |
| Subtotal of additions | | | 45,752,890 ▶ | 45,752,890 |
| **Other additions:** | | | | |
| **Miscellaneous other additions:** | | | | |
| 600 Employee Future Benefit Adjustment to Opening Balance | | 290 | 5,988,000 | |
| 604 12(1)(g) inclusion | 2,986,888 | | | |
| Apprentice tax credit - Federal 2011 | 18,426 | | | |
| Apprentice tax credit - Ont 2012 | 173,885 | | | |
| Coop student tax credit - Ont 2012 | 48,895 | | | |
| Employee Future Benefits expensed in F/S | 647,823 | | | |
| ARO expenses accrued in 2012 | 14,375 | | | |
| Total | 3,890,292 | 294 | 3,890,292 | |
| Subtotal of other additions | | 199 | 9,878,292 ▶ | 9,878,292 |
| **Total additions** | | 500 | 55,631,182 ▶ | 55,631,182 B |
| Amount A **plus** amount B | | | | 82,044,182 |

**Deduct:**

| | | | |
|---|---|---|---|
| Capital cost allowance from Schedule 8 | 403 | 44,037,141 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 66,662 | |
| Other reserves on line 280 from Schedule 13 | 413 | 704,169 | |
| Reserves from financial statements – balance at the beginning of the year | 414 | 7,713,642 | |
| Subtotal of deductions | | 52,521,614 ▶ | 52,521,614 |

**Other deductions:**

**Miscellaneous other deductions:**

| | | | | |
|---|---|---|---|---|
| 700 | ARO costs incurred in 2012 | 390 | 203,315 | |
| 701 | AFUDC | 391 | 1,772,526 | |
| 702 | Employee Future Benefits paid during the year | 392 | 542,723 | |
| 704 | | | | |
| | Total | 394 | | |
| | Subtotal of other deductions | 499 | 2,518,564 ▶ | 2,518,564 |
| | **Total deductions** | 510 | 55,040,178 ▶ | 55,040,178 |

**Net income (loss) for income tax purposes** – enter on line 300 of the T2 return . . . 27,004,004

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**SCHEDULE 2**

# CHARITABLE DONATIONS AND GIFTS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

## Part 1 – Charitable donations

| Charity/Recipient | Amount ($100 or more only) |
|---|---|
| United Way | 69,885 |
| United Way | 25,000 |
| United Way | 100 |
| Alogonquin College | 6,000 |
| South East Ottawa Community Health Centre | 1,000 |
| Our Youth At Work Assoication | 500 |
| Clarendon & Miller Fire Department | 100 |
| The Ottawa Hospital Foundation | 100 |
| Canada Helps | 100 |
| Royal Ottawa Foundation for Mental Health | 100 |
| Colorectal Cancer Association of Canada | 100 |
| Heart & Stroke Foundation of Canada | 100 |
| University of Ottawa Heart Institute | 100 |
| Subtotal | 103,185 |
| **Add:** Total donations of less than $100 each | |
| Total donations in current tax year | 103,185 |

| | Line | | Federal | Québec | Alberta |
|---|---|---|---|---|---|
| Charitable donations at the end of the previous tax year | | | | | |
| **Deduct:** Charitable donations expired after five tax years* | 239 | | | | |
| Charitable donations at the beginning of the tax year | 240 | | | | |
| **Add:** | | | | | |
| Charitable donations transferred on an amalgamation or the wind-up of a subsidiary | 250 | | | | |
| Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) | 210 | 103,185 | | 103,185 | |
| Subtotal (line 250 **plus** line 210) | | | 103,185 | 103,185 | 103,185 |
| **Deduct:** Adjustment for an acquisition of control (for donations made after March 22, 2004) | 255 | | | | |
| Total charitable donations available | | | 103,185 A | 103,185 | 103,185 |
| **Deduct:** Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return) | 260 | | 103,185 | 103,185 | 103,185 |
| Charitable donations closing balance | 280 | | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Charitable donations

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2011-12-31 | | | |
| 2nd prior year | 2010-12-31 | | | |
| 3rd prior year | 2009-12-31 | | | |
| 4th prior year | 2008-12-31 | | | |
| 5th prior year | 2007-12-31 | | | |
| 6th prior year* | 2006-12-31 | | | |
| 7th prior year | 2005-12-31 | | | |
| 8th prior year | 2004-12-31 | | | |
| 9th prior year | 2003-12-31 | | | |
| 10th prior year | 2002-12-31 | | | |
| 11th prior year | 2001-12-31 | | | |
| 12th prior year | 2001-09-30 | | | |
| 13th prior year | 2000-09-30 | | | |
| 14th prior year | 1999-09-30 | | | |
| 15th prior year | 1998-09-30 | | | |
| 16th prior year | 1997-09-30 | | | |
| 17th prior year | 1996-09-30 | | | |
| 18th prior year | 1995-09-30 | | | |
| 19th prior year | 1994-09-30 | | | |
| 20th prior year | 1993-09-30 | | | |
| 21st prior year* | 1992-09-30 | | | |
| **Total** (to line A) | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 2 – Calculation of the maximum allowable deduction for charitable donations

| | | | | |
|---|---|---|---|---|
| Net income for tax purposes* **multiplied** by 75 % | | | 20,253,003 | B |
| Taxable capital gains arising in respect of gifts of capital property included in Part 1** | 225 | | C | |
| Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) | 227 | | D | |
| The amount of the recapture of capital cost allowance in respect of charitable gifts | 230 | | | |
| Proceeds of disposition, less outlays and expenses** | | E | | |
| Capital cost** | | F | | |
| Amount E or F, whichever is less | 235 | | | |
| Amount on line 230 or 235, whichever is less | | | G | |
| Subtotal (**add** amounts C, D, and G) | | | H | |
| Amount H **multiplied** by 25 % | | | | I |
| Subtotal (amount B **plus** amount I) | | | 20,253,003 | J |
| **Maximum allowable deduction for charitable donations** (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) | | | 103,185 | K |

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

## Part 3 – Gifts to Canada, a province, or a territory

| | | | |
|---|---|---|---|
| Gifts to Canada, a province, or a territory at the end of the previous tax year | | | |
| **Deduct:** Gifts to Canada, a province, or a territory expired after five tax years | 339 | | |
| Gifts to Canada, a province, or a territory at the beginning of the tax year | 340 | | ► |
| **Add:** Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary | 350 | | |
| Total current-year gifts made to Canada, a province, or a territory* | 310 | | |
| Subtotal (line 350 **plus** line 310) | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 355 | | |
| Total gifts to Canada, a province, or a territory available | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 312 of the T2 return). | 360 | | |
| Gifts to Canada, a province, or a territory closing balance | 380 | | |

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

## Part 4 – Gifts of certified cultural property

| | | Federal | Québec | Alberta |
|---|---|---|---|---|
| Gifts of certified cultural property at the end of the previous tax year | | | | |
| **Deduct:** Gifts of certified cultural property expired after five tax years* | 439 | | | |
| Gifts of certified cultural property at the beginning of the tax year | 440 | | | |
| **Add:** Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary | 450 | | | |
| Total current-year gifts of certified cultural property | 410 | | | |
| Subtotal (line 450 **plus** line 410) | | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 455 | | | |
| Total gifts of certified cultural property available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 313 of the T2 return) | 460 | | | |
| Gifts of certified cultural property closing balance | 480 | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amount carried forward – Gifts of certified cultural property

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2011-12-31 | | | |
| 2nd prior year | 2010-12-31 | | | |
| 3rd prior year | 2009-12-31 | | | |
| 4th prior year | 2008-12-31 | | | |
| 5th prior year | 2007-12-31 | | | |
| 6th prior year* | 2006-12-31 | | | |
| 7th prior year | 2005-12-31 | | | |
| 8th prior year | 2004-12-31 | | | |
| 9th prior year | 2003-12-31 | | | |
| 10th prior year | 2002-12-31 | | | |
| 11th prior year | 2001-12-31 | | | |
| 12th prior year | 2001-09-30 | | | |
| 13th prior year | 2000-09-30 | | | |
| 14th prior year | 1999-09-30 | | | |
| 15th prior year | 1998-09-30 | | | |
| 16th prior year | 1997-09-30 | | | |
| 17th prior year | 1996-09-30 | | | |
| 18th prior year | 1995-09-30 | | | |
| 19th prior year | 1994-09-30 | | | |
| 20th prior year | 1993-09-30 | | | |
| 21st prior year* | 1992-09-30 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 5 – Gifts of certified ecologically sensitive land

| | Line | Federal | Québec | Alberta |
|---|---|---|---|---|
| Gifts of certified ecologically sensitive land at the end of the previous tax year | | | | |
| **Deduct:** Gifts of certified ecologically sensitive land expired after five tax years* | 539 | | | |
| Gifts of certified ecologically sensitive land at the beginning of the tax year | 540 | | | |
| **Add:** Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary | 550 | | | |
| Total current-year gifts of certified ecologically sensitive land | 510 | | | |
| Subtotal (line 550 **plus** line 510) | | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 555 | | | |
| Total gifts of certified ecologically sensitive land available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 314 of the T2 return) | 560 | | | |
| Gifts of certified ecologically sensitive land closing balance | 580 | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Gifts of certified ecologically sensitive land

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2011-12-31 | | | |
| 2nd prior year | 2010-12-31 | | | |
| 3rd prior year | 2009-12-31 | | | |
| 4th prior year | 2008-12-31 | | | |
| 5th prior year | 2007-12-31 | | | |
| 6th prior year* | 2006-12-31 | | | |
| 7th prior year | 2005-12-31 | | | |
| 8th prior year | 2004-12-31 | | | |
| 9th prior year | 2003-12-31 | | | |
| 10th prior year | 2002-12-31 | | | |
| 11th prior year | 2001-12-31 | | | |
| 12th prior year | 2001-09-30 | | | |
| 13th prior year | 2000-09-30 | | | |
| 14th prior year | 1999-09-30 | | | |
| 15th prior year | 1998-09-30 | | | |
| 16th prior year | 1997-09-30 | | | |
| 17th prior year | 1996-09-30 | | | |
| 18th prior year | 1995-09-30 | | | |
| 19th prior year | 1994-09-30 | | | |
| 20th prior year | 1993-09-30 | | | |
| 21st prior year* | 1992-09-30 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 6 – Additional deduction for gifts of medicine

| | | Federal | | Québec | | Alberta | |
|---|---|---|---|---|---|---|---|
| Additional deduction for gifts of medicine at the end of the previous tax year | | | | | | | |
| **Deduct:** Additional deduction for gifts of medicine expired after five tax years | 639 | | | | | | |
| Additional deduction for gifts of medicine at the beginning of the tax year | 640 | | | | | | |
| **Add:** Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary | 650 | | | | | | |
| Additional deduction for gifts of medicine for the current year: | | | | | | | |
| Proceeds of disposition | 602 | | 1 | | 1 | | 1 |
| Cost of gifts of medicine | 601 | | 2 | | 2 | | 2 |
| Subtotal (line 1 **minus** line 2) | | | 3 | | 3 | | 3 |
| Line 3 **multiplied** by 50 % | | | 4 | | 4 | | 4 |
| Eligible amount of gifts | 600 | | 5 | | 5 | | 5 |

Federal

A ______ x ( B ______ / C ) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x ( B ______ / C ) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x ( B ______ / C ) = Additional deduction for gifts of medicine for the current year ______

where:

**A** is the **lesser** of line 2 and line 4

**B** is the eligible amount of gifts (line 600)

**C** is the proceeds of disposition (line 602)

| | | Federal | Québec | Alberta |
|---|---|---|---|---|
| Subtotal (line 650 **plus** line 610) | | | | |
| **Deduct:** Adjustment for an acquisition of control | 655 | | | |
| Total additional deduction for gifts of medicine available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 315 of the T2 return) | 660 | | | |
| Additional deduction for gifts of medicine closing balance | 680 | | | |

## Amounts carried forward – Additional deduction for gifts of medicine

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2011-12-31 | | | |
| 2nd prior year | 2010-12-31 | | | |
| 3rd prior year | 2009-12-31 | | | |
| 4th prior year | 2008-12-31 | | | |
| 5th prior year | 2007-12-31 | | | |
| 6th prior year* | 2006-12-31 | | | |
| **Total** | | | | |

***** These donations expired in the current year.

## Québec – Gifts of musical instruments

| | | |
|---|---|---|
| Gifts of musical instruments at the end of the previous tax year | | A |
| **Deduct:** Gifts of musical instruments expired after twenty tax years | | B |
| Gifts of musical instruments at the beginning of the tax year | | C |
| **Add:** | | |
| Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary | | D |
| Total current-year gifts of musical instruments | | E |
| Subtotal (line D **plus** line E) | | F |
| **Deduct:** Adjustment for an acquisition of control | | G |
| Total gifts of musical instruments available | | H |
| **Deduct:** Amount applied against taxable income | | I |
| Gifts of musical instruments closing balance | | J |

## Amounts carried forward – Gifts of musical instruments

| Year of origin: | | Québec |
|---|---|---|
| 1st prior year | 2011-12-31 | |
| 2nd prior year | 2010-12-31 | |
| 3rd prior year | 2009-12-31 | |
| 4th prior year | 2008-12-31 | |
| 5th prior year | 2007-12-31 | |
| 6th prior year* | 2006-12-31 | |
| 7th prior year | 2005-12-31 | |
| 8th prior year | 2004-12-31 | |
| 9th prior year | 2003-12-31 | |
| 10th prior year | 2002-12-31 | |
| 11th prior year | 2001-12-31 | |
| 12th prior year | 2001-09-30 | |
| 13th prior year | 2000-09-30 | |
| 14th prior year | 1999-09-30 | |
| 15th prior year | 1998-09-30 | |
| 16th prior year | 1997-09-30 | |
| 17th prior year | 1996-09-30 | |
| 18th prior year | 1995-09-30 | |
| 19th prior year | 1994-09-30 | |
| 20th prior year | 1993-09-30 | |
| 21st prior year* | 1992-09-30 | |
| **Total** | | |

* These gifts expired in the current year.

T2 SCH 2 E (07) Canada

Canada Revenue Agency Agence du revenu du Canada

# DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

**SCHEDULE 3**

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

## Part 1 – Dividends received in the tax year

**Do not include dividends received from foreign non-affiliates.**

| | | Complete if payer corporation is connected | | | |
|---|---|---|---|---|---|
| Name of payer corporation (from which the corporation received the dividend) 200 | A | B Enter 1 if payer corporation is connected 205 | C Business Number of connected corporation 210 | D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220 | E Non-taxable dividend under section 83 230 |
| | | | | | |

**Total** (enter on line 402 of Schedule 1)

**Note**: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

| | | | | Complete if payer corporation is connected | | |
|---|---|---|---|---|---|---|
| F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240 | F1 Eligible dividends (included in column F) | F2 | F3 | G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 | H Dividend refund of the connected payer corporation (for tax year in column D)** 260 | I Part IV tax before deductions F x 1 / 3 *** 270 |
| | | | | | | |
| | | | | | | J |

**Total** (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter “0” in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation’s tax year ends after the corporation’s balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer’s dividend refund when you calculate the corporation’s Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

## Part 2 – Calculation of Part IV tax payable

| | | | |
|---|---|---|---|
| Part IV tax before deductions (amount J in Part 1) | | | |
| **Deduct:** | | | |
| Part IV.I tax payable on dividends subject to Part IV tax | | 320 | |
| | | Subtotal | |
| **Deduct:** | | | |
| Current-year non-capital loss claimed to reduce Part IV tax | 330 | | |
| Non-capital losses from previous years claimed to reduce Part IV tax | 335 | | |
| Current-year farm loss claimed to reduce Part IV tax | 340 | | |
| Farm losses from previous years claimed to reduce Part IV tax | 345 | | |
| Total losses applied against Part IV tax | | x 1 / 3 = | |
| Part IV tax payable (enter amount on line 712 of the T2 return) | | 360 | |

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

| | A | B | C | D | D1 |
|---|---|---|---|---|---|
| | Name of connected recipient corporation | Business Number | Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) | Taxable dividends paid to connected corporations | Eligible dividends (included in column D) |
| | 400 | 410 | 420 | 430 | |
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 2012-12-31 | 15,000,000 | |

**Note**

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

**Total** 15,000,000

| | | | |
|---|---|---|---|
| Total taxable dividends paid in the tax year to other than connected corporations | | 450 | |
| Eligible dividends (included in line 450) | 450a | | |
| Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) | | 460 | 15,000,000 |

## Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

| | | | |
|---|---|---|---|
| Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) | | | 15,000,000 |
| Other dividends paid in the tax year (total of 510 to 540) | | | |
| Total dividends paid in the tax year | | 500 | 15,000,000 |
| **Deduct:** | | | |
| Dividends paid out of capital dividend account | 510 | | |
| Capital gains dividends | 520 | | |
| Dividends paid on shares described in subsection 129(1.2) | 530 | | |
| Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year | 540 | | |
| Subtotal | | ▶ | |
| Total taxable dividends paid in the tax year that qualify for a dividend refund | | | 15,000,000 |

T2 SCH 3 E (10)

Canada

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 5**

# TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

**100** ______ Enter the Regulation that applies (402 to 413).

| A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. * | | B Total salaries and wages paid in jurisdiction | C (B x taxable income**) / G | D Gross revenue | E (D x taxable income**) / H | F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 1 Yes | 103 | | 143 | | |
| Newfoundland and Labrador offshore | 004 1 Yes | 104 | | 144 | | |
| Prince Edward Island | 005 1 Yes | 105 | | 145 | | |
| Nova Scotia | 007 1 Yes | 107 | | 147 | | |
| Nova Scotia offshore | 008 1 Yes | 108 | | 148 | | |
| New Brunswick | 009 1 Yes | 109 | | 149 | | |
| Quebec | 011 1 Yes | 111 | | 151 | | |
| Ontario | 013 1 Yes | 113 | | 153 | | |
| Manitoba | 015 1 Yes | 115 | | 155 | | |
| Saskatchewan | 017 1 Yes | 117 | | 157 | | |
| Alberta | 019 1 Yes | 119 | | 159 | | |
| British Columbia | 021 1 Yes | 121 | | 161 | | |
| Yukon | 023 1 Yes | 123 | | 163 | | |
| Northwest Territories | 025 1 Yes | 125 | | 165 | | |
| Nunavut | 026 1 Yes | 126 | | 166 | | |
| Outside Canada | 027 1 Yes | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| 26,900,819 | | 26,900,819 | 3,058,594 |

| | | | | |
|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | 3,093,594 | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | 35,000 | | |
| Subtotal | | 3,058,594 | 3,058,594 | A6 |
| **Add:** | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | |
| Subtotal | | | | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | 3,058,594 | C6 |
| **Deduct:** | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | |
| Ontario transitional tax credits (from Schedule 506) | 414 | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | |
| Subtotal | | | | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | 3,058,594 | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | 416 | | | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | 3,058,594 | F6 |
| **Deduct:** Ontario corporate minimum tax credit (from Schedule 510) | 418 | | | |
| Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") | | | 3,058,594 | G6 |
| **Add:** | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | |
| Subtotal | | | | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | 3,058,594 | I6 |
| **Deduct:** | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 48,895 | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 173,885 | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | | | |
| Other Ontario tax credits | | | | |
| Subtotal | | 222,780 | 222,780 | J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | 290 | | 2,835,814 | K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

**Net provincial and territorial tax payable or refundable credits** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **255** 2,835,814

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**SCHEDULE 8**

# CAPITAL COST ALLOWANCE (CCA)

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

| | 1<br>Class number (See Note)<br>200 | Description | 2<br>Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)<br>201 | 3<br>Cost of acquisitions during the year (new property must be available for use)*<br>203 | 4<br>Net adjustments**<br>205 | 5<br>Proceeds of dispositions during the year (amount not to exceed the capital cost)<br>207 | 6<br>50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***<br>211 | 7<br>Reduced undepreciated capital cost | 8<br>CCA rate %<br>****<br>212 | 9<br>Recapture of capital cost allowance (line 107 of Schedule 1)<br>213 | 10<br>Terminal loss (line 404 of Schedule 1)<br>215 | 11<br>Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1)<br>*****<br>217 | 12<br>Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)<br>220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 219,419,763 | | | 0 | | 219,419,763 | 4 | 0 | 0 | 8,776,791 | 210,642,972 |
| 2. | 1b | | 16,227,639 | 1,248,780 | | 0 | 624,390 | 16,852,029 | 6 | 0 | 0 | 1,011,122 | 16,465,297 |
| 3. | 2 | Dist equip pre 88 | 76,452,959 | | | 0 | | 76,452,959 | 6 | 0 | 0 | 4,587,178 | 71,865,781 |
| 4. | 3 | buildings pre 88 | 11,283,024 | | | 0 | | 11,283,024 | 5 | 0 | 0 | 564,151 | 10,718,873 |
| 5. | 8 | | 8,824,731 | 1,822,090 | | 0 | 911,045 | 9,735,776 | 20 | 0 | 0 | 1,947,155 | 8,699,666 |
| 6. | 10 | | 4,812,930 | 1,983,051 | | 9,206 | 986,923 | 5,799,852 | 30 | 0 | 0 | 1,739,956 | 5,046,819 |
| 7. | 12 | | 1,260,883 | 2,289,625 | | 0 | 1,144,813 | 2,405,695 | 100 | 0 | 0 | 2,405,695 | 1,144,813 |
| 8. | 42 | | 545,416 | | | 0 | | 545,416 | 12 | 0 | 0 | 65,450 | 479,966 |
| 9. | 45 | | 157,105 | | | 0 | | 157,105 | 45 | 0 | 0 | 70,697 | 86,408 |
| 10. | 50 | | 1,150,153 | 1,659,176 | | 0 | 829,588 | 1,979,741 | 55 | 0 | 0 | 1,088,858 | 1,720,471 |
| 11. | 47 | | 249,898,195 | 44,705,815 | | 0 | 22,352,908 | 272,251,102 | 8 | 0 | 0 | 21,780,088 | 272,823,922 |
| | | **Totals** | 590,032,798 | 53,708,537 | | 9,206 | 26,849,667 | 616,882,462 | | | | 44,037,141 | 599,694,988 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

# Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

## Tax return

| | | | | |
|---|---|---|---|---|
| Additions for tax purposes – Schedule 8 regular classes | | 53,708,537 | | |
| Additions for tax purposes – Schedule 8 leasehold improvements | + | | | |
| Operating leases capitalized for book purposes | + | | | |
| Capital gain deferred | + | | | |
| Recapture deferred | + | | | |
| Deductible expenses capitalized for book purposes – Schedule 1 | + | | | |
| Other (specify): | | | | |
| Change in CIP etc. | + | 29,555,149 | | |
| Change in Land | + | 10,336 | | |
| Change in Inventory | + | 647,000 | | |
| Beaconhill adjustment | + | 2,574,569 | | |
| **Total additions per books** | = | 86,495,591 | ▶ | 86,495,591 |
| Proceeds up to original cost – Schedule 8 regular classes | | 9,206 | | |
| Proceeds up to original cost – Schedule 8 leasehold improvements | + | | | |
| Proceeds in excess of original cost – capital gain | + | | | |
| Recapture deferred – as above | + | | | |
| Capital gain deferred – as above | + | | | |
| Pre V-day appreciation | + | | | |
| Other (specify): | | | | |
| | + | | | |
| **Total proceeds per books** | = | 9,206 | ▶ – | 9,206 |
| Depreciation and amortization per accounts – Schedule 1 | | | – | 35,519,000 |
| Loss on disposal of fixed assets per accounts | | | – | |
| Gain on disposal of fixed assets per accounts | | | + | |
| **Net change per tax return** | | | = | 50,967,385 |

## Financial statements

**Fixed assets (excluding land) per financial statements**

| | | |
|---|---|---|
| Closing net book value | | 625,315,000 |
| Opening net book value | – | 573,762,000 |
| **Net change per financial statements** | = | 51,553,000 |

If the amounts from the tax return and the financial statements differ, explain why below.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Hydro Ottawa Holding Inc. | | 89411 0816 RC0001 | 1 | | | | | |
| 2. | Energy Ottawa Inc. | | 86338 9961 RC0001 | 3 | | | | | |
| 3. | Telecom Ottawa Holding Inc. | | 86202 9337 RC0001 | 3 | | | | | |
| 4. | PowerTrail Inc. | | 82829 3944 RC0001 | 3 | | | | | |
| 5. | Moose Creek Energy Inc. | | 82851 1311 RC0001 | 3 | | | | | |
| 6. | Chaudiere Hydro Inc. | | 81281 3103 RC0001 | 3 | | | | | |
| 7. | Chaudiere Water Power Inc. | | 10093 1955 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

| | | | | | |
|---|---|---|---|---|---|
| **Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") | | | 200 | 944,758 | A |
| **Add:** Cost of eligible capital property acquired during the taxation year | 222 | 10,072 | | | |
| Other adjustments | 226 | | | | |
| Subtotal (line 222 plus line 226) | | 10,072 x 3 / 4 = | 7,554 | | B |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 | 228 | x 1 / 2 = | | | C |
| amount B minus amount C (if negative, enter "0") | | | 7,554 ▶ | 7,554 | D |
| Amount transferred on amalgamation or wind-up of subsidiary | | | 224 | | E |
| Subtotal (add amounts A, D, and E) | | | 230 | 952,312 | F |
| **Deduct:** Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year | 242 | | G | | |
| The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) | 244 | | H | | |
| Other adjustments | 246 | | I | | |
| (add amounts G,H, and I) | | x 3 / 4 = | 248 | | J |
| **Cumulative eligible capital balance** (amount F minus amount J) | | | | 952,312 | K |
| (if amount K is negative, enter "0" at line M and proceed to Part 2) | | | | | |
| Cumulative eligible capital for a property no longer owned after ceasing to carry on that business | | | 249 | | |
| amount K | 952,312 | | | | |
| **less** amount from line 249 | | | | | |
| **Current year deduction** | 952,312 | x 7.00 % = | 250 | 66,662 * | |
| (line 249 plus line 250) (enter this amount at line 405 of Schedule 1) | | | 66,662 ▶ | 66,662 | L |
| **Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") | | | 300 | 885,650 | M |

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | | |
|---|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | | 400 | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | | 401 | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | 402 | 3 | | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | 408 | 4 | | | |
| Line 3 minus line 4 (if negative, enter "0") | | ▶ | | 5 | |
| Total of lines 1, 2 and 5 | | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | 7 | | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | 8 | | | |
| Subtotal (line 7 plus line 8) | 409 | ▶ | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | ▶ | O |
| Line N minus line O (if negative, enter "0") | | | | | P |
| | | Line 5 | x 1 / 2 = | | Q |
| Line P minus line Q (if negative, enter "0") | | | | | R |
| | | Amount R | x 2 / 3 = | | S |
| Amount N or amount O, whichever is less | | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | | | 410 | |

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**SCHEDULE 13**

# CONTINUITY OF RESERVES

| Name of corporation | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

## Part 1 – Capital gains reserves

| | Description of property 001 | Balance at the beginning of the year $ 002 | Transfer on an amalgamation or the wind-up of a subsidiary $ 003 | Add $ | Deduct $ | Balance at the end of the year $ 004 |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| | **Totals** | 008 | 009 | | | 010 |

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

## Part 2 – Other reserves

| Description | Balance at the beginning of the year $ | Transfer on an amalgamation or the wind-up of a subsidiary $ | Add $ | Deduct $ | Balance at the end of the year $ |
|---|---|---|---|---|---|
| Reserve for doubtful debts | 110 649,697 | 115 | 54,472 | | 120 704,169 |
| Reserve for undelivered goods and services not rendered | 130 | 135 | | | 140 |
| Reserve for prepaid rent | 150 | 155 | | | 160 |
| Reserve for refundable containers | 190 | 195 | | | 200 |
| Reserve for unpaid amounts | 210 | 215 | | | 220 |
| Other tax reserves | 230 | 235 | | | 240 |
| **Totals** | 270 649,697 | 275 | 54,472 | | 280 704,169 |

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | Allowance for Doubtful Debts | 1,176,400 | | | 105,501 | 1,070,899 |
| 2 | Contingent Liability | 549,242 | | | | 549,242 |
| 3 | Employee future benefit | 5,988,000 | | | 5,988,000 | |
| 4 | | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | | | |
| | **Totals** | 7,713,642 | | | 6,093,501 | 1,620,141 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 15**

# DEFERRED INCOME PLANS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) 100 | Amount of contribution $ (see note 2) 200 | Registration number (RPP, RSUBP, and DPSP only) 300 | Name of EPSP trust 400 | Address of EPSP trust 500 | T4PS slip(s) filed by: (see note 3) (EPSP only) 600 |
|---|---|---|---|---|---|---|
| 1 | 1 | 4,537,094 | 345983 | | | |

**Note 1**: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

**Note 2**: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule ........................... 4,537,094 **A**

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements 4,537,094 **B**

Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0") ..................................... **C**

**Enter amount C on line 417 of Schedule 1**

**Note 3**: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

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Canada

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes ☐ 2 No ☒

| | 1<br>Names of associated corporations<br>100 | 2<br>Business Number of associated corporations<br>200 | 3<br>Association code<br>300 | 4<br>Business limit for the year (before the allocation)<br>$ | 5<br>Percentage of the business limit<br>%<br>350 | 6<br>Business limit allocated*<br>$<br>400 |
|---|---|---|---|---|---|---|
| 1 | Hydro Ottawa Limited | 86339 1363 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 2 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 1 | 500,000 | | |
| 3 | Energy Ottawa Inc. | 86338 9961 RC0001 | 1 | 500,000 | | |
| 4 | Telecom Ottawa Holding Inc. | 86202 9337 RC0001 | 1 | 500,000 | | |
| 5 | PowerTrail Inc. | 82829 3944 RC0001 | 1 | 500,000 | | |
| 6 | Moose Creek Energy Inc. | 82851 1311 RC0001 | 1 | 500,000 | | |
| 7 | Chaudiere Hydro Inc. | 81281 3103 RC0001 | 1 | 500,000 | | |
| 8 | Chaudiere Water Power Inc. | 10093 1955 RC0001 | 1 | 500,000 | | |
| | | | | **Total** | 100.0000 | 500,000 A |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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**Schedule 31**

# Investment Tax Credit – Corporations

## General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see the section called "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088*, Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim.* Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca//txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

## Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more details.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more details.

## Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.
- For the purpose of this schedule, **pre-production mining development expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.

## Part 1 – Investments, expenditures and percentages

| **Investments** | **Specified percentage** |
|---|---|
| Qualified property acquired primarily for use in Atlantic Canada | 10 % |
| Qualified resource property acquired primarily for use in Atlantic Canada and acquired: | |
| – after March 28, 2012, and before 2014 | 10 % |
| – after 2013 and before 2016 | 5 % |
| – after 2015* | 0 % |
| **Expenditures** | |
| If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) | 35 % |
| **Note:** If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**. | |
| If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada: | |
| – before 2014** | 20 % |
| – after 2013** | 15 % |
| If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012 | 10 % |
| If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***: | |
| – after March 28, 2012, and before 2013 | 10 % |
| – in 2013 | 5 % |
| – after 2013*** | 0 % |
| If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****: | |
| – after March 28, 2012, and before 2014**** | 10 % |
| – in 2014 | 7 % |
| – in 2015 | 4 % |
| – after 2015**** | 0 % |
| If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment | 10 % |
| If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children | 25 % |

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a phase of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more details.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more details. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

## Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . 101 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

**Note:** A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

## Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . 102 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . . 103

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

# Qualified Property and Qualified Resource Property

## Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

| CCA* class number 105 | Description of investment 110 | Date available for use 115 | Location used (province or territory) 120 | Amount of investment 125 |
|---|---|---|---|---|
| | | | | |

**Total of investments for qualified property and qualified resource property** ______ A

* CCA: capital cost allowance

## Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . . . . . . . B

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . **210**

Credit expired . . . . . . . . . . **215**

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) . . . . . . **220**

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . **230**

ITC from repayment of assistance . . . . . . . . **235**

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . . x 10 % = **240**

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . . . x 5 % = **242**

Credit allocated from a partnership . . . . . . . . **250**

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . . . . . . . E

**Deduct:**

Credit deducted from Part I tax (enter at amount D in Part 30) . . . . . . **260**

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . . a

Credit transferred to offset Part VII tax liability . . . . . . **280**

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . . . . . G

**Deduct:**

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) . . . . . . **310**

**ITC closing balance of investments from qualified property and qualified resource property** (amount G **minus** line 310) **320**

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

## Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

| | Year | Month | Day | | |
|---|---|---|---|---|---|
| 1st previous tax year | | | | . . . . . . Credit to be applied | **901** |
| 2nd previous tax year | | | | . . . . . . Credit to be applied | **902** |
| 3rd previous tax year | | | | . . . . . . Credit to be applied | **903** |

**Total** (enter at amount a in Part 5) H

## Part 7 – Refund for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) . . . . . . . . I

Credit balance before refund (amount G from Part 5) . . . . . . . . J

**Refund** ( 40 % of amount I or J, whichever is less) . . . . . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

## SR&ED

### Part 8 – Qualified SR&ED expenditures

**Current expenditures**

| | | | |
|---|---|---|---|
| Current expenditures (from line 557 on Form T661) | | | |
| **Add:** | | | |
| Contributions to agricultural organizations for SR&ED* | | | |
| Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)* | | ► 350 | |
| Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** | | 360 | |
| Repayments made in the year (from line 560 on Form T661) | | 370 | |
| **Qualified SR&ED expenditures** (total of lines 350 to 370) | | 380 | |

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

### Part 9 – Components of the SR&ED expenditure limit calculation

**Part 9 only applies if the corporation is a CCPC.**

**Note:** A CCPC that calculates SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

| | | | |
|---|---|---|---|
| Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) | | 390 | 32,674,141 |
| Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million | 612,746,430 | 398 | 40,000,000 |

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

### Part 10 – SR&ED expenditure limit for a CCPC

| | | | |
|---|---|---|---|
| **For a stand-alone corporation:** | | $ 8,000,000 | |
| **Deduct:** | | | |
| Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more | 32,674,141 x 10 = | 326,741,410 | A |
| Excess ($8,000,000 **minus** amount A; if negative, enter "0") | | | B |
| $ 40,000,000 **minus** line 398 from Part 9 | a | | |
| Amount a **divided** by $ 40,000,000 | | | C |
| **Expenditure limit for the stand-alone corporation** (amount B **multiplied** by amount C) | | | D* |
| **For an associated corporation:** | | | |
| If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 | 400 | | E* |

**Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:**

Amount D or E ______ x $\frac{\text{Number of days in the tax year}}{365}$ 366 = ______ F

**Your SR&ED expenditure limit for the year** (enter the amount from line D, E, or F, whichever applies) 410 ______

* Amount D or E cannot be more than $3,000,000.

## Part 11 – Investment tax credits on SR&ED expenditures

| | | | | | | |
|---|---|---|---|---|---|---|
| Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less* | 420 | | x | 35 % | = | G |
| Line 350 **minus** line 410 (if negative, enter "0")** | 430 | | x | 20 % | = | H |
| Line 410 **minus** line 350 (if negative, enter "0") | | | b | | | |
| Capital expenditures (line 360 from Part 8) or amount b above, whichever is less* | 440 | | x | 35 % | = | I |
| Line 360 **minus** amount b above (if negative, enter "0")** | 450 | | x | 20 % | = | J |
| **Repayments** (amount from line 370 in Part 8) | | | | | | |

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

| | | | | | | |
|---|---|---|---|---|---|---|
| 460 | | x | 35 % | = | | c |
| 480 | | x | 20 % | = | | d |

Subtotal (amount c **plus** amount d) ▶ K

**Current-year SR&ED ITC** (total of amounts G to K; enter on line 540 in Part 12) L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

## Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year M

**Deduct:**

Credit deemed as a remittance of co-op corporations 510

Credit expired 515

Subtotal (line 510 **plus** line 515) ▶ N

ITC at the beginning of the tax year (amount M **minus** amount N) 520

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary 530

Total current-year credit (from amount L in Part 11) 540

Credit allocated from a partnership 550

Subtotal (total of lines 530 to 550) ▶ O

Total credit available (line 520 **plus** amount O) P

**Deduct:**

Credit deducted from Part I tax (enter at amount E in Part 30) 560

Credit carried back to the previous year(s) (amount S from Part 13) e

Credit transferred to offset Part VII tax liability 580

Subtotal (total of line 560, amount e, and line 580) ▶ Q

Credit balance before refund (amount P **minus** amount Q) R

**Deduct:**

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) 610

**ITC closing balance on SR&ED** (amount R **minus** line 610) 620

## Part 13 – Request for carryback of credit from SR&ED expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 911 | |
| 2nd previous tax year | | | | Credit to be applied | 912 | |
| 3rd previous tax year | | | | Credit to be applied | 913 | |
| | | | | **Total** (enter at amount e in Part 12) | | S |

## Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . . . f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . . . T

**Deduct:**

Amount T or amount G from Part 11, whichever is less . . . . . U

Net amount (amount T **minus** amount U; if negative, enter "0") . . . . . V

Amount V **multiplied** by 40 % . . . . . W

**Add:**

Amount U . . . . . X

**Refund of ITC** (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

## Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . . . Z

**Deduct:**

Amount Z or amount G from Part 11, whichever is less . . . . . AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . . . BB

Amount BB or amount I from Part 11, whichever is less . . . . . CC

Amount CC **multiplied** by 40 % . . . . . DD

**Add :**

Amount AA . . . . . EE

**Refund of ITC** (amount DD **plus** amount EE) . . . . . FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

# Recapture – SR&ED

## Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

**Note:**

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

### Calculation 1 – If you meet all of the above conditions

| Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700** | Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710** | Amount from column 700 or 710, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount C in Part 17) ______ A

### Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

| **A**<br>Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720** | **B**<br>Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730** | **C**<br>Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740** |
|---|---|---|
| | | |

### Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

| **D**<br>Amount determined by the formula (A x B) – C | **E**<br>ITC earned by the transferee for the qualified expenditures that were transferred **750** | **F**<br>Amount from column D or E, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount D in Part 17) ______ B

**Calculation 3**

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ______

## Part 17 – Total recapture of SR&ED investment tax credit

| | | |
|---|---|---|
| Recaptured ITC for calculation 1 from amount A in Part 16 | | C |
| Recaptured ITC for calculation 2 from amount B in Part 16 | | D |
| Recaptured ITC for calculation 3 from line 760 in Part 16 | | E |
| **Total recapture of SR&ED investment tax credit** – total of amounts C to E | | F |

Enter amount F at amount A in Part 29.

# Pre-Production Mining

## Part 18 – Pre-production mining expenditures

**Exploration information**

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

| List of minerals 800 | Project name 805 |
|---|---|
| | |

| Mineral title 806 | Mining division 807 |
|---|---|
| | |

**Pre-production mining expenditures***

**Exploration:**

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting . . . . . 810 ______

Geological, geophysical, or geochemical surveys . . . . . 811 ______

Drilling by rotary, diamond, percussion, or other methods . . . . . 812 ______

Trenching, digging test pits, and preliminary sampling . . . . . 813 ______

**Development:**

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping . . . . . 820 ______

Sinking a mine shaft, constructing an adit, or other underground entry . . . . . 821 ______

Other pre-production mining expenditures incurred in the tax year:

| Description 825 | Amount 826 |
|---|---|
| | |

Add amounts in column 826 ______ ► ______ A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A) . . . . . 830 ______

**Deduct:**

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above . . . . . 832 ______

Excess (line 830 **minus** line 832) (if negative, enter "0") . . . . . ______ B

**Add:**

Repayments of government and non-government assistance . . . . . 835 ______

**Pre-production mining expenditures** (amount B **plus** line 835) . . . . . ______ C

* A pre-production mining expenditure is defined under subsection 127(9).

## Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

| | | | | | |
|---|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | | D |
| **Deduct:** | | | | | |
| Credit deemed as a remittance of co-op corporations | 841 | | | | |
| Credit expired | 845 | | | | |
| Subtotal (line 841 **plus** line 845) | | | ▶ | | E |
| ITC at the beginning of the tax year (amount D **minus** amount E) | | | 850 | | |
| **Add:** | | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | | | 860 | | |
| Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) 870 ____ x 10 % = | | | a | | |
| Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) 872 ____ x 5 % = | | | b | | |
| Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) 874 ____ x 7 % = | | | c | | |
| Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) 876 ____ x 4 % = | | | d | | |
| Current year credit (total of amounts a to d) | 880 | | ▶ | | F |
| Total credit available (total of lines 850, 860, and amount F) | | | | | G |
| **Deduct:** | | | | | |
| Credit deducted from Part I tax (enter at amount F in Part 30) | 885 | | | | |
| Credit carried back to the previous year(s) (amount I from Part 20) | | | e | | |
| Subtotal (line 885 **plus** amount e) | | | ▶ | | H |
| **ITC closing balance from pre-production mining expenditures** (amount G **minus** amount H) | | | 890 | | |

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

## Part 20 – Request for carryback of credit from pre-production mining expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 921 | |
| 2nd previous tax year | | | | Credit to be applied | 922 | |
| 3rd previous tax year | | | | Credit to be applied | 923 | |
| | | | | **Total** (enter at amount e in Part 19) | | I |

### Apprenticeship Job Creation

## Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x<br>10 %<br>604 | E<br>Lesser of<br>column D or<br>$ 2,000<br>605 |
|---|---|---|---|---|---|
| 1. | [redacted] | [redacted] | | | |
| 2. | [redacted] | [redacted] | | | |

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 |
|---|---|---|---|---|---|
| 3. | [redacted] | [redacted] | | | |
| 4. | [redacted] | [redacted] | | | |
| 5. | [redacted] | [redacted] | | | |
| 6. | [redacted] | [redacted] | | | |
| 7. | [redacted] | [redacted] | | | |
| 8. | [redacted] | [redacted] | | | |
| 9. | [redacted] | [redacted] | | | |
| 10. | [redacted] | [redacted] | | | |
| 11. | [redacted] | [redacted] | 53,460 | 5,346 | 2,000 |
| 12. | [redacted] | [redacted] | 54,330 | 5,433 | 2,000 |
| 13. | [redacted] | [redacted] | 53,919 | 5,392 | 2,000 |
| 14. | [redacted] | [redacted] | | | |
| 15. | [redacted] | [redacted] | 53,546 | 5,355 | 2,000 |
| 16. | [redacted] | [redacted] | 75,000 | 7,500 | 2,000 |
| 17. | [redacted] | [redacted] | 54,083 | 5,408 | 2,000 |
| 18. | [redacted] | [redacted] | 55,075 | 5,508 | 2,000 |
| 19. | [redacted] | [redacted] | | | |

Total current-year credit (enter at line 640 in Part 22) 14,000 A

* Net of any other government or non-government assistance received or to be received.

## Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . . . . . B

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . 612

Credit expired after 20 tax years . . . . . . 615

Subtotal (line 612 **plus** line 615) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) . . . . . . 625

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . 630

ITC from repayment of assistance . . . . . . 635

Total current-year credit (amount A from Part 21) . . . . . . 640 14,000

Credit allocated from a partnership . . . . . . 655

Subtotal (total of lines 630 to 655) 14,000 ▶ 14,000 D

Total credit available (line 625 **plus** amount D) . . . . . . 14,000 E

**Deduct:**

Credit deducted from Part I tax (enter at amount G in Part 30) . . . . . . 660 14,000

Credit carried back to the previous year(s) (amount G from Part 23) . . . . . . a

Subtotal (line 660 **plus** amount a) 14,000 ▶ 14,000 F

**ITC closing balance from apprenticeship job creation expenditures** (amount E **minus** amount F) . . . . . . 690

## Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 931 | |
| 2nd previous tax year | | | | Credit to be applied | 932 | |
| 3rd previous tax year | | | | Credit to be applied | 933 | |

**Total** (enter at amount a in Part 22) G

# Child Care Spaces

## Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

### Cost of depreciable property from the current tax year

| | CCA* class number 665 | Description of investment 675 | Date available for use 685 | Amount of investment 695 |
|---|---|---|---|---|
| 1. | | | | |

Total cost of depreciable property from the current tax year **715**

**Add:**

Specified child care start-up expenditures from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **705**

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . A

**Deduct:**

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A) . . . . . . . . . . . . . . . . . . **725**

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . B

**Add:**

Repayments of government and non-government assistance . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **735**

**Total eligible expenditures for child care spaces** (amount B **plus** line 735) . . . . . . . . . . . . . . . . . . . . . . . . . . . **745**

* CCA: capital cost allowance

## Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . x 25 % = C

Number of child care spaces . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **755** x $ 10,000 = D

**ITC from child care spaces expenditures** (amount C or D, whichever is less) . . . . . . . . . . . . . . . . . . . . . . . . . . . . E

## Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . F

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . . . . . . . . . . . . . . . . . . . 765

Credit expired after 20 tax years . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 770

Subtotal (line 765 **plus** line 770) ► G

ITC at the beginning of the tax year (amount F **minus** amount G) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 775

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . . . . . . . . . . . . . . . . 777

Total current-year credit (amount E from Part 25) . . . . . . . . . . . . . . . . . . . . . . . . . 780

Credit allocated from a partnership . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 782

Subtotal (total of lines 777 to 782) ► H

Total credit available (line 775 **plus** amount H) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . I

**Deduct:**

Credit deducted from Part I tax (enter at amount H in Part 30) . . . . . . . . . . . . . . . . . . . . 785

Credit carried back to the previous year(s) (amount K from Part 27) . . . . . . . . . . . . . . . . . . . a

Subtotal (line 785 **plus** amount a) ► J

**ITC closing balance from child care spaces expenditures** (amount I **minus** amount J) . . . . . . . . . . . . . . . . . . . . 790

## Part 27 – Request for carryback of credit from child care space expenditures

| | Year / Month / Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2011-12-31 | . . . . . . . . . . . . . . . . . . . . . . . . Credit to be applied | 941 | |
| 2nd previous tax year | 2010-12-31 | . . . . . . . . . . . . . . . . . . . . . . . . Credit to be applied | 942 | |
| 3rd previous tax year | 2009-12-31 | . . . . . . . . . . . . . . . . . . . . . . . . Credit to be applied | 943 | |

**Total** (enter at amount a in Part 26) K

## Recapture – Child Care Spaces

### Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

| | | | |
|---|---|---|---|
| If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) | 792 | | |
| In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of: | | | |
| The amount that can reasonably be considered to have been included in the original ITC | 795 | | |
| 25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property | 797 | | |
| Amount from line 795 or line 797, whichever is less | | | A |

**Corporate partnerships**

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

| | | | |
|---|---|---|---|
| **Corporate partner's share of the excess of ITC** | 799 | | |
| **Total recapture of child care spaces investment tax credit** (total of line 792, amount A, and line 799) | | | B |

Enter amount B at amount B in Part 29.

## Summary of Investment Tax Credits

### Part 29 – Total recapture of investment tax credit

| | | |
|---|---|---|
| Recaptured SR&ED ITC (from amount F in Part 17) | | A |
| Recaptured child care spaces ITC (from amount B in Part 28) | | B |
| **Total recapture of investment tax credit** (amount A **plus** amount B) | | C |

Enter amount C on line 602 of the T2 return.

### Part 30 – Total ITC deducted from Part I tax

| | | |
|---|---|---|
| ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) | | D |
| ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) | | E |
| ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) | | F |
| ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) | 14,000 | G |
| ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) | | H |
| **Total ITC deducted from Part I tax** (total of amounts D to H) | 14,000 | I |

Enter amount I at line 652 of the T2 return.

*Privacy Act*, Personal Information Bank number CRA PPU 047

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|
| 14,000 | 14,000 | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | |
| 2002-12-31 | | | | * |
| 2001-12-31 | | | | |
| 2001-09-30 | | | | |
| 2000-09-30 | | | | |
| 1999-09-30 | | | | |
| 1998-09-30 | | | | |
| 1997-09-30 | | | | |
| 1996-09-30 | | | | |
| 1995-09-30 | | | | |
| 1994-09-30 | | | | |
| 1993-09-30 | | | | * |
| **Total** | | | | |

B+C+D+G **Total ITC utilized** 14,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") | Social insurance number | Trust number | Percentage common shares | Percentage preferred shares |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 350 | 400 | 500 |
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |



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**SCHEDULE 53**

# GENERAL RATE INCOME POOL (GRIP) CALCULATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

On: 2012-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 . . . . . 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – Calculation of general rate income pool (GRIP)

| | | | | | |
|---|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | 100 | 153,012,807 | A |
| Taxable income for the year (DICs enter "0") * | 110 | 26,900,819 | B | | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) 120 | | | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * 130 | | | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * 140 | | | | | |
| Subtotal (**add** lines 120, 130, and 140) ► | | | C | | |
| Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") | 150 | 26,900,819 | | | |
| After-tax income (line 150 x general rate factor for the tax year ** 0.72 ) | | | 190 | 19,368,590 | D |
| Eligible dividends received in the tax year | 200 | | | | |
| Dividends deductible under section 113 received in the tax year | 210 | | | | |
| Subtotal (**add** lines 200 and 210) ► | | | | | E |
| GRIP addition: | | | | | |
| Becoming a CCPC (line PP from Part 4) | 220 | | | | |
| Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) | 230 | | | | |
| Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) | 240 | | | | |
| Subtotal (**add** lines 220, 230, and 240) ► | | | 290 | | F |
| Subtotal (**add** lines A, D, E, and F) | | | | 172,381,397 | G |
| Eligible dividends paid in the previous tax year | 300 | | | | |
| Excessive eligible dividend designations made in the previous tax year | 310 | | | | |
| **Note:** If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. | | | | | |
| Subtotal (line 300 **minus** line 310) ► | | | | | H |
| GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) | | | 490 | 172,381,397 | |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | | 560 | | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) | | | 590 | 172,381,397 | |

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2011-12-31

| | | | |
|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | 32,674,141 J1 | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | |
| Aggregate investment income (line 440 of the T2 return) | M1 | | |
| Subtotal (**add** lines K1, L1, and M1) ► | | N1 | |
| Subtotal (line J1 **minus** line N1) (if negative, enter "0") | | 32,674,141 ► | 32,674,141 O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S1

Subtotal (**add** lines Q1, R1, and S1) ____ ► ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ____ ► ____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(line V1 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ____

**Second previous tax year** 2010-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 40,602,698 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 1,259,282 M2

Subtotal (**add** lines K2, L2, and M2) 1,259,282 ► 1,259,282 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 39,343,416 ► 39,343,416 O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S2

Subtotal (**add** lines Q2, R2, and S2) ____ ► ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ► ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(line V2 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ____

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2009-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . 39,787,060 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 39,787,060 ► 39,787,060 O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(line V3 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . **540** ______

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . . . . . ______ W

Enter amount W on line 560.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(line AA **minus** line DD) . . . . . . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

| | | | | |
|---|---|---|---|---|
| Cost amount to the corporation of all property immediately before the end of its previous/last tax year | | | | FF |
| The corporation's money on hand immediately before the end of its previous/last tax year | | | | GG |
| Unused and unexpired losses at the end of the corporation's previous/last tax year: | | | | |
| Non-capital losses | | | | |
| Net capital losses | | | | |
| Farm losses | | | | |
| Restricted farm losses | | | | |
| Limited partnership losses | | | | |
| Subtotal | | ► | | HH |
| Subtotal (**add** lines FF, GG, and HH) | | | | II |
| All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year | | JJ | | |
| Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year | | KK | | |
| All the corporation's reserves deducted in its previous/last tax year | | LL | | |
| The corporation's capital dividend account immediately before the end of its previous/last tax year | | MM | | |
| The corporation's low rate income pool immediately before the end of its previous/last tax year | | NN | | |
| Subtotal (**add** lines JJ, KK, LL, MM, and NN) | | ► | | OO |
| **GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (line II **minus** line OO) (if negative, enter "0") | | | | PP |

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

| | | | | | | |
|---|---|---|---|---|---|---|
| 0.68 | x | number of days in the tax year before January 1, 2010 / number of days in the tax year | / 366 | . . . . . . . . . . . = | | QQ |
| 0.69 | x | number of days in the tax year in 2010 / number of days in the tax year | / 366 | . . . . . . . . . . . = | | RR |
| 0.7 | x | number of days in the tax year in 2011 / number of days in the tax year | / 366 | . . . . . . . . . . . = | | SS |
| 0.72 | x | number of days in the tax year after December 31, 2011 / number of days in the tax year | 366 / 366 | . . . . . . . . . . . = | 0.72000 | TT |

**General rate factor for the tax year** (total of lines QQ to TT) . . . . . . . . . . . . . . . . . . . . 0.72000 UU

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**SCHEDULE 55**

# PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

**Do not use this area**

## Part 1 – Canadian-controlled private corporations and deposit insurance corporations

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | 15,000,000 | | |
| Total taxable dividends paid in the tax year | 100 | 15,000,000 | | |
| Total eligible dividends paid in the tax year | | | 150 | A |
| GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0") | | | 160 172,381,397 | B |
| Excessive eligible dividend designation (line 150 **minus** line 160) | | | | C |
| **Deduct**: | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 180 | D |
| Subtotal (amount C **minus** amount D) | | | | E |
| **Part III.1 tax on excessive eligible dividend designations – CCPC or DIC** (amount E **multiplied** by 20 %) | | | 190 | F |

Enter the amount from line 190 on line 710 of the T2 return.

## Part 2 – Other corporations

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | | | |
| Total taxable dividends paid in the tax year | 200 | | | |
| Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54) | | | | G |
| **Deduct**: | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 280 | H |
| Subtotal (amount G **minus** amount H) | | | | I |
| **Part III.1 tax on excessive eligible dividend designations – Other corporations** (amount I **multiplied** by 20 %) | | | 290 | J |

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.



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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

## Part 1 – Calculation of Ontario basic rate of tax for the year

| | | | | | | |
|---|---|---|---|---|---|---|
| Number of days in the tax year before July 1, 2011 / Number of days in the tax year | / 366 | x | 12.00 % | = | % | A1 |
| Number of days in the tax year after June 30, 2011 / Number of days in the tax year | 366 / 366 | x | 11.50 % | = | 11.50000 % | A2 |

**Ontario basic rate of tax for the year** (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

## Part 2 – Calculation of Ontario basic income tax

Ontario taxable income* . . . . . 26,900,819 B

**Ontario basic income tax**: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . . 3,093,594 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

## Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

| | | |
|---|---|---|
| Income from active business carried on in Canada (amount from line 400 of the T2 return) | 27,004,004 | 1 |
| Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) | 26,900,819 | 2 |
| Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) | 500,000 | 3 |
| Enter the least of amounts 1, 2, and 3 | 500,000 | D |

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 26,900,819.00 / 26,900,819 = 1.00000 E

Amount D x factor E 500,000 a

Ontario taxable income (amount B from Part 2) 26,900,819 b

Ontario small business income (lesser of amount a and amount b) 500,000 F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year: ____ / 366 x 7.50 % = % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year: 366 / 366 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

**Ontario small business deduction**: amount F **multiplied** by OSBD rate for the year (rate G3) 35,000 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

## Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount b from Part 3) 500,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

## Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

| | | | | |
|---|---|---|---|---|
| Amount D from Part 3 of Schedule 17 | | | J | |
| **Deduct:** | | | | |
| Ontario adjusted small business income (amount I from Part 4) | | | K | |
| Subtotal (amount J **minus** amount K) (if negative, enter "0") | | | L | |
| OSBD rate for the year (rate G3 from Part 3) | 7.00000 % | | | |
| Amount L **multiplied** by the OSBD rate for the year | | | | M |
| Ontario domestic factor (factor E from Part 3) | | | 1.00000 | N |
| **Ontario credit union tax reduction** (amount M **multiplied** by factor N) | | | | O |

Enter amount O on line 410 of Schedule 5.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 825,163,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 725,158,771 |
| Total assets (total of lines 112 to 116) | | 1,550,321,771 |
| Total revenue of the corporation for the tax year ** | 142 | 886,094,000 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 62,361,448 |
| Total revenue (total of lines 142 to 146) | | 948,455,448 |

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.
If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | Code | Amount | Code | Amount |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 26,413,000 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | 6,635,000 | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | 6,635,000 | ▶ | 6,635,000 A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 | 382 | | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | | ▶ | B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 33,048,000 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | | |
|---|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | 515 | | 33,048,000 | |
| **Deduct:** | | | | |
| CMT loss available (amount R from Part 7) | | | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | | |
| Adjusted CMT loss available | | ▶ | | C |
| Net income subject to CMT calculation (if negative, enter "0") | 520 | | 33,048,000 | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Amount from line 520 | 33,048,000 | x | Number of days in the tax year before July 1, 2010 / Number of days in the tax year | / 366 | x 4 % = | | 1 |
| Amount from line 520 | 33,048,000 | x | Number of days in the tax year after June 30, 2010 / Number of days in the tax year | 366 / 366 | x 2.7 % = | 892,296 | 2 |
| | | | Subtotal (amount 1 **plus** amount 2) | | | 892,296 | 3 |

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | 892,296 | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | 892,296 | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,058,594 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

$$\frac{\text{Ontario taxable income ****}}{\text{Taxable income *****}} \quad \underline{\qquad\qquad} = \underline{\qquad\qquad}$$

**Ontario allocation factor** . . . . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

## Part 4 – CMT credit carryforward

| | | | | | |
|---|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | G | | |
| **Deduct:** | | | | | |
| CMT credit expired * | 600 | | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | ▶ | 620 | |
| **Add:** | | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | | H |
| **Deduct:** | | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | | I |
| Subtotal (amount H **minus** amount I) | | | | | J |
| **Add:** | | | | | |
| Net CMT payable (amount E from Part 3) | | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | | |
| Subtotal | | | ▶ | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – CMT credit deducted from Ontario corporate income tax payable

| | | | | | |
|---|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,058,594 | 1 | | |
| For a corporation that is not a life insurance corporation: | | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 892,296 2 | | | | |
| For a life insurance corporation: | | | | | |
| Gross CMT (line 540 from Part 3) | 3 | | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | 4 | | | | |
| The **greater** of amounts 3 and 4 | 5 | | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | 892,296 | 6 | | |
| Subtotal (if negative, enter "0") | | 2,166,298 | ▶ | 2,166,298 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,058,594 | | | |
| **Deduct:** | | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | 222,780 | | | |
| Subtotal (if negative, enter "0") | | 2,835,814 | ▶ | 2,835,814 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . ▶ 720

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . 750

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . .

Subtotal (if negative, enter "0") S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 596,614,000 | 42,209,000 |
| 2 | Energy Ottawa Inc. | 86338 9961 RC0001 | 90,908,000 | 15,291,000 |
| 3 | Telecom Ottawa Holding Inc. | 86202 9337 RC0001 | 26,200,720 | 271,327 |
| 4 | PowerTrail Inc. | 82829 3944 RC0001 | 10,840,000 | 2,987,000 |
| 5 | Moose Creek Energy Inc. | 82851 1311 RC0001 | 201 | 0 |
| 6 | Chaudiere Hydro Inc. | 81281 3103 RC0001 | 101 | 0 |
| 7 | Chaudiere Water Power Inc. | 10093 1955 RC0001 | 595,749 | 1,603,121 |
| | | **Total** | 450 725,158,771 | 550 62,361,448 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 546**

# *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

## Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Hydro Ottawa Limited

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | 110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day) | 120 Ontario Corporation No. |
|---|---|---|
| Ontario | 2000-10-03 | 1427586 |

## Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable)

| 210 Street number | 220 Street name/Rural route/Lot and Concession number | 230 Suite number |
|---|---|---|
| 3025 | Albion Road North | |

**240** Additional address information if applicable (line 220 must be completed first)
PO Box 8700

| 250 Municipality (e.g., city, town) | 260 Province/state | 270 Country | 280 Postal/zip code |
|---|---|---|---|
| Ottawa | ON | CA | K1G 3S4 |

## Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

## Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** Hoverd (Last name) **451** Alan (First name)

**454** ________________, (Middle name(s))

**460** 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

**500** Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

**510** Care of (if applicable)

| | | |
|---|---|---|
| **520** Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number |

**550** Additional address information if applicable (line 530 must be completed first)

| | | | |
|---|---|---|---|
| **560** Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code |

## Part 6 – Language of preference

**600** Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| Mike Grue | (613) 738-5499 |

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 58,000,000

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[ 5\% \times \left( \frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[ 5\% \times \left( \frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | **A**<br>Name of university, college, or other eligible educational institution<br>**400** | **B**<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 2. | UNIVERSITY OF WATERLOO | ENVIRONMENTAL ENGINEERING |
| 3. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 4. | FANSHAWE COLLEGE | ELECTRICAL ENGINEERING |
| 5. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 6. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 7. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 8. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 9. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 10. | UNIVERSITY OF WATERLOO | ELECTRICAL ENGINEERING |
| 11. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 12. | UNIVERSITY OF WATERLOO | ELECTRICAL ENGINEERING |
| 13. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 14. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 15. | GEORGIAN COLLEGE | ELECTRICAL ENGINEERING TECHNOLOGY |
| 16. | CONESTA COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 17. | CONESTA COLLEGE | POWERLINE TECHNICIAN PROGRAM |
| 18. | CARLETON UNIVERSITY | DEGREE |
| 19. | UNIVERSITY OF WATERLOO | ELECTRICAL ENGINEERING |
| 20. | FANSHAWE COLLEGE | ELECTRICAL ENGINEERING |

| | C<br>Name of student<br>410 | D<br>Start date of WP<br>(see note 1 below)<br>430 | E<br>End date of WP<br>(see note 2 below)<br>435 |
|---|---|---|---|
| 1. | [redacted] | 2012-09-04 | 2012-12-31 |
| 2. | [redacted] | 2012-09-04 | 2012-12-21 |
| 3. | [redacted] | 2012-09-04 | 2012-12-21 |
| 4. | [redacted] | 2012-05-01 | 2012-09-07 |
| 5. | [redacted] | 2012-05-14 | 2012-08-24 |
| 6. | [redacted] | 2012-05-14 | 2012-08-04 |
| 7. | [redacted] | 2012-09-04 | 2012-12-21 |
| 8. | [redacted] | 2012-05-14 | 2012-08-24 |
| 9. | [redacted] | 2012-05-14 | 2012-08-24 |
| 10. | [redacted] | 2012-01-03 | 2012-04-27 |
| 11. | [redacted] | 2012-09-04 | 2012-12-21 |
| 12. | [redacted] | 2012-09-04 | 2012-12-21 |
| 13. | [redacted] | 2012-05-14 | 2012-08-24 |
| 14. | [redacted] | 2012-05-14 | 2012-08-24 |
| 15. | [redacted] | 2012-09-10 | 2012-12-21 |
| 16. | [redacted] | 2012-01-03 | 2012-05-04 |
| 17. | [redacted] | 2012-01-03 | 2012-05-04 |
| 18. | [redacted] | 2012-04-30 | 2012-08-24 |
| 19. | [redacted] | 2012-01-03 | 2012-04-27 |
| 20. | [redacted] | 2012-01-01 | 2012-04-30 |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1<br>Eligible expenditures before March 27, 2009 (see note 1 below)<br>450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2<br>Eligible expenditures after March 26, 2009 (see note 1 below)<br>452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X<br>Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y<br>Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 9,994 | 25.000 % | | 16 |
| 2. | | 10.000 % | 9,235 | 25.000 % | | 15 |
| 3. | | 10.000 % | 10,230 | 25.000 % | | 15 |
| 4. | | 10.000 % | 8,693 | 25.000 % | | 18 |
| 5. | | 10.000 % | 9,427 | 25.000 % | | 15 |
| 6. | | 10.000 % | 10,248 | 25.000 % | | 12 |
| 7. | | 10.000 % | 10,367 | 25.000 % | | 15 |
| 8. | | 10.000 % | 9,896 | 25.000 % | | 15 |
| 9. | | 10.000 % | 9,635 | 25.000 % | | 15 |
| 10. | | 10.000 % | 10,234 | 25.000 % | | 16 |
| 11. | | 10.000 % | 9,411 | 25.000 % | | 15 |
| 12. | | 10.000 % | 9,360 | 25.000 % | | 15 |
| 13. | | 10.000 % | 9,878 | 25.000 % | | 15 |
| 14. | | 10.000 % | 9,412 | 25.000 % | | 15 |
| 15. | | 10.000 % | 8,486 | 25.000 % | | 15 |
| 16. | | 10.000 % | 10,888 | 25.000 % | | 17 |
| 17. | | 10.000 % | 10,888 | 25.000 % | | 17 |
| 18. | | 10.000 % | 10,483 | 25.000 % | | 17 |
| 19. | | 10.000 % | 10,109 | 25.000 % | | 16 |
| 20. | | 10.000 % | 8,693 | 25.000 % | | 17 |

| | G<br>Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below)<br>460 | H<br>Maximum CETC per WP (see note 3 below)<br>462 | I<br>CETC on eligible expenditures (column G or H, whichever is less)<br>470 | J<br>CETC on repayment of government assistance (see note 4 below)<br>480 | K<br>CETC for each WP (column I or column J)<br>490 |
|---|---|---|---|---|---|
| 1. | 2,499 | 3,000 | 2,499 | | 2,499 |
| 2. | 2,309 | 3,000 | 2,309 | | 2,309 |
| 3. | 2,558 | 3,000 | 2,558 | | 2,558 |
| 4. | 2,173 | 3,000 | 2,173 | | 2,173 |
| 5. | 2,357 | 3,000 | 2,357 | | 2,357 |
| 6. | 2,562 | 3,000 | 2,562 | | 2,562 |
| 7. | 2,592 | 3,000 | 2,592 | | 2,592 |
| 8. | 2,474 | 3,000 | 2,474 | | 2,474 |
| 9. | 2,409 | 3,000 | 2,409 | | 2,409 |
| 10. | 2,559 | 3,000 | 2,559 | | 2,559 |
| 11. | 2,353 | 3,000 | 2,353 | | 2,353 |
| 12. | 2,340 | 3,000 | 2,340 | | 2,340 |
| 13. | 2,470 | 3,000 | 2,470 | | 2,470 |
| 14. | 2,353 | 3,000 | 2,353 | | 2,353 |
| 15. | 2,122 | 3,000 | 2,122 | | 2,122 |
| 16. | 2,722 | 3,000 | 2,722 | | 2,722 |
| 17. | 2,722 | 3,000 | 2,722 | | 2,722 |
| 18. | 2,621 | 3,000 | 2,621 | | 2,621 |
| 19. | 2,527 | 3,000 | 2,527 | | 2,527 |
| 20. | 2,173 | 3,000 | 2,173 | | 2,173 |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 48,895 L or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . . . . . . . . . ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009,
and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 552**

# ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2012-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information (please print)

| 110 Name of person to contact for more information | 120 Telephone number including area code |
|---|---|
| Mike Grue | (613) 738-5499 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **300** 50,000,000

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

**Specified percentage** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>**400** | B<br>Apprenticeship program/ trade name<br>**405** | C<br>Name of apprentice<br>**410** |
|---|---|---|---|
| 1. | [redacted] | [redacted] | [redacted] |
| 2. | [redacted] | [redacted] | [redacted] |
| 3. | [redacted] | [redacted] | [redacted] |
| 4. | [redacted] | [redacted] | [redacted] |
| 5. | [redacted] | [redacted] | [redacted] |
| 6. | [redacted] | [redacted] | [redacted] |
| 7. | [redacted] | [redacted] | [redacted] |
| 8. | [redacted] | [redacted] | [redacted] |
| 9. | [redacted] | [redacted] | [redacted] |
| 10. | [redacted] | [redacted] | [redacted] |
| 11. | [redacted] | [redacted] | [redacted] |
| 12. | [redacted] | [redacted] | [redacted] |
| 13. | [redacted] | [redacted] | [redacted] |
| 14. | [redacted] | [redacted] | [redacted] |
| 15. | [redacted] | [redacted] | [redacted] |
| 16. | [redacted] | [redacted] | [redacted] |
| 17. | [redacted] | [redacted] | [redacted] |
| 18. | [redacted] | [redacted] | [redacted] |
| 19. | [redacted] | [redacted] | [redacted] |

| | D<br>Original contract or training agreement number<br>**420** | E<br>Original registration date of apprenticeship contract or training agreement (see note 1 below)<br>**425** | F<br>Start date of employment as an apprentice in the tax year (see note 2 below)<br>**430** | G<br>End date of employment as an apprentice in the tax year (see note 3 below)<br>**435** |
|---|---|---|---|---|
| 1. | PB5164 | 2008-10-28 | 2012-01-01 | 2012-10-27 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement<br>(see note 1 below)<br>425 | F<br>Start date of employment as an apprentice in the tax year<br>(see note 2 below)<br>430 | G<br>End date of employment as an apprentice in the tax year<br>(see note 3 below)<br>435 |
|---|---|---|---|---|
| 2. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 3. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 4. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 5. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 6. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 7. | [redacted] | 2008-10-28 | 2012-01-01 | 2012-10-27 |
| 8. | [redacted] | 2008-11-04 | 2012-01-01 | 2012-11-03 |
| 9. | [redacted] | 2009-02-03 | 2012-01-01 | 2012-12-31 |
| 10. | [redacted] | 2009-02-03 | 2012-01-01 | 2012-12-31 |
| 11. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 12. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 13. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 14. | [redacted] | 2008-11-04 | 2012-01-01 | 2012-11-03 |
| 15. | [redacted] | 2011-05-10 | 2012-01-01 | 2012-12-31 |
| 16. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 17. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 18. | [redacted] | 2011-10-17 | 2012-01-01 | 2012-12-31 |
| 19. | [redacted] | 2010-01-06 | 2012-01-01 | 2012-12-31 |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below)<br>441 | H2<br>Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below)<br>442 | H3<br>Number of days employed as an apprentice in the tax year (column H1 **plus** column H2)<br>440 | I<br>Maximum credit amount for the tax year (see note 2 below)<br>445 |
|---|---|---|---|---|
| 1. | | 300 | 300 | 8,197 |
| 2. | | 300 | 300 | 8,197 |
| 3. | | 300 | 300 | 8,197 |
| 4. | | 300 | 300 | 8,197 |
| 5. | | 300 | 300 | 8,197 |
| 6. | | 300 | 300 | 8,197 |
| 7. | | 300 | 300 | 8,197 |
| 8. | | 307 | 307 | 8,388 |
| 9. | | 365 | 365 | 9,973 |
| 10. | | 365 | 365 | 9,973 |
| 11. | | 365 | 365 | 9,973 |
| 12. | | 365 | 365 | 9,973 |
| 13. | | 365 | 365 | 9,973 |
| 14. | | 307 | 307 | 8,388 |
| 15. | | 365 | 365 | 9,973 |
| 16. | | 365 | 365 | 9,973 |
| 17. | | 365 | 365 | 9,973 |
| 18. | | 365 | 365 | 9,973 |
| 19. | | 365 | 365 | 9,973 |

| | J1<br>Eligible expenditures before March 27, 2009 (see note 3 below)<br>451 | J2<br>Eligible expenditures after March 26, 2009 (see note 3 below)<br>452 | J3<br>Eligible expenditures for the tax year (column J1 **plus** column J2)<br>450 | K<br>Eligible expenditures **multiplied** by specified percentage (see note 4 below)<br>460 |
|---|---|---|---|---|
| 1. | | 78,568 | 78,568 | 27,499 |
| 2. | | 77,885 | 77,885 | 27,260 |
| 3. | | 75,181 | 75,181 | 26,313 |
| 4. | | 79,447 | 79,447 | 27,806 |
| 5. | | 70,106 | 70,106 | 24,537 |
| 6. | | 71,993 | 71,993 | 25,198 |
| 7. | | 77,058 | 77,058 | 26,970 |
| 8. | | 68,881 | 68,881 | 24,108 |
| 9. | | 71,684 | 71,684 | 25,089 |
| 10. | | 65,487 | 65,487 | 22,920 |
| 11. | | 53,460 | 53,460 | 18,711 |
| 12. | | 54,330 | 54,330 | 19,016 |
| 13. | | 53,919 | 53,919 | 18,872 |
| 14. | | 56,218 | 56,218 | 19,676 |
| 15. | | 53,546 | 53,546 | 18,741 |
| 16. | | 53,403 | 53,403 | 18,691 |
| 17. | | 54,083 | 54,083 | 18,929 |
| 18. | | 55,075 | 55,075 | 19,276 |
| 19. | | 59,745 | 59,745 | 20,911 |

| | L<br>ATTC on eligible expenditures (lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance (see note 5 below)<br>480 | N<br>ATTC for each apprentice (column L or column M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 8,197 | | 8,197 |
| 2. | 8,197 | | 8,197 |
| 3. | 8,197 | | 8,197 |
| 4. | 8,197 | | 8,197 |
| 5. | 8,197 | | 8,197 |
| 6. | 8,197 | | 8,197 |
| 7. | 8,197 | | 8,197 |
| 8. | 8,388 | | 8,388 |
| 9. | 9,973 | | 9,973 |
| 10. | 9,973 | | 9,973 |
| 11. | 9,973 | | 9,973 |
| 12. | 9,973 | | 9,973 |
| 13. | 9,973 | | 9,973 |
| 14. | 8,388 | | 8,388 |
| 15. | 9,973 | | 9,973 |
| 16. | 9,973 | | 9,973 |
| 17. | 9,973 | | 9,973 |
| 18. | 9,973 | | 9,973 |
| 19. | 9,973 | | 9,973 |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 173,885 O

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . ______ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Canada Revenue Agency / Agence du revenu du Canada

PIL FILING

# T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

## Identification

**Business number (BN)** . . . . . . . . . . 001 86339 1363 RC0001

**Corporation's name**
002 Hydro Ottawa Limited

**Address of head office**
Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 3025 Albion Road North
012 P.O. Box 8700
City: 015 Ottawa
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 K1G 3S4

**Mailing address** (if different from head office address)
Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

**Location of books and records**
Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031
032
City: 035
Province, territory, or state: 036
Country (other than Canada): 037
Postal code/Zip code: 038

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . . . . . . . . . . 043 ____ YYYY MM DD

**To which tax year does this return apply?**
Tax year start: 060 2013-01-01 (YYYY MM DD)
Tax year-end: 061 2013-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . . . . . . . . . . 065 ____ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to:**
subparagraph 88(2)(a)(iv)? . . . . . . . . 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

**Is the corporation a professional corporation that is a member of a partnership?** . . . . . . . . . . . . . . . . 067 1 Yes [ ] 2 No [X]

**Is this the first year of filing after:**
Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079 ____

**Is the corporation a resident of Canada?**
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ____

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**
095 096

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| Is the corporation an associated CCPC? | 160 | X | 23 |
| Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders who own voting shares? | 151 | | 19 |
| Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | X | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership account number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation have any foreign affiliates during the year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Has the corporation had any non-arm's length transactions with a non-resident? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | X | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | X | 3 |
| Is the corporation claiming any type of losses? | 204 | | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | X | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)? | 213 | X | 13 |
| Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | X | 31 |
| Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| | | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates that are not controlled foreign affiliates? | 256 | | T1134 |
| Did the corporation have any controlled foreign affiliates? | 258 | | T1134 |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | X | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

| | | | |
|---|---|---|---|
| 284 | DIST. OF ELECTRICITY | 285 | 100.000 % |
| 286 | | 287 | % |
| 288 | | 289 | % |

| | | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes [ ] 2 No [ ]

## Taxable income

| | | | | | |
|---|---|---|---|---|---|
| Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. | | | 300 | 26,553,071 | A |
| **Deduct:** Charitable donations from Schedule 2 | 311 | 124,771 | | | |
| Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | | |
| Cultural gifts from Schedule 2 | 313 | | | | |
| Ecological gifts from Schedule 2 | 314 | | | | |
| Gifts of medicine from Schedule 2 | 315 | | | | |
| Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | | |
| Part VI.1 tax deduction* | 325 | | | | |
| Non-capital losses of previous tax years from Schedule 4 | 331 | | | | |
| Net capital losses of previous tax years from Schedule 4 | 332 | | | | |
| Restricted farm losses of previous tax years from Schedule 4 | 333 | | | | |
| Farm losses of previous tax years from Schedule 4 | 334 | | | | |
| Limited partnership losses of previous tax years from Schedule 4 | 335 | | | | |
| Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | | |
| Prospector's and grubstaker's shares | 350 | | | | |
| Subtotal | | 124,771 | ► | 124,771 | B |
| Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | 26,428,300 | C |
| **Add:** Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | | | 355 | | D |
| **Taxable income** (amount C **plus** amount D) | | | 360 | 26,428,300 | |
| Income exempt under paragraph 149(1)(t) | | | 370 | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | 26,428,300 | Z |

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

| | | | |
|---|---|---|---|
| Income from active business carried on in Canada from Schedule 7 | 400 | 26,553,071 | A |
| Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax | 405 | 26,428,300 | B |
| Business limit (see notes 1 and 2 below) | 410 | 500,000 | C |

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C 500,000 x (415 ***** 1,636,031 D / 11,250) = 72,712,489 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable income from line 360 on page 3* | | | 26,428,300 | A |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | B | | |
| Amount QQ from Part 13 of Schedule 27 | | C | | |
| Personal service business income** | 432 | D | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | E | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | F | | |
| Aggregate investment income from line 440 on page 6*** | | G | | |
| Total of amounts B to G | | ▶ | | H |
| Amount A **minus** amount H (if negative, enter "0") | | | 26,428,300 | I |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Amount I | 26,428,300 | x | Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year | / 365 | x | 11.5 % | = | | J |
| Amount I | 26,428,300 | x | Number of days in the tax year after December 31, 2011 / Number of days in the tax year | 365 / 365 | x | 13 % | = | 3,435,679 | K |

**General tax reduction for Canadian-controlled private corporations** – Amount J **plus** amount K ........ 3,435,679 L

Enter amount L on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

| | | | | |
|---|---|---|---|---|
| Taxable income from page 3 (line 360 or amount Z, whichever applies) | | | | M |
| Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 | | N | | |
| Amount QQ from Part 13 of Schedule 27 | | O | | |
| Personal service business income* | 434 | P | | |
| Amount used to calculate the credit union deduction (amount F from Schedule 17) | | Q | | |
| Total of amounts N to Q | | ▶ | | R |
| Amount M **minus** amount R (if negative, enter "0") | | | | S |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Amount S | | x | Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year | / 365 | x | 11.5 % | = | | T |
| Amount S | | x | Number of days in the tax year after December 31, 2011 / Number of days in the tax year | 365 / 365 | x | 13 % | = | | U |

**General tax reduction** – Amount T **plus** amount U ........ V

Enter amount V on line 639 on page 7.

* For tax years beginning after October 31, 2011.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Aggregate investment income from Schedule 7 | **440** | x 26 2/3 % = | | A |
| Foreign non-business income tax credit from line 632 on page 7 | | | | B |
| **Deduct:** Foreign investment income from Schedule 7 | **445** | x 9 1/3 % = | | C |
| | | (if negative, enter "0") | | D |
| Amount A **minus** amount D (if negative, enter "0") | | | | E |

| | | | | |
|---|---|---|---|---|
| Taxable income from line 360 on page 3 | | | 26,428,300 | F |
| **Deduct:** | | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | | | G |
| Foreign non-business income tax credit from line 632 on page 7 | | x 25/9* 100 / 35 = | | H |
| Foreign business income tax credit from line 636 on page 7 | | x 1(0.38 - X**) 4 = | | I |
| | | Subtotal | | J |
| | | | 26,428,300 | K |
| | | x 26 2/3 % = | 7,047,547 | L |
| Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) | | | 3,952,367 | M |
| **Refundable portion of Part I tax** – Amount E, L, or M, whichever is the least | **450** | | | N |

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

## Refundable dividend tax on hand

| | | | | |
|---|---|---|---|---|
| Refundable dividend tax on hand at the end of the previous tax year | **460** | | | |
| **Deduct:** Dividend refund for the previous tax year | **465** | | | |
| | | | | O |
| **Add** the total of: | | | | |
| Refundable portion of Part I tax from line 450 above | | | | P |
| Total Part IV tax payable from Schedule 3 | | | | Q |
| Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation | **480** | | | |
| | | | | R |
| **Refundable dividend tax on hand at the end of the tax year** – Amount O **plus** amount R | **485** | | | |

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 | 15,000,000 | x 1 / 3 = | 5,000,000 | S |
| Refundable dividend tax on hand at the end of the tax year from line 485 above | | | | T |
| **Dividend refund** – Amount S or T, whichever is less (enter this amount on line 784 on page 8) | | | | |

## Part I tax

| | | | | | |
|---|---|---|---|---|---|
| **Base amount of Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % | | | 550 | 10,042,754 | A |
| **Recapture of investment tax credit from Schedule 31** | | | 602 | | B |

**Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income**
(if it was a CCPC throughout the tax year)

| | | | |
|---|---|---|---|
| Aggregate investment income from line 440 on page 6 | | | i |
| Taxable income from line 360 on page 3 | 26,428,300 | | |
| **Deduct:** | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | | |
| Net amount | 26,428,300 ▶ | 26,428,300 | ii |

| | | | |
|---|---|---|---|
| **Refundable tax on CCPC's investment income** – 6 2 / 3 % of whichever is less: amount i or ii | 604 | | C |
| Subtotal (**add** amounts A to C) | | 10,042,754 | D |

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Small business deduction from line 430 on page 4 | | | 1 | | |
| Federal tax abatement | 608 | 2,642,830 | | | |
| Manufacturing and processing profits deduction from Schedule 27 | 616 | | | | |
| Investment corporation deduction | 620 | | | | |
| Taxed capital gains 624 | | | | | |
| Additional deduction – credit unions from Schedule 17 | 628 | | | | |
| Federal foreign non-business income tax credit from Schedule 21 | 632 | | | | |
| Federal foreign business income tax credit from Schedule 21 | 636 | | | | |
| General tax reduction for CCPCs from amount L on page 5 | 638 | 3,435,679 | | | |
| General tax reduction from amount V on page 5 | 639 | | | | |
| Federal logging tax credit from Schedule 21 | 640 | | | | |
| Federal qualifying environmental trust tax credit | 648 | | | | |
| Investment tax credit from Schedule 31 | 652 | 11,878 | | | |
| Subtotal | | 6,090,387 | ▶ | 6,090,387 | E |

| | | |
|---|---|---|
| **Part I tax payable** – Amount D **minus** amount E | 3,952,367 | F |

Enter amount F on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from page 7 | 700 | 3,952,367 |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | 3,952,367 |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | | |
|---|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | 2,853,456 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | | |
| (The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.) Total provincial tax | | 2,853,456 ▶ | 2,853,456 |
| Total tax payable | 770 | | 6,805,823 A |

**Deduct other credits:**

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | |
| Tax instalments paid | 840 | 7,050,000 |
| Total credits | 890 | 7,050,000 ▶ 7,050,000 B |

Refund code 894 1 Overpayment 244,177

Balance (amount A **minus** amount B) -244,177

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

## Certification

I, 950 Simpson (Last name (print)) 951 Geoff (First name (print)) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2014-06-13 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (613) 738-5499 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 Mike Grue Name (print) 959 (613) 738-5499 Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

# Schedule of Instalment Remittances

Name of corporation contact: Mike Grue
Telephone number: (613) 738-5499

| Effective interest date | Description (instalment remittance, split payment, assessed credit) | Amount of credit |
|---|---|---|
| | 2013 INSTALLMENTS | 7,050,000 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

**Total amount of instalments claimed (carry the result to line 840 of the T2 Return)** 7,050,000 **A**

**Total instalments credited to the taxation year per T9** 7,050,000 **B**

## Transfer

| | Account number | Taxation year end | Amount | Effective interest date | Description |
|---|---|---|---|---|---|
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |
| From: | | | | | |
| To: | | | | | |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 181,668,000 | 168,080,000 |
| | Total tangible capital assets | 2008 | + | 1,090,072,000 | 1,016,871,000 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | 438,495,000 | 421,239,000 |
| | Total intangible capital assets | 2178 | + | 100,496,000 | 83,000,000 |
| | Total accumulated amortization of intangible capital assets | 2179 | – | 55,763,000 | 53,317,000 |
| | Total long-term assets | 2589 | + | 32,334,000 | 31,768,000 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 910,312,000 | 825,163,000 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 198,807,000 | 172,048,000 |
| | Total long-term liabilities | 3450 | + | 441,911,000 | 393,960,000 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 640,718,000 | 566,008,000 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | 269,594,000 | 259,155,000 |
| | **Total liabilities and shareholder equity** | 3640 | = | 910,312,000 | 825,163,000 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | 102,513,000 | 92,074,000 |

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 952,790,000 | 886,094,000 |
| | Cost of sales | 8518 | – | 768,079,000 | 709,935,000 |
| | **Gross profit/loss** | 8519 | = | 184,711,000 | 176,159,000 |
| | Cost of sales | 8518 | + | 768,079,000 | 709,935,000 |
| | Total operating expenses | 9367 | + | 152,522,000 | 143,111,000 |
| | **Total expenses** (mandatory field) | 9368 | = | 920,601,000 | 853,046,000 |
| | Total revenue (mandatory field) | 8299 | + | 952,790,000 | 886,094,000 |
| | Total expenses (mandatory field) | 9368 | – | 920,601,000 | 853,046,000 |
| | **Net non-farming income** | 9369 | = | 32,189,000 | 33,048,000 |
| | **Farming income statement information** | | | | |
| | Total farm revenue (mandatory field) | 9659 | + | | |
| | Total farm expenses (mandatory field) | 9898 | – | | |
| | **Net farm income** | 9899 | = | | |
| | **Net income/loss before taxes and extraordinary items** | 9970 | = | 32,189,000 | 33,048,000 |
| | **Total other comprehensive income** | 9998 | = | | |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | 6,750,000 | 6,635,000 |
| | Future (deferred) income tax provision | 9995 | – | | |
| | Total – Other comprehensive income | 9998 | + | | |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 25,439,000 | 26,413,000 |

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**Schedule 141**

# Notes checklist

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

| | | | |
|---|---|---|---|
| Does the accountant have a professional designation? | 095 | 1 Yes X | 2 No |
| Is the accountant connected* with the corporation? | 097 | 1 Yes | 2 No X |

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note**
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

| | | |
|---|---|---|
| Completed an auditor's report | 1 | X |
| Completed a review engagement report | 2 | |
| Conducted a compilation engagement | 3 | |

## Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

| | | | |
|---|---|---|---|
| Has the accountant expressed a reservation? | 099 | 1 Yes | 2 No X |

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

| | | |
|---|---|---|
| Prepared the tax return (financial statements prepared by client) | 1 | |
| Prepared the tax return and the financial information contained therein (financial statements have not been prepared) | 2 | |

| | | | |
|---|---|---|---|
| Were notes to the financial statements prepared? | 101 | 1 Yes X | 2 No |

If **yes**, complete lines 104 to 107 below:

| | | | |
|---|---|---|---|
| Are subsequent events mentioned in the notes? | 104 | 1 Yes | 2 No X |
| Is re-evaluation of asset information mentioned in the notes? | 105 | 1 Yes | 2 No X |
| Is contingent liability information mentioned in the notes? | 106 | 1 Yes X | 2 No |
| Is information regarding commitments mentioned in the notes? | 107 | 1 Yes X | 2 No |
| Does the corporation have investments in joint venture(s) or partnership(s)? | 108 | 1 Yes | 2 No X |

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income<br>Increase (decrease) | | In OCI<br>Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

**SCHEDULE 100**

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

## Assets – lines 1000 to 2599

| | | | | | |
|---|---|---|---|---|---|
| 1000 | 5,038,000 | 1060 | 65,842,000 | 1062 | 106,551,000 |
| 1480 | 31,000 | 1481 | 818,000 | 1483 | 457,000 |
| 1484 | 2,931,000 | 1599 | 181,668,000 | 1600 | 24,995,000 |
| 1680 | 80,274,000 | 1681 | -21,689,000 | 1740 | 17,970,000 |
| 1741 | -11,768,000 | 1900 | 966,833,000 | 1901 | -405,038,000 |
| 2008 | 1,090,072,000 | 2009 | -438,495,000 | 2010 | 100,496,000 |
| 2011 | -55,763,000 | 2178 | 100,496,000 | 2179 | -55,763,000 |
| 2420 | 12,441,000 | 2421 | 19,893,000 | 2589 | 32,334,000 |
| 2599 | 910,312,000 | | | | |

## Liabilities – lines 2600 to 3499

| | | | | | |
|---|---|---|---|---|---|
| 2620 | 178,816,000 | 2960 | 19,173,000 | 2963 | 818,000 |
| 3139 | 198,807,000 | 3140 | 387,185,000 | 3240 | 19,893,000 |
| 3270 | 8,533,000 | 3320 | 26,300,000 | 3450 | 441,911,000 |
| 3499 | 640,718,000 | | | | |

## Shareholder equity – lines 3500 to 3640

| | | | | | |
|---|---|---|---|---|---|
| 3500 | 167,081,000 | 3600 | 102,513,000 | 3620 | 269,594,000 |
| 3640 | 910,312,000 | | | | |

## Retained earnings – lines 3660 to 3849

| | | | | | |
|---|---|---|---|---|---|
| 3660 | 92,074,000 | 3680 | 25,439,000 | 3700 | -15,000,000 |
| 3849 | 102,513,000 | | | | |

**SCHEDULE 125**

## GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

### Description

Sequence number . . . . . . . 0003 01

### Revenue – lines 8000 to 8299

| | | | | | |
|---|---|---|---|---|---|
| 8000 | 952,790,000 | 8089 | 952,790,000 | 8299 | 952,790,000 |

### Cost of sales – lines 8300 to 8519

| | | | | | |
|---|---|---|---|---|---|
| 8320 | 768,079,000 | 8518 | 768,079,000 | 8519 | 184,711,000 |

### Operating expenses – lines 8520 to 9369

| | | | | | |
|---|---|---|---|---|---|
| 8570 | 7,711,000 | 8670 | 29,388,000 | 8740 | 15,672,000 |
| 9270 | 99,751,000 | 9367 | 152,522,000 | 9368 | 920,601,000 |
| 9369 | 32,189,000 | | | | |

### Extraordinary items and taxes – lines 9970 to 9999

| | | | | | |
|---|---|---|---|---|---|
| 9970 | 32,189,000 | 9990 | 6,750,000 | 9999 | 25,439,000 |

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# Net Income (Loss) for Income Tax Purposes

**SCHEDULE 1**

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

| | | | | |
|---|---|---|---|---|
| Amount calculated on line 9999 from Schedule 125 | | | 25,439,000 | A |
| **Add:** | | | | |
| Provision for income taxes – current | 101 | 6,750,000 | | |
| Interest and penalties on taxes | 103 | 330 | | |
| Amortization of tangible assets | 104 | 29,388,000 | | |
| Amortization of intangible assets | 106 | 7,711,000 | | |
| Loss on disposal of assets | 111 | 2,505,741 | | |
| Charitable donations and gifts from Schedule 2 | 112 | 124,771 | | |
| Non-deductible meals and entertainment expenses | 121 | 82,667 | | |
| Other reserves on lines 270 and 275 from Schedule 13 | 125 | 704,169 | | |
| Reserves from financial statements – balance at the end of the year | 126 | 3,063,750 | | |
| Subtotal of additions | | 50,330,428 ▶ | 50,330,428 | |

## Other additions:

### Miscellaneous other additions:

| 604 | Description | Amount |
|---|---|---|
| | 12(1)(g) inclusion | 2,983,317 |
| | Apprentice tax credit - Federal 2012 | 14,000 |
| | Apprentice tax credit - Ont 2013 | 106,354 |
| | Coop student tax credit - Ont 2013 | 44,445 |
| | Employee Future Benefits expensed in F/S | 563,640 |
| | ARO expenses accrued in 2013 | 2,475 |
| | | |
| | Total | 3,714,231 |

| | | | | |
|---|---|---|---|---|
| Total | 294 | 3,714,231 | | |
| Subtotal of other additions | 199 | 3,714,231 ▶ | 3,714,231 | |
| **Total additions** | 500 | 54,044,659 ▶ | 54,044,659 | B |
| Amount A **plus** amount B | | | 79,483,659 | |

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Capital cost allowance from Schedule 8 | | 403 | 46,192,065 | | |
| Cumulative eligible capital deduction from Schedule 10 | | 405 | 62,092 | | |
| Other reserves on line 280 from Schedule 13 | | 413 | 1,110,910 | | |
| Reserves from financial statements – balance at the beginning of the year | | 414 | 1,620,141 | | |
| Subtotal of deductions | | | 48,985,208 | ▶ | 48,985,208 |

**Other deductions:**

**Miscellaneous other deductions:**

| | | | | | | |
|---|---|---|---|---|---|---|
| 700 | ARO costs incurred in 2013 | | 390 | 140,737 | | |
| 701 | AFUDC | | 391 | 2,375,633 | | |
| 702 | Employee Future Benefits paid during the year | | 392 | 454,941 | | |
| 704 | Payments included for tax in prior years | 974,069 | | | | |
| | Total | 974,069 | 394 | 974,069 | | |
| | Subtotal of other deductions | | 499 | 3,945,380 | ▶ | 3,945,380 |
| | **Total deductions** | | 510 | 52,930,588 | ▶ | 52,930,588 |

**Net income (loss) for income tax purposes** – enter on line 300 of the T2 return . . . 26,553,071

T2 SCH 1 E (12)

Canada

Canada Revenue Agency / Agence du revenu du Canada

**Schedule 2**

# Charitable Donations and Gifts

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- For use by corporations to claim any of the following:
  - charitable donations to qualified donees;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the federal *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- The eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- A gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

## Part 1 – Charitable donations

| Charity/Recipient | Amount ($100 or more only) |
|---|---|
| United Way | 65,979 |
| United Way | 57,792 |
| Our Youth At Work Assoication | 500 |
| Canada Helps | 100 |
| Heart & Stroke Foundation of Canada | 100 |
| Ottawa Regional Cancer Foundation | 100 |
| Heart & Stroke Foundation of Canada | 100 |
| The Great War Memorial Hospital of Perth Dis | 100 |
| | |
| | |
| | |
| | |
| Subtotal | 124,771 |
| **Add:** Total donations of less than $100 each | |
| Total donations in current tax year | 124,771 |

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Charitable donations at the end of the previous tax year | | | A | | |
| **Deduct:** Charitable donations expired after five tax years* | 239 | | | | |
| Charitable donations at the beginning of the tax year | 240 | | B | | |
| **Add:** | | | | | |
| Charitable donations transferred on an amalgamation or the wind-up of a subsidiary | 250 | | | | |
| Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) | 210 | 124,771 | | 124,771 | 124,771 |
| Subtotal (line 250 **plus** line 210) | | 124,771 | C | 124,771 | 124,771 |
| Subtotal (amount B **plus** amount C) | | 124,771 | D | 124,771 | 124,771 |
| **Deduct:** Adjustment for an acquisition of control (for donations made after March 22, 2004) | 255 | | | | |
| Total charitable donations available (amount D **minus** amount on line 255) | | 124,771 | E | 124,771 | 124,771 |
| **Deduct:** Amount applied against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return) | 260 | 124,771 | | 124,771 | 124,771 |
| Charitable donations closing balance (amount E **minus** amount on line 260) | 280 | | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Charitable donations

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2012-12-31 | | | |
| 2nd prior year | 2011-12-31 | | | |
| 3rd prior year | 2010-12-31 | | | |
| 4th prior year | 2009-12-31 | | | |
| 5th prior year | 2008-12-31 | | | |
| 6th prior year* | 2007-12-31 | | | |
| 7th prior year | 2006-12-31 | | | |
| 8th prior year | 2005-12-31 | | | |
| 9th prior year | 2004-12-31 | | | |
| 10th prior year | 2003-12-31 | | | |
| 11th prior year | 2002-12-31 | | | |
| 12th prior year | 2001-12-31 | | | |
| 13th prior year | 2001-09-30 | | | |
| 14th prior year | 2000-09-30 | | | |
| 15th prior year | 1999-09-30 | | | |
| 16th prior year | 1998-09-30 | | | |
| 17th prior year | 1997-09-30 | | | |
| 18th prior year | 1996-09-30 | | | |
| 19th prior year | 1995-09-30 | | | |
| 20th prior year | 1994-09-30 | | | |
| 21st prior year* | 1993-09-30 | | | |
| **Total** (to line A) | | | | |

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 2 – Calculation of the maximum allowable deduction for charitable donations

| | | | | |
|---|---|---|---|---|
| Net income for tax purposes * **multiplied** by 75 % | | | 19,914,803 | F |
| Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** | 225 | | | G |
| Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) | 227 | | | H |
| The amount of the recapture of capital cost allowance in respect of charitable gifts | 230 | | | |
| Proceeds of disposition, less outlays and expenses ** | | | | I |
| Capital cost ** | | | | J |
| Amount I or J, whichever is less | 235 | | | |
| Amount on line 230 or 235, whichever is less | | | | K |
| Subtotal (**add** amounts G, H, and K) | | | | L |
| Amount L **multiplied** by 25 % | | | | M |
| Subtotal (amount F **plus** amount M) | | | 19,914,803 | N |
| **Maximum allowable deduction for charitable donations** (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less) | | | 124,771 | O |

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

## Part 3 – Gifts to Canada, a province, or a territory

| | | | | |
|---|---|---|---|---|
| Gifts to Canada, a province, or a territory at the end of the previous tax year | | | | A |
| **Deduct:** Gifts to Canada, a province, or a territory expired after five tax years | 339 | | | |
| Gifts to Canada, a province, or a territory at the beginning of the tax year | 340 | | | B |
| **Add:** | | | | |
| Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary | 350 | | | |
| Total current-year gifts made to Canada, a province, or a territory * | 310 | | | |
| Subtotal (line 350 **plus** line 310) | | | ► | C |
| Subtotal (amount B **plus** amount C) | | | | D |
| **Deduct:** | | | | |
| Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 355 | | | |
| Amount applied against taxable income (enter this amount on line 312 of the T2 return) | 360 | | | |
| Subtotal (line 355 **plus** line 360) | | | ► | E |
| Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E) | 380 | | | |

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

## Part 4 – Gifts of certified cultural property

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Gifts of certified cultural property at the end of the previous tax year | | | F | | |
| **Deduct:** Gifts of certified cultural property expired after five tax years* | 439 | | | | |
| Gifts of certified cultural property at the beginning of the tax year | 440 | | G | | |
| **Add:** | | | | | |
| Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary | 450 | | | | |
| Total current-year gifts of certified cultural property | 410 | | | | |
| Subtotal (line 450 **plus** line 410) | | | H | | |
| Subtotal (amount G **plus** amount H) | | | I | | |
| **Deduct:** | | | | | |
| Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 455 | | | | |
| Amount applied against taxable income (enter this amount on line 313 of the T2 return) | 460 | | | | |
| Subtotal (line 455 **plus** line 460) | | | J | | |
| Gifts of certified cultural property closing balance (amount I **minus** amount J) | 480 | | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amount carried forward – Gifts of certified cultural property

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2012-12-31 | | | |
| 2nd prior year | 2011-12-31 | | | |
| 3rd prior year | 2010-12-31 | | | |
| 4th prior year | 2009-12-31 | | | |
| 5th prior year | 2008-12-31 | | | |
| 6th prior year* | 2007-12-31 | | | |
| 7th prior year | 2006-12-31 | | | |
| 8th prior year | 2005-12-31 | | | |
| 9th prior year | 2004-12-31 | | | |
| 10th prior year | 2003-12-31 | | | |
| 11th prior year | 2002-12-31 | | | |
| 12th prior year | 2001-12-31 | | | |
| 13th prior year | 2001-09-30 | | | |
| 14th prior year | 2000-09-30 | | | |
| 15th prior year | 1999-09-30 | | | |
| 16th prior year | 1998-09-30 | | | |
| 17th prior year | 1997-09-30 | | | |
| 18th prior year | 1996-09-30 | | | |
| 19th prior year | 1995-09-30 | | | |
| 20th prior year | 1994-09-30 | | | |
| 21st prior year* | 1993-09-30 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 5 – Gifts of certified ecologically sensitive land

| | Line | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Gifts of certified ecologically sensitive land at the end of the previous tax year | | | K | | |
| **Deduct:** Gifts of certified ecologically sensitive land expired after five tax years | 539 | | | | |
| Gifts of certified ecologically sensitive land at the beginning of the tax year | 540 | | L | | |
| **Add:** | | | | | |
| Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary | 550 | | | | |
| Total current-year gifts of certified ecologically sensitive land | 510 | | | | |
| Subtotal (line 550 **plus** line 510) | | | M | | |
| Subtotal (amount L **plus** amount M) | | | N | | |
| **Deduct:** | | | | | |
| Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 555 | | | | |
| Amount applied against taxable income (enter this amount on line 314 of the T2 return) | 560 | | | | |
| Subtotal (line 555 **plus** line 560) | | | O | | |
| Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O) | 580 | | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Gifts of certified ecologically sensitive land

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2012-12-31 | | | |
| 2nd prior year | 2011-12-31 | | | |
| 3rd prior year | 2010-12-31 | | | |
| 4th prior year | 2009-12-31 | | | |
| 5th prior year | 2008-12-31 | | | |
| 6th prior year* | 2007-12-31 | | | |
| 7th prior year | 2006-12-31 | | | |
| 8th prior year | 2005-12-31 | | | |
| 9th prior year | 2004-12-31 | | | |
| 10th prior year | 2003-12-31 | | | |
| 11th prior year | 2002-12-31 | | | |
| 12th prior year | 2001-12-31 | | | |
| 13th prior year | 2001-09-30 | | | |
| 14th prior year | 2000-09-30 | | | |
| 15th prior year | 1999-09-30 | | | |
| 16th prior year | 1998-09-30 | | | |
| 17th prior year | 1997-09-30 | | | |
| 18th prior year | 1996-09-30 | | | |
| 19th prior year | 1995-09-30 | | | |
| 20th prior year | 1994-09-30 | | | |
| 21st prior year* | 1993-09-30 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 6 – Additional deduction for gifts of medicine

| | | Federal | | Québec | | Alberta | |
|---|---|---|---|---|---|---|---|
| Additional deduction for gifts of medicine at the end of the previous tax year | | | P | | | | |
| **Deduct:** Additional deduction for gifts of medicine expired after five tax years | 639 | | | | | | |
| Additional deduction for gifts of medicine at the beginning of the tax year | 640 | | Q | | | | |
| **Add:** | | | | | | | |
| Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary | 650 | | | | | | |
| Additional deduction for gifts of medicine for the current year: | | | | | | | |
| Proceeds of disposition | 602 | | 1 | | 1 | | 1 |
| Cost of gifts of medicine | 601 | | 2 | | 2 | | 2 |
| Subtotal (line 1 **minus** line 2) | | | 3 | | 3 | | 3 |
| Line 3 **multiplied** by 50 % | | | 4 | | 4 | | 4 |
| Eligible amount of gifts | 600 | | 5 | | 5 | | 5 |

**Federal**

a ______ x ( b ______ / c ) = Additional deduction for gifts of medicine for the current year **610** ______

**Québec**

a ______ x ( b ______ / c ) = Additional deduction for gifts of medicine for the current year ______

**Alberta**

a ______ x ( b ______ / c ) = Additional deduction for gifts of medicine for the current year ______

where:

**a** is the **lesser** of line 2 and line 4

**b** is the eligible amount of gifts (line 600)

**c** is the proceeds of disposition (line 602)

| | | Federal | | Québec | Alberta |
|---|---|---|---|---|---|
| Subtotal (line 650 **plus** line 610) | | | R | | |
| Subtotal (amount Q **plus** amount R) | | | S | | |
| **Deduct:** | | | | | |
| Adjustment for an acquisition of control | 655 | | | | |
| Amount applied against taxable income (enter this amount on line 315 of the T2 return) | 660 | | | | |
| Subtotal (line 655 **plus** line 660) | | | T | | |
| Additional deduction for gifts of medicine closing balance (amount S **minus** amount T) | 680 | | | | |

## Amounts carried forward – Additional deduction for gifts of medicine

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2012-12-31 | | | |
| 2nd prior year | 2011-12-31 | | | |
| 3rd prior year | 2010-12-31 | | | |
| 4th prior year | 2009-12-31 | | | |
| 5th prior year | 2008-12-31 | | | |
| 6th prior year* | 2007-12-31 | | | |
| **Total** | | | | |

***** These donations expired in the current year.

## Québec – Gifts of musical instruments

| | | |
|---|---|---|
| Gifts of musical instruments at the end of the previous tax year | | A |
| **Deduct:** Gifts of musical instruments expired after twenty tax years | | B |
| Gifts of musical instruments at the beginning of the tax year | | C |
| **Add:** | | |
| Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary | | D |
| Total current-year gifts of musical instruments | | E |
| Subtotal (line D **plus** line E) | | F |
| **Deduct:** Adjustment for an acquisition of control | | G |
| Total gifts of musical instruments available | | H |
| **Deduct:** Amount applied against taxable income | | I |
| Gifts of musical instruments closing balance | | J |

## Amounts carried forward – Gifts of musical instruments

| Year of origin: | | Québec |
|---|---|---|
| 1st prior year | 2012-12-31 | |
| 2nd prior year | 2011-12-31 | |
| 3rd prior year | 2010-12-31 | |
| 4th prior year | 2009-12-31 | |
| 5th prior year | 2008-12-31 | |
| 6th prior year* | 2007-12-31 | |
| 7th prior year | 2006-12-31 | |
| 8th prior year | 2005-12-31 | |
| 9th prior year | 2004-12-31 | |
| 10th prior year | 2003-12-31 | |
| 11th prior year | 2002-12-31 | |
| 12th prior year | 2001-12-31 | |
| 13th prior year | 2001-09-30 | |
| 14th prior year | 2000-09-30 | |
| 15th prior year | 1999-09-30 | |
| 16th prior year | 1998-09-30 | |
| 17th prior year | 1997-09-30 | |
| 18th prior year | 1996-09-30 | |
| 19th prior year | 1995-09-30 | |
| 20th prior year | 1994-09-30 | |
| 21st prior year* | 1993-09-30 | |
| **Total** | | |

* These gifts expired in the current year.

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# DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

**SCHEDULE 3**

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

## Part 1 – Dividends received in the tax year

**Do not include dividends received from foreign non-affiliates.**

| Name of payer corporation (from which the corporation received the dividend) | A | B Enter 1 if payer corporation is connected | C Business Number of connected corporation | D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) | E Non-taxable dividend under section 83 |
|---|---|---|---|---|---|
| 200 | | 205 | 210 | 220 | 230 |
| | | | | | |

(Columns B, C and D: Complete if payer corporation is connected)

**Total** (enter on line 402 of Schedule 1)

**Note**: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

| F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* | F1 Eligible dividends (included in column F) | F2 | F3 | G Total taxable dividends paid by connected payer corporation (for tax year in column D) | H Dividend refund of the connected payer corporation (for tax year in column D)** | I Part IV tax before deductions F x 1 / 3 *** |
|---|---|---|---|---|---|---|
| 240 | | | | 250 | 260 | 270 |
| | | | | | | |
| | | | | | | J |

(Columns G and H: Complete if payer corporation is connected)

**Total** (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

## Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .

**Deduct:**

Part IV.I tax payable on dividends subject to Part IV tax . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **320**

Subtotal

**Deduct:**

Current-year non-capital loss claimed to reduce Part IV tax . . . . . . . . . . . . . . . . . **330**

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . . . . . . **335**

Current-year farm loss claimed to reduce Part IV tax . . . . . . . . . . . . . . . . . . . . . **340**

Farm losses from previous years claimed to reduce Part IV tax . . . . . . . . . . . . . . **345**

Total losses applied against Part IV tax x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **360**

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

| | A | B | C | D | D1 |
|---|---|---|---|---|---|
| | Name of connected recipient corporation | Business Number | Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) | Taxable dividends paid to connected corporations | Eligible dividends (included in column D) |
| | 400 | 410 | 420 | 430 | |
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 2013-12-31 | 15,000,000 | |

**Note**

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

**Total** 15,000,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . . . . . . . . . . . . . . . . . . . . . . . . **450**

Eligible dividends (included in line 450) . . . . . . . . . . . . . . . . . . . . . . . . . . . . 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **460** 15,000,000

## Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) . . . . . . . . . . . . . . . . . . . 15,000,000

Other dividends paid in the tax year (total of 510 to 540) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .

Total dividends paid in the tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** 15,000,000

**Deduct:**

Dividends paid out of capital dividend account . . . . . . . . . . . . . . . . . . . . . . . . . **510**

Capital gains dividends . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520**

Dividends paid on shares described in subsection 129(1.2) . . . . . . . . . . . . . . . . **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **540**

Subtotal ▶

Total taxable dividends paid in the tax year that qualify for a dividend refund . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 15,000,000

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**Schedule 5**

# TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

| Corporation's name | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

## Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

| A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. * | | B Total salaries and wages paid in jurisdiction | C (B x taxable income**) / G | D Gross revenue | E (D x taxable income**) / H | F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2) |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 003 1 Yes ☐ | 103 | | 143 | | |
| Newfoundland and Labrador offshore | 004 1 Yes ☐ | 104 | | 144 | | |
| Prince Edward Island | 005 1 Yes ☐ | 105 | | 145 | | |
| Nova Scotia | 007 1 Yes ☐ | 107 | | 147 | | |
| Nova Scotia offshore | 008 1 Yes ☐ | 108 | | 148 | | |
| New Brunswick | 009 1 Yes ☐ | 109 | | 149 | | |
| Quebec | 011 1 Yes ☐ | 111 | | 151 | | |
| Ontario | 013 1 Yes ☐ | 113 | | 153 | | |
| Manitoba | 015 1 Yes ☐ | 115 | | 155 | | |
| Saskatchewan | 017 1 Yes ☐ | 117 | | 157 | | |
| Alberta | 019 1 Yes ☐ | 119 | | 159 | | |
| British Columbia | 021 1 Yes ☐ | 121 | | 161 | | |
| Yukon | 023 1 Yes ☐ | 123 | | 163 | | |
| Northwest Territories | 025 1 Yes ☐ | 125 | | 165 | | |
| Nunavut | 026 1 Yes ☐ | 126 | | 166 | | |
| Outside Canada | 027 1 Yes ☐ | 127 | | 167 | | |
| **Total** | | 129 G | | 169 H | | |

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

**Notes:**
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

## Part 2 – Ontario tax payable, tax credits, and rebates

| Total taxable income | Income eligible for small business deduction | Provincial or territorial allocation of taxable income | Provincial or territorial tax payable before credits |
|---|---|---|---|
| 26,428,300 | | 26,428,300 | 3,004,255 |

| | Line | Amount | | Total | |
|---|---|---|---|---|---|
| **Ontario basic income tax** (from Schedule 500) | 270 | 3,039,255 | | | |
| **Deduct:** Ontario small business deduction (from Schedule 500) | 402 | 35,000 | | | |
| Subtotal | | 3,004,255 | ▶ | 3,004,255 | A6 |
| **Add:** | | | | | |
| Ontario additional tax re Crown royalties (from Schedule 504) | 274 | | | | |
| Ontario transitional tax debits (from Schedule 506) | 276 | | | | |
| Recapture of Ontario research and development tax credit (from Schedule 508) | 277 | | | | |
| Subtotal | | | ▶ | | B6 |
| Subtotal (amount A6 **plus** amount B6) | | | | 3,004,255 | C6 |
| **Deduct:** | | | | | |
| Ontario resource tax credit (from Schedule 504) | 404 | | | | |
| Ontario tax credit for manufacturing and processing (from Schedule 502) | 406 | | | | |
| Ontario foreign tax credit (from Schedule 21) | 408 | | | | |
| Ontario credit union tax reduction (from Schedule 500) | 410 | | | | |
| Ontario transitional tax credits (from Schedule 506) | 414 | | | | |
| Ontario political contributions tax credit (from Schedule 525) | 415 | | | | |
| Ontario tax credit for the purchase of vehicles that use natural gas as a fuel | | | | | |
| Subtotal | | | ▶ | | D6 |
| Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") | | | | 3,004,255 | E6 |
| **Deduct:** Ontario research and development tax credit (from Schedule 508) | 416 | | | | |
| Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") | | | | 3,004,255 | F6 |
| **Deduct:** Ontario corporate minimum tax credit (from Schedule 510) | 418 | | | | |
| Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") | | | | 3,004,255 | G6 |
| **Add:** | | | | | |
| Ontario corporate minimum tax (from Schedule 510) | 278 | | | | |
| Ontario special additional tax on life insurance corporations (from Schedule 512) | 280 | | | | |
| Subtotal | | | ▶ | | H6 |
| Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) | | | | 3,004,255 | I6 |
| **Deduct:** | | | | | |
| Ontario qualifying environmental trust tax credit | 450 | | | | |
| Ontario co-operative education tax credit (from Schedule 550) | 452 | 44,445 | | | |
| Ontario apprenticeship training tax credit (from Schedule 552) | 454 | 106,354 | | | |
| Ontario computer animation and special effects tax credit (from Schedule 554) | 456 | | | | |
| Ontario film and television tax credit (from Schedule 556) | 458 | | | | |
| Ontario production services tax credit (from Schedule 558) | 460 | | | | |
| Ontario interactive digital media tax credit (from Schedule 560) | 462 | | | | |
| Ontario sound recording tax credit (from Schedule 562) | 464 | | | | |
| Ontario book publishing tax credit (from Schedule 564) | 466 | | | | |
| Ontario innovation tax credit (from Schedule 566) | 468 | | | | |
| Ontario business-research institute tax credit (from Schedule 568) | 470 | | | | |
| Other Ontario tax credits | | | | | |
| Subtotal | | 150,799 | ▶ | 150,799 | J6 |
| **Net Ontario tax payable or refundable credit** (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255. | 290 | | | 2,853,456 | K6 |

## Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

| | | |
|---|---|---|
| **Net provincial and territorial tax payable or refundable credits** | 255 | 2,853,456 |

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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**SCHEDULE 8**

# CAPITAL COST ALLOWANCE (CCA)

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Net adjustments** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 210,642,972 | | | 0 | | 210,642,972 | 4 | 0 | 0 | 8,425,719 | 202,217,253 |
| 2. | 1b | | 16,465,297 | 8,598,283 | | 0 | 4,299,142 | 20,764,438 | 6 | 0 | 0 | 1,245,866 | 23,817,714 |
| 3. | 2 | Dist equip pre 88 | 71,865,781 | | | 0 | | 71,865,781 | 6 | 0 | 0 | 4,311,947 | 67,553,834 |
| 4. | 3 | buildings pre 88 | 10,718,873 | | | 0 | | 10,718,873 | 5 | 0 | 0 | 535,944 | 10,182,929 |
| 5. | 8 | | 8,699,666 | 1,568,800 | | 0 | 784,400 | 9,484,066 | 20 | 0 | 0 | 1,896,813 | 8,371,653 |
| 6. | 10 | | 5,046,819 | 2,141,364 | | 28,270 | 1,056,547 | 6,103,366 | 30 | 0 | 0 | 1,831,010 | 5,328,903 |
| 7. | 12 | | 1,144,813 | 1,305,861 | | 0 | 652,931 | 1,797,743 | 100 | 0 | 0 | 1,797,743 | 652,931 |
| 8. | 42 | | 479,966 | | | 0 | | 479,966 | 12 | 0 | 0 | 57,596 | 422,370 |
| 9. | 45 | | 86,408 | | | 0 | | 86,408 | 45 | 0 | 0 | 38,884 | 47,524 |
| 10. | 50 | | 1,720,471 | 1,686,456 | | 0 | 843,228 | 2,563,699 | 55 | 0 | 0 | 1,410,034 | 1,996,893 |
| 11. | 47 | | 272,823,922 | 70,584,407 | | 219,525 | 35,182,441 | 308,006,363 | 8 | 0 | 0 | 24,640,509 | 318,548,295 |
| | | **Totals** | 599,694,988 | 85,885,171 | | 247,795 | 42,818,689 | 642,513,675 | | | | 46,192,065 | 639,140,299 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

# Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

## Tax return

| | | | | |
|---|---|---|---|---|
| Additions for tax purposes – Schedule 8 regular classes | | 85,885,171 | | |
| Additions for tax purposes – Schedule 8 leasehold improvements | + | | | |
| Operating leases capitalized for book purposes | + | | | |
| Capital gain deferred | + | | | |
| Recapture deferred | + | | | |
| Deductible expenses capitalized for book purposes – Schedule 1 | + | | | |
| Other (specify): | | | | |
| Change in CIP etc. | + | 533,282 | | |
| Change in Land | + | 19,614,000 | | |
| Change in Inventory | + | 1,463,000 | | |
| Damage to Plant/Capital Contribution | + | 974,069 | | |
| ECE balance | + | 824,938 | | |
| **Total additions per books** | = | 109,294,460 | ▶ | 109,294,460 |
| Proceeds up to original cost – Schedule 8 regular classes | | 247,795 | | |
| Proceeds up to original cost – Schedule 8 leasehold improvements | + | | | |
| Proceeds in excess of original cost – capital gain | + | | | |
| Recapture deferred – as above | + | | | |
| Capital gain deferred – as above | + | | | |
| Pre V-day appreciation | + | | | |
| Other (specify): | | | | |
| | + | | | |
| **Total proceeds per books** | = | 247,795 | ▶ – | 247,795 |
| Depreciation and amortization per accounts – Schedule 1 | | | – | 37,099,000 |
| Loss on disposal of fixed assets per accounts | | | – | 989,000 |
| Gain on disposal of fixed assets per accounts | | | + | |
| **Net change per tax return** | | | = | 70,958,665 |

## Financial statements

**Fixed assets (excluding land) per financial statements**

| | | |
|---|---|---|
| Closing net book value | | 696,310,000 |
| Opening net book value | – | 625,315,000 |
| **Net change per financial statements** | = | 70,995,000 |

If the amounts from the tax return and the financial statements differ, explain why below.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Hydro Ottawa Holding Inc. | | 89411 0816 RC0001 | 1 | | | | | |
| 2. | Energy Ottawa Inc. | | 86338 9961 RC0001 | 3 | | | | | |
| 3. | Telecom Ottawa Holding Inc. / Soci | | 86202 9337 RC0001 | 3 | | | | | |
| 4. | PowerTrail Inc. | | 82829 3944 RC0001 | 3 | | | | | |
| 5. | Moose Creek Energy Inc. | | 82851 1311 RC0001 | 3 | | | | | |
| 6. | Chaudiere Hydro Inc. Hydro Chaudi | | 81281 3103 RC0001 | 3 | | | | | |
| 7. | Chaudiere Water Power Inc/Energie | | 10093 1955 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

**Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") . . . 200: 885,650 A

**Add:**

| | Line | Amount | | Result | | | |
|---|---|---|---|---|---|---|---|
| Cost of eligible capital property acquired during the taxation year | 222 | 1,840 | | | | | |
| Other adjustments | 226 | | | | | | |
| Subtotal (line 222 plus line 226) | | 1,840 | x 3 / 4 = | 1,380 | B | | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 | 228 | | x 1 / 2 = | | C | | |
| amount B minus amount C (if negative, enter "0") | | | | 1,380 | ▶ | 1,380 | D |
| Amount transferred on amalgamation or wind-up of subsidiary | | | | | 224 | | E |
| Subtotal (add amounts A, D, and E) | | | | | 230 | 887,030 | F |

**Deduct:**

| | Line | Amount | | | | | |
|---|---|---|---|---|---|---|---|
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year | 242 | | G | | | | |
| The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) | 244 | | H | | | | |
| Other adjustments | 246 | | I | | | | |
| (add amounts G,H, and I) | | | x 3 / 4 = | | 248 | | J |

**Cumulative eligible capital balance** (amount F minus amount J) . . . 887,030 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| amount K | 887,030 | | | | | | |
| **less** amount from line 249 | | | | | | | |
| **Current year deduction** | 887,030 | x | 7.00 % = | 250 | 62,092 * | | |
| (line 249 plus line 250) (enter this amount at line 405 of Schedule 1) | | | | | 62,092 | ▶ | 62,092 L |

**Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") . . . 300: 824,938 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | | | |
|---|---|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | | 400 | | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | | 401 | | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | 402 | | 3 | | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | 408 | | 4 | | | |
| Line 3 minus line 4 (if negative, enter "0") | | | ▶ | | 5 | |
| Total of lines 1, 2 and 5 | | | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | | 7 | | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | | 8 | | | |
| Subtotal (line 7 plus line 8) | 409 | | ▶ | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | | ▶ | O |
| Line N minus line O (if negative, enter "0") | | | | | | P |
| | | | Line 5 | | x 1 / 2 = | Q |
| Line P minus line Q (if negative, enter "0") | | | | | | R |
| | | | Amount R | | x 2 / 3 = | S |
| Amount N or amount O, whichever is less | | | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | | | | 410 | |

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**SCHEDULE 13**

# CONTINUITY OF RESERVES

| Name of corporation | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

## Part 1 – Capital gains reserves

| | Description of property 001 | Balance at the beginning of the year $ 002 | Transfer on an amalgamation or the wind-up of a subsidiary $ 003 | Add $ | Deduct $ | Balance at the end of the year $ 004 |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| | **Totals** | 008 | 009 | | | 010 |

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

## Part 2 – Other reserves

| Description | | Balance at the beginning of the year $ | Transfer on an amalgamation or the wind-up of a subsidiary $ | Add $ | Deduct $ | Balance at the end of the year $ |
|---|---|---|---|---|---|---|
| Reserve for doubtful debts | ☐ | 110 704,169 | 115 | 406,741 | | 120 1,110,910 |
| Reserve for undelivered goods and services not rendered | ☐ | 130 | 135 | | | 140 |
| Reserve for prepaid rent | ☐ | 150 | 155 | | | 160 |
| Reserve for refundable containers | ☐ | 190 | 195 | | | 200 |
| Reserve for unpaid amounts | ☐ | 210 | 215 | | | 220 |
| Other tax reserves | ☐ | 230 | 235 | | | 240 |
| **Totals** | | 270 704,169 | 275 | 406,741 | | 280 1,110,910 |

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | Allowance for Doubtful Debts | 1,070,899 | | 571,609 | | 1,642,508 |
| 2 | Contingent Liability | 549,242 | | 872,000 | | 1,421,242 |
| 3 | Employee future benefit | | | | | |
| | Reserves from Part 2 of Schedule 13 | | | | | |
| | **Totals** | 1,620,141 | | 1,443,609 | | 3,063,750 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**Schedule 15**

# Deferred Income Plans

| Corporation's name | Business number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

| | Type of plan (see note 1) 100 | Amount of contribution $ (see note 2) 200 | Registration number (RPP, RSUBP, PRPP, and DPSP only) 300 | Name of EPSP trust 400 | Address of EPSP trust 500 | T4PS slip(s) (see note 3) 600 |
|---|---|---|---|---|---|---|
| 1 | 1 | 5,304,262 | 345983 | | | |

**Note 1**

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

**Note 2**

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . . . . . . . . . . . . . . . 5,304,262 A

**Less:**

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 5,304,262 B

**Deductible amount for contributions to deferred income plans**
(amount A **minus** amount B) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . C

Enter amount C on line 417 of Schedule 1

**Note 3**

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

| | 1 Names of associated corporations **100** | 2 Business Number of associated corporations **200** | 3 Association code **300** | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % **350** | 6 Business limit allocated* $ **400** |
|---|---|---|---|---|---|---|
| 1 | Hydro Ottawa Limited | 86339 1363 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 2 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 1 | 500,000 | | |
| 3 | Energy Ottawa Inc. | 86338 9961 RC0001 | 1 | 500,000 | | |
| 4 | Telecom Ottawa Holding Inc. / Societe De Port | 86202 9337 RC0001 | 1 | 500,000 | | |
| 5 | PowerTrail Inc. | 82829 3944 RC0001 | 1 | 500,000 | | |
| 6 | Moose Creek Energy Inc. | 82851 1311 RC0001 | 1 | 500,000 | | |
| 7 | Chaudiere Hydro Inc. Hydro Chaudiere Inc. | 81281 3103 RC0001 | 1 | 500,000 | | |
| 8 | Chaudiere Water Power Inc/Energie Hydrauliqu | 10093 1955 RC0001 | 1 | 500,000 | | |
| | | | | **Total** | 100.0000 | 500,000 A |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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**Schedule 31**

# Investment Tax Credit – Corporations

## General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

## Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more information.

## Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

## Part 1 – Investments, expenditures, and percentages

| **Investments** | **Specified percentage** |
|---|---|
| Qualified property acquired primarily for use in Atlantic Canada | 10 % |
| Qualified resource property acquired primarily for use in Atlantic Canada and acquired: | |
| – after March 28, 2012, and before 2014 | 10 % |
| – after 2013 and before 2016 | 5 % |
| – after 2015* | 0 % |
| **Expenditures** | |
| If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) | 35 % |
| **Note:** If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**. | |
| If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada: | |
| – before 2014** | 20 % |
| – after 2013** | 15 % |
| If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012 | 10 % |
| If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***: | |
| – after March 28, 2012, and before 2013 | 10 % |
| – in 2013 | 5 % |
| – after 2013*** | 0 % |
| If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****: | |
| – after March 28, 2012, and before 2014**** | 10 % |
| – in 2014 | 7 % |
| – in 2015 | 4 % |
| – after 2015**** | 0 % |
| If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment | 10 % |
| If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children | 25 % |

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

## Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . 101 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

**Note:** A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

## Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . 102 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . . 103 ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

# Qualified Property and Qualified Resource Property

## Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

| CCA* class number 105 | Description of investment 110 | Date available for use 115 | Location used (province or territory) 120 | Amount of investment 125 |
|---|---|---|---|---|
| | | | | |

**Total of investments for qualified property and qualified resource property** ______ A

* CCA: capital cost allowance

## Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . . . . . . . B

**Deduct:**

Credit deemed as a remittance of co-op corporations . . . . . . . . 210

Credit expired . . . . . . . . 215

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) . . . . . . . . 220

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . . . 230

ITC from repayment of assistance . . . . . . . . 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . . . x 5 % = 242

Credit allocated from a partnership . . . . . . . . 250

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . . . . . E

**Deduct:**

Credit deducted from Part I tax (enter at amount D in Part 30) . . . . . . . . 260

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . . . . a

Credit transferred to offset Part VII tax liability . . . . . . . . 280

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . . . . . G

**Deduct:**

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) . . . . . . . . . . 310

**ITC closing balance of investments from qualified property and qualified resource property** (amount G **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

## Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 901 | |
| 2nd previous tax year | | | | Credit to be applied | 902 | |
| 3rd previous tax year | | | | Credit to be applied | 903 | |
| | | | | **Total** (enter at amount a in Part 5) | | H |

## Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) . . . . . . . . I

Credit balance before refund (amount G from Part 5) . . . . . . . . J

**Refund** ( 40 % of amount I or J, whichever is less) . . . . . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

## SR&ED

### Part 8 – Qualified SR&ED expenditures

**Current expenditures**

| | | | |
|---|---|---|---|
| Current expenditures (from line 557 on Form T661) | | | |
| **Add:** | | | |
| Contributions to agricultural organizations for SR&ED* | | | |
| Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)* | ► | 350 | |
| Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** | | 360 | |
| Repayments made in the year (from line 560 on Form T661) | | 370 | |
| **Qualified SR&ED expenditures** (total of lines 350 to 370) | | 380 | |

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

### Part 9 – Components of the SR&ED expenditure limit calculation

**Part 9 only applies if the corporation is a CCPC.**

**Note:** A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

| | | |
|---|---|---|
| Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) | 390 | 26,900,819 |
| Enter your taxable capital employed in Canada for the previous tax year 642,512,864 minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million | 398 | 40,000,000 |

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

### Part 10 – SR&ED expenditure limit for a CCPC

| | | | |
|---|---|---|---|
| **For a stand-alone corporation:** | | $ 8,000,000 | |
| **Deduct:** | | | |
| Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more | 26,900,819 x 10 = | 269,008,190 | A |
| Excess ($8,000,000 **minus** amount A; if negative, enter "0") | | | B |
| $ 40,000,000 **minus** line 398 from Part 9 | a | | |
| Amount a **divided** by $ 40,000,000 | | | C |
| **Expenditure limit for the stand-alone corporation** (amount B **multiplied** by amount C) | | | D* |
| **For an associated corporation:** | | | |
| If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 | 400 | | E* |

**Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:**

Amount D or E ______ x Number of days in the tax year 365 / 365 = ______ F

**Your SR&ED expenditure limit for the year** (enter the amount from line D, E, or F, whichever applies) 410 ______

* Amount D or E cannot be more than $3,000,000.

## Part 11 – Investment tax credits on SR&ED expenditures

| | | | | | | |
|---|---|---|---|---|---|---|
| Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less* | 420 | | x | 35 % | = | G |
| Line 350 **minus** line 410 (if negative, enter "0")** | 430 | | x | 20 % | = | H |
| Line 410 **minus** line 350 (if negative, enter "0") | | b | | | | |
| Capital expenditures (line 360 from Part 8) or amount b above, whichever is less* | 440 | | x | 35 % | = | I |
| Line 360 **minus** amount b above (if negative, enter "0")** | 450 | | x | 20 % | = | J |

**Repepayments** (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

| | | | | | | |
|---|---|---|---|---|---|---|
| 460 | | x | 35 % | = | | c |
| 480 | | x | 20 % | = | | d |
| | | | Subtotal (amount c **plus** amount d) | | ▶ | K |

**Current-year SR&ED ITC** (total of amounts G to K; enter on line 540 in Part 12) L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

## Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

| | | | |
|---|---|---|---|
| ITC at the end of the previous tax year | | | M |
| **Deduct:** | | | |
| Credit deemed as a remittance of co-op corporations | 510 | | |
| Credit expired | 515 | | |
| Subtotal (line 510 **plus** line 515) | | ▶ | N |
| ITC at the beginning of the tax year (amount M **minus** amount N) | | 520 | |
| **Add:** | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 530 | | |
| Total current-year credit (from amount L in Part 11) | 540 | | |
| Credit allocated from a partnership | 550 | | |
| Subtotal (total of lines 530 to 550) | | ▶ | O |
| Total credit available (line 520 **plus** amount O) | | | P |
| **Deduct:** | | | |
| Credit deducted from Part I tax (enter at amount E in Part 30) | 560 | | |
| Credit carried back to the previous year(s) (amount S from Part 13) | | e | |
| Credit transferred to offset Part VII tax liability | 580 | | |
| Subtotal (total of line 560, amount e, and line 580) | | ▶ | Q |
| Credit balance before refund (amount P **minus** amount Q) | | | R |
| **Deduct:** | | | |
| Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) | | 610 | |
| **ITC closing balance on SR&ED** (amount R **minus** line 610) | | 620 | |

## Part 13 – Request for carryback of credit from SR&ED expenditures

| | Year | Month | Day | | | | |
|---|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 911 | | |
| 2nd previous tax year | | | | Credit to be applied | 912 | | |
| 3rd previous tax year | | | | Credit to be applied | 913 | | |
| | | | | **Total** (enter at amount e in Part 12) | | | S |

## Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) ______ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* ______ T

**Deduct:**

Amount T or amount G from Part 11, whichever is less ______ U

Net amount (amount T **minus** amount U; if negative, enter "0") ______ V

Amount V **multiplied** by 40 % ______ W

**Add:**

Amount U ______ X

**Refund of ITC** (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) ______ Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

## Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) ______ Z

**Deduct:**

Amount Z or amount G from Part 11, whichever is less ______ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") ______ BB

Amount BB or amount I from Part 11, whichever is less ______ CC

Amount CC **multiplied** by 40 % ______ DD

**Add :**

Amount AA ______ EE

**Refund of ITC** (amount DD **plus** amount EE) ______ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

# Recapture – SR&ED

## Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

**Note:**

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

### Calculation 1 – If you meet all of the above conditions

| Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700** | Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710** | Amount from column 700 or 710, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount C in Part 17) ______ A

### Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

| **A** Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720** | **B** Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730** | **C** Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740** |
|---|---|---|
| | | |

### Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

| **D** Amount determined by the formula (A x B) – C | **E** ITC earned by the transferee for the qualified expenditures that were transferred **750** | **F** Amount from column D or E, whichever is less |
|---|---|---|
| | | |

**Subtotal** (enter this amount at amount D in Part 17) ______ B

**Calculation 3**

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ____________

## Part 17 – Total recapture of SR&ED investment tax credit

| | | |
|---|---|---|
| Recaptured ITC for calculation 1 from amount A in Part 16 | | C |
| Recaptured ITC for calculation 2 from amount B in Part 16 | | D |
| Recaptured ITC for calculation 3 from line 760 in Part 16 | | E |
| **Total recapture of SR&ED investment tax credit** – total of amounts C to E<br>Enter amount F at amount A in Part 29. | | F |

# Pre-Production Mining

## Part 18 – Pre-production mining expenditures

**Exploration information**

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

| List of minerals 800 | Project name 805 |
|---|---|
| | |

| Mineral title 806 | Mining division 807 |
|---|---|
| | |

**Pre-production mining expenditures***

**Exploration:**

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

| | | |
|---|---|---|
| Prospecting | 810 | |
| Geological, geophysical, or geochemical surveys | 811 | |
| Drilling by rotary, diamond, percussion, or other methods | 812 | |
| Trenching, digging test pits, and preliminary sampling | 813 | |

**Development:**

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

| | | |
|---|---|---|
| Clearing, removing overburden, and stripping | 820 | |
| Sinking a mine shaft, constructing an adit, or other underground entry | 821 | |

Other pre-production mining expenditures incurred in the tax year:

| Description 825 | Amount 826 |
|---|---|
| | |

Add amounts in column 826 ▶ A

| | | |
|---|---|---|
| Total pre-production mining expenditures (total of lines 810 to 821 and amount A) | 830 | |

**Deduct:**

| | | |
|---|---|---|
| Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above | 832 | |
| Excess (line 830 **minus** line 832) (if negative, enter "0") | | B |

**Add:**

| | | |
|---|---|---|
| Repayments of government and non-government assistance | 835 | |
| **Pre-production mining expenditures** (amount B **plus** line 835) | | C |

* A pre-production mining expenditure is defined under subsection 127(9).

## Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year ........ D

**Deduct:**

Credit deemed as a remittance of co-op corporations ........ 841

Credit expired ........ 845

Subtotal (line 841 **plus** line 845) ▶ E

ITC at the beginning of the tax year (amount D **minus** amount E) ........ 850

**Add:**

Credit transferred on amalgamation or wind-up of subsidiary ........ 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) .. 870 x 10 % = a

Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) .. 872 x 5 % = b

Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) .. 874 x 7 % = c

Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) .. 876 x 4 % = d

Current year credit (total of amounts a to d) 880 ▶ F

Total credit available (total of lines 850, 860, and amount F) ........ G

**Deduct:**

Credit deducted from Part I tax (enter at amount F in Part 30) ........ 885

Credit carried back to the previous year(s) (amount I from Part 20) ........ e

Subtotal (line 885 **plus** amount e) ▶ H

**ITC closing balance from pre-production mining expenditures** (amount G **minus** amount H) ........ 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

## Part 20 – Request for carryback of credit from pre-production mining expenditures

| | Year | Month | Day | | |
|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 921 |
| 2nd previous tax year | | | | Credit to be applied | 922 |
| 3rd previous tax year | | | | Credit to be applied | 923 |

**Total** (enter at amount e in Part 19) I

### Apprenticeship Job Creation

## Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) ....... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

| | A Contract number (SIN or name of apprentice) 601 | B Name of eligible trade 602 | C Eligible salary and wages* 603 | D Column C x 10 % 604 | E Lesser of column D or $ 2,000 605 |
|---|---|---|---|---|---|
| 1. | [redacted] | [redacted] | 36,805 | 3,681 | 2,000 |
| 2. | [redacted] | [redacted] | 35,752 | 3,575 | 2,000 |

| | A<br>Contract number<br>(SIN or name of apprentice)<br>601 | B<br>Name of eligible trade<br>602 | C<br>Eligible salary and wages*<br>603 | D<br>Column C x 10 %<br>604 | E<br>Lesser of column D or $ 2,000<br>605 |
|---|---|---|---|---|---|
| 3. | [redacted] | [redacted] | 37,103 | 3,710 | 2,000 |
| 4. | [redacted] | [redacted] | 36,428 | 3,643 | 2,000 |
| 5. | [redacted] | [redacted] | 35,926 | 3,593 | 2,000 |
| 6. | [redacted] | [redacted] | 18,782 | 1,878 | 1,878 |

Total current-year credit (enter at line 640 in Part 22) 11,878 A

* Net of any other government or non-government assistance received or to be received.

## Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | B |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 612 | | | |
| Credit expired after 20 tax years | 615 | | | |
| Subtotal (line 612 **plus** line 615) | | | ▶ | C |
| ITC at the beginning of the tax year (amount B **minus** amount C) | 625 | | | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 630 | | | |
| ITC from repayment of assistance | 635 | | | |
| Total current-year credit (amount A from Part 21) | 640 | 11,878 | | |
| Credit allocated from a partnership | 655 | | | |
| Subtotal (total of lines 630 to 655) | | 11,878 | ▶ 11,878 | D |
| Total credit available (line 625 **plus** amount D) | | | 11,878 | E |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount G in Part 30) | 660 | 11,878 | | |
| Credit carried back to the previous year(s) (amount G from Part 23) | | a | | |
| Subtotal (line 660 **plus** amount a) | | 11,878 | ▶ 11,878 | F |
| **ITC closing balance from apprenticeship job creation expenditures** (amount E **minus** amount F) | 690 | | | |

## Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

| | Year | Month | Day | | | |
|---|---|---|---|---|---|---|
| 1st previous tax year | | | | Credit to be applied | 931 | |
| 2nd previous tax year | | | | Credit to be applied | 932 | |
| 3rd previous tax year | | | | Credit to be applied | 933 | |
| | | | | **Total** (enter at amount a in Part 22) | | G |

# Child Care Spaces

## Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

### Cost of depreciable property from the current tax year

| | CCA* class number 665 | Description of investment 675 | Date available for use 685 | Amount of investment 695 |
|---|---|---|---|---|
| 1. | | | | |

Total cost of depreciable property from the current tax year 715

**Add:**

Specified child care start-up expenditures from the current tax year . . . . . 705

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . A

**Deduct:**

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . . 725

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . B

**Add:**

Repayments by the corporation of government and non-government assistance . . . . . 735

**Total eligible expenditures for child care spaces** (amount B **plus** line 735) . . . . . 745

* CCA: capital cost allowance

## Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . x 25 % = C

Number of child care spaces . . . . . 755 x $ 10,000 = D

**ITC from child care spaces expenditures** (amount C or D, whichever is less) . . . . . E

## Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

| | | | | |
|---|---|---|---|---|
| ITC at the end of the previous tax year | | | | F |
| **Deduct:** | | | | |
| Credit deemed as a remittance of co-op corporations | 765 | | | |
| Credit expired after 20 tax years | 770 | | | |
| Subtotal (line 765 **plus** line 770) | | | ▶ | G |
| ITC at the beginning of the tax year (amount F **minus** amount G) | | | 775 | |
| **Add:** | | | | |
| Credit transferred on amalgamation or wind-up of subsidiary | 777 | | | |
| Total current-year credit (amount E from Part 25) | 780 | | | |
| Credit allocated from a partnership | 782 | | | |
| Subtotal (total of lines 777 to 782) | | | ▶ | H |
| Total credit available (line 775 **plus** amount H) | | | | I |
| **Deduct:** | | | | |
| Credit deducted from Part I tax (enter at amount H in Part 30) | 785 | | | |
| Credit carried back to the previous year(s) (amount K from Part 27) | | | a | |
| Subtotal (line 785 **plus** amount a) | | | ▶ | J |
| **ITC closing balance from child care spaces expenditures** (amount I **minus** amount J) | | | 790 | |

## Part 27 – Request for carryback of credit from child care space expenditures

| | Year Month Day | | | |
|---|---|---|---|---|
| 1st previous tax year | 2012-12-31 | Credit to be applied | 941 | |
| 2nd previous tax year | 2011-12-31 | Credit to be applied | 942 | |
| 3rd previous tax year | 2010-12-31 | Credit to be applied | 943 | |
| | | **Total** (enter at amount a in Part 26) | | K |

# Recapture – Child Care Spaces

## Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

| | | | |
|---|---|---|---|
| If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) | | 792 | |
| In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of: | | | |
| The amount that can reasonably be considered to have been included in the original ITC | 795 | | |
| 25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property | 797 | | |
| Amount from line 795 or line 797, whichever is less | | | A |

**Corporate partnerships**

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

| | | | |
|---|---|---|---|
| **Corporate partner's share of the excess of ITC** | 799 | | |
| **Total recapture of child care spaces investment tax credit** (total of line 792, amount A, and line 799) | | | B |

Enter amount B at amount B in Part 29.

# Summary of Investment Tax Credits

## Part 29 – Total recapture of investment tax credit

| | | |
|---|---|---|
| Recaptured SR&ED ITC (from amount F in Part 17) | | A |
| Recaptured child care spaces ITC (from amount B in Part 28) | | B |
| **Total recapture of investment tax credit** (amount A **plus** amount B) | | C |

Enter amount C on line 602 of the T2 return.

## Part 30 – Total ITC deducted from Part I tax

| | | |
|---|---|---|
| ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) | | D |
| ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) | | E |
| ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) | | F |
| ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) | 11,878 | G |
| ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) | | H |
| **Total ITC deducted from Part I tax** (total of amounts D to H) | 11,878 | I |

Enter amount I at line 652 of the T2 return.

*Privacy Act*, Personal Information Bank number CRA PPU 047

# Summary of Investment Tax Credit Carryovers

## Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

**Current year**

| | Addition current year (A) | Applied current year (B) | Claimed as a refund (C) | Carried back (D) | ITC end of year (A-B-C-D) |
|---|---|---|---|---|---|
| | 11,878 | 11,878 | | | |

**Prior years**

| Taxation year | ITC beginning of year (E) | Adjustments (F) | Applied current year (G) | ITC end of year (E-F-G) |
|---|---|---|---|---|
| 2012-12-31 | | | | |
| 2011-12-31 | | | | |
| 2010-12-31 | | | | |
| 2009-12-31 | | | | |
| 2008-12-31 | | | | |
| 2007-12-31 | | | | |
| 2006-12-31 | | | | |
| 2005-12-31 | | | | |
| 2004-12-31 | | | | |
| 2003-12-31 | | | | * |
| 2002-12-31 | | | | |
| 2001-12-31 | | | | |
| 2001-09-30 | | | | |
| 2000-09-30 | | | | |
| 1999-09-30 | | | | |
| 1998-09-30 | | | | |
| 1997-09-30 | | | | |
| 1996-09-30 | | | | |
| 1995-09-30 | | | | |
| 1994-09-30 | | | | * |
| **Total** | | | | |

B+C+D+G **Total ITC utilized** 11,878

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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**SCHEDULE 50**

# SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) | Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") | Social insurance number | Trust number | Percentage common shares | Percentage preferred shares |
|---|---|---|---|---|---|---|
| | 100 | 200 | 300 | 350 | 400 | 500 |
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |



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**SCHEDULE 53**

# GENERAL RATE INCOME POOL (GRIP) CALCULATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

On: 2013-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – Calculation of general rate income pool (GRIP)

| | | | | |
|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | 100 | 172,381,397 A |
| Taxable income for the year (DICs enter "0") * | 110 | 26,428,300 B | | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) ... 120 | | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * ... 130 | | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * ... 140 | | | | |
| Subtotal (**add** lines 120, 130, and 140) ► | | C | | |
| Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") | 150 | 26,428,300 | | |
| After-tax income (line 150 x general rate factor for the tax year ** 0.72 ) | | | 190 | 19,028,376 D |
| Eligible dividends received in the tax year | 200 | | | |
| Dividends deductible under section 113 received in the tax year | 210 | | | |
| Subtotal (**add** lines 200 and 210) ► | | | | E |
| GRIP addition: | | | | |
| Becoming a CCPC (line PP from Part 4) | 220 | | | |
| Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) | 230 | | | |
| Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) | 240 | | | |
| Subtotal (**add** lines 220, 230, and 240) ► | | | 290 | F |
| Subtotal (**add** lines A, D, E, and F) | | | | 191,409,773 G |
| Eligible dividends paid in the previous tax year | 300 | | | |
| Excessive eligible dividend designations made in the previous tax year | 310 | | | |
| **Note:** If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. | | | | |
| Subtotal (line 300 **minus** line 310) ► | | | | H |
| GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) | | | 490 | 191,409,773 |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | | 560 | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55. | | | 590 | 191,409,773 |

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2012-12-31

| | | | |
|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | 26,900,819 J1 | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | |
| Aggregate investment income (line 440 of the T2 return) | M1 | | |
| Subtotal (**add** lines K1, L1, and M1) ► | | N1 | |
| Subtotal (line J1 **minus** line N1) (if negative, enter "0") | | 26,900,819 ► | 26,900,819 O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(line V1 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ______

**Second previous tax year** 2011-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 32,674,141 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 32,674,141 ▶ 32,674,141 O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(line V2 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ______

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2010-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . 40,602,698 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . 1,259,282 M3

Subtotal (**add** lines K3, L3, and M3) 1,259,282 ► 1,259,282 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 39,343,416 ► 39,343,416 O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(line V3 **multiplied by** the general rate factor for the tax year 0.72 ) . . . . . **540** ______

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . ______ W

Enter amount W on line 560.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(line AA **minus** line DD) . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

| | | | |
|---|---|---|---|
| Cost amount to the corporation of all property immediately before the end of its previous/last tax year | | | FF |
| The corporation's money on hand immediately before the end of its previous/last tax year | | | GG |
| Unused and unexpired losses at the end of the corporation's previous/last tax year: | | | |
| Non-capital losses | | | |
| Net capital losses | | | |
| Farm losses | | | |
| Restricted farm losses | | | |
| Limited partnership losses | | | |
| Subtotal | | ► | HH |
| Subtotal (**add** lines FF, GG, and HH) | | | II |
| All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year | | JJ | |
| Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year | | KK | |
| All the corporation's reserves deducted in its previous/last tax year | | LL | |
| The corporation's capital dividend account immediately before the end of its previous/last tax year | | MM | |
| The corporation's low rate income pool immediately before the end of its previous/last tax year | | NN | |
| Subtotal (**add** lines JJ, KK, LL, MM, and NN) | | ► | OO |
| **GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (line II **minus** line OO) (if negative, enter "0") | | | PP |

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

| Rate | | Numerator description | Days | | Result | Line |
|---|---|---|---|---|---|---|
| 0.68 | x | number of days in the tax year before January 1, 2010 / number of days in the tax year | / 365 | = | | QQ |
| 0.69 | x | number of days in the tax year in 2010 / number of days in the tax year | / 365 | = | | RR |
| 0.7 | x | number of days in the tax year in 2011 / number of days in the tax year | / 365 | = | | SS |
| 0.72 | x | number of days in the tax year after December 31, 2011 / number of days in the tax year | 365 / 365 | = | 0.720000000 | TT |

**General rate factor for the tax year** (total of lines QQ to TT) . . . . . . . . . . . . . . . . . . . . 0.72000 UU

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**SCHEDULE 55**

# PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

**Do not use this area**

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

## Part 1 – Canadian-controlled private corporations and deposit insurance corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | 15,000,000 | | | |
| Total taxable dividends paid in the tax year | 100 | 15,000,000 | | | |
| Total eligible dividends paid in the tax year | | | 150 | | A |
| GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0") | | | 160 | 191,409,773 | B |
| Excessive eligible dividend designation (line 150 **minus** line 160) | | | | | C |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 180 | | D |
| Subtotal (amount C **minus** amount D) | | | | | E |
| **Part III.1 tax on excessive eligible dividend designations – CCPC or DIC** (amount E **multiplied** by 20 %) | | | 190 | | F |

Enter the amount from line 190 on line 710 of the T2 return.

## Part 2 – Other corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | | | | |
| Total taxable dividends paid in the tax year | 200 | | | | |
| Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54) | | | | | G |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 280 | | H |
| Subtotal (amount G **minus** amount H) | | | | | I |
| **Part III.1 tax on excessive eligible dividend designations – Other corporations** (amount I **multiplied** by 20 %) | | | 290 | | J |

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.



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**Schedule 500**

# Ontario Corporation Tax Calculation

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

## Part 1 – Calculation of Ontario basic rate of tax for the year

| | | | | | | |
|---|---|---|---|---|---|---|
| Number of days in the tax year before July 1, 2011 / Number of days in the tax year | / 365 | x | 12.00 % | = | % | A1 |
| Number of days in the tax year after June 30, 2011 / Number of days in the tax year | 365 / 365 | x | 11.50 % | = | 11.50000 % | A2 |

**Ontario basic rate of tax for the year** (rate A1 **plus** A2) 11.50000 ▶ 11.50000 % A3

## Part 2 – Calculation of Ontario basic income tax

| | | |
|---|---|---|
| Ontario taxable income * | 26,428,300 | B |
| **Ontario basic income tax**: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) | 3,039,255 | C |

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

## Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

| | | |
|---|---|---|
| Income from active business carried on in Canada (amount from line 400 of the T2 return) | 26,553,071 | 1 |
| Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) | 26,428,300 | 2 |
| Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) | 500,000 | 3 |
| Enter the least of amounts 1, 2, and 3 | 500,000 | D |

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 26,428,300.00 / 26,428,300 = 1.00000 E

| | | |
|---|---|---|
| Amount D x factor E | 500,000 | a |
| Ontario taxable income (amount B from Part 2) | 26,428,300 | b |

Ontario small business income (lesser of amount a and amount b) 500,000 F

| | | | | | | |
|---|---|---|---|---|---|---|
| Number of days in the tax year before July 1, 2011 / Number of days in the tax year | / 365 | x | 7.50 % | = | % | G1 |
| Number of days in the tax year after June 30, 2011 / Number of days in the tax year | 365 / 365 | x | 7.00 % | = | 7.00000 % | G2 |

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

**Ontario small business deduction**: amount F **multiplied** by OSBD rate for the year (rate G3) 35,000 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

## Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

**Ontario adjusted small business income** (lesser of amount D and amount b from Part 3) 500,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

## Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

| | | | | |
|---|---|---|---|---|
| Amount D from Part 3 of Schedule 17 | | | J | |
| **Deduct:** | | | | |
| Ontario adjusted small business income (amount I from Part 4) | | | K | |
| Subtotal (amount J **minus** amount K) (if negative, enter "0") | | | L | |
| OSBD rate for the year (rate G3 from Part 3) | 7.00000 % | | | |
| Amount L **multiplied** by the OSBD rate for the year | | | | M |
| Ontario domestic factor (factor E from Part 3) | | | 1.00000 | N |
| **Ontario credit union tax reduction** (amount M **multiplied** by factor N) | | | | O |

Enter amount O on line 410 of Schedule 5.

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**Schedule 510**

# Ontario Corporate Minimum Tax

| Corporation's name | Business number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Determination of CMT applicability

| | | |
|---|---|---|
| Total assets of the corporation at the end of the tax year * | 112 | 910,312,000 |
| Share of total assets from partnership(s) and joint venture(s) * | 114 | |
| Total assets of associated corporations (amount from line 450 on Schedule 511) | 116 | 796,998,204 |
| Total assets (total of lines 112 to 116) | | 1,707,310,204 |
| Total revenue of the corporation for the tax year ** | 142 | 952,790,000 |
| Share of total revenue from partnership(s) and joint venture(s) ** | 144 | |
| Total revenue of associated corporations (amount from line 550 on Schedule 511) | 146 | 79,526,427 |
| Total revenue (total of lines 142 to 146) | | 1,032,316,427 |

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

## Part 2 – Adjusted net income/loss for CMT purposes

| | | | | |
|---|---|---|---|---|
| Net income/loss per financial statements * | | | 210 | 25,439,000 |
| **Add** (to the extent reflected in income/loss): | | | | |
| Provision for current income taxes/cost of current income taxes | 220 | 6,750,000 | | |
| Provision for deferred income taxes (debits)/cost of future income taxes | 222 | | | |
| Equity losses from corporations | 224 | | | |
| Financial statement loss from partnerships and joint ventures | 226 | | | |
| Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act | 230 | | | |
| **Other additions** (see note below): | | | | |
| Share of adjusted net income of partnerships and joint ventures ** | 228 | | | |
| Total patronage dividends received, not already included in net income/loss | 232 | | | |
| 281 | 282 | | | |
| 283 | 284 | | | |
| Subtotal | | 6,750,000 ▶ | | 6,750,000 A |
| **Deduct** (to the extent reflected in income/loss): | | | | |
| Provision for recovery of current income taxes/benefit of current income taxes | 320 | | | |
| Provision for deferred income taxes (credits)/benefit of future income taxes | 322 | | | |
| Equity income from corporations | 324 | | | |
| Financial statement income from partnerships and joint ventures | 326 | | | |
| Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act | 330 | | | |
| Dividends not taxable under section 83 of the federal Act (from Schedule 3) | 332 | | | |
| Gain on donation of listed security or ecological gift | 340 | | | |
| Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act *** | 342 | | | |
| Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act **** | 344 | | | |
| Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act ***** | 346 | | | |
| Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act | 348 | | | |
| **Other deductions** (see note below): | | | | |
| Share of adjusted net loss of partnerships and joint ventures ** | 328 | | | |
| Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3 | 334 | | | |
| Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss | 336 | | | |
| Patronage dividends paid (from Schedule 16) not already included in net income/loss | 338 | | | |
| 381 | 382 | | | |
| 383 | 384 | | | |
| 385 | 386 | | | |
| 387 | 388 | | | |
| 389 | 390 | | | |
| Subtotal | | ▶ | | B |
| Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B) | | | 490 | 32,189,000 |

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

**Note**

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

## Part 2 – Adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

## Part 3 – CMT payable

| | | | |
|---|---|---|---|
| Adjusted net income for CMT purposes (line 490 in Part 2, if positive) | | 515 | 32,189,000 |
| **Deduct:** | | | |
| CMT loss available (amount R from Part 7) | | | |
| **Minus:** Adjustment for an acquisition of control * | 518 | | |
| Adjusted CMT loss available | | ▶ | C |
| Net income subject to CMT calculation (if negative, enter "0") | | 520 | 32,189,000 |

Amount from line 520: 32,189,000 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 365) x 4 % = ________ 1

Amount from line 520: 32,189,000 x (Number of days in the tax year after June 30, 2010: 365 / Number of days in the tax year: 365) x 2.7 % = 869,103 2

Subtotal (amount 1 **plus** amount 2) 869,103 3

| | | | |
|---|---|---|---|
| Gross CMT: amount on line 3 above x OAF ** | 540 | 869,103 | |
| **Deduct:** | | | |
| Foreign tax credit for CMT purposes *** | 550 | | |
| CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") | | 869,103 | D |
| **Deduct:** | | | |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,004,255 | |
| Net CMT payable (if negative, enter "0") | | | E |

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ________

**Ontario allocation factor** 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

## Part 4 – CMT credit carryforward

| | | | | | |
|---|---|---|---|---|---|
| CMT credit carryforward at the end of the previous tax year * | | | G | | |
| **Deduct:** | | | | | |
| CMT credit expired * | 600 | | | | |
| CMT credit carryforward at the beginning of the current tax year * (see note below) | | | ▶ | 620 | |
| **Add:** | | | | | |
| CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) | | | | 650 | |
| CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) | | | | | H |
| **Deduct:** | | | | | |
| CMT credit deducted in the current tax year (amount P from Part 5) | | | | | I |
| Subtotal (amount H **minus** amount I) | | | | | J |
| **Add:** | | | | | |
| Net CMT payable (amount E from Part 3) | | | | | |
| SAT payable (amount O from Part 6 of Schedule 512) | | | | | |
| Subtotal | | | ▶ | | K |
| CMT credit carryforward at the end of the tax year (amount J **plus** amount K) | | | | 670 | L |

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

**Note:** If you entered an amount on line 620 or line 650, complete Part 6.

## Part 5 – CMT credit deducted from Ontario corporate income tax payable

| | | | | | |
|---|---|---|---|---|---|
| CMT credit available for the tax year (amount H from Part 4) | | | | | M |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,004,255 | 1 | | |
| For a corporation that is not a life insurance corporation: | | | | | |
| CMT after foreign tax credit deduction (amount D from Part 3) | 869,103 | 2 | | | |
| For a life insurance corporation: | | | | | |
| Gross CMT (line 540 from Part 3) | | 3 | | | |
| Gross SAT (line 460 from Part 6 of Schedule 512) | | 4 | | | |
| The **greater** of amounts 3 and 4 | | 5 | | | |
| **Deduct:** line 2 or line 5, whichever applies: | | 869,103 | 6 | | |
| Subtotal (if negative, enter "0") | | 2,135,152 | ▶ | 2,135,152 | N |
| Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) | | 3,004,255 | | | |
| **Deduct:** | | | | | |
| Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) | | 150,799 | | | |
| Subtotal (if negative, enter "0") | | 2,853,456 | ▶ | 2,853,456 | O |
| CMT credit deducted in the current tax year (least of amounts M, N, and O) | | | | | P |

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

## Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | CMT credit balance * |
|---|---|
| 10th previous tax year | 680 |
| 9th previous tax year | 681 |
| 8th previous tax year | 682 |
| 7th previous tax year | 683 |
| 6th previous tax year | 684 |
| 5th previous tax year | 685 |
| 4th previous tax year | 686 |
| 3rd previous tax year | 687 |
| 2nd previous tax year | 688 |
| 1st previous tax year | 689 |
| Total ** | |

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

## Part 7 – CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . . . . . . . . . . . . . . . . . . . Q

**Deduct:**

CMT loss expired * . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . . . . . . . . . . . ► 720

**Add:**

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . . . . . . . . . . . . . . 750

CMT loss available (line 720 **plus** line 750) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . R

**Deduct:**

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . . . . . .

Subtotal (if negative, enter "0") S

**Add:**

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . . . . . . 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . . . . . . . . . . . . . . . . . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

**Note:** If you entered an amount on line 720 or line 750, complete Part 8.

## Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

| Year of origin | Balance earned in a tax year ending before March 23, 2007 * | Balance earned in a tax year ending after March 22, 2007 ** |
|---|---|---|
| 10th previous tax year | 810 | 820 |
| 9th previous tax year | 811 | 821 |
| 8th previous tax year | 812 | 822 |
| 7th previous tax year | 813 | 823 |
| 6th previous tax year | 814 | 824 |
| 5th previous tax year | 815 | 825 |
| 4th previous tax year | 816 | 826 |
| 3rd previous tax year | 817 | 827 |
| 2nd previous tax year | 818 | 828 |
| 1st previous tax year | | 829 |
| Total *** | | |

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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**SCHEDULE 511**

# ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

| | Names of associated corporations 200 | Business number (Canadian corporation only) (see Note 1) 300 | Total assets* (see Note 2) 400 | Total revenue** (see Note 2) 500 |
|---|---|---|---|---|
| 1 | Hydro Ottawa Holding Inc. | 89411 0816 RC0001 | 683,552,000 | 57,745,000 |
| 2 | Energy Ottawa Inc. | 86338 9961 RC0001 | 86,832,000 | 15,910,000 |
| 3 | Telecom Ottawa Holding Inc. / Societe De Portefeuill | 86202 9337 RC0001 | 14,873,596 | 253,316 |
| 4 | PowerTrail Inc. | 82829 3944 RC0001 | 10,623,000 | 3,340,000 |
| 5 | Moose Creek Energy Inc. | 82851 1311 RC0001 | 201 | 0 |
| 6 | Chaudiere Hydro Inc. Hydro Chaudiere Inc. | 81281 3103 RC0001 | 100 | 0 |
| 7 | Chaudiere Water Power Inc/Energie Hydraulique De l | 10093 1955 RC0001 | 1,117,307 | 2,278,111 |
| | | **Total** | 450 796,998,204 | 550 79,526,427 |

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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**SCHEDULE 546**

# *CORPORATIONS INFORMATION ACT* ANNUAL RETURN FOR ONTARIO CORPORATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

## Part 1 – Identification

**100** Corporation's name (exactly as shown on the MGS public record)
Hydro Ottawa Limited

| Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent | **110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day) | **120** Ontario Corporation No. |
|---|---|---|
| Ontario | 2000-10-03 | 1427586 |

## Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

**200** Care of (if applicable)

| **210** Street number | **220** Street name/Rural route/Lot and Concession number | **230** Suite number |
|---|---|---|
| 3025 | Albion Road North | |

**240** Additional address information if applicable (line 220 must be completed first)
PO Box 8700

| **250** Municipality (e.g., city, town) | **260** Province/state | **270** Country | **280** Postal/zip code |
|---|---|---|---|
| Ottawa | ON | CA | K1G 3S4 |

## Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

**300** 2 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

## Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

**450** Simpson (Last name) **451** Geoff (First name)

**454** ______________________ , (Middle name(s))

**460** 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

**Complete the applicable parts to report changes in the information recorded on the MGS public record.**

## Part 5 – Mailing address

**500** Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

**510** Care of (if applicable)

| | | |
|---|---|---|
| **520** Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number |

**550** Additional address information if applicable (line 530 must be completed first)

| | | | |
|---|---|---|---|
| **560** Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code |

## Part 6 – Language of preference

**600** Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

CRA internal form identifier 547

## Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

**Full name and address for service** (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

| | | |
|---|---|---|
| 700 Last name: SIMPSON | 705 First name: GEOFF | 710 Middle name(s): |
| 720 Street number: 3025 | 730 Street name/Rural route/Lot and Concession number: ALBION RD NORTH PO BOX 8700 | 740 Suite number: |

750 Additional address information if applicable (line 730 must be completed first):

| | | | |
|---|---|---|---|
| 760 Municipality (e.g., city, town): OTTAWA | 770 Province/state: ON | 780 Country: CA | 790 Postal/zip code: K1G 3S4 |

**Director**

Is this director a resident Canadian? . . . 795 **1** Yes ☐ **2** No ☐

(applies to directors of corporations with share capital only)

796 Date elected/appointed Year Month Day:

797 Date ceased, if applicable Year Month Day:

**Officer information**

| Officer | | Date appointed Year Month Day | | Date ceased, if applicable Year Month Day |
|---|---|---|---|---|
| President | 801 | | 802 | |
| Secretary | 806 | | 807 | |
| Treasurer | 811 | | 812 | |
| General Manager | 816 | | 817 | |
| Chair | 821 | | 822 | |
| Chairperson | 826 | | 827 | |
| Chairman | 831 | | 832 | |
| Chairwoman | 836 | | 837 | |
| Vice-Chair | 841 | | 842 | |
| Vice-President | 846 | | 847 | |
| Assistant Secretary | 851 | | 852 | |
| Assistant Treasurer | 856 | | 857 | |
| Chief Manager | 861 | | 862 | |
| Executive Director | 866 | | 867 | |
| Managing Director | 871 | | 872 | |
| Chief Executive Officer | 876 | | 877 | |
| Chief Financial Officer | 881 | 2013-08-06 | 882 | |
| Chief Information Officer | 886 | | 887 | |
| Chief Operating Officer | 891 | | 892 | |
| Chief Administrative Officer | 896 | | 897 | |
| Comptroller | 901 | | 902 | |
| Authorized Signing Officer | 906 | | 907 | |
| Other (untitled) | 911 | | 912 | |

**Once you have completed this page, complete the certification in Part 4 of this schedule.**

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 550**

# ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information

**110** Name of person to contact for more information: Mike Grue

**120** Telephone number including area code: (613) 738-5499

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

## Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 64,000,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \;\; 400{,}000}{\$ \;\; 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \;\; 400{,}000}{\$ \;\; 200{,}000} \right) \right]$$

**Eligible percentage for determining the eligible amount** . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

| | **A**<br>Name of university, college, or other eligible educational institution<br>**400** | **B**<br>Name of qualifying co-operative education program<br>**405** |
|---|---|---|
| 1. | CARLETON UNIVERSITY | DEGREE |
| 2. | CARLETON UNIVERSITY | DEGREE |
| 3. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN |
| 4. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN |
| 5. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN |
| 6. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN |
| 7. | ALGONQUIN COLLEGE | POWERLINE TECHNICIAN |
| 8. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 9. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 10. | UNIVERSITY OF WATERLOO | CIVIL ENGINEERING |
| 11. | CARLETON UNIVERSITY | DEGREE |
| 12. | NIAGARA COLLEGE | ELECTRICAL ENGINEERING TECHNOLOGY |
| 13. | CARLETON UNIVERSITY | DEGREE |
| 14. | UNIVERSITY OF WATERLOO | MECHANICAL ENGINEERING |
| 15. | CAMBRIAN COLLEGE | MTCU TRAINING |
| 16. | GEORGIAN COLLEGE | ELECTRICAL ENGINEERING TECHNOLOGY/TECHNICIA |
| 17. | CARLETON UNIVERSITY | DEGREE |
| 18. | NIAGARA COLLEGE | ELECTRICAL ENGINEERING TECHNOLOGY |
| 19. | | |

| | C<br>Name of student<br>410 | D<br>Start date of WP<br>(see note 1 below)<br>430 | E<br>End date of WP<br>(see note 2 below)<br>435 |
|---|---|---|---|
| 1. | STUDENT1 | 2013-01-07 | 2013-04-26 |
| 2. | STUDENT 2A | 2013-04-29 | 2013-08-22 |
| 3. | STUDENT 3 | 2013-04-29 | 2013-08-23 |
| 4. | STUDENT 4 | 2013-04-29 | 2013-08-23 |
| 5. | STUDENT 5 | 2013-04-29 | 2013-08-23 |
| 6. | STUDENT 6 | 2013-04-29 | 2013-08-23 |
| 7. | STUDENT 7 | 2013-04-29 | 2013-08-23 |
| 8. | STUDENT 8 | 2013-05-13 | 2013-08-23 |
| 9. | STUDENT 9 | 2013-05-13 | 2013-08-16 |
| 10. | STUDENT 10 | 2013-04-29 | 2013-08-23 |
| 11. | STUDENT 11 | 2013-04-29 | 2013-08-23 |
| 12. | STUDENT 11A | 2013-05-13 | 2013-08-23 |
| 13. | STDUENT 12 | 2013-09-03 | 2013-12-31 |
| 14. | STUDNT 13 | 2013-09-03 | 2013-12-20 |
| 15. | STUDENT 14 | 2013-09-03 | 2013-12-20 |
| 16. | STUDENT 15 | 2013-09-03 | 2013-12-20 |
| 17. | STUDENT 2B | 2013-09-03 | 2013-12-20 |
| 18. | STUDENT 11B | 2013-09-03 | 2013-12-20 |
| 19. | | | |

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

## Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

| | F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450 | Eligible percentage before March 27, 2009 (from line 310 in Part 3) | F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452 | Eligible percentage after March 26, 2009 (from line 310a in Part 3) | X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below) | Y Total number of consecutive weeks of the student's WP (see note 3 below) |
|---|---|---|---|---|---|---|
| 1. | | 10.000 % | 9,110 | 25.000 % | | 16 |
| 2. | | 10.000 % | 9,921 | 25.000 % | | 16 |
| 3. | | 10.000 % | 10,887 | 25.000 % | | 17 |
| 4. | | 10.000 % | 11,191 | 25.000 % | | 17 |
| 5. | | 10.000 % | 10,474 | 25.000 % | | 17 |
| 6. | | 10.000 % | 12,799 | 25.000 % | | 17 |
| 7. | | 10.000 % | 10,452 | 25.000 % | | 17 |
| 8. | | 10.000 % | 7,132 | 25.000 % | | 15 |
| 9. | | 10.000 % | 8,903 | 25.000 % | | 14 |
| 10. | | 10.000 % | 10,483 | 25.000 % | | 17 |
| 11. | | 10.000 % | 10,483 | 25.000 % | | 17 |
| 12. | | 10.000 % | 9,610 | 25.000 % | | 15 |
| 13. | | 10.000 % | 9,326 | 25.000 % | | 16 |
| 14. | | 10.000 % | 9,235 | 25.000 % | | 15 |
| 15. | | 10.000 % | 9,790 | 25.000 % | | 15 |
| 16. | | 10.000 % | 9,235 | 25.000 % | | 15 |
| 17. | | 10.000 % | 9,921 | 25.000 % | | 15 |
| 18. | | 10.000 % | 9,610 | 25.000 % | | 15 |
| 19. | | 10.000 % | | 25.000 % | | |

| | G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460 | H Maximum CETC per WP (see note 3 below) 462 | I CETC on eligible expenditures (column G or H, whichever is less) 470 | J CETC on repayment of government assistance (see note 4 below) 480 | K CETC for each WP (column I or column J) 490 |
|---|---|---|---|---|---|
| 1. | 2,278 | 3,000 | 2,278 | | 2,278 |
| 2. | 2,480 | 3,000 | 2,480 | | 2,480 |
| 3. | 2,722 | 3,000 | 2,722 | | 2,722 |
| 4. | 2,798 | 3,000 | 2,798 | | 2,798 |
| 5. | 2,619 | 3,000 | 2,619 | | 2,619 |
| 6. | 3,200 | 3,000 | 3,000 | | 3,000 |
| 7. | 2,613 | 3,000 | 2,613 | | 2,613 |
| 8. | 1,783 | 3,000 | 1,783 | | 1,783 |
| 9. | 2,226 | 3,000 | 2,226 | | 2,226 |
| 10. | 2,621 | 3,000 | 2,621 | | 2,621 |
| 11. | 2,621 | 3,000 | 2,621 | | 2,621 |
| 12. | 2,403 | 3,000 | 2,403 | | 2,403 |
| 13. | 2,332 | 3,000 | 2,332 | | 2,332 |
| 14. | 2,309 | 3,000 | 2,309 | | 2,309 |
| 15. | 2,448 | 3,000 | 2,448 | | 2,448 |
| 16. | 2,309 | 3,000 | 2,309 | | 2,309 |
| 17. | 2,480 | 3,000 | 2,480 | | 2,480 |
| 18. | 2,403 | 3,000 | 2,403 | | 2,403 |
| 19. | | | | | |

**Ontario co-operative education tax credit** (total of amounts in column K) 500 44,445 L or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = . . . . . . . . . . . . . . . . . . . . . . . ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009,
and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 552**

# ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| Hydro Ottawa Limited | 86339 1363 RC0001 | 2013-12-31 |

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

## Part 1 – Corporate information (please print)

| **110** Name of person to contact for more information | **120** Telephone number including area code |
|---|---|
| Mike Grue | (613) 738-5499 |

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

## Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

## Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * . . . . . **300** 25,000,000

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[ 5\,\% \times \left( \frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[ 10\,\% \times \left( \frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

**Specified percentage** . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

| | A<br>Trade code<br>400 | B<br>Apprenticeship program/ trade name<br>405 | C<br>Name of apprentice<br>410 |
|---|---|---|---|
| 1. | [redacted] | [redacted] | APPRENTICE 1 |
| 2. | [redacted] | [redacted] | APPRENTICE 2 |
| 3. | [redacted] | [redacted] | APPRENTICE 3 |
| 4. | [redacted] | [redacted] | APPRENTICE 4 |
| 5. | [redacted] | [redacted] | APPRENTICE 5 |
| 6. | [redacted] | [redacted] | APPRENTICE 6 |
| 7. | [redacted] | [redacted] | APPRENTICE 7 |
| 8. | [redacted] | [redacted] | APPRENTICE 8 |
| 9. | [redacted] | [redacted] | APPRENTICE 9 |
| 10. | [redacted] | [redacted] | APPRENTICE 10 |
| 11. | [redacted] | [redacted] | APPRENTICE 11 |
| 12. | [redacted] | [redacted] | APPRENTICE 12 |
| 13. | [redacted] | [redacted] | APPRENTICE 13 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement (see note 1 below)<br>425 | F<br>Start date of employment as an apprentice in the tax year (see note 2 below)<br>430 | G<br>End date of employment as an apprentice in the tax year (see note 3 below)<br>435 |
|---|---|---|---|---|
| 1. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |
| 2. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |
| 3. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |
| 4. | [redacted] | 2011-05-10 | 2013-01-01 | 2013-12-31 |
| 5. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |
| 6. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |
| 7. | [redacted] | 2011-10-17 | 2013-01-01 | 2013-12-31 |

| | D<br>Original contract or training agreement number<br>420 | E<br>Original registration date of apprenticeship contract or training agreement<br>(see note 1 below)<br>425 | F<br>Start date of employment as an apprentice in the tax year<br>(see note 2 below)<br>430 | G<br>End date of employment as an apprentice in the tax year<br>(see note 3 below)<br>435 |
|---|---|---|---|---|
| 8. | [redacted] | 2012-05-16 | 2013-05-06 | 2013-12-31 |
| 9. | [redacted] | 2012-05-16 | 2013-05-06 | 2013-12-31 |
| 10. | [redacted] | 2012-08-13 | 2013-08-26 | 2013-12-31 |
| 11. | [redacted] | 2012-05-16 | 2013-05-06 | 2013-12-31 |
| 12. | [redacted] | 2012-05-16 | 2013-05-06 | 2013-12-31 |
| 13. | [redacted] | 2012-05-16 | 2013-05-06 | 2013-12-31 |

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

## Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

| | H1<br>Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below)<br>441 | H2<br>Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below)<br>442 | H3<br>Number of days employed as an apprentice in the tax year (column H1 **plus** column H2)<br>440 | I<br>Maximum credit amount for the tax year (see note 2 below)<br>445 |
|---|---|---|---|---|
| 1. | | 365 | 365 | 10,000 |
| 2. | | 365 | 365 | 10,000 |
| 3. | | 365 | 365 | 10,000 |
| 4. | | 365 | 365 | 10,000 |
| 5. | | 365 | 365 | 10,000 |
| 6. | | 365 | 365 | 10,000 |
| 7. | | 365 | 365 | 10,000 |
| 8. | | 240 | 240 | 6,575 |
| 9. | | 240 | 240 | 6,575 |
| 10. | | 127 | 127 | 3,479 |
| 11. | | 240 | 240 | 6,575 |
| 12. | | 240 | 240 | 6,575 |
| 13. | | 240 | 240 | 6,575 |

| | J1<br>Eligible expenditures before March 27, 2009 (see note 3 below)<br>451 | J2<br>Eligible expenditures after March 26, 2009 (see note 3 below)<br>452 | J3<br>Eligible expenditures for the tax year (column J1 **plus** column J2)<br>450 | K<br>Eligible expenditures **multiplied** by specified percentage (see note 4 below)<br>460 |
|---|---|---|---|---|
| 1. | | 76,209 | 76,209 | 26,673 |
| 2. | | 72,342 | 72,342 | 25,320 |
| 3. | | 69,714 | 69,714 | 24,400 |
| 4. | | 76,653 | 76,653 | 26,829 |
| 5. | | 69,811 | 69,811 | 24,434 |
| 6. | | 69,084 | 69,084 | 24,179 |
| 7. | | 76,545 | 76,545 | 26,791 |
| 8. | | 36,805 | 36,805 | 12,882 |
| 9. | | 35,752 | 35,752 | 12,513 |
| 10. | | 18,782 | 18,782 | 6,574 |
| 11. | | 37,103 | 37,103 | 12,986 |
| 12. | | 35,926 | 35,926 | 12,574 |
| 13. | | 36,428 | 36,428 | 12,750 |

| | L<br>ATTC on eligible expenditures (lesser of columns I and K)<br>470 | M<br>ATTC on repayment of government assistance (see note 5 below)<br>480 | N<br>ATTC for each apprentice (column L or column M, whichever applies)<br>490 |
|---|---|---|---|
| 1. | 10,000 | | 10,000 |
| 2. | 10,000 | | 10,000 |
| 3. | 10,000 | | 10,000 |
| 4. | 10,000 | | 10,000 |
| 5. | 10,000 | | 10,000 |
| 6. | 10,000 | | 10,000 |
| 7. | 10,000 | | 10,000 |
| 8. | 6,575 | | 6,575 |
| 9. | 6,575 | | 6,575 |
| 10. | 3,479 | | 3,479 |
| 11. | 6,575 | | 6,575 |
| 12. | 6,575 | | 6,575 |

| | L<br>ATTC on eligible expenditures<br>(lesser of columns I and K)<br>470 | M<br>ATTC on repayment of<br>government assistance<br>(see note 5 below)<br>480 | N<br>ATTC for each apprentice<br>(column L or column M,<br>whichever applies)<br>490 |
|---|---|---|---|
| 13. | 6,575 | | 6,575 |

**Ontario apprenticeship training tax credit** (total of amounts in column N) 500 ..... 106,354 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = . . . . . . . . . . . . . . . . ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

**Version** **3.0**

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | Patrick Hoey, Director Regulatory Affairs |
| **Phone Number** | 613-738-5499, x7472 |
| **Email Address** | patrickhoey@hydroottawa.com |
| **Date** | |
| **Last COS Re-based Year** | **2012** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| | | | | | |
|---|---|---|---|---|---|
| **Rate Base** | | | **$** | **923,305,865** | |
| | | | | | |
| **Return on Ratebase** | | | | | |
| Deemed ShortTerm Debt % | 4.00% | T | $ | 36,932,235 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ | 517,051,284 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ | 369,322,346 | *Y = S * V* |
| | | | | | |
| Short Term Interest Rate | 2.16% | Z | $ | 797,736 | *AC = W * Z* |
| Long Term Interest | 3.72% | AA | $ | 19,234,308 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 9.30% | AB | **$** | **34,346,978** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$** | **54,379,022** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historical | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | Yes | Yes |
| 2. Does the applicant have any SRED Expenditures? | No | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | No | No | No |
| 7. Did the applicant pay dividends?<br>*If Yes, please describe what was the tax treatment in the manager's summary.* | Yes | Yes | Yes |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| Tax Rates<br>Federal & Provincial<br>As of June 20, 2012 | Effective<br>January 1, 2011 | Effective<br>January 1, 2012 | Effective<br>January 1, 2013 | Effective<br>January 1, 2014 | Effective<br>January 1, 2015 |
|---|---|---|---|---|---|
| **Federal income tax** | | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% | 28.00% |
| | | | | | |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% | 15.00% |
| | | | | | |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% | 11.50% |
| | | | | | |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% | 26.50% |
| | | | | | |
| **Federal & Ontario Small Business** | | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| | | | | | |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% | 11.00% |
| | | | | | |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historical per tax returns | Less: Non-Distribution Portion | UCC Regulated Historical Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 194,128,563 | 994,943 | 193,133,620 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | 24,260,047 | 610,109 | 23,649,938 |
| 2 | Distribution System - pre 1988 | 63,500,604 | | 63,500,604 |
| 8 | General Office/Stores Equip | 7,794,891 | | 7,794,891 |
| 10 | Computer Hardware/ Vehicles | 6,155,081 | | 6,155,081 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 17,952,133 | | 17,952,133 |
| $13_1$ | Lease # 1 | | | 0 |
| $13_2$ | Lease #2 | | | 0 |
| $13_3$ | Lease # 3 | | | 0 |
| $13_4$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | 371,686 | | 371,686 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 26,138 | | 26,138 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 353,240,954 | | 353,240,954 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 2,060,914 | | 2,060,914 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| 3 | Buildings - pre1988 | 9,673,782 | | 9,673,782 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | SUB-TOTAL - UCC | **679,164,793** | **1,605,052** | **677,559,741** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **824,938** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 7,717,496 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 7,717,496 | **x 3/4 =** | 5,788,122 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 5,788,122 | **5,788,122** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **6,613,060** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **6,613,060** |
| **Current Year Deduction** | | **6,613,060** | **x 7% =** | **462,914** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **6,150,146** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Historical

## Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | | | 0 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Historical

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historical | | | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historical | | | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Historical Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 30,585,000 | | 30,585,000 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | 6,439 | | 6,439 |
| Amortization of tangible assets | 104 | | | 0 |
| Amortization of intangible assets | 106 | 36,517,006 | | 36,517,006 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | 597,688 | | 597,688 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 75,000 | | 75,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | | | 0 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | 600,000 | | 600,000 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | 11,878 | | 11,878 |
| Current Year Investment Tax Credits received | | 222,500 | | 222,500 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **38,030,511** | **0** | **38,030,511** |
| | | | | |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | | | 0 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 66,168,396 | | 66,168,396 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 462,914 | | 462,914 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | | | 0 |
| Contributions to deferred income plans | 416 | 500,000 | | 500,000 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | 1,862,000 | | 1,862,000 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **68,993,310** | **0** | **68,993,310** |
| | | | | |
| **Net Income for Tax Purposes** | | **-377,799** | **0** | **-377,799** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | 120,000 | | 120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **-497,799** | **0** | **-497,799** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Historical Year

**Note: Input the actual information from the tax returns for the historical year.**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | **Wires Only** | |
| **Regulatory Taxable Income** | | | | | | -$ 497,799 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | | **B** | | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ - | **D** | | | | |
| | Rate reduction (negative) | | **E** | | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ - | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 0.00% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 0.00% | **L** | | |
| | Combined tax rate | | | | | 0.00% | **M = K + L** |
| **Total Income Taxes** | | | | | | $ - | **N = A * M** |
| Investment Tax Credits | | | | | | | **O** |
| Miscellaneous Tax Credits | | | | | | | **P** |
| **Total Tax Credits** | | | | | | $ - | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historical Year** | | | | | | $ - | **R = N - Q** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historical Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 193,133,620 | | | $ 193,133,620 | $ - | $ 193,133,620 | 4% | $ 7,725,345 | $ 185,408,275 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 23,649,938 | $ 2,259,608 | | $ 25,909,546 | $ 1,129,804 | $ 24,779,742 | 6% | $ 1,486,785 | $ 24,422,761 |
| 2 | Distribution System - pre 1988 | $ 63,500,604 | | | $ 63,500,604 | $ - | $ 63,500,604 | 6% | $ 3,810,036 | $ 59,690,568 |
| 8 | General Office/Stores Equip | $ 7,794,891 | $ 1,458,199 | | $ 9,253,090 | $ 729,100 | $ 8,523,991 | 20% | $ 1,704,798 | $ 7,548,292 |
| 10 | Computer Hardware/ Vehicles | $ 6,155,081 | $ 1,537,328 | | $ 7,692,409 | $ 768,664 | $ 6,923,745 | 30% | $ 2,077,124 | $ 5,615,286 |
| 10.1 | Certain Automobiles | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 17,952,133 | $ 8,494,616 | | $ 26,446,749 | $ 4,247,308 | $ 22,199,441 | 100% | $ 22,199,441 | $ 4,247,308 |
| 13 1 | Lease # 1 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 371,686 | | | $ 371,686 | $ - | $ 371,686 | 12% | $ 44,602 | $ 327,084 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 26,138 | | | $ 26,138 | $ - | $ 26,138 | 45% | $ 11,762 | $ 14,376 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 353,240,954 | $ 74,595,543 | | $ 427,836,497 | $ 37,297,772 | $ 390,538,726 | 8% | $ 31,243,098 | $ 396,593,399 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 2,060,914 | $ 1,097,672 | | $ 3,158,586 | $ 548,836 | $ 2,609,750 | 55% | $ 1,435,363 | $ 1,723,224 |
| 52 | Computer Hardware and system software | | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | | | $ - | $ - | $ - | | $ - | $ - |
| 3 | Buildings - pre1988 | $ 9,673,782 | | | $ 9,673,782 | $ - | $ 9,673,782 | 5% | $ 483,689 | $ 9,190,093 |
| | | | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 677,559,741 | $ 89,442,966 | $ - | $ 767,002,707 | $ 44,721,483 | $ 722,281,224 | | $ 72,222,042 | $ 694,780,665 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **6,150,146** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 17,400,735 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 17,400,735 | **x 3/4 =** | ######## | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | ######## | **13,050,551** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **19,200,697** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **19,200,697** |
| **Current Year Deduction** | | **19,200,697** | **x 7% =** | **1,344,049** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **17,856,648** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| | | | | Bridge Year Adjustments | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Historical Utility Only** | **Eliminate Amounts Not Relevant for Bridge Year** | **Adjusted Utility Balance** | **Additions** | **Disposals** | **Balance for Bridge Year** | **Change During the Year** | **Disallowed Expenses** |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | 0 |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | **A** | 27,637,000 |

| | | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets | 104 | 38,557,773 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | 75,000 |
| Non-deductible meals and entertainment expense | 121 | |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | |
| Current Year Investment Tax Credits received | | 207,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **40,458,326** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 72,222,042 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,344,049 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | 1,427,000 |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **75,493,091** |
| | | |
| **Net Income for Tax Purposes** | | **-7,397,765** |
| Charitable donations from Schedule 2 | 311 | -120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **-7,517,765** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | -$ 7,517,765 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 4.50% | **B** | $ - | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ - | **D** | | | | |
| | Rate reduction | -7.00% | **E** | $ - | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ - | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 0.00% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 0.00% | **L** | | |
| | Combined tax rate | | | | | 0.00% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ -** | **N = A * M** |
| Investment Tax Credits | | | | | | | **O** |
| Miscellaneous Tax Credits | | | | | | | **P** |
| **Total Tax Credits** | | | | | | **$ -** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | **$ -** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 185,408,275 | | | $ 185,408,275 | $ - | $ 185,408,275 | 4% | $ 7,416,331 | $ 177,991,944 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 24,422,761 | 3,085,755 | | $ 27,508,516 | $ 1,542,878 | $ 25,965,639 | 6% | $ 1,557,938 | $ 25,950,578 |
| 2 | Distribution System - pre 1988 | $ 59,690,568 | | | $ 59,690,568 | $ - | $ 59,690,568 | 6% | $ 3,581,434 | $ 56,109,134 |
| 8 | General Office/Stores Equip | $ 7,548,292 | 4,522,422 | | $ 12,070,714 | $ 2,261,211 | $ 9,809,503 | 20% | $ 1,961,901 | $ 10,108,813 |
| 10 | Computer Hardware/ Vehicles | $ 5,615,286 | 1,455,474 | | $ 7,070,760 | $ 727,737 | $ 6,343,023 | 30% | $ 1,902,907 | $ 5,167,853 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 4,247,308 | 5,746,639 | | $ 9,993,947 | $ 2,873,320 | $ 7,120,628 | 100% | $ 7,120,628 | $ 2,873,320 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 327,084 | | | $ 327,084 | $ - | $ 327,084 | 12% | $ 39,250 | $ 287,834 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 14,376 | | | $ 14,376 | $ - | $ 14,376 | 45% | $ 6,469 | $ 7,907 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 396,593,399 | 65,468,861 | | $ 462,062,260 | $ 32,734,431 | $ 429,327,829 | 8% | $ 34,346,226 | $ 427,716,034 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 1,723,224 | 3,067,144 | | $ 4,790,368 | $ 1,533,572 | $ 3,256,796 | 55% | $ 1,791,238 | $ 2,999,130 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| 3 | Buildings - pre1988 | $ 9,190,093 | | | $ 9,190,093 | $ - | $ 9,190,093 | 5% | $ 459,505 | $ 8,730,588 |
| | | $ - | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 694,780,665 | $ 83,346,295 | $ - | $ 778,126,960 | $ 41,673,148 | $ 736,453,812 | | $ 60,183,826 | $ 717,943,134 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Test Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **17,856,648** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 4,951,403 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 4,951,403 | **x 3/4 =** | 3,713,552 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,713,552 | **3,713,552** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **21,570,201** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **21,570,201** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **21,570,201** | **x 7% =** | **1,509,914** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **20,060,286** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| Description | Bridge Year | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Test Year Adjustments: Additions | Test Year Adjustments: Disposals | Balance for Test Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | 0 | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Taxable Income - Test Year

| | | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 34,346,978 |

| | T2 S1 line # | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | 40,826,114 |
| Amortization of intangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 75,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | |
| Current Year Investment Tax Credits received | | 197,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **42,716,667** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 60,183,826 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 1,509,914 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **62,193,740** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **14,869,905** |
| | | |
| Charitable donations | 311 | 120,000 |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | 0 |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **14,749,905** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Test Year

| | | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | | $ 14,749,905 | **A** |
| **Ontario Income Taxes** | | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ | 1,696,239 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | | |
| | Rate reduction | -7.00% | **E** | -$ | 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | | $ 1,661,239 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | | 11.26% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | | 26.26% | **M = K + L** |
| **Total Income Taxes** | | | | | | | **$ 3,873,725** | **N = A * M** |
| Investment Tax Credits | | | | | | | $ 217,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | | **$ 217,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | | **$ 3,656,225** | **R = N - Q** |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | | 73.74% | **S = 1 - M** | **$ 1,302,223** | **T = R / S - R** |
| **Income Tax** (grossed-up) | | | | | | | **$ 4,958,448** | **U = R + T** |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

**Version** **3.0**

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | Patrick Hoey, Director Regulatory Affairs |
| **Phone Number** | 613-738-5499, x7472 |
| **Email Address** | patrickhoey@hydroottawa.com |
| **Date** | |
| **Last COS Re-based Year** | **2012** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| | | | | | |
|---|---|---|---|---|---|
| **Rate Base** | | | **$** | **970,581,813** | |
| **Return on Ratebase** | | | | | |
| Deemed ShortTerm Debt % | 4.00% | T | $ | 38,823,273 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ | 543,525,815 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ | 388,232,725 | *Y = S * V* |
| Short Term Interest Rate | 2.16% | Z | $ | 838,583 | *AC = W * Z* |
| Long Term Interest | 3.94% | AA | $ | 21,414,917 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 9.30% | AB | **$** | **36,105,643** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$** | **58,359,143** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historical | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | Yes | Yes |
| 2. Does the applicant have any SRED Expenditures? | No | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | No | No | No |
| 7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.* | Yes | Yes | Yes |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| Tax Rates<br>Federal & Provincial<br>As of June 20, 2012 | Effective<br>January 1, 2011 | Effective<br>January 1, 2012 | Effective<br>January 1, 2013 | Effective<br>January 1, 2014 | Effective<br>January 1, 2015 |
|---|---|---|---|---|---|
| **Federal income tax** | | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% | 28.00% |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% | 15.00% |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% | 11.50% |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% | 26.50% |
| **Federal & Ontario Small Business** | | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% | 11.00% |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historical per tax returns | Less: Non-Distribution Portion | UCC Regulated Historical Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 185,408,275 | | 185,408,275 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | 24,422,761 | | 24,422,761 |
| 2 | Distribution System - pre 1988 | 59,690,568 | | 59,690,568 |
| 8 | General Office/Stores Equip | 7,548,292 | | 7,548,292 |
| 10 | Computer Hardware/ Vehicles | 5,615,286 | | 5,615,286 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 4,247,308 | | 4,247,308 |
| $13_1$ | Lease # 1 | | | 0 |
| $13_2$ | Lease #2 | | | 0 |
| $13_3$ | Lease # 3 | | | 0 |
| $13_4$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | 327,084 | | 327,084 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 14,376 | | 14,376 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 396,593,399 | | 396,593,399 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 1,723,224 | | 1,723,224 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| 3 | Buildings - pre1988 | 9,190,093 | | 9,190,093 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | SUB-TOTAL - UCC | **694,780,665** | **0** | **694,780,665** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **6,150,146** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 17,400,735 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 17,400,735 | **x 3/4 =** | ######## | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | ######## | **13,050,551** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **19,200,697** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **19,200,697** |
| **Current Year Deduction** | | **19,200,697** | **x 7% =** | **1,344,049** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **17,856,648** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Historical

## Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | | | 0 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Historical

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historical | | | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historical | | | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Historical Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 27,637,000 | | 27,637,000 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | 5,000 | | 5,000 |
| Amortization of tangible assets | 104 | | | 0 |
| Amortization of intangible assets | 106 | 38,557,773 | | 38,557,773 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | 1,013,053 | | 1,013,053 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 75,000 | | 75,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | | | 0 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | 600,000 | | 600,000 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | | | 0 |
| Current Year Investment Tax Credits received | | 207,500 | | 207,500 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **40,458,326** | **0** | **40,458,326** |
| | | | | |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | | | 0 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 72,222,042 | | 72,222,042 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,344,049 | | 1,344,049 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | | | 0 |
| Contributions to deferred income plans | 416 | 500,000 | | 500,000 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | 1,427,000 | | 1,427,000 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **75,493,091** | **0** | **75,493,091** |
| | | | | |
| **Net Income for Tax Purposes** | | **-7,397,765** | **0** | **-7,397,765** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | 120,000 | | 120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **-7,517,765** | **0** | **-7,517,765** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Historical Year

**Note: Input the actual information from the tax returns for the historical year.**

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | -$ 7,517,765 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | | **B** | | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ - | **D** | | | | |
| | Rate reduction (negative) | | **E** | | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ - | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 0.00% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 0.00% | **L** | | |
| | Combined tax rate | | | | | 0.00% | **M = K + L** |
| **Total Income Taxes** | | | | | | $ - | **N = A * M** |
| Investment Tax Credits | | | | | | | **O** |
| Miscellaneous Tax Credits | | | | | | | **P** |
| **Total Tax Credits** | | | | | | $ - | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historical Year** | | | | | | $ - | **R = N - Q** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historical Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 185,408,275 | | | $ 185,408,275 | $ - | $ 185,408,275 | 4% | $ 7,416,331 | $ 177,991,944 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 24,422,761 | $ 3,085,755 | | $ 27,508,516 | $ 1,542,878 | $ 25,965,639 | 6% | $ 1,557,938 | $ 25,950,578 |
| 2 | Distribution System - pre 1988 | $ 59,690,568 | | | $ 59,690,568 | $ - | $ 59,690,568 | 6% | $ 3,581,434 | $ 56,109,134 |
| 8 | General Office/Stores Equip | $ 7,548,292 | $ 4,522,422 | | $ 12,070,714 | $ 2,261,211 | $ 9,809,503 | 20% | $ 1,961,901 | $ 10,108,813 |
| 10 | Computer Hardware/ Vehicles | $ 5,615,286 | $ 1,455,474 | | $ 7,070,760 | $ 727,737 | $ 6,343,023 | 30% | $ 1,902,907 | $ 5,167,853 |
| 10.1 | Certain Automobiles | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 4,247,308 | $ 5,746,639 | | $ 9,993,947 | $ 2,873,320 | $ 7,120,628 | 100% | $ 7,120,628 | $ 2,873,320 |
| 13 1 | Lease # 1 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 327,084 | | | $ 327,084 | $ - | $ 327,084 | 12% | $ 39,250 | $ 287,834 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 14,376 | | | $ 14,376 | $ - | $ 14,376 | 45% | $ 6,469 | $ 7,907 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 396,593,399 | $ 65,468,861 | | $ 462,062,260 | $ 32,734,431 | $ 429,327,829 | 8% | $ 34,346,226 | $ 427,716,034 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 1,723,224 | $ 3,067,144 | | $ 4,790,368 | $ 1,533,572 | $ 3,256,796 | 55% | $ 1,791,238 | $ 2,999,130 |
| 52 | Computer Hardware and system software | | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | | | $ - | $ - | $ - | | $ - | $ - |
| 3 | Buildings - pre1988 | $ 9,190,093 | | | $ 9,190,093 | $ - | $ 9,190,093 | 5% | $ 459,505 | $ 8,730,588 |
| | | | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 694,780,665 | $ 83,346,295 | $ - | $ 778,126,960 | $ 41,673,148 | $ 736,453,812 | | $ 60,183,826 | $ 717,943,134 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **17,856,648** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 4,951,403 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 4,951,403 | **x 3/4 =** | 3,713,552 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,713,552 | **3,713,552** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **21,570,201** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **21,570,201** |
| **Current Year Deduction** | | **21,570,201** | **x 7% =** | **1,509,914** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **20,060,286** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| Description | Historical Utility Only | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Bridge Year Adjustments: Additions | Bridge Year Adjustments: Disposals | Balance for Bridge Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | 0 |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | **A** | 34,346,978 |
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets | 104 | 40,826,114 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | 75,000 |
| Non-deductible meals and entertainment expense | 121 | |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | |
| Current Year Investment Tax Credits received | | 197,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **42,716,667** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 60,183,826 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,509,914 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | 0 |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **62,193,740** |
| | | |
| **Net Income for Tax Purposes** | | **14,869,905** |
| Charitable donations from Schedule 2 | 311 | -120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **14,749,905** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | | $ 14,749,905 | **A** |
| **Ontario Income Taxes** | | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ | 1,696,239 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | | |
| | Rate reduction | -7.00% | **E** | -$ | 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | | $ 1,661,239 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | | 11.26% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | | 26.26% | **M = K + L** |
| **Total Income Taxes** | | | | | | | **$ 3,873,725** | **N = A * M** |
| Investment Tax Credits | | | | | | | $ 217,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | | **P** |
| **Total Tax Credits** | | | | | | | **$ 217,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | | **$ 3,656,225** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 177,991,944 | | | $ 177,991,944 | $ - | $ 177,991,944 | 4% | $ 7,119,678 | $ 170,872,266 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 25,950,578 | 2,500,925 | 0 | $ 28,451,503 | $ 1,250,463 | $ 27,201,041 | 6% | $ 1,632,062 | $ 26,819,441 |
| 2 | Distribution System - pre 1988 | $ 56,109,134 | | | $ 56,109,134 | $ - | $ 56,109,134 | 6% | $ 3,366,548 | $ 52,742,586 |
| 8 | General Office/Stores Equip | $ 10,108,813 | 5,485,318 | | $ 15,594,131 | $ 2,742,659 | $ 12,851,472 | 20% | $ 2,570,294 | $ 13,023,837 |
| 10 | Computer Hardware/ Vehicles | $ 5,167,853 | 1,208,917 | | $ 6,376,770 | $ 604,459 | $ 5,772,311 | 30% | $ 1,731,693 | $ 4,645,076 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,873,320 | 14,487,488 | | $ 17,360,808 | $ 7,243,744 | $ 10,117,064 | 100% | $ 10,117,064 | $ 7,243,744 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 287,834 | | | $ 287,834 | $ - | $ 287,834 | 12% | $ 34,540 | $ 253,294 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 7,907 | | | $ 7,907 | $ - | $ 7,907 | 45% | $ 3,558 | $ 4,349 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 427,716,034 | 57,120,445 | | $ 484,836,479 | $ 28,560,223 | $ 456,276,256 | 8% | $ 36,502,100 | $ 448,334,378 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 2,999,130 | 957,202 | | $ 3,956,332 | $ 478,601 | $ 3,477,731 | 55% | $ 1,912,752 | $ 2,043,580 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| 3 | Buildings - pre1988 | $ 8,730,588 | | | $ 8,730,588 | $ - | $ 8,730,588 | 5% | $ 436,529 | $ 8,294,059 |
| | | $ - | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 717,943,134 | $ 81,760,295 | $ - | $ 799,703,429 | $ 40,880,148 | $ 758,823,281 | | $ 65,426,820 | $ 734,276,609 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Test Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **20,060,286** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,054,317 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 5,054,317 | **x 3/4 =** | 3,790,738 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,790,738 | **3,790,738** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **23,851,024** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **23,851,024** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **23,851,024** | **x 7% =** | **1,669,572** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **22,181,453** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| | | | | Test Year Adjustments | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Bridge Year** | **Eliminate Amounts Not Relevant for Bridge Year** | **Adjusted Utility Balance** | **Additions** | **Disposals** | **Balance for Test Year** | **Change During the Year** | **Disallowed Expenses** |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| **Non-Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | 0 | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Taxable Income - Test Year

| | | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 36,105,643 |

| | T2 S1 line # | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | 44,145,078 |
| Amortization of intangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 75,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 247,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **46,105,631** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 65,426,820 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 1,669,572 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **67,596,391** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **14,614,883** |
| | | |
| Charitable donations | 311 | 120,000 |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | 0 |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **14,494,883** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Test Year

| | | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | | $ 14,494,883 | **A** |
| **Ontario Income Taxes** | | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ | 1,666,912 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | | |
| | Rate reduction | -7.00% | **E** | -$ | 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | | $ 1,631,912 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | | 11.26% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | | 26.26% | **M = K + L** |
| **Total Income Taxes** | | | | | | | **$ 3,806,144** | **N = A * M** |
| Investment Tax Credits | | | | | | | $ 267,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | | **$ 267,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | | **$ 3,538,644** | **R = N - Q** |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | | 73.74% | **S = 1 - M** | **$ 1,260,073** | **T = R / S - R** |
| **Income Tax** (grossed-up) | | | | | | | **$ 4,798,717** | **U = R + T** |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

**Version** **3.0**

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | Patrick Hoey, Director Regulatory Affairs |
| **Phone Number** | 613-738-5499, x7472 |
| **Email Address** | patrickhoey@hydroottawa.com |
| **Date** | |
| **Last COS Re-based Year** | **2012** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| | | | | | |
|---|---|---|---|---|---|
| **Rate Base** | | | **$** | **1,020,297,432** | |
| **Return on Ratebase** | | | | | |
| Deemed ShortTerm Debt % | 4.00% | T | $ | 40,811,897 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ | 571,366,562 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ | 408,118,973 | *Y = S * V* |
| Short Term Interest Rate | 2.16% | Z | $ | 881,537 | *AC = W * Z* |
| Long Term Interest | 4.08% | AA | $ | 23,311,756 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 9.30% | AB | **$** | **37,955,064** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$** | **62,148,357** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historical | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | Yes | Yes |
| 2. Does the applicant have any SRED Expenditures? | No | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | No | No | No |
| 7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.* | Yes | Yes | Yes |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| Tax Rates<br>Federal & Provincial<br>As of June 20, 2012 | Effective<br>January 1, 2011 | Effective<br>January 1, 2012 | Effective<br>January 1, 2013 | Effective<br>January 1, 2014 | Effective<br>January 1, 2015 |
|---|---|---|---|---|---|
| **Federal income tax** | | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% | 28.00% |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% | 15.00% |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% | 11.50% |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% | 26.50% |
| **Federal & Ontario Small Business** | | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% | 11.00% |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historical per tax returns | Less: Non-Distribution Portion | UCC Regulated Historical Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 177,991,944 | | 177,991,944 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | 25,950,578 | | 25,950,578 |
| 2 | Distribution System - pre 1988 | 56,109,134 | | 56,109,134 |
| 8 | General Office/Stores Equip | 10,108,813 | | 10,108,813 |
| 10 | Computer Hardware/ Vehicles | 5,167,853 | | 5,167,853 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 2,873,320 | | 2,873,320 |
| $13_1$ | Lease # 1 | | | 0 |
| $13_2$ | Lease #2 | | | 0 |
| $13_3$ | Lease # 3 | | | 0 |
| $13_4$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | 287,834 | | 287,834 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 7,907 | | 7,907 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 427,716,034 | | 427,716,034 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 2,999,130 | | 2,999,130 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| 3 | Buildings - pre1988 | 8,730,588 | | 8,730,588 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | SUB-TOTAL - UCC | **717,943,134** | **0** | **717,943,134** |

# Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **17,856,648** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 4,951,403 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 4,951,403 | **x 3/4 =** | 3,713,552 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,713,552 | **3,713,552** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **21,570,201** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **21,570,201** |
| **Current Year Deduction** | | **21,570,201** | **x 7% =** | **1,509,914** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **20,060,286** |

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Historical

## Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | | | 0 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Historical

## Corporation Loss Continuity and Application

| **Non-Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Historical Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 34,346,978 | | 34,346,978 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | 5,000 | | 5,000 |
| Amortization of tangible assets | 104 | | | 0 |
| Amortization of intangible assets | 106 | 40,826,114 | | 40,826,114 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | 1,013,053 | | 1,013,053 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 75,000 | | 75,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | | | 0 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | 600,000 | | 600,000 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | | | 0 |
| Current Year Investment Tax Credits received | | 197,500 | | 197,500 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **42,716,667** | **0** | **42,716,667** |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | | | 0 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 60,183,826 | | 60,183,826 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,509,914 | | 1,509,914 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | | | 0 |
| Contributions to deferred income plans | 416 | 500,000 | | 500,000 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | | | 0 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Deductions** | | **62,193,740** | **0** | **62,193,740** |
| **Net Income for Tax Purposes** | | **14,869,905** | **0** | **14,869,905** |
| Charitable donations from Schedule 2 | 311 | 120,000 | | 120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| **TAXABLE INCOME** | | **14,749,905** | **0** | **14,749,905** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Historical Year

**Note: Input the actual information from the tax returns for the historical year.**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | **Wires Only** | |
| **Regulatory Taxable Income** | | | | | | | $ 14,749,905 | **A** |
| **Ontario Income Taxes** | | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 1,696,239 | **C = A * B** | | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | | |
| | Rate reduction (negative) | | **E** | | **F = D * E** | | | |
| *Ontario Income tax* | | | | | | | $ 1,696,239 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.50% | **K = J / A** | | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | | |
| | Combined tax rate | | | | | | 26.50% | **M = K + L** |
| **Total Income Taxes** | | | | | | | **$ 3,908,725** | **N = A * M** |
| Investment Tax Credits | | | | | | | $ 217,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | | **P** |
| **Total Tax Credits** | | | | | | | **$ 217,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historical Year** | | | | | | | **$ 3,691,225** | **R = N - Q** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historical Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 177,991,944 | $ - | | $ 177,991,944 | $ - | $ 177,991,944 | 4% | $ 7,119,678 | $ 170,872,266 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 25,950,578 | $ 2,500,925 | $ - | $ 28,451,503 | $ 1,250,463 | $ 27,201,041 | 6% | $ 1,632,062 | $ 26,819,441 |
| 2 | Distribution System - pre 1988 | $ 56,109,134 | $ - | | $ 56,109,134 | $ - | $ 56,109,134 | 6% | $ 3,366,548 | $ 52,742,586 |
| 8 | General Office/Stores Equip | $ 10,108,813 | $ 5,485,318 | | $ 15,594,131 | $ 2,742,659 | $ 12,851,472 | 20% | $ 2,570,294 | $ 13,023,837 |
| 10 | Computer Hardware/ Vehicles | $ 5,167,853 | $ 1,208,917 | | $ 6,376,770 | $ 604,459 | $ 5,772,311 | 30% | $ 1,731,693 | $ 4,645,076 |
| 10.1 | Certain Automobiles | | $ - | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,873,320 | $ 14,487,488 | | $ 17,360,808 | $ 7,243,744 | $ 10,117,064 | 100% | $ 10,117,064 | $ 7,243,744 |
| 13 1 | Lease # 1 | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | $ - | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 287,834 | $ - | | $ 287,834 | $ - | $ 287,834 | 12% | $ 34,540 | $ 253,294 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | $ - | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | $ - | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 7,907 | $ - | | $ 7,907 | $ - | $ 7,907 | 45% | $ 3,558 | $ 4,349 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | $ - | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 427,716,034 | $ 57,120,445 | | $ 484,836,479 | $ 28,560,223 | $ 456,276,256 | 8% | $ 36,502,100 | $ 448,334,378 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 2,999,130 | $ 957,202 | | $ 3,956,332 | $ 478,601 | $ 3,477,731 | 55% | $ 1,912,752 | $ 2,043,580 |
| 52 | Computer Hardware and system software | | $ - | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 3 | Buildings - pre1988 | $ 8,730,588 | $ - | | $ 8,730,588 | $ - | $ 8,730,588 | 5% | $ 436,529 | $ 8,294,059 |
| | | | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 717,943,134 | $ 81,760,295 | $ - | $ 799,703,429 | $ 40,880,148 | $ 758,823,281 | | $ 65,426,820 | $ 734,276,609 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **20,060,286** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,054,317 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 5,054,317 | **x 3/4 =** | 3,790,738 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,790,738 | **3,790,738** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **23,851,024** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **23,851,024** |
| **Current Year Deduction** | | **23,851,024** | **x 7% =** | **1,669,572** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **22,181,453** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| Description | Historical Utility Only | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Bridge Year Adjustments: Additions | Bridge Year Adjustments: Disposals | Balance for Bridge Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | 0 |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | A | 36,105,643 |

| **Additions:** | | |
|---|---|---|
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets | 104 | 44,145,078 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | 75,000 |
| Non-deductible meals and entertainment expense | 121 | |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 247,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **46,105,631** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 65,426,820 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,669,572 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **67,596,391** |
| | | |
| **Net Income for Tax Purposes** | | **14,614,883** |
| Charitable donations from Schedule 2 | 311 | -120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **14,494,883** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 14,494,883 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 1,666,912 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 1,631,912 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.26% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.26% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 3,806,144** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 267,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 267,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | **$ 3,538,644** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 170,872,266 | | | $ 170,872,266 | $ - | $ 170,872,266 | 4% | $ 6,834,891 | $ 164,037,376 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 26,819,441 | 2,929,713 | 0 | $ 29,749,154 | $ 1,464,857 | $ 28,284,297 | 6% | $ 1,697,058 | $ 28,052,096 |
| 2 | Distribution System - pre 1988 | $ 52,742,586 | | | $ 52,742,586 | $ - | $ 52,742,586 | 6% | $ 3,164,555 | $ 49,578,031 |
| 8 | General Office/Stores Equip | $ 13,023,837 | 4,303,997 | | $ 17,327,834 | $ 2,151,999 | $ 15,175,835 | 20% | $ 3,035,167 | $ 14,292,667 |
| 10 | Computer Hardware/ Vehicles | $ 4,645,076 | 1,451,508 | | $ 6,096,584 | $ 725,754 | $ 5,370,830 | 30% | $ 1,611,249 | $ 4,485,335 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 7,243,744 | 4,427,066 | | $ 11,670,810 | $ 2,213,533 | $ 9,457,277 | 100% | $ 9,457,277 | $ 2,213,533 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 253,294 | | | $ 253,294 | $ - | $ 253,294 | 12% | $ 30,395 | $ 222,898 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 4,349 | | | $ 4,349 | $ - | $ 4,349 | 45% | $ 1,957 | $ 2,392 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 448,334,378 | 74,671,869 | | $ 523,006,247 | $ 37,335,935 | $ 485,670,313 | 8% | $ 38,853,625 | $ 484,152,622 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 2,043,580 | 1,016,261 | | $ 3,059,841 | $ 508,131 | $ 2,551,710 | 55% | $ 1,403,441 | $ 1,656,400 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| 3 | Buildings - pre1988 | $ 8,294,059 | | | $ 8,294,059 | $ - | $ 8,294,059 | 5% | $ 414,703 | $ 7,879,356 |
| | | $ - | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 734,276,609 | $ 88,800,414 | $ - | $ 823,077,023 | $ 44,400,207 | $ 778,676,816 | | $ 66,504,318 | $ 756,572,706 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Test Year

### Cumulative Eligible Capital

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **22,181,453** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,339,288 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 5,339,288 | **x 3/4 =** | 4,004,466 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 4,004,466 | **4,004,466** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **26,185,919** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **26,185,919** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **26,185,919** | **x 7% =** | **1,833,014** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **24,352,904** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| | | | | Test Year Adjustments | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Bridge Year** | **Eliminate Amounts Not Relevant for Bridge Year** | **Adjusted Utility Balance** | **Additions** | **Disposals** | **Balance for Test Year** | **Change During the Year** | **Disallowed Expenses** |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | 0 | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Taxable Income - Test Year

| | | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 37,955,064 |

| | T2 S1 line # | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | 47,047,409 |
| Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 75,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 237,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **48,997,962** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 66,504,318 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 1,833,014 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **68,837,332** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **18,115,695** |
| | | |
| Charitable donations | 311 | 120,000 |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | 0 |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **17,995,695** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Test Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 17,995,695 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 2,069,505 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 2,034,505 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.31% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.31% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 4,733,859** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 257,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 257,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | **$ 4,476,359** | **R = N - Q** |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | 73.69% | **S = 1 - M** | **$ 1,597,852** | **T = R / S - R** |
| **Income Tax** (grossed-up) | | | | | | **$ 6,074,211** | **U = R + T** |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

**Version** **3.0**

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | Patrick Hoey, Director Regulatory Affairs |
| **Phone Number** | 613-738-5499, x7472 |
| **Email Address** | patrickhoey@hydroottawa.com |
| **Date** | |
| **Last COS Re-based Year** | **2012** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| | | | | |
|---|---|---|---|---|
| **Rate Base** | | | **$ 1,050,724,150** | |

## Return on Ratebase

| | | | | |
|---|---|---|---|---|
| Deemed ShortTerm Debt % | 4.00% | T | $ 42,028,966 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ 588,405,524 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ 420,289,660 | *Y = S * V* |
| | | | | |
| Short Term Interest Rate | 2.16% | Z | $ 907,826 | *AC = W * Z* |
| Long Term Interest | 4.17% | AA | $ 24,536,510 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 9.30% | AB | **$ 39,086,938** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$ 64,531,274** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historical | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | Yes | Yes |
| 2. Does the applicant have any SRED Expenditures? | No | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | No | No | No |
| 7. Did the applicant pay dividends?<br>*If Yes, please describe what was the tax treatment in the manager's summary.* | Yes | Yes | Yes |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| **Tax Rates**<br>**Federal & Provincial**<br>**As of June 20, 2012** | **Effective January 1, 2011** | **Effective January 1, 2012** | **Effective January 1, 2013** | **Effective January 1, 2014** | **Effective January 1, 2015** |
|---|---|---|---|---|---|
| **Federal income tax** | | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% | 28.00% |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% | 15.00% |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% | 11.50% |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% | 26.50% |
| **Federal & Ontario Small Business** | | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% | 11.00% |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historical per tax returns | Less: Non-Distribution Portion | UCC Regulated Historical Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 170,872,266 | | 170,872,266 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | 26,819,441 | | 26,819,441 |
| 2 | Distribution System - pre 1988 | 52,742,586 | | 52,742,586 |
| 8 | General Office/Stores Equip | 13,023,837 | | 13,023,837 |
| 10 | Computer Hardware/ Vehicles | 4,645,076 | | 4,645,076 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 7,243,744 | | 7,243,744 |
| $13_1$ | Lease # 1 | | | 0 |
| $13_2$ | Lease #2 | | | 0 |
| $13_3$ | Lease # 3 | | | 0 |
| $13_4$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | 253,294 | | 253,294 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 4,349 | | 4,349 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 448,334,378 | | 448,334,378 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 2,043,580 | | 2,043,580 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| 3 | Buildings - pre1988 | 8,294,059 | | 8,294,059 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | SUB-TOTAL - UCC | **734,276,609** | **0** | **734,276,609** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **20,060,286** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,054,317 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 5,054,317 | **x 3/4 =** | 3,790,738 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,790,738 | **3,790,738** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **23,851,024** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **23,851,024** |
| **Current Year Deduction** | | **23,851,024** | **x 7% =** | **1,669,572** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **22,181,453** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Historical

## Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | | | 0 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Historical

## Corporation Loss Continuity and Application

| **Non-Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Historical Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 36,105,643 | | 36,105,643 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | 5,000 | | 5,000 |
| Amortization of tangible assets | 104 | | | 0 |
| Amortization of intangible assets | 106 | 44,145,078 | | 44,145,078 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | 1,013,053 | | 1,013,053 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 75,000 | | 75,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | | | 0 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | 600,000 | | 600,000 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | 20,000 | | 20,000 |
| Current Year Investment Tax Credits received | | 247,500 | | 247,500 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **46,105,631** | **0** | **46,105,631** |
| | | | | |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | | | 0 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 65,426,820 | | 65,426,820 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,669,572 | | 1,669,572 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | | | 0 |
| Contributions to deferred income plans | 416 | 500,000 | | 500,000 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | | | 0 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **67,596,391** | **0** | **67,596,391** |
| | | | | |
| **Net Income for Tax Purposes** | | **14,614,883** | **0** | **14,614,883** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | 120,000 | | 120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **14,494,883** | **0** | **14,494,883** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Historical Year

**Note: Input the actual information from the tax returns for the historical year.**

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 14,494,883 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 1,666,912 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction (negative) | 0.00% | **E** | $ - | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 1,666,912 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.50% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.50% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 3,841,144** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 267,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 267,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historical Year** | | | | | | **$ 3,573,644** | **R = N - Q** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historical Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 170,872,266 | | | $ 170,872,266 | $ - | $ 170,872,266 | 4% | $ 6,834,891 | $ 164,037,376 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 26,819,441 | $ 2,929,713 | $ - | $ 29,749,154 | $ 1,464,857 | $ 28,284,297 | 6% | $ 1,697,058 | $ 28,052,096 |
| 2 | Distribution System - pre 1988 | $ 52,742,586 | | | $ 52,742,586 | $ - | $ 52,742,586 | 6% | $ 3,164,555 | $ 49,578,031 |
| 8 | General Office/Stores Equip | $ 13,023,837 | $ 4,303,997 | | $ 17,327,834 | $ 2,151,999 | $ 15,175,835 | 20% | $ 3,035,167 | $ 14,292,667 |
| 10 | Computer Hardware/ Vehicles | $ 4,645,076 | $ 1,451,508 | | $ 6,096,584 | $ 725,754 | $ 5,370,830 | 30% | $ 1,611,249 | $ 4,485,335 |
| 10.1 | Certain Automobiles | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 7,243,744 | $ 4,427,066 | | $ 11,670,810 | $ 2,213,533 | $ 9,457,277 | 100% | $ 9,457,277 | $ 2,213,533 |
| 13 1 | Lease # 1 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 253,294 | | | $ 253,294 | $ - | $ 253,294 | 12% | $ 30,395 | $ 222,898 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 4,349 | | | $ 4,349 | $ - | $ 4,349 | 45% | $ 1,957 | $ 2,392 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 448,334,378 | $ 74,671,869 | | $ 523,006,247 | $ 37,335,935 | $ 485,670,313 | 8% | $ 38,853,625 | $ 484,152,622 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 2,043,580 | $ 1,016,261 | | $ 3,059,841 | $ 508,131 | $ 2,551,710 | 55% | $ 1,403,441 | $ 1,656,400 |
| 52 | Computer Hardware and system software | | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | | | $ - | $ - | $ - | | $ - | $ - |
| 3 | Buildings - pre1988 | $ 8,294,059 | | | $ 8,294,059 | $ - | $ 8,294,059 | 5% | $ 414,703 | $ 7,879,356 |
| | | | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 734,276,609 | $ 88,800,414 | $ - | $ 823,077,023 | $ 44,400,207 | $ 778,676,816 | | $ 66,504,318 | $ 756,572,706 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **22,181,453** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,339,288 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 5,339,288 | **x 3/4 =** | 4,004,466 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 4,004,466 | **4,004,466** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **26,185,919** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **26,185,919** |
| **Current Year Deduction** | | **26,185,919** | **x 7% =** | **1,833,014** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **24,352,904** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| | | | | Bridge Year Adjustments | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Historical Utility Only** | **Eliminate Amounts Not Relevant for Bridge Year** | **Adjusted Utility Balance** | **Additions** | **Disposals** | **Balance for Bridge Year** | **Change During the Year** | **Disallowed Expenses** |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | 0 |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | **A** | 37,955,064 |

| **Additions:** | | |
|---|---|---|
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets | 104 | 47,047,409 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | 75,000 |
| Non-deductible meals and entertainment expense | 121 | |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 237,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **48,997,962** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 66,504,318 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,833,014 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

# Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **68,837,332** |
| | | |
| **Net Income for Tax Purposes** | | **18,115,695** |
| Charitable donations from Schedule 2 | 311 | -120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **17,995,695** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 17,995,695 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 2,069,505 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 2,034,505 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.31% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.31% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 4,733,859** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 257,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 257,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | **$ 4,476,359** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 164,037,376 | | | $ 164,037,376 | $ - | $ 164,037,376 | 4% | $ 6,561,495 | $ 157,475,881 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 28,052,096 | 860,917 | | $ 28,913,013 | $ 430,459 | $ 28,482,554 | 6% | $ 1,708,953 | $ 27,204,060 |
| 2 | Distribution System - pre 1988 | $ 49,578,031 | | | $ 49,578,031 | $ - | $ 49,578,031 | 6% | $ 2,974,682 | $ 46,603,349 |
| 8 | General Office/Stores Equip | $ 14,292,667 | 3,095,502 | | $ 17,388,169 | $ 1,547,751 | $ 15,840,418 | 20% | $ 3,168,084 | $ 14,220,085 |
| 10 | Computer Hardware/ Vehicles | $ 4,485,335 | 1,479,811 | | $ 5,965,146 | $ 739,906 | $ 5,225,241 | 30% | $ 1,567,572 | $ 4,397,574 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,213,533 | 4,325,277 | | $ 6,538,810 | $ 2,162,639 | $ 4,376,172 | 100% | $ 4,376,172 | $ 2,162,639 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 222,898 | | | $ 222,898 | $ - | $ 222,898 | 12% | $ 26,748 | $ 196,151 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 2,392 | | | $ 2,392 | $ - | $ 2,392 | 45% | $ 1,076 | $ 1,315 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 484,152,622 | 52,817,278 | | $ 536,969,900 | $ 26,408,639 | $ 510,561,261 | 8% | $ 40,844,901 | $ 496,124,999 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 1,656,400 | 900,848 | | $ 2,557,248 | $ 450,424 | $ 2,106,824 | 55% | $ 1,158,753 | $ 1,398,495 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| 3 | Buildings - pre1988 | $ 7,879,356 | | | $ 7,879,356 | $ - | $ 7,879,356 | 5% | $ 393,968 | $ 7,485,388 |
| | | $ - | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 756,572,706 | $ 63,479,633 | $ - | $ 820,052,339 | $ 31,739,817 | $ 788,312,522 | | $ 62,782,404 | $ 757,269,935 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Test Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **24,352,904** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,056,723 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 5,056,723 | **x 3/4 =** | 3,792,542 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,792,542 | **3,792,542** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **28,145,446** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **28,145,446** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **28,145,446** | **x 7% =** | **1,970,181** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **26,175,265** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| Description | Bridge Year | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Test Year Adjustments: Additions | Test Year Adjustments: Disposals | Balance for Test Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | 0 | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Taxable Income - Test Year

| | | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 39,086,938 |

| | T2 S1 line # | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | 48,948,694 |
| Amortization of intangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 75,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 227,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **50,889,247** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 62,782,404 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 1,970,181 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **65,252,585** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **24,723,601** |
| | | |
| Charitable donations | 311 | 120,000 |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | 0 |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **24,603,601** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Test Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 24,603,601 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 2,829,414 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 2,794,414 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.36% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.36% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 6,484,954** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 245,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 245,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | **$ 6,239,454** | **R = N - Q** |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | 73.64% | **S = 1 - M** | **$ 2,233,201** | **T = R / S - R** |
| **Income Tax** (grossed-up) | | | | | | **$ 8,472,655** | **U = R + T** |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

**Version** 3.0

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | Patrick Hoey, Director Regulatory Affairs |
| **Phone Number** | 613-738-5499, x7472 |
| **Email Address** | patrickhoey@hydroottawa.com |
| **Date** | |
| **Last COS Re-based Year** | **2012** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| | | | | |
|---|---|---|---|---|
| **Rate Base** | | | **$ 1,094,270,321** | |

## Return on Ratebase

| | | | | |
|---|---|---|---|---|
| Deemed ShortTerm Debt % | 4.00% | T | $ 43,770,813 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ 612,791,380 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ 437,708,128 | *Y = S * V* |
| | | | | |
| Short Term Interest Rate | 2.16% | Z | $ 945,450 | *AC = W * Z* |
| Long Term Interest | 4.23% | AA | $ 25,921,075 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 9.30% | AB | **$ 40,706,856** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$ 67,573,381** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historical | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | Yes | Yes |
| 2. Does the applicant have any SRED Expenditures? | No | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | No | No | No |
| 7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.* | Yes | Yes | Yes |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

| Tax Rates<br>Federal & Provincial<br>As of June 20, 2012 | Effective<br>January 1, 2011 | Effective<br>January 1, 2012 | Effective<br>January 1, 2013 | Effective<br>January 1, 2014 | Effective<br>January 1, 2015 |
|---|---|---|---|---|---|
| **Federal income tax** | | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% | 28.00% |
| | | | | | |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% | 15.00% |
| | | | | | |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% | 11.50% |
| | | | | | |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% | 26.50% |
| | | | | | |
| **Federal & Ontario Small Business** | | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 | 500,000 |
| | | | | | |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% | 11.00% |
| | | | | | |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historical per tax returns | Less: Non-Distribution Portion | UCC Regulated Historical Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 164,037,376 | | 164,037,376 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | 28,052,096 | | 28,052,096 |
| 2 | Distribution System - pre 1988 | 49,578,031 | | 49,578,031 |
| 8 | General Office/Stores Equip | 14,292,667 | | 14,292,667 |
| 10 | Computer Hardware/ Vehicles | 4,485,335 | | 4,485,335 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 2,213,533 | | 2,213,533 |
| $13_1$ | Lease # 1 | | | 0 |
| $13_2$ | Lease #2 | | | 0 |
| $13_3$ | Lease # 3 | | | 0 |
| $13_4$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | 222,898 | | 222,898 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | 2,392 | | 2,392 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 484,152,622 | | 484,152,622 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 1,656,400 | | 1,656,400 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| 3 | Buildings - pre1988 | 7,879,356 | | 7,879,356 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | **SUB-TOTAL - UCC** | **756,572,706** | **0** | **756,572,706** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **22,181,453** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,339,288 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 5,339,288 | **x 3/4 =** | 4,004,466 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 4,004,466 | **4,004,466** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **26,185,919** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **26,185,919** |
| **Current Year Deduction** | | **26,185,919** | **x 7% =** | **1,833,014** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **24,352,904** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Historical

## Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | 0 | 0 | 0 |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | | | 0 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Historical

## Corporation Loss Continuity and Application

| **Non-Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual Historical | | | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Historical Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 37,955,064 | | 37,955,064 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | 5,000 | | 5,000 |
| Amortization of tangible assets | 104 | | | 0 |
| Amortization of intangible assets | 106 | 47,047,409 | | 47,047,409 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | 1,013,053 | | 1,013,053 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 75,000 | | 75,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | | | 0 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | 600,000 | | 600,000 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | 20,000 | | 20,000 |
| Current Year Investment Tax Credits received | | 237,500 | | 237,500 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **48,997,962** | **0** | **48,997,962** |
| | | | | |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | | | 0 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 66,504,318 | | 66,504,318 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,833,014 | | 1,833,014 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | | | 0 |
| Contributions to deferred income plans | 416 | 500,000 | | 500,000 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | | | 0 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **68,837,332** | **0** | **68,837,332** |
| | | | | |
| **Net Income for Tax Purposes** | | **18,115,695** | **0** | **18,115,695** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | 120,000 | | 120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **17,995,695** | **0** | **17,995,695** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Historical Year

**Note: Input the actual information from the tax returns for the historical year.**

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 17,995,695 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 2,069,505 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction (negative) | 0.00% | **E** | $ - | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 2,069,505 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.50% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.50% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 4,768,859** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 257,500 | **O** |
| Miscellaneous Tax Credits | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | **$ 257,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historical Year** | | | | | | **$ 4,511,359** | **R = N - Q** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historical Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 164,037,376 | | | $ 164,037,376 | $ - | $ 164,037,376 | 4% | $ 6,561,495 | $ 157,475,881 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 28,052,096 | $ 860,917 | | $ 28,913,013 | $ 430,459 | $ 28,482,554 | 6% | $ 1,708,953 | $ 27,204,060 |
| 2 | Distribution System - pre 1988 | $ 49,578,031 | | | $ 49,578,031 | $ - | $ 49,578,031 | 6% | $ 2,974,682 | $ 46,603,349 |
| 8 | General Office/Stores Equip | $ 14,292,667 | $ 3,095,502 | | $ 17,388,169 | $ 1,547,751 | $ 15,840,418 | 20% | $ 3,168,084 | $ 14,220,085 |
| 10 | Computer Hardware/ Vehicles | $ 4,485,335 | $ 1,479,811 | | $ 5,965,146 | $ 739,906 | $ 5,225,241 | 30% | $ 1,567,572 | $ 4,397,574 |
| 10.1 | Certain Automobiles | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,213,533 | $ 4,325,277 | | $ 6,538,810 | $ 2,162,639 | $ 4,376,172 | 100% | $ 4,376,172 | $ 2,162,639 |
| 13 1 | Lease # 1 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 222,898 | | | $ 222,898 | $ - | $ 222,898 | 12% | $ 26,748 | $ 196,151 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 2,392 | | | $ 2,392 | $ - | $ 2,392 | 45% | $ 1,076 | $ 1,315 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 484,152,622 | $ 52,817,278 | | $ 536,969,900 | $ 26,408,639 | $ 510,561,261 | 8% | $ 40,844,901 | $ 496,124,999 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 1,656,400 | $ 900,848 | | $ 2,557,248 | $ 450,424 | $ 2,106,824 | 55% | $ 1,158,753 | $ 1,398,495 |
| 52 | Computer Hardware and system software | | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | | | $ - | $ - | $ - | | $ - | $ - |
| 3 | Buildings - pre1988 | $ 7,879,356 | | | $ 7,879,356 | $ - | $ 7,879,356 | 5% | $ 393,968 | $ 7,485,388 |
| | | | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 756,572,706 | $ 63,479,633 | $ - | $ 820,052,339 | $ 31,739,817 | $ 788,312,522 | | $ 62,782,404 | $ 757,269,935 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **24,352,904** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,056,723 | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 5,056,723 | **x 3/4 =** | 3,792,542 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,792,542 | **3,792,542** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **28,145,446** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **28,145,446** |
| **Current Year Deduction** | | **28,145,446** | **x 7% =** | **1,970,181** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **26,175,265** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| | | | | Bridge Year Adjustments | | | | |
|---|---|---|---|---|---|---|---|---|
| **Description** | **Historical Utility Only** | **Eliminate Amounts Not Relevant for Bridge Year** | **Adjusted Utility Balance** | **Additions** | **Disposals** | **Balance for Bridge Year** | **Change During the Year** | **Disallowed Expenses** |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | 0 |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historical | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | **A** | 39,086,938 |

| | | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets | 104 | 48,948,694 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | 75,000 |
| Non-deductible meals and entertainment expense | 121 | |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 20,000 |
| Current Year Investment Tax Credits received | | 227,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **50,889,247** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 62,782,404 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 1,970,181 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **65,252,585** |
| | | |
| **Net Income for Tax Purposes** | | **24,723,601** |
| Charitable donations from Schedule 2 | 311 | -120,000 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **24,603,601** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 24,603,601 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 2,829,414 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 2,794,414 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 11.36% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 26.36% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 6,484,954** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 245,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | **P** |
| **Total Tax Credits** | | | | | | **$ 245,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | **$ 6,239,454** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 157,475,881 | | | $ 157,475,881 | $ - | $ 157,475,881 | 4% | $ 6,299,035 | $ 151,176,846 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ 27,204,060 | 7,064,568 | | $ 34,268,628 | $ 3,532,284 | $ 30,736,344 | 6% | $ 1,844,181 | $ 32,424,447 |
| 2 | Distribution System - pre 1988 | $ 46,603,349 | | | $ 46,603,349 | $ - | $ 46,603,349 | 6% | $ 2,796,201 | $ 43,807,148 |
| 8 | General Office/Stores Equip | $ 14,220,085 | 4,381,036 | | $ 18,601,121 | $ 2,190,518 | $ 16,410,603 | 20% | $ 3,282,121 | $ 15,319,001 |
| 10 | Computer Hardware/ Vehicles | $ 4,397,574 | 1,875,726 | | $ 6,273,300 | $ 937,863 | $ 5,335,437 | 30% | $ 1,600,631 | $ 4,672,669 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,162,639 | 11,398,852 | | $ 13,561,491 | $ 5,699,426 | $ 7,862,065 | 100% | $ 7,862,065 | $ 5,699,426 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ 196,151 | | | $ 196,151 | $ - | $ 196,151 | 12% | $ 23,538 | $ 172,612 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ 1,315 | | | $ 1,315 | $ - | $ 1,315 | 45% | $ 592 | $ 724 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 496,124,999 | 82,851,650 | | $ 578,976,649 | $ 41,425,825 | $ 537,550,824 | 8% | $ 43,004,066 | $ 535,972,583 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 1,398,495 | 919,028 | | $ 2,317,523 | $ 459,514 | $ 1,858,009 | 55% | $ 1,021,905 | $ 1,295,618 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| 3 | Buildings - pre1988 | $ 7,485,388 | | | $ 7,485,388 | $ - | $ 7,485,388 | 5% | $ 374,269 | $ 7,111,119 |
| | | $ - | | | $ - | $ - | $ - | 10% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 757,269,935 | $ 108,490,860 | $ - | $ 865,760,795 | $ 54,245,430 | $ 811,515,365 | | $ 68,108,603 | $ 797,652,192 |

## Schedule 10 CEC - Test Year

### Cumulative Eligible Capital

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **26,175,265** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 5,089,596 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 5,089,596 | **x 3/4 =** | 3,817,197 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 3,817,197 | **3,817,197** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **29,992,462** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **29,992,462** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **29,992,462** | **x 7% =** | **2,099,472** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **27,892,990** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| Description | Bridge Year | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Test Year Adjustments: Additions | Test Year Adjustments: Disposals | Balance for Test Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 0 | | 0 | | | 0 | 0 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | 0 | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | 0 | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual/Estimated Bridge Year | 0 | | 0 |
| | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## Taxable Income - Test Year

| | | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 40,706,856 |

| | T2 S1 line # | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | 5,000 |
| Amortization of tangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | 50,294,804 |
| Amortization of intangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | 1,013,053 |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 75,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 0 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | 600,000 |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | 18,000 |
| Current Year Investment Tax Credits received | | 217,500 |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **52,223,357** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 68,108,603 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 2,099,472 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 0 |
| Contributions to deferred income plans | 416 | 500,000 |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **70,708,076** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **22,222,137** |
| | | |
| Charitable donations | 311 | 120,000 |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | 0 |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **22,102,137** |

Ontario Energy Board

# Income Tax/PILs Workform for 2015 Filers

## PILs Tax Provision - Test Year

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | **Wires Only** | |
| **Regulatory Taxable Income** | | | | | | | $ 22,102,137 | **A** |
| **Ontario Income Taxes** | | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ | 2,541,746 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | | |
| | Rate reduction | -7.00% | **E** | -$ | 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | | $ 2,506,746 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | | 11.34% | **K = J / A** | | |
| | Federal tax rate (Maximum 15%) | | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | | 26.34% | **M = K + L** |
| **Total Income Taxes** | | | | | | | **$ 5,822,066** | **N = A * M** |
| Investment Tax Credits | | | | | | | $ 233,500 | **O** |
| Miscellaneous Tax Credits | | | | | | | $ - | **P** |
| **Total Tax Credits** | | | | | | | **$ 233,500** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | | **$ 5,588,566** | **R = N - Q** |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | | 73.66% | **S = 1 - M** | **$ 1,998,579** | **T = R / S - R** |
| **Income Tax** (grossed-up) | | | | | | | **$ 7,587,145** | **U = R + T** |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

# LOST REVENUE ADJUSTMENT MECHANISM

## 1.0 INTRODUCTION

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive ("2010 Directive") to the Ontario Energy Board ("the Board") (to take steps in order to establish electricity and Conservation and Demand Management ("CDM") targets to be met by licenced electricity distributors over a four year period beginning January 1, 2011.

In response to the 2010 Directive, the Board issued a new set of Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements indicating electricity distributors must comply with the CDM targets as set out in their licences. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period. The current CDM Framework results were predominantly delivered by provincially developed programs that were funded by the Ontario Power Authority ("OPA")[1] in cooperation with electricity distributors. It ended on December 31, 2014. The Conservation and Demand Management Code for Electricity Distributors ("CDM Code"), issued September 16, 2010 and 2012 CDM Guidelines are applicable for all activities related to the 2011 to 2014 CDM Framework.

The Government of Ontario released its Long-Term Energy Plan ("LTEP") of which one of the priories is to reinforce the conservation first planning process. The Board received a Directive from the Ministry of Energy on March 31, 2014 altogether the ("Conservation Directive") that required the Board to promote CDM and establish guidelines (the "2015 CDM Guidelines"). The 2015 CDM Guidelines are effective as of the programs beginning January 1, 2015. This new framework is to achieve 7 terawatt-hours of

[1] References to the OPA remain for activities occurring prior to January 1, 2015. As of January 1, 2015, all functions of the OPA will be those of the Independent Electricity System Operator ("IESO")
[2] References made to the IESO in Exhibit D-5-1 are in relation to CDM activities on or after January 1, 2015
[3]Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, Appendix B
[4]Conservation and Demand Management Requirement Guidelines for Electricity Distributors, EB-2014-0278, Section 7 - LRAM

electricity savings province-wide from 2015 to 2020. These programs will be either Local CDM programs or Province-Wide Distributor initiatives that will be funded by the IESO[2].

## 2.0 Lost Revenue Adjustment Mechanism Variance Account

The Board authorized the establishment of an LRAM variance account ("LRAMVA") Uniform System of Accounts ("USofA") 1568 to capture at the customer rate-class, the difference between:

i. The results of the actual verified impacts of authorized CDM activities undertaken by the electricity distributor for Board-Approved CDM programs and/or OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area)

AND

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates)[3].

Hydro Ottawa Limited ("Hydro Ottawa") will follow Appendix A of the 2012 CDM Guidelines, which states Local Distribution Companies ("LDCs") in the 2016 Cost of Service ("COS") year can apply for approval of lost revenues for 2014 LRAMVA programs and persistence for LRAMVA 2011 to 2013. According to the 2014 CDM Guidelines, "Distributors should continue to rely on the LRAMVA to track and dispose lost revenues that result from approved CDM programs between 2015 and 2020."[4] At the time of drafting this evidence, Hydro Ottawa can support the 2011, 2012 and 2013 LRAM claims. The 2014 results are expected in the fall of 2015. Hydro Ottawa will file for additional LRAM and persistence claims in the future, and potentially for annual adjustments or other OPA adjustments.

[1] References to the OPA remain for activities occurring prior to January 1, 2015. As of January 1, 2015, all functions of the OPA will be those of the Independent Electricity System Operator ("IESO")
[2] References made to the IESO in Exhibit D-5-1 are in relation to CDM activities on or after January 1, 2015
[3]Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, Appendix B
[4]Conservation and Demand Management Requirement Guidelines for Electricity Distributors, EB-2014-0278, Section 7 - LRAM

Hydro Ottawa has relied on the most recent final CDM Evaluation Report from the OPA in support of the lost revenue calculation; please refer to Exhibit D-5-2 for further details. Please see Attachment D–5(A) for the OPA report and Attachment D–5(B) for Hydro Ottawa's 2013 Annual Report on Conservation and Demand Management.

[1] References to the OPA remain for activities occurring prior to January 1, 2015. As of January 1, 2015, all functions of the OPA will be those of the Independent Electricity System Operator ("IESO")
[2] References made to the IESO in Exhibit D-5-1 are in relation to CDM activities on or after January 1, 2015
[3]Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, Appendix B
[4]Conservation and Demand Management Requirement Guidelines for Electricity Distributors, EB-2014-0278, Section 7 - LRAM

**Message from the Vice President:**

The OPA is pleased to provide you with the enclosed Final 2013 Verified Results Report.

2013 Report highlights:

- We have achieved 86% of our cumulative energy savings target and 48% of our annual peak demand savings target to date (Scenario 2).

  By the end of 2013, 42 LDCs have exceeded 80% of their energy target and 19 LDCs have met or exceeded their 2011-14 energy target.
- In 2013, LDCs have achieved over 600 GWh in savings, representing an increase of 20% over the 2012 net incremental energy savings results.
- The BUSINESS PROGRAM continues to generate strong interest and participation amongst business customers with significant savings results. 71% of total energy savings in 2013 came from the BUSINESS PROGRAM and its momentum continues. Also, as the program matures, we are seeing more and more studies in the PROCESS AND SYSTEMS pipeline converting to completed projects.
- Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

2013 has been a year of significant operational advancements centered around creating a better customer and LDC experience:

- A number of operational changes were made in 2013 to enhance processes, such as payment of LDC invoices streamlined to an average of 20 days, enhanced reporting and iCon updates to improve users' experience.
- Proactive updates to measures incentivized through saveONenergy have allowed programs to stay ahead of changing market conditions. Specifically in 2013, LEDs became popular measures in both the Consumer and Business programs.
- Technical tools also played a significant role in 2013, which included an updated Measure and Assumptions List as well as new and improved engineering worksheets for RETROFIT which allow customers to more easily access programs by building strong business cases based on latest estimates of savings potential.
- The Conservation Fund introduced the LDC Fast Track stream to support LDCs with innovative program ideas. 2013 LDC pilots included Oshawa PUC Networks Inc.'s retro-commissioning program, Toronto Hydro-Electric System Limited multi-unit demand response, and Niagara-on-the-Lake Hydro Inc.'s electric vehicles load shifting program.
- Key market sectors were also engaged in 2013 through Capability Building programs targeted at Home Builders and HVAC Installers to build conservation knowledge with these partners. Energy Efficiency Services Programs (EESPs) also provided valuable support to a variety of sectors.

The format of this report was developed in collaboration with the Reporting Working Group and is designed to help LDCs populate their 2013 Annual Reports that will be submitted to the OEB by September 30th. Any additional 2013 program activity not captured here will be reported in your Final 2014 Verified Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2014.

Sincerely,

Andrew Pride

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## OPA-Contracted Province-Wide CDM Programs Final Verified 2013 Results

**LDC:** Hydro Ottawa Limited

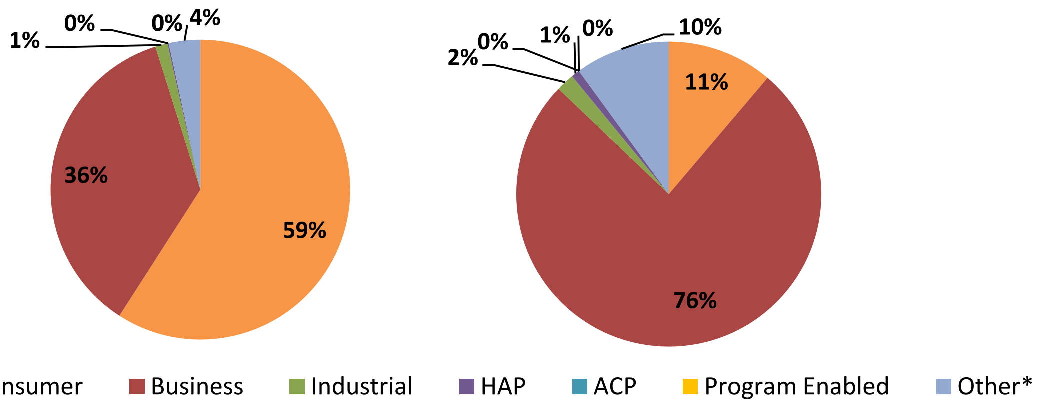
| FINAL 2013 Progress to Targets | 2013 Incremental | Program-to-Date Progress to Target (Scenario 1) | Scenario 1: % of Target Achieved | Scenario 2: % of Target Achieved |
|---|---|---|---|---|
| **Net Annual Peak Demand Savings (MW)** | 22.5 | 25.4 | **29.8%** | **45.6%** |
| **Net Energy Savings (GWh)** | 42.6 | 332.4 | **88.7%** | **88.7%** |

Scenario 1 = Assumes that demand response resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in the LDC service territory until 2014

## Achievement by Sector

**2013 Incremental Peak Demand Savings (MW)** | **2013 Incremental Energy Savings (GWh)**

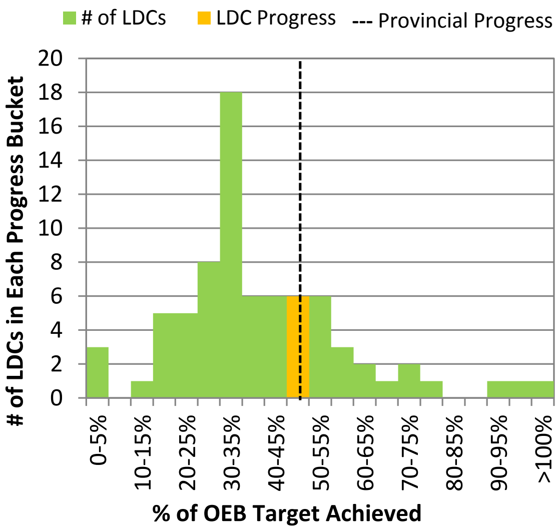



**Other includes adjustments to previous years' results and savings from pre-2011 initiatives*

## Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in the LDC service territory until 2014 (aligns with Scenario 2)

**% of OEB Peak Demand Savings Target Achieved**




**% of OEB Energy Savings Target Achieved**

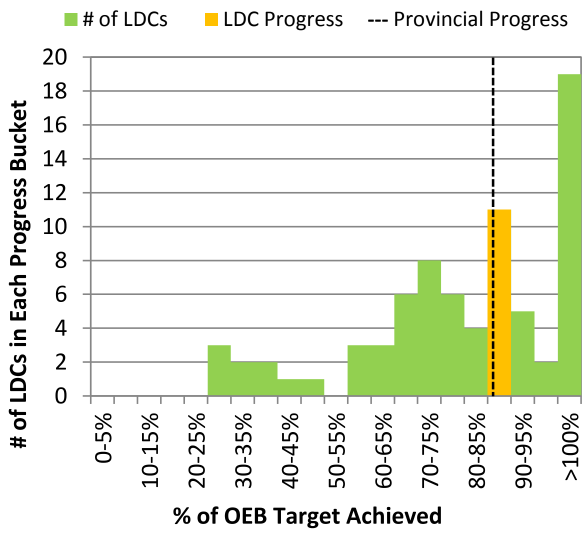


Table 1: Hydro Ottawa Limited Initiative and Program Level Net Savings by Year (Scenario 1)

| Initiative | Unit | Incremental Activity (new program activity occurring within the specified reporting period) | | | | Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | | Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW) | Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011* | 2012* | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2014 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | | | |
| Appliance Retirement | Appliances | 4,110 | 2,604 | 1,602 | | 246 | 146 | 104 | | 1,754,416 | 1,040,845 | 681,703 | | 487 | 11,496,435 |
| Appliance Exchange | Appliances | 183 | 178 | 191 | | 19 | 25 | 40 | | 22,795 | 43,987 | 70,563 | | 72 | 353,929 |
| HVAC Incentives | Equipment | 7,863 | 7,269 | 6,674 | | 2,880 | 1,606 | 1,448 | | 5,465,411 | 2,835,583 | 2,563,561 | | 5,934 | 35,495,512 |
| Conservation Instant Coupon Booklet | Items | 29,787 | 1,728 | 19,410 | | 69 | 13 | 29 | | 1,104,610 | 78,235 | 431,268 | | 111 | 5,515,683 |
| Bi-Annual Retailer Event | Items | 53,276 | 59,361 | 52,864 | | 94 | 83 | 66 | | 1,644,342 | 1,498,537 | 961,278 | | 243 | 12,995,535 |
| Retailer Co-op | Items | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Residential Demand Response | Devices | 5,701 | 16,134 | 23,018 | | 3,193 | 7,249 | 11,608 | | 8,266 | 55,891 | 48,406 | | 0 | 112,564 |
| Residential Demand Response (IHD) | Devices | 0 | 9,659 | 18,720 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Residential New Construction | Homes | 0 | 0 | 2 | | 0 | 0 | 2 | | 0 | 0 | 16,548 | | 2 | 33,097 |
| **Consumer Program Total** | | | | | | **6,500** | **9,122** | **13,296** | | **9,999,841** | **5,553,079** | **4,773,328** | | **6,849** | **66,002,755** |
| **Business Program** | | | | | | | | | | | | | | | |
| Retrofit | Projects | 338 | 594 | 777 | | 2,832 | 5,116 | 4,897 | | 14,868,304 | 22,549,482 | 26,220,638 | | 12,429 | 178,026,480 |
| Direct Install Lighting | Projects | 1,063 | 1,107 | 1,133 | | 1,416 | 843 | 1,011 | | 3,870,853 | 3,365,166 | 3,655,868 | | 2,632 | 30,957,182 |
| Building Commissioning | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| New Construction | Buildings | 0 | 5 | 9 | | 0 | 14 | 125 | | 0 | 16,176 | 117,105 | | 139 | 282,738 |
| Energy Audit | Audits | 13 | 25 | 48 | | 0 | 124 | 423 | | 0 | 604,230 | 2,325,637 | | 547 | 6,463,964 |
| Small Commercial Demand Response | Devices | 7 | 33 | 215 | | 4 | 21 | 138 | | 16 | 120 | 46 | | 0 | 182 |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | 25 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Demand Response 3 | Facilities | 10 | 11 | 12 | | 597 | 644 | 1,520 | | 23,305 | 9,354 | 24,274 | | 0 | 56,934 |
| **Business Program Total** | | | | | | **4,850** | **6,761** | **8,115** | | **18,762,479** | **26,544,529** | **32,343,568** | | **15,748** | **215,787,481** |
| **Industrial Program** | | | | | | | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Monitoring & Targeting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Energy Manager | Projects | 0 | 0 | 17 | | 0 | 0 | 109 | | 0 | 0 | 816,987 | | 60 | 1,337,308 |
| Retrofit | Projects | 12 | 0 | 0 | | 81 | 0 | 0 | | 533,952 | 0 | 0 | | 81 | 2,135,807 |
| Demand Response 3 | Facilities | 0 | 1 | 2 | | 0 | 42 | 189 | | 0 | 1,010 | 4,299 | | 0 | 5,309 |
| **Industrial Program Total** | | | | | | **81** | **42** | **297** | | **533,952** | **1,010** | **821,286** | | **142** | **3,478,424** |
| **Home Assistance Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 394 | 534 | | 0 | 26 | 32 | | 0 | 319,766 | 384,041 | | 58 | 1,724,858 |
| **Home Assistance Program Total** | | | | | | **0** | **26** | **32** | | **0** | **319,766** | **384,041** | | **58** | **1,724,858** |
| **Aboriginal Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Direct Install Lighting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Aboriginal Program Total** | | | | | | **0** | **0** | **0** | | **0** | **0** | **0** | | **0** | **0** |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 175 | 0 | 0 | | 934 | 0 | 0 | | 4,899,976 | 0 | 0 | | 934 | 19,599,902 |
| High Performance New Construction | Projects | 16 | 12 | 1 | | 321 | 807 | 286 | | 1,651,092 | 2,431,058 | 1,899,180 | | 1,415 | 17,695,901 |
| Toronto Comprehensive | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| LDC Custom Programs | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Pre-2011 Programs completed in 2011 Total** | | | | | | **1,255** | **807** | **286** | | **6,551,068** | **2,431,058** | **1,899,180** | | **2,348** | **37,295,803** |
| **Other** | | | | | | | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Time-of-Use Savings | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Other Total** | | | | | | **0** | **0** | **0** | | **0** | **0** | **0** | | **0** | **0** |
| **Adjustments to 2011 Verified Results** | | | | | | | **-209** | **0** | | | **244,069** | **0** | | **-217** | **953,652** |
| **Adjustments to 2012 Verified Results** | | | | | | | | **478** | | | | **2,376,882** | | **473** | **7,115,957** |
| **Energy Efficiency Total** | | | | | | **8,893** | **8,803** | **8,571** | | **35,815,751** | **34,783,066** | **40,144,378** | | **25,145** | **324,114,331** |
| **Demand Response Total (Scenario 1)** | | | | | | **3,794** | **7,956** | **13,455** | | **31,588** | **66,376** | **77,026** | | **0** | **174,989** |
| **Adjustments to Previous Years' Verified Results Total** | | | | | | **0** | **-209** | **478** | | **0** | **244,069** | **2,376,882** | | **256** | **8,069,609** |
| **OPA-Contracted LDC Portfolio Total (inc. Adjustments)** | | | | | | **12,687** | **16,550** | **22,503** | | **35,847,339** | **35,093,510** | **42,598,285** | | **25,401** | **332,358,930** |
| | | | | | | | | | | | | | **Full OEB Target:** | **85,260** | **374,730,000** |
| | | | | | | | | | | | | | **% of Full OEB Target Achieved to Date (Scenario 1):** | **29.8%** | **88.7%** |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 2: Adjustments to Hydro Ottawa Limited Net Verified Results due to Variances

| Initiative | Unit | Incremental Activity (new program activity occurring within the specified reporting period) | | | | Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011* | 2012* | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | |
| Appliance Retirement | Appliances | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Appliance Exchange | Appliances | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| HVAC Incentives | Equipment | -1,817 | 263 | | | -519 | 54 | | | -968,746 | 110,909 | | |
| Conservation Instant Coupon Booklet | Items | 460 | 0 | | | 1 | 0 | | | 15,424 | 0 | | |
| Bi-Annual Retailer Event | Items | 4,578 | 0 | | | 6 | 0 | | | 122,169 | 0 | | |
| Retailer Co-op | Items | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential New Construction | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Consumer Program Total** | | | | | | **-512** | **54** | | | **-831,152** | **110,909** | | |
| **Business Program** | | | | | | | | | | | | | |
| Retrofit | Projects | 34 | 47 | | | 162 | 399 | | | 927,562 | 2,177,263 | | |
| Direct Install Lighting | Projects | 38 | 34 | | | 44 | 19 | | | 108,877 | 63,534 | | |
| Building Commissioning | Buildings | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| New Construction | Buildings | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Energy Audit | Audits | 5 | 1 | | | 26 | 5 | | | 125,881 | 25,176 | | |
| Small Commercial Demand Response | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Business Program Total** | | | | | | **232** | **423** | | | **1,162,320** | **2,265,973** | | |
| **Industrial Program** | | | | | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Monitoring & Targeting | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Energy Manager | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Retrofit | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Industrial Program Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Home Assistance Program** | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Home Assistance Program Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Aboriginal Program** | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Direct Install Lighting | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Aboriginal Program Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 6 | 0 | | | 27 | 0 | | | 157,372 | 0 | | |
| High Performance New Construction | Projects | 2 | 0 | | | 43 | 0 | | | -244,470 | 0 | | |
| Toronto Comprehensive | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| LDC Custom Programs | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Pre-2011 Programs completed in 2011 Total** | | | | | | **70** | **0** | | | **-87,098** | **0** | | |
| **Other** | | | | | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Time-of-Use Savings | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Other Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Adjustments to 2011 Verified Results** | | | | | | **-209** | | | | **244,069** | | | |
| **Adjustments to 2012 Verified Results** | | | | | | | **478** | | | | **2,376,882** | | |
| **Total Adjustments to Previous Years' Verified Results** | | | | | | **-209** | **478** | | | **244,069** | **2,376,882** | | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

## Table 3: Hydro Ottawa Limited Realization Rate & NTG

| Initiative | Peak Demand Savings | | | | | | | | Energy Savings | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Realization Rate | | | | Net-to-Gross Ratio | | | | Realization Rate | | | | Net-to-Gross Ratio | | | |
| | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | | | | |
| Appliance Retirement | 1.00 | 1.00 | n/a | | 0.52 | 0.47 | 0.42 | | 1.00 | 1.00 | n/a | | 0.52 | 0.47 | 0.44 | |
| Appliance Exchange | 1.00 | 1.00 | 1.00 | | 0.52 | 0.52 | 0.53 | | 1.00 | 1.00 | 1.00 | | 0.52 | 0.52 | 0.53 | |
| HVAC Incentives | 1.00 | 1.00 | n/a | | 0.60 | 0.49 | 0.48 | | 1.00 | 1.00 | n/a | | 0.60 | 0.49 | 0.48 | |
| Conservation Instant Coupon Booklet | 1.00 | 1.00 | 1.00 | | 1.14 | 1.00 | 1.11 | | 1.00 | 1.00 | 1.00 | | 1.11 | 1.05 | 1.13 | |
| Bi-Annual Retailer Event | 1.00 | 1.00 | 1.00 | | 1.13 | 0.91 | 1.04 | | 1.00 | 1.00 | 1.00 | | 1.10 | 0.92 | 1.04 | |
| Retailer Co-op | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential Demand Response | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential Demand Response (IHD) | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential New Construction | n/a | n/a | 1.12 | | n/a | n/a | 0.63 | | n/a | n/a | 1.53 | | n/a | n/a | 0.63 | |
| **Business Program** | | | | | | | | | | | | | | | | |
| Retrofit | 0.93 | 0.95 | 0.92 | | 0.73 | 0.74 | 0.74 | | 1.24 | 1.05 | 1.00 | | 0.75 | 0.75 | 0.73 | |
| Direct Install Lighting | 1.08 | 0.68 | 0.82 | | 0.93 | 0.94 | 0.94 | | 0.90 | 0.85 | 0.84 | | 0.93 | 0.94 | 0.94 | |
| Building Commissioning | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| New Construction | n/a | 0.57 | 0.62 | | n/a | 0.49 | 0.54 | | n/a | 0.68 | 0.61 | | n/a | 0.49 | 0.54 | |
| Energy Audit | n/a | n/a | 1.02 | | n/a | n/a | 0.66 | | n/a | n/a | 0.97 | | n/a | n/a | 0.66 | |
| Small Commercial Demand Response | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Small Commercial Demand Response (IHD) | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Demand Response 3 | 0.76 | n/a | n/a | | n/a | n/a | n/a | | 1.00 | n/a | n/a | | n/a | n/a | n/a | |
| **Industrial Program** | | | | | | | | | | | | | | | | |
| Process & System Upgrades | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Monitoring & Targeting | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Energy Manager | n/a | n/a | 0.90 | | n/a | n/a | 0.90 | | n/a | n/a | 0.90 | | n/a | n/a | 0.90 | |
| Retrofit | | | | | | | | | | | | | | | | |
| Demand Response 3 | 0.84 | n/a | n/a | | n/a | n/a | n/a | | 1.00 | n/a | n/a | | n/a | n/a | n/a | |
| **Home Assistance Program** | | | | | | | | | | | | | | | | |
| Home Assistance Program | n/a | 1.07 | 1.07 | | n/a | 1.00 | 1.00 | | n/a | 1.00 | 0.90 | | n/a | 1.00 | 1.00 | |
| **Aboriginal Program** | | | | | | | | | | | | | | | | |
| Home Assistance Program | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Direct Install Lighting | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | 0.79 | n/a | n/a | | 0.53 | n/a | n/a | | 0.78 | n/a | n/a | | 0.53 | n/a | n/a | |
| High Performance New Construction | 1.00 | 1.00 | 1.00 | | 0.50 | 0.50 | 0.50 | | 1.00 | 1.00 | 1.00 | | 0.50 | 0.50 | 0.50 | |
| Toronto Comprehensive | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Multifamily Energy Efficiency Rebates | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| LDC Custom Programs | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Other** | | | | | | | | | | | | | | | | |
| Program Enabled Savings | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Time-of-Use Savings | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

## Summary Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

### Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

| Implementation Period | Annual | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| **2011 - Verified** | 12.7 | 8.9 | 8.9 | 8.3 |
| **2012 - Verified†** | -0.2 | 16.6 | 8.5 | 8.4 |
| **2013 - Verified†** | 0.0 | 0.5 | 22.5 | 8.8 |
| **2014** | | | | |
| **Verified Net Annual Peak Demand Savings Persisting in 2014:** | | | | **25.4** |
| **Hydro Ottawa Limited 2014 Annual CDM Capacity Target:** | | | | **85.3** |
| **Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):** | | | | **29.8%** |

### Table 5: Net Energy Savings at the End User Level (GWh)

| Implementation Period | Annual | | | | Cumulative |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2011-2014 |
| **2011 - Verified** | 35.8 | 35.8 | 35.7 | 34.0 | 141.4 |
| **2012 - Verified†** | 0.2 | 35.1 | 34.9 | 34.4 | 104.6 |
| **2013 - Verified†** | 0.0 | 2.4 | 42.6 | 41.4 | 86.4 |
| **2014** | | | | | |
| **Verified Net Cumulative Energy Savings 2011-2014:** | | | | | **332.4** |
| **Hydro Ottawa Limited 2011-2014 Annual CDM Energy Target:** | | | | | **374.7** |
| **Verified Portion of Cumulative Energy Target Achieved in 2014 (%):** | | | | | **88.7%** |

*†Includes adjustments to previous Years' verified results*

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

| Initiative | Unit | Incremental Activity (new program activity occurring within the specified reporting period) | | | | Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | | Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW) | Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011* | 2012* | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2014 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | | | |
| Appliance Retirement | Appliances | 56,110 | 34,146 | 20,952 | | 3,299 | 2,011 | 1,433 | | 23,005,812 | 13,424,518 | 8,713,107 | | 6,605 | 149,603,072 |
| Appliance Exchange | Appliances | 3,688 | 3,836 | 5,337 | | 371 | 556 | 1,106 | | 450,187 | 974,621 | 1,971,701 | | 1,795 | 8,455,927 |
| HVAC Incentives | Equipment | 92,743 | 87,427 | 91,581 | | 32,037 | 19,060 | 19,552 | | 59,437,670 | 32,841,283 | 33,923,592 | | 70,650 | 404,121,713 |
| Conservation Instant Coupon Booklet | Items | 567,678 | 30,891 | 346,896 | | 1,344 | 230 | 517 | | 21,211,537 | 1,398,202 | 7,707,573 | | 2,091 | 104,455,900 |
| Bi-Annual Retailer Event | Items | 952,149 | 1,060,901 | 944,772 | | 1,681 | 1,480 | 1,184 | | 29,387,468 | 26,781,674 | 17,179,841 | | 4,345 | 232,254,579 |
| Retailer Co-op | Items | 152 | 0 | 0 | | 0 | 0 | 0 | | 2,652 | 0 | 0 | | 0 | 10,607 |
| Residential Demand Response | Devices | 19,550 | 98,388 | 171,733 | | 10,947 | 49,038 | 93,076 | | 24,870 | 359,408 | 390,303 | | 0 | 774,582 |
| Residential Demand Response (IHD) | Devices | 0 | 49,689 | 133,657 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Residential New Construction | Homes | 26 | 19 | 86 | | 0 | 2 | 18 | | 743 | 17,152 | 163,690 | | 20 | 381,811 |
| **Consumer Program Total** | | | | | | **49,681** | **72,377** | **116,886** | | **133,520,941** | **75,796,859** | **70,049,807** | | **85,506** | **900,058,189** |
| **Business Program** | | | | | | | | | | | | | | | |
| Retrofit | Projects | 2,819 | 6,134 | 8,785 | | 24,467 | 61,147 | 59,678 | | 136,002,258 | 314,922,468 | 345,346,008 | | 142,831 | 2,168,497,702 |
| Direct Install Lighting | Projects | 20,741 | 18,691 | 17,782 | | 23,724 | 15,284 | 18,708 | | 61,076,701 | 57,345,798 | 64,315,558 | | 49,886 | 519,693,356 |
| Building Commissioning | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| New Construction | Buildings | 22 | 69 | 86 | | 123 | 764 | 1,584 | | 411,717 | 1,814,721 | 4,959,266 | | 2,472 | 17,009,564 |
| Energy Audit | Audits | 198 | 345 | 319 | | 0 | 1,450 | 2,811 | | 0 | 7,049,351 | 15,455,795 | | 4,261 | 52,059,644 |
| Small Commercial Demand Response | Devices | 132 | 294 | 1,211 | | 84 | 187 | 773 | | 157 | 1,068 | 373 | | 0 | 1,597 |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | 378 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Demand Response 3 | Facilities | 145 | 151 | 175 | | 16,218 | 19,389 | 23,706 | | 633,421 | 281,823 | 346,659 | | 0 | 1,261,903 |
| **Business Program Total** | | | | | | **64,617** | **98,221** | **107,261** | | **198,124,253** | **381,415,230** | **430,423,659** | | **199,449** | **2,758,523,766** |
| **Industrial Program** | | | | | | | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | 3 | | 0 | 0 | 294 | | 0 | 0 | 2,603,764 | | 294 | 5,207,528 |
| Monitoring & Targeting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Energy Manager | Projects | 0 | 42 | 205 | | 0 | 1,086 | 3,558 | | 0 | 7,372,108 | 21,994,263 | | 3,194 | 54,888,570 |
| Retrofit | Projects | 433 | 0 | 0 | | 4,615 | 0 | 0 | | 28,866,840 | 0 | 0 | | 4,613 | 115,462,282 |
| Demand Response 3 | Facilities | 124 | 185 | 281 | | 52,484 | 74,056 | 162,543 | | 3,080,737 | 1,784,712 | 4,309,160 | | 0 | 9,174,609 |
| **Industrial Program Total** | | | | | | **57,098** | **75,141** | **166,395** | | **31,947,577** | **9,156,820** | **28,907,187** | | **8,101** | **184,732,989** |
| **Home Assistance Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 46 | 5,033 | 26,756 | | 2 | 566 | 2,361 | | 39,283 | 5,442,232 | 20,987,275 | | 2,904 | 57,949,913 |
| **Home Assistance Program Total** | | | | | | **2** | **566** | **2,361** | | **39,283** | **5,442,232** | **20,987,275** | | **2,904** | **57,949,913** |
| **Aboriginal Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 584 | | 0 | 0 | 267 | | 0 | 0 | 1,609,393 | | 267 | 3,218,786 |
| Direct Install Lighting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Aboriginal Program Total** | | | | | | **0** | **0** | **267** | | **0** | **0** | **1,609,393** | | **267** | **3,218,786** |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 2,028 | 0 | 0 | | 21,662 | 0 | 0 | | 121,138,219 | 0 | 0 | | 21,662 | 484,552,876 |
| High Performance New Construction | Projects | 179 | 69 | 4 | | 5,098 | 3,251 | 772 | | 26,185,591 | 11,901,944 | 3,522,240 | | 9,121 | 147,492,677 |
| Toronto Comprehensive | Projects | 577 | 0 | 0 | | 15,805 | 0 | 0 | | 86,964,886 | 0 | 0 | | 15,805 | 347,859,545 |
| Multifamily Energy Efficiency Rebates | Projects | 110 | 0 | 0 | | 1,981 | 0 | 0 | | 7,595,683 | 0 | 0 | | 1,981 | 30,382,733 |
| LDC Custom Programs | Projects | 8 | 0 | 0 | | 399 | 0 | 0 | | 1,367,170 | 0 | 0 | | 399 | 5,468,679 |
| **Pre-2011 Programs completed in 2011 Total** | | | | | | **44,945** | **3,251** | **772** | | **243,251,550** | **11,901,944** | **3,522,240** | | **48,967** | **1,015,756,510** |
| **Other** | | | | | | | | | | | | | | | |
| Program Enabled Savings | Projects | 14 | 56 | 13 | | 0 | 2,304 | 3,692 | | 0 | 1,188,362 | 4,075,382 | | 5,996 | 11,715,850 |
| Time-of-Use Savings | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Other Total** | | | | | | **0** | **2,304** | **3,692** | | **0** | **1,188,362** | **4,075,382** | | **5,996** | **11,715,850** |
| **Adjustments to 2011 Verified Results** | | | | | | | **1,406** | **641** | | | **18,689,081** | **1,736,381** | | **1,797** | **80,864,121** |
| **Adjustments to 2012 Verified Results** | | | | | | | | **6,260** | | | | **41,947,840** | | **6,180** | **126,287,857** |
| **Energy Efficiency Total** | | | | | | **136,610** | **109,191** | **117,536** | | **603,144,419** | **482,474,435** | **554,528,447** | | **351,190** | **4,920,743,312** |
| **Demand Response Total (Scenario 1)** | | | | | | **79,733** | **142,670** | **280,099** | | **3,739,185** | **2,427,011** | **5,046,495** | | **0** | **11,212,691** |
| **Adjustments to Previous Years' Verified Results Total** | | | | | | **0** | **1,406** | **6,901** | | **0** | **18,689,081** | **43,684,221** | | **7,976** | **207,151,978** |
| **OPA-Contracted LDC Portfolio Total (inc. Adjustments)** | | | | | | **216,343** | **253,267** | **404,536** | | **606,883,604** | **503,590,526** | **603,259,163** | | **359,166** | **5,139,107,980** |
| | | | | | | | | | | | | | **Full OEB Target:** | **1,330,000** | **6,000,000,000** |
| | | | | | | | | | | | | | **% of Full OEB Target Achieved to Date (Scenario 1):** | **27.0%** | **85.7%** |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

| Initiative | Unit | Incremental Activity (new program activity occurring within the specified reporting period) | | | | Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011* | 2012* | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | |
| Appliance Retirement | Appliances | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Appliance Exchange | Appliances | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| HVAC Incentives | Equipment | -18,844 | 2,206 | | | -5,271 | 452 | | | -9,709,500 | 907,735 | | |
| Conservation Instant Coupon Booklet | Items | 8,216 | 0 | | | 16 | 0 | | | 275,655 | 0 | | |
| Bi-Annual Retailer Event | Items | 81,817 | 0 | | | 108 | 0 | | | 2,183,391 | 0 | | |
| Retailer Co-op | Items | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Residential New Construction | Homes | 19 | 0 | | | 1 | 0 | | | 13,767 | 0 | | |
| **Consumer Program Total** | | | | | | **-5,146** | **452** | | | **-7,236,687** | **907,735** | | |
| **Business Program** | | | | | | | | | | | | | |
| Retrofit | Projects | 303 | 529 | | | 3,204 | 4,443 | | | 16,216,165 | 28,739,635 | | |
| Direct Install Lighting | Projects | 444 | 197 | | | 501 | 204 | | | 1,250,388 | 736,541 | | |
| Building Commissioning | Buildings | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| New Construction | Buildings | 12 | 0 | | | 828 | 0 | | | 3,520,620 | 0 | | |
| Energy Audit | Audits | 95 | 65 | | | 492 | 337 | | | 2,391,744 | 1,636,457 | | |
| Small Commercial Demand Response | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Business Program Total** | | | | | | **5,025** | **4,984** | | | **23,378,917** | **31,112,632** | | |
| **Industrial Program** | | | | | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Monitoring & Targeting | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Energy Manager | Projects | 0 | 3 | | | 0 | 68 | | | 0 | 719,235 | | |
| Retrofit | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Industrial Program Total** | | | | | | **0** | **68** | | | **0** | **719,235** | | |
| **Home Assistance Program** | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Home Assistance Program Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Aboriginal Program** | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Direct Install Lighting | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Aboriginal Program Total** | | | | | | **0** | **0** | | | **0** | **0** | | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 12 | 0 | | | 138 | 0 | | | 545,536 | 0 | | |
| High Performance New Construction | Projects | 34 | 0 | | | 1,407 | 0 | | | 2,065,200 | 0 | | |
| Toronto Comprehensive | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| LDC Custom Programs | Projects | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Pre-2011 Programs completed in 2011 Total** | | | | | | **1,545** | **0** | | | **2,610,736** | **0** | | |
| **Other** | | | | | | | | | | | | | |
| Program Enabled Savings | Projects | 14 | 40 | | | 624 | 824 | | | 1,673,712 | 9,927,473 | | |
| Time-of-Use Savings | Homes | 0 | 0 | | | 0 | 0 | | | 0 | 0 | | |
| **Other Total** | | | | | | **624** | **824** | | | **1,673,712** | **9,927,473** | | |
| **Adjustments to 2011 Verified Results** | | | | | | **2,047** | | | | **20,426,678** | | | |
| **Adjustments to 2012 Verified Results** | | | | | | | **6,328** | | | | **42,667,076** | | |
| **Adjustments to Previous Years' Verified Results Total** | | | | | | **2,047** | **6,328** | | | **20,426,678** | **42,667,076** | | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

**Table 8: Province-Wide Realization Rate & NTG**

| Initiative | Peak Demand Savings | | | | | | | | Energy Savings | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Realization Rate | | | | Net-to-Gross Ratio | | | | Realization Rate | | | | Net-to-Gross Ratio | | | |
| | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | | | | |
| Appliance Retirement | 1.00 | 1.00 | 1.00 | | 0.51 | 0.46 | 0.42 | | 1.00 | 1.00 | 1.00 | | 0.46 | 0.47 | 0.44 | |
| Appliance Exchange | 1.00 | 1.00 | 1.00 | | 0.51 | 0.52 | 0.53 | | 1.00 | 1.00 | 1.00 | | 0.52 | 0.52 | 0.53 | |
| HVAC Incentives | 1.00 | 1.00 | 1.00 | | 0.60 | 0.50 | 0.48 | | 1.00 | 1.00 | 1.00 | | 0.50 | 0.49 | 0.48 | |
| Conservation Instant Coupon Booklet | 1.00 | 1.00 | 1.00 | | 1.14 | 1.00 | 1.11 | | 1.00 | 1.00 | 1.00 | | 1.00 | 1.05 | 1.13 | |
| Bi-Annual Retailer Event | 1.00 | 1.00 | 1.00 | | 1.12 | 0.91 | 1.04 | | 1.00 | 1.00 | 1.00 | | 0.91 | 0.92 | 1.04 | |
| Retailer Co-op | 1.00 | n/a | n/a | | 0.68 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential Demand Response | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential Demand Response (IHD) | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Residential New Construction | 1.00 | 3.65 | 0.78 | | 0.41 | 0.49 | 0.63 | | 3.65 | 7.17 | 3.09 | | 0.49 | 0.49 | 0.63 | |
| **Business Program** | | | | | | | | | | | | | | | | |
| Retrofit | 1.06 | 0.93 | 0.92 | | 0.72 | 0.75 | 0.73 | | 0.93 | 1.05 | 1.01 | | 0.75 | 0.76 | 0.73 | |
| Direct Install Lighting | 1.08 | 0.69 | 0.82 | | 1.08 | 0.94 | 0.94 | | 0.69 | 0.85 | 0.84 | | 0.94 | 0.94 | 0.94 | |
| Building Commissioning | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| New Construction | 0.50 | 0.98 | 0.68 | | 0.50 | 0.49 | 0.54 | | 0.98 | 0.99 | 0.76 | | 0.49 | 0.49 | 0.54 | |
| Energy Audit | n/a | n/a | 1.02 | | n/a | n/a | 0.66 | | n/a | n/a | 0.97 | | n/a | n/a | 0.66 | |
| Small Commercial Demand Response | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Small Commercial Demand Response (IHD) | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Demand Response 3 | 0.76 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Industrial Program** | | | | | | | | | | | | | | | | |
| Process & System Upgrades | n/a | n/a | 0.85 | | n/a | n/a | 0.94 | | n/a | n/a | 0.87 | | n/a | n/a | 0.93 | |
| Monitoring & Targeting | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Energy Manager | n/a | 1.16 | 0.90 | | n/a | 0.90 | 0.90 | | 1.16 | 1.16 | 0.90 | | 0.90 | 0.90 | 0.90 | |
| Retrofit | 1.11 | n/a | n/a | | 0.72 | n/a | n/a | | 0.91 | n/a | n/a | | 0.75 | n/a | n/a | |
| Demand Response 3 | 0.84 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Home Assistance Program** | | | | | | | | | | | | | | | | |
| Home Assistance Program | 1.00 | 0.32 | 0.26 | | 0.70 | 1.00 | 1.00 | | 0.32 | 0.99 | 0.88 | | 1.00 | 1.00 | 1.00 | |
| **Aboriginal Program** | | | | | | | | | | | | | | | | |
| Home Assistance Program | n/a | n/a | 0.05 | | n/a | n/a | 1.00 | | n/a | n/a | 0.95 | | n/a | n/a | 1.00 | |
| Direct Install Lighting | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | 0.80 | n/a | n/a | | 0.54 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| High Performance New Construction | 1.00 | 1.00 | 1.00 | | 0.49 | 0.50 | 0.50 | | 1.00 | 1.00 | 1.00 | | 0.50 | 0.50 | 0.50 | |
| Toronto Comprehensive | 1.13 | n/a | n/a | | 0.50 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| Multifamily Energy Efficiency Rebates | 0.93 | n/a | n/a | | 0.78 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| LDC Custom Programs | 1.00 | n/a | n/a | | 1.00 | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |
| **Other** | | | | | | | | | | | | | | | | |
| Program Enabled Savings | n/a | 1.06 | 1.00 | | n/a | 1.00 | 1.00 | | 1.06 | 2.26 | 1.00 | | 1.00 | 1.00 | 1.00 | |
| Time-of-Use Savings | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | | n/a | n/a | n/a | |

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

## Summary Provincial Progress Towards CDM Targets

### Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

| Implementation Period | Annual | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| **2011** | 216.3 | 136.6 | 135.8 | 129.0 |
| **2012†** | 1.4 | 253.3 | 109.8 | 108.2 |
| **2013†** | 0.6 | 7.0 | 404.5 | 122.0 |
| **2014** | | | | |
| **Verified Net Annual Peak Demand Savings in 2014:** | | | | **359.2** |
| **2014 Annual CDM Capacity Target:** | | | | **1,330** |
| **Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):** | | | | **27.0%** |

### Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

| Implementation Period | Annual | | | | Cumulative |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2011-2014 |
| **2011** | 606.9 | 603.0 | 601.0 | 582.3 | 2,393.1 |
| **2012†** | 18.7 | 503.6 | 498.4 | 492.6 | 1,513.3 |
| **2013†** | 1.7 | 44.4 | 603.3 | 583.4 | 1,232.8 |
| **2014** | | | | | |
| **Verified Net Cumulative Energy Savings 2011-2014:** | | | | | **5,139.1** |
| **2011-2014 Cumulative CDM Energy Target:** | | | | | **6,000** |
| **Verified Portion of Cumulative Energy Target Achieved in 2014 (%):** | | | | | **85.7%** |

*†Includes adjustments to previous Years' verified results*

## METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

| EQUATIONS | |
|---|---|
| Prescriptive Measures and Projects | **Gross Savings = Activity * Per Unit Assumption**<br>**Net Savings = Gross Savings * Net-to-Gross Ratio**<br>**All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)** |
| Engineered and Custom Projects | **Gross Savings = Reported Savings * Realization Rate**<br>**Net Savings = Gross Savings * Net-to-Gross Ratio**<br>**All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)** |
| Demand Response | **Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio**<br>**Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW**<br>**All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)** |
| Adjustments to Previous Years' Verified Results | All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings. |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| **Consumer Program** | | | |
| Appliance Retirement | Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection. | Savings are considered to begin in the year the appliance is picked up. | Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| Appliance Exchange | When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year that the exchange event occurred. | |
| HVAC Incentives | Results directly attributed to LDC based on customer postal code. | Savings are considered to begin in the year that the installation occurred. | |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Conservation Instant Coupon Booklet | LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year in which the coupon was redeemed. | Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| Bi-Annual Retailer Event | Results are allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year in which the event occurs. | Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| Retailer Co-op | When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year of the home visit and installation date. | Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| Residential Demand Response | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists. | Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement. | Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated. |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Residential New Construction | Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case. | Savings are considered to begin in the year of the project completion date. | Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| **Business Program** | | | |
| Efficiency: Equipment Replacement | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page  for Building type to Sector mapping. | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings  to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |
| | Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2013) | | |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Direct Installed Lighting | Results are directly attributed to LDC based on the LDC specified on the work order. | Savings are considered to begin in the year of the actual project completion date. | Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net). |
| Existing Building Commissioning Incentive | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012. | Savings are considered to begin in the year of the actual project completion date. | Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| New Construction and Major Renovation Incentive | Results are directly attributed to LDC based on LDC identified in the application. | Savings are considered to begin in the year of the actual project completion date. | |
| Energy Audit | Projects are directly attributed to LDC based on LDC identified in the application. | Savings are considered to begin in the year of the audit date. | Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Commercial Demand Response (part of the Residential program schedule) | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists | Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement. | Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated. |
| Demand Response 3 (part of the Industrial program schedule) | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |
| **Industrial Program** | | | |
| Process & System Upgrades | Results are directly attributed to LDC based on LDC identified in application. | Savings are considered to begin in the year in which the incentive project was completed. | Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Monitoring & Targeting | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013. | Savings are considered to begin in the year in which the incentive project was completed. | Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| Energy Manager | Results are directly attributed to LDC based on LDC identified in the application. | Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager. | Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping. | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings  to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |
| Demand Response 3 | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year.  Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| **Home Assistance Program** | | | |
| Home Assistance Program | Results are directly attributed to LDC based on LDC identified in the application. | Savings are considered to begin in the year in which the measures were installed. | Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| **Aboriginal Program** | | | |
| Aboriginal Program | Results are directly attributed to LDC based on LDC identified in the application. | Savings are considered to begin in the year in which the measures were installed. | Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |

| Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|
| **Pre-2011 Programs completed in 2011** | | | |
| Electricity Retrofit Incentive Program | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013 assumptions as per 2010 evaluation. | Savings are considered to begin in the year in which a project was completed. | Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports). |
| High Performance New Construction | Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation. | Savings are considered to begin in the year in which a project was completed. | |
| Toronto Comprehensive | Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation. | | |

<table>
<tr><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td>Multifamily Energy Efficiency Rebates</td><td>Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.</td><td rowspan="3">Savings are considered to begin in the year in which a project was completed.</td><td rowspan="3">Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).</td></tr>
<tr><td>Data Centre Incentive Program</td><td>Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.</td></tr>
<tr><td>EnWin Green Suites</td><td>Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.</td></tr>
</table>

| Retrofit Sector (C&I vs. Industrial Mapping) | |
|---|---|
| **Building Type** | **Sector** |
| Agribusiness - Cattle Farm | C&I |
| Agribusiness - Dairy Farm | C&I |
| Agribusiness - Greenhouse | C&I |
| Agribusiness - Other | C&I |
| Agribusiness - Other,Mixed-Use - Office/Retail | C&I |
| Agribusiness - Other,Office,Retail,Warehouse | C&I |
| Agribusiness - Other,Office,Warehouse | C&I |
| Agribusiness - Poultry | C&I |
| Agribusiness - Poultry,Hospitality - Motel | C&I |
| Agribusiness - Swine | C&I |
| Convenience Store | C&I |
| Education - College / Trade School | C&I |
| Education - College / Trade School,Multi-Residential - Condominium | C&I |
| Education - College / Trade School,Multi-Residential - Rental Apartment | C&I |
| Education - College / Trade School,Retail | C&I |
| Education - Primary School | C&I |
| Education - Primary School,Education - Secondary School | C&I |
| Education - Primary School,Multi-Residential - Rental Apartment | C&I |
| Education - Primary School,Not-for-Profit | C&I |
| Education - Secondary School | C&I |
| Education - University | C&I |
| Education - University,Office | C&I |
| Hospital/Healthcare - Clinic | C&I |
| Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Clinic,Industrial | C&I |
| Hospital/Healthcare - Clinic,Retail | C&I |
| Hospital/Healthcare - Long-term Care | C&I |
| Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail | C&I |
| Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office | C&I |
| Hospitality - Hotel | C&I |
| Hospitality - Hotel,Restaurant - Dining | C&I |
| Hospitality - Motel | C&I |
| Industrial | Industrial |
| Mixed-Use - Office/Retail | C&I |
| Mixed-Use - Office/Retail,Industrial | Industrial |
| Mixed-Use - Office/Retail,Mixed-Use - Other | C&I |
| Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse | C&I |
| Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail | C&I |
| Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse | C&I |

| | |
|---|---|
| Mixed-Use - Office/Retail,Office,Warehouse | C&I |
| Mixed-Use - Office/Retail,Retail | C&I |
| Mixed-Use - Office/Retail,Warehouse | C&I |
| Mixed-Use - Office/Retail,Warehouse,Industrial | Industrial |
| Mixed-Use - Other | C&I |
| Mixed-Use - Other,Industrial | Industrial |
| Mixed-Use - Other,Not-for-Profit,Office | C&I |
| Mixed-Use - Other,Office | C&I |
| Mixed-Use - Other,Other: Please specify | C&I |
| Mixed-Use - Other,Retail,Warehouse | C&I |
| Mixed-Use - Other,Warehouse | C&I |
| Mixed-Use - Residential/Retail | C&I |
| Mixed-Use - Residential/Retail,Multi-Residential - Condominium | C&I |
| Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment | C&I |
| Mixed-Use - Residential/Retail,Retail | C&I |
| Multi-Residential - Condominium | C&I |
| Multi-Residential - Condominium,Multi-Residential - Rental Apartment | C&I |
| Multi-Residential - Condominium,Other: Please specify | C&I |
| Multi-Residential - Rental Apartment | C&I |
| Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit | C&I |
| Multi-Residential - Rental Apartment,Not-for-Profit | C&I |
| Multi-Residential - Rental Apartment,Warehouse | C&I |
| Multi-Residential - Social Housing Provider | C&I |
| Multi-Residential - Social Housing Provider,Industrial | C&I |
| Multi-Residential - Social Housing Provider,Not-for-Profit | C&I |
| Not-for-Profit | C&I |
| Not-for-Profit,Office | C&I |
| Not-for-Profit,Other: Please specify | C&I |
| Not-for-Profit,Warehouse | C&I |
| Office | C&I |
| Office,Industrial | Industrial |
| Office,Other: Please specify | C&I |
| Office,Other: Please specify,Warehouse | C&I |
| Office,Restaurant - Dining | C&I |
| Office,Restaurant - Dining,Industrial | Industrial |
| Office,Retail | C&I |
| Office,Retail,Industrial | C&I |
| Office,Retail,Warehouse | C&I |
| Office,Warehouse | C&I |
| Office,Warehouse,Industrial | Industrial |
| Other: Please specify | C&I |
| Other: Please specify,Industrial | Industrial |
| Other: Please specify,Retail | C&I |
| Other: Please specify,Warehouse | C&I |
| Restaurant - Dining | C&I |
| Restaurant - Dining,Retail | C&I |

| | |
|---|---|
| Restaurant - Quick Serve | C&I |
| Restaurant - Quick Serve,Retail | C&I |
| Retail | C&I |
| Retail,Industrial | Industrial |
| Retail,Warehouse | C&I |
| Warehouse | C&I |
| Warehouse,Industrial | Industrial |

## Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

| Local Distribution Company | Allocation |
|---|---|
| Algoma Power Inc. | 0.2% |
| Atikokan Hydro Inc. | 0.0% |
| Attawapiskat Power Corporation | 0.0% |
| Bluewater Power Distribution Corporation | 0.6% |
| Brant County Power Inc. | 0.2% |
| Brantford Power Inc. | 0.7% |
| Burlington Hydro Inc. | 1.4% |
| Cambridge and North Dumfries Hydro Inc. | 1.0% |
| Canadian Niagara Power Inc. | 0.5% |
| Centre Wellington Hydro Ltd. | 0.1% |
| Chapleau Public Utilities Corporation | 0.0% |
| COLLUS Power Corporation | 0.3% |
| Cooperative Hydro Embrun Inc. | 0.0% |
| E.L.K. Energy Inc. | 0.2% |
| Enersource Hydro Mississauga Inc. | 3.9% |
| ENTEGRUS | 0.6% |
| ENWIN Utilities Ltd. | 1.6% |
| Erie Thames Powerlines Corporation | 0.4% |
| Espanola Regional Hydro Distribution Corporation | 0.1% |
| Essex Powerlines Corporation | 0.7% |
| Festival Hydro Inc. | 0.3% |
| Fort Albany Power Corporation | 0.0% |
| Fort Frances Power Corporation | 0.1% |
| Greater Sudbury Hydro Inc. | 1.0% |
| Grimsby Power Inc. | 0.2% |
| Guelph Hydro Electric Systems Inc. | 0.9% |
| Haldimand County Hydro Inc. | 0.4% |
| Halton Hills Hydro Inc. | 0.5% |
| Hearst Power Distribution Company Limited | 0.1% |
| Horizon Utilities Corporation | 4.0% |
| Hydro 2000 Inc. | 0.0% |
| Hydro Hawkesbury Inc. | 0.1% |
| Hydro One Brampton Networks Inc. | 2.8% |
| Hydro One Networks Inc. | 30.0% |

| | |
|---|---|
| Hydro Ottawa Limited | 5.6% |
| Innisfil Hydro Distribution Systems Limited | 0.4% |
| Kashechewan Power Corporation | 0.0% |
| Kenora Hydro Electric Corporation Ltd. | 0.1% |
| Kingston Hydro Corporation | 0.5% |
| Kitchener-Wilmot Hydro Inc. | 1.6% |
| Lakefront Utilities Inc. | 0.2% |
| Lakeland Power Distribution Ltd. | 0.2% |
| London Hydro Inc. | 2.7% |
| Middlesex Power Distribution Corporation | 0.1% |
| Midland Power Utility Corporation | 0.1% |
| Milton Hydro Distribution Inc. | 0.6% |
| Newmarket - Tay Power Distribution Ltd. | 0.7% |
| Niagara Peninsula Energy Inc. | 1.0% |
| Niagara-on-the-Lake Hydro Inc. | 0.2% |
| Norfolk Power Distribution Inc. | 0.3% |
| North Bay Hydro Distribution Limited | 0.5% |
| Northern Ontario Wires Inc. | 0.1% |
| Oakville Hydro Electricity Distribution Inc. | 1.5% |
| Orangeville Hydro Limited | 0.2% |
| Orillia Power Distribution Corporation | 0.3% |
| Oshawa PUC Networks Inc. | 1.2% |
| Ottawa River Power Corporation | 0.2% |
| Parry Sound Power Corporation | 0.1% |
| Peterborough Distribution Incorporated | 0.7% |
| PowerStream Inc. | 6.6% |
| PUC Distribution Inc. | 0.9% |
| Renfrew Hydro Inc. | 0.1% |
| Rideau St. Lawrence Distribution Inc. | 0.1% |
| Sioux Lookout Hydro Inc. | 0.1% |
| St. Thomas Energy Inc. | 0.3% |
| Thunder Bay Hydro Electricity Distribution Inc. | 0.9% |
| Tillsonburg Hydro Inc. | 0.1% |
| Toronto Hydro-Electric System Limited | 12.8% |
| Veridian Connections Inc. | 2.4% |
| Wasaga Distribution Inc. | 0.2% |
| Waterloo North Hydro Inc. | 1.0% |
| Welland Hydro-Electric System Corp. | 0.4% |
| Wellington North Power Inc. | 0.1% |
| West Coast Huron Energy Inc. | 0.1% |
| Westario Power Inc. | 0.5% |
| Whitby Hydro Electric Corporation | 0.9% |
| Woodstock Hydro Services Inc. | 0.3% |

## Reporting Glossary

**Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).**

**Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.**

**End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).**

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

**Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.**

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

**Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover**

**Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.**

**Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.**

**Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).**

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

**Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).**

Table 11: Hydro Ottawa Limited Initiative and Program Level Gross Savings by Year

| Initiative | Unit | Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | |
| Appliance Retirement** | Appliances | 484 | 146 | 224 | | 3,383,778 | 1,040,845 | 1,449,558 | |
| Appliance Exchange** | Appliances | 36 | 25 | 75 | | 44,231 | 43,987 | 134,065 | |
| HVAC Incentives | Equipment | 4,807 | 3,258 | 3,015 | | 9,163,550 | 5,804,920 | 5,403,040 | |
| Conservation Instant Coupon Booklet | Items | 61 | 13 | 26 | | 1,000,717 | 74,189 | 382,850 | |
| Bi-Annual Retailer Event | Items | 84 | 91 | 64 | | 1,505,117 | 1,635,087 | 919,955 | |
| Retailer Co-op | Items | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Residential Demand Response | Devices | 3,193 | 7,249 | 11,608 | | 8,266 | 55,891 | 48,406 | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Residential New Construction | Homes | 0 | 0 | 2 | | 0 | 0 | 26,267 | |
| **Consumer Program Total** | | **8,664** | **10,783** | **15,014** | | **15,105,660** | **8,654,920** | **8,364,142** | |
| **Business Program** | | | | | | | | | |
| Retrofit | Projects | 3,878 | 6,654 | 6,747 | | 19,754,306 | 28,161,679 | 36,547,733 | |
| Direct Install Lighting | Projects | 1,323 | 1,131 | 1,071 | | 4,168,756 | 4,044,402 | 3,873,274 | |
| Building Commissioning | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | |
| New Construction | Buildings | 0 | 48 | 231 | | 0 | 48,345 | 216,862 | |
| Energy Audit | Audits | 0 | 124 | 645 | | 0 | 604,230 | 3,518,913 | |
| Small Commercial Demand Response | Devices | 4 | 21 | 138 | | 16 | 120 | 46 | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Demand Response 3 | Facilities | 597 | 644 | 1,520 | | 23,305 | 9,354 | 24,274 | |
| **Business Program Total** | | **5,802** | **8,622** | **10,352** | | **23,946,384** | **32,868,130** | **44,181,101** | |
| **Industrial Program** | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Monitoring & Targeting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Energy Manager | Projects | 0 | 0 | 121 | | 0 | 0 | 907,763 | |
| Retrofit | Projects | 119 | 0 | 0 | | 765,408 | 0 | 0 | |
| Demand Response 3 | Facilities | 0 | 42 | 189 | | 0 | 1,010 | 4,299 | |
| **Industrial Program Total** | | **119** | **42** | **309** | | **765,408** | **1,010** | **912,062** | |
| **Home Assistance Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 25 | 32 | | 0 | 319,849 | 384,041 | |
| **Home Assistance Program Total** | | **0** | **25** | **32** | | **0** | **319,849** | **384,041** | |
| **Aboriginal Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Direct Install Lighting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| **Aboriginal Program Total** | | **0** | **0** | **0** | | **0** | **0** | **0** | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 1,774 | 0 | 0 | | 9,327,285 | 0 | 0 | |
| High Performance New Construction | Projects | 643 | 1,614 | 286 | | 3,302,184 | 4,862,115 | 1,899,180 | |
| Toronto Comprehensive | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| LDC Custom Programs | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| **Pre-2011 Programs completed in 2011 Total** | | **2,417** | **1,614** | **286** | | **12,629,469** | **4,862,115** | **1,899,180** | |
| **Other** | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Time-of-Use Savings | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | |
| **Other Total** | | **0** | **0** | **0** | | **0** | **0** | **0** | |
| **Adjustments to 2011 Verified Results** | | **0** | **290** | **0** | | **0** | **2,190,674** | **0** | |
| **Adjustments to 2012 Verified Results** | | **0** | **0** | **751** | | **0** | **0** | **3,557,363** | |
| **Energy Efficiency Total** | | **13,208** | **13,130** | **12,538** | | **52,415,333** | **46,639,648** | **55,663,501** | |
| **Demand Response Total** | | **3,794** | **7,956** | **13,455** | | **31,588** | **66,376** | **77,026** | |
| **Adjustments to Previous Years' Verified Results Total** | | **0** | **290** | **751** | | **0** | **2,190,674** | **3,557,363** | |
| **OPA-Contracted LDC Portfolio Total (inc. Adjustments)** | | **17,002** | **21,376** | **26,744** | | **52,446,922** | **48,896,698** | **59,297,889** | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Hydro Ottawa Limited Gross Verified Results due to Variances

| Initiative | Unit | Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | |
| Appliance Retirement | Appliances | 0 | 0 | | | 0 | 0 | | |
| Appliance Exchange | Appliances | 0 | 0 | | | 0 | 0 | | |
| HVAC Incentives | Equipment | -865 | 125 | | | -1,623,490 | 227,388 | | |
| Conservation Instant Coupon Booklet | Items | 1 | 0 | | | 14,323 | 0 | | |
| Bi-Annual Retailer Event | Items | 7 | 0 | | | 132,813 | 0 | | |
| Retailer Co-op | Items | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response | Devices | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | |
| Residential New Construction | Homes | 0 | 0 | | | 0 | 0 | | |
| **Consumer Program Total** | | **-857** | **125** | | | **-1,476,354** | **227,388** | | |
| **Business Program** | | | | | | | | | |
| Retrofit | Projects | 244 | 601 | | | 1,341,295 | 3,237,356 | | |
| Direct Install Lighting | Projects | 48 | 20 | | | 117,256 | 67,443 | | |
| Building Commissioning | Buildings | 0 | 0 | | | 0 | 0 | | |
| New Construction | Buildings | 48 | 0 | | | 48,345 | 0 | | |
| Energy Audit | Audits | 26 | 5 | | | 125,881 | 25,176 | | |
| Small Commercial Demand Response | Devices | 0 | 0 | | | 0 | 0 | | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | |
| **Business Program Total** | | **366** | **626** | | | **1,632,777** | **3,329,975** | | |
| **Industrial Program** | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | | | 0 | 0 | | |
| Monitoring & Targeting | Projects | 0 | 0 | | | 0 | 0 | | |
| Energy Manager | Projects | 0 | 0 | | | 0 | 0 | | |
| Retrofit | Projects | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | |
| **Industrial Program Total** | | **0** | **0** | | | **0** | **0** | | |
| **Home Assistance Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | |
| **Home Assistance Program Total** | | **0** | **0** | | | **0** | **0** | | |
| **Aboriginal Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | |
| Direct Install Lighting | Projects | 0 | 0 | | | 0 | 0 | | |
| **Aboriginal Program Total** | | | | | | | | | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 52 | 0 | | | 302,638 | 0 | | |
| High Performance New Construction | Projects | 730 | 0 | | | 1,731,613 | 0 | | |
| Toronto Comprehensive | Projects | 0 | 0 | | | 0 | 0 | | |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | | | 0 | 0 | | |
| LDC Custom Programs | Projects | 0 | 0 | | | 0 | 0 | | |
| **Pre-2011 Programs completed in 2011 Total** | | **782** | **0** | | | **2,034,251** | **0** | | |
| **Other** | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 0 | | | 0 | 0 | | |
| Time-of-Use Savings | Homes | 0 | 0 | | | 0 | 0 | | |
| **Other Total** | | **0** | **0** | | | **0** | **0** | | |
| **Adjustments to 2011 Verified Results** | | **290** | | | | **2,190,674** | | | |
| **Adjustments to 2012 Verified Results** | | | **751** | | | | **3,557,363** | | |
| **Total Adjustments to Previous Years' Verified Results** | | **290** | **751** | | | **2,190,674** | **3,557,363** | | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results*

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

| Initiative | Unit | Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 |
| **Consumer Program** | | | | | | | | | |
| Appliance Retirement** | Appliances | 6,750 | 2,011 | 3,151 | | 45,971,627 | 13,424,518 | 18,616,239 | |
| Appliance Exchange** | Appliances | 719 | 556 | 2,101 | | 873,531 | 974,621 | 3,746,106 | |
| HVAC Incentives | Equipment | 53,209 | 38,346 | 40,418 | | 99,413,430 | 66,929,213 | 71,225,037 | |
| Conservation Instant Coupon Booklet | Items | 1,184 | 231 | 464 | | 19,192,453 | 1,325,898 | 6,842,244 | |
| Bi-Annual Retailer Event | Items | 1,504 | 1,622 | 1,142 | | 26,899,265 | 29,222,072 | 16,441,329 | |
| Retailer Co-op | Items | 0 | 0 | 0 | | 3,917 | 0 | 0 | |
| Residential Demand Response | Devices | 10,390 | 49,038 | 93,076 | | 23,597 | 359,408 | 390,303 | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Residential New Construction | Homes | 0 | 1 | 29 | | 1,813 | 4,884 | 259,826 | |
| **Consumer Program Total** | | **73,757** | **91,805** | **140,380** | | **192,379,633** | **112,240,615** | **117,521,084** | |
| **Business Program** | | | | | | | | | |
| Retrofit | Projects | 34,201 | 78,965 | 82,896 | | 184,070,265 | 387,817,248 | 478,410,896 | |
| Direct Install Lighting | Projects | 22,155 | 20,469 | 19,807 | | 65,777,197 | 68,896,046 | 68,140,249 | |
| Building Commissioning | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | |
| New Construction | Buildings | 247 | 1,596 | 2,934 | | 823,434 | 3,755,869 | 9,183,826 | |
| Energy Audit | Audits | 0 | 1,450 | 4,283 | | 0 | 7,049,351 | 23,386,108 | |
| Small Commercial Demand Response | Devices | 55 | 187 | 773 | | 131 | 1,068 | 373 | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Demand Response 3 | Facilities | 21,390 | 19,389 | 23,706 | | 633,421 | 281,823 | 346,659 | |
| **Business Program Total** | | **78,048** | **122,056** | **134,399** | | **251,304,448** | **467,801,406** | **579,468,111** | |
| **Industrial Program** | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | 313 | | 0 | 0 | 2,799,746 | |
| Monitoring & Targeting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| Energy Manager | Projects | 0 | 1,034 | 3,953 | | 0 | 7,067,535 | 24,438,070 | |
| Retrofit | Projects | 6,372 | 0 | 0 | | 38,412,408 | 0 | 0 | |
| Demand Response 3 | Facilities | 176,180 | 74,056 | 162,543 | | 4,243,958 | 1,784,712 | 4,309,160 | |
| **Industrial Program Total** | | **182,552** | **75,090** | **166,809** | | **42,656,366** | **8,852,247** | **31,546,976** | |
| **Home Assistance Program** | | | | | | | | | |
| Home Assistance Program | Homes | 4 | 1,777 | 2,361 | | 56,119 | 5,524,230 | 20,987,275 | |
| **Home Assistance Program Total** | | **4** | **1,777** | **2,361** | | **56,119** | **5,524,230** | **20,987,275** | |
| **Aboriginal Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 267 | | 0 | 0 | 1,609,393 | |
| Direct Install Lighting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | |
| **Aboriginal Program Total** | | **0** | **0** | **267** | | **0** | **0** | **1,609,393** | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 40,418 | 0 | 0 | | 223,956,390 | 0 | 0 | |
| High Performance New Construction | Projects | 10,197 | 6,501 | 772 | | 52,371,183 | 23,803,888 | 3,522,240 | |
| Toronto Comprehensive | Projects | 33,467 | 0 | 0 | | 174,070,574 | 0 | 0 | |
| Multifamily Energy Efficiency Rebates | Projects | 2,553 | 0 | 0 | | 9,774,792 | 0 | 0 | |
| LDC Custom Programs | Projects | 534 | 0 | 0 | | 649,140 | 0 | 0 | |
| **Pre-2011 Programs completed in 2011 Total** | | **87,169** | **6,501** | **772** | | **460,822,079** | **23,803,888** | **3,522,240** | |
| **Other** | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 2,177 | 3,692 | | 0 | 525,011 | 4,075,382 | |
| Time-of-Use Savings | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | |
| **Other Total** | | **0** | **2,177** | **3,692** | | **0** | **525,011** | **4,075,382** | |
| **Adjustments to 2011 Verified Results** | | | **13,266** | **645** | | | **48,705,294** | **1,744,645** | |
| **Adjustments to 2012 Verified Results** | | | | **8,707** | | | | **55,101,043** | |
| **Energy Efficiency Total** | | **213,515** | **156,735** | **168,583** | | **942,317,539** | **616,320,385** | **753,683,966** | |
| **Demand Response Total** | | **208,015** | **142,670** | **280,099** | | **4,901,107** | **2,427,011** | **5,046,495** | |
| **Adjustments to Previous Years' Verified Results Total** | | **0** | **13,266** | **9,352** | | **0** | **48,705,294** | **56,845,688** | |
| **OPA-Contracted LDC Portfolio Total (inc. Adjustments)** | | **421,530** | **312,671** | **458,033** | | **947,218,646** | **667,452,690** | **815,576,149** | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

| Initiative | Unit | Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) 2011 | 2012 | 2013 | 2014 | Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|
| **Consumer Program** | | | | | | | | | |
| Appliance Retirement | Appliances | 0 | 0 | | | 0 | 0 | | |
| Appliance Exchange | Appliances | 0 | 0 | | | 0 | 0 | | |
| HVAC Incentives | Equipment | -8,762 | 1,036 | | | -16,245,279 | 1,854,833 | | |
| Conservation Instant Coupon Booklet | Items | 15 | 0 | | | 255,975 | 0 | | |
| Bi-Annual Retailer Event | Items | 117 | 0 | | | 2,373,616 | 0 | | |
| Retailer Co-op | Items | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response | Devices | 0 | 0 | | | 0 | 0 | | |
| Residential Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | |
| Residential New Construction | Homes | 0 | 0 | | | 328,256 | 0 | | |
| **Consumer Program Total** | | **-8,630** | **1,036** | | | **-13,287,430** | **1,854,833** | | |
| **Business Program** | | | | | | | | | |
| Retrofit | Projects | 4,504 | 6,218 | | | 22,046,931 | 40,101,273 | | |
| Direct Install Lighting | Projects | 541 | 217 | | | 1,346,618 | 781,858 | | |
| Building Commissioning | Buildings | 0 | 0 | | | 0 | 0 | | |
| New Construction | Buildings | 3,243 | 0 | | | 11,323,593 | 0 | | |
| Energy Audit | Audits | 492 | 337 | | | 2,391,744 | 1,636,457 | | |
| Small Commercial Demand Response | Devices | 0 | 0 | | | 0 | 0 | | |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | |
| **Business Program Total** | | **8,780** | **6,771** | | | **37,108,886** | **42,519,588** | | |
| **Industrial Program** | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | | | 0 | 0 | | |
| Monitoring & Targeting | Projects | 0 | 0 | | | 0 | 0 | | |
| Energy Manager | Projects | 0 | 75 | | | 0 | 799,151 | | |
| Retrofit | Projects | 0 | 0 | | | 0 | 0 | | |
| Demand Response 3 | Facilities | 0 | 0 | | | 0 | 0 | | |
| **Industrial Program Total** | | **0** | **75** | | | **0** | **799,151** | | |
| **Home Assistance Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | |
| **Home Assistance Program Total** | | **0** | **0** | | | **0** | **0** | | |
| **Aboriginal Program** | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | | | 0 | 0 | | |
| Direct Install Lighting | Projects | 0 | 0 | | | 0 | 0 | | |
| **Aboriginal Program Total** | | **0** | **0** | | | **0** | **0** | | |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 266 | 0 | | | 1,049,108 | 0 | | |
| High Performance New Construction | Projects | 12,872 | 0 | | | 23,905,663 | 0 | | |
| Toronto Comprehensive | Projects | 0 | 0 | | | 0 | 0 | | |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | | | 0 | 0 | | |
| LDC Custom Programs | Projects | 0 | 0 | | | 0 | 0 | | |
| **Pre-2011 Programs completed in 2011 Total** | | **13,137** | **0** | | | **24,954,771** | **0** | | |
| **Other** | | | | | | | | | |
| Program Enabled Savings | Projects | 624 | 824 | | | 1,673,712 | 9,927,473 | | |
| Time-of-Use Savings | Homes | 0 | 0 | | | 0 | 0 | | |
| **Other Total** | | **624** | **824** | | | **1,673,712** | **9,927,473** | | |
| **Adjustments to 2011 Verified Results** | | **13,911** | | | | **50,449,939** | | | |
| **Adjustments to 2012 Verified Results** | | | **8,707** | | | | **55,101,043** | | |
| **Adjustments to Previous Years' Verified Results Total** | | **13,911** | **8,707** | | | **50,449,939** | **55,101,043** | | |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results*

# Hydro Ottawa

## Conservation and Demand Management

# 2013 Annual Report

**Submitted to:**

## Ontario Energy Board

**Submitted on September 30, 2014**

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# Executive Summary

This annual report is submitted by Hydro Ottawa in accordance with the filing requirements set out in the CDM Code (Board File No. EB-2010-0215), specifically Appendix C Annual Report Template, as a progress report and modification to Hydro Ottawa Strategy. Accordingly, this report outlines Hydro Ottawa CDM activities for the period of January 1, 2013 to December 31, 2013. It includes net peak demand and net energy savings achieved from 2011, 2012 and 2013, with discussion of the current/future CDM framework, CDM program activities, successes and challenges, as well as forecasted savings to the end of 2014.

Hydro Ottawa did not apply for any Board-Approved CDM Programs during 2013; however, as noted in the CDM guidelines, released April 26, 2012, the Ontario Energy Board (OEB) has deemed Time-of-Use (TOU) pricing a Province-wide Board-Approved CDM Program. The Ontario Power Authority (OPA) is to provide measurement and verification on TOU. At the time of this report the OPA has not released any verified results of TOU savings to Hydro Ottawa.

In 2011, Hydro Ottawa contracted with the Ontario Power Authority (OPA) to deliver a portfolio of OPA-Contracted Province-Wide CDM Programs to all customer segments including residential, commercial, institutional, industrial and low income. These programs were rolled-out by the OPA in June 2011. In 2011 Program activities were centered on building a foundation for full program execution over the next three years of the program term, including staffing, procurement, and program delivery.

In 2012, Hydro Ottawa focused efforts on lead generation and program execution. In the Commercial and Industrial segments the focus was on leveraging marketplace delivery channels such as heating, cooling and lighting manufacturers, suppliers and distributors for maximum program uptake. Hydro Ottawa achieved excellent program results by working with and through these delivery channels and with major property managers, high volume customers and the municipal, university, school and hospital (MUSH) segment. The efforts of Hydro Ottawa were augmented through the strategic deployment of Energy Managers embedded in a number of large customers including a national retailer, local Colleges and Universities, Federal and Municipal Governments and Property Management organizations with broad scale.

In the Residential segment, Hydro Ottawa focused on mass marketing, direct mail and on-line promotion to attract and enlist greater participation in this segment.

In 2013, Hydro Ottawa continued to focus on lead generation, expanded channel management and program execution as efforts are delivering good results. Three additional Embedded Energy Managers were added. A street team was deployed to deliver and install Energy Displays to eligible customers. This had a very positive impact on the profile of the *peaksaver* PLUS program.

Hydro Ottawa achieved 22.5 MW of net incremental peak demand savings and 42.6 GWh of net incremental energy savings in 2013. A summary of the achievements towards the CDM targets is shown below:

## OPA-Contracted Province-Wide CDM Programs Final Verified 2013 Results

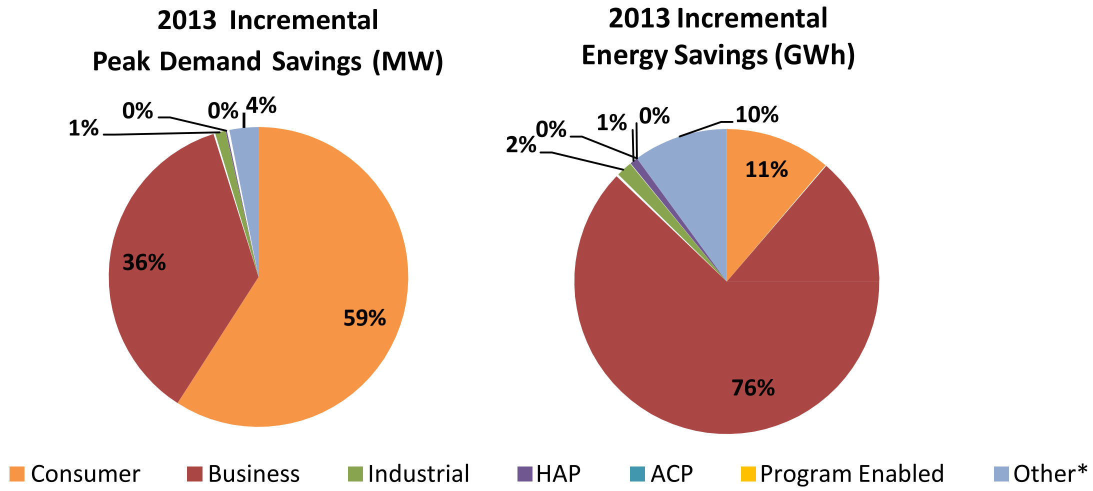
**LDC:** Hydro Ottawa Limited

| FINAL 2013 Progress to Targets | 2013 Incremental | Program-to-Date Progress to Target (Scenario 1) | Scenario 1: % of Target Achieved | Scenario 2: % of Target Achieved |
|---|---|---|---|---|
| **Net Annual Peak Demand Savings (MW)** | 22.5 | 25.4 | **29.8%** | **45.6%** |
| **Net Energy Savings (GWh)** | 42.6 | 332.4 | **88.7%** | **88.7%** |

Scenario 1 = Assumes that demand response resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in the LDC service territory until 2014

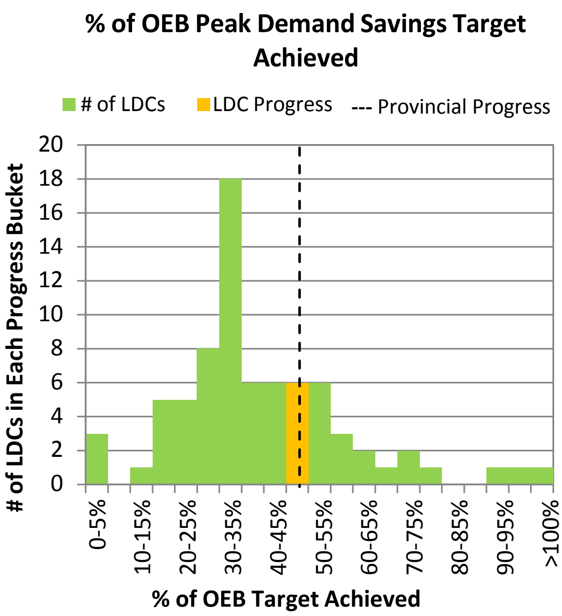
## Achievement by Sector

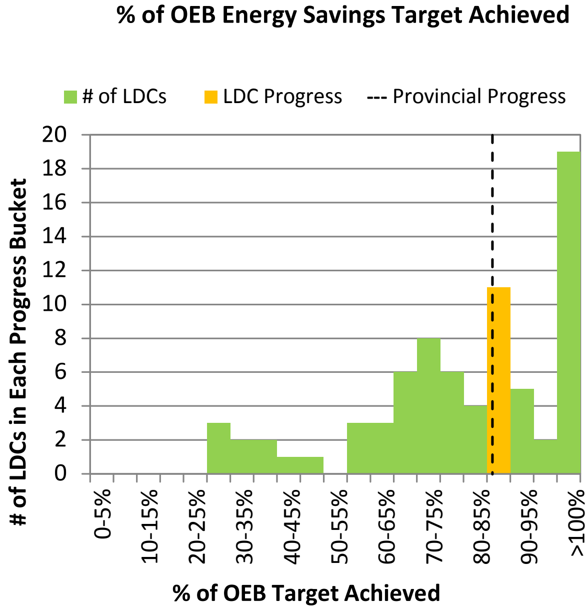



**Other includes adjustments to previous years' results and savings from pre-2011 initiatives*

## Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in the LDC service territory until 2014 (aligns with Scenario 2)



Hydro Ottawa expects to achieve the 2014 electricity energy savings target and 90% of the peak demand target. Hydro Ottawa continues to work actively on participant engagement. In addition Hydro Ottawa has partnered with other LDCs, and has been working with the Ontario Power Authority ("OPA") and the Electrical Distribution Association ("EDA") to improve program effectiveness, however it is Hydro Ottawa's position that these actions will not fully overcome the forecasted peak demand savings shortfall.

# Background

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998*, directed the Ontario Energy Board (OEB) to establish Conservation and Demand Management (CDM) targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended the distribution license of Hydro Ottawa to require Hydro Ottawa, as a condition of its license, to achieve 374.73 GWh of energy savings and 85.26 MW of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

In accordance with the same Minister's directive, the OEB issued the Conservation and Demand Management Code for Electricity Distributors (the Code) on September 16, 2010. The code sets out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets set out in their licenses. To comply with the Code requirements, Hydro Ottawa submitted its CDM Strategy on June 13, 2011 which provided a high level of description of how Hydro Ottawa intended to achieve its CDM targets.

The Code also requires a distributor to file annual reports with the Board. This is the third Annual Report by Hydro Ottawa and has been prepared in accordance with the Code requirement and covers the period from January 1, 2013 to December 31, 2013.

Hydro Ottawa submitted its 2011 Annual Report on September 30, 2012 which summarized the CDM activities, successes and challenges experienced by Hydro Ottawa for the January 1, 2011 to December 31, 2011 period. The OEB's 2011 CDM Results report identified that the delay in the full suite of CDM Programs being made available by the OPA, and the absence of some programs negatively impacted the final 2011 results for the LDCs. This issue was also highlighted in Volumes I & II of the Environmental Commissioner's Report on Ontario's Annual Energy Conservation Progress.

On December 21, 2012, the Minister of Energy directed the Ontario Power Authority (OPA) to fund CDM programs which meet the definition and criteria for OPA-Contracted Province-Wide CDM Programs for an additional one-year period from January 1, 2015 to December 31, 2015.

The Ministerial Directive did not amend the timelines for LDCs to achieve their energy savings and demand savings targets. Therefore, the main focus of the LDCs remains the achievement of CDM targets by December 31, 2014.

Hydro Ottawa submitted its 2012 Annual Report on September 30, 2013 which summarized the CDM activities undertaken by Hydro Ottawa for the January 1, 2012 to December 31, 2012 period. The OEB's 2012 CDM Results report identified that the majority of LDCs achieved close to 20% of their net peak demand (MW) target from their 2012 results. However, LDCs generally advised the Board that meeting their peak demand (MW) target is not likely and that a shortfall is expected.

LDCs collectively achieved approximately 8% of the energy savings (GWh) target, which is slightly below the 10% incremental annual savings needed each year to achieve the energy savings target. Overall the cumulative results represent approximately 65% of the net energy target of 6,000 GWh.

The report identified that although there have been improvements to programs there still remains some shortcoming to the design and delivery of certain initiatives that have resulted in a negative impact to some programs. In particular, the change management process still requires improvements to expedite enhancements to initiatives. The report also noted that certain initiatives may be reaching the point of market saturation and that new initiatives may need to be developed in order to take the place of the existing initiatives.

# 1 Board-Approved CDM Program

## 1.1 Introduction

In its Decision and Order dated November 12 2010 (**EB-2010-0215 & EB-2010-0216**), the OEB ordered that, (to meet its mandatory CDM targets), "Each licensed electricity distributor must, as a condition of its license, deliver Board-Approved CDM Programs, OPA-Contracted Province-Wide CDM Programs, or a combination of the two".

At this time, the implementation of Time-of-Use ("TOU") Pricing has been deemed as a Board-Approved Conservation and Demand Management ("CDM") program that is being offered in Hydro Ottawa's service area.

## 1.2 TOU Pricing

### 1.2.1 Background

In its April 26, 2012 CDM Guidelines, the OEB recognizes that a portion of the aggregate electricity demand target was intended to be attributable to savings achieved through the implementation of TOU Pricing. The OEB establishes TOU prices and has made the implementation of this pricing mechanism mandatory for distributors. On this basis, the OEB has determined that distributors will not have to file a Board-Approved CDM program application regarding TOU pricing. The OEB has deemed the implementation of TOU pricing to be a Board-Approved CDM program for the purposes of achieving the CDM targets. The costs associated with the implementation of TOU pricing are recoverable through distribution rates, and not through the Global Adjustment Mechanism ("GAM").

In accordance with a Directive dated March 31, 2010 by the Minister of Energy and Infrastructure, the OEB is of the view that any evaluations of savings from TOU pricing should be conducted by the OPA for the province, and then allocated to distributors. Hydro Ottawa will report these results upon receipt from the OPA.

The OPA had retained The Brattle Group as the evaluation contractor and has been working with an expert panel convened to provide ongoing advice on methodology, data collection, models, savings allocation, etc. The initial evaluations were conducted in 2013 with five LDCs – Hydro One, THESL, Ottawa Hydro, Thunder Bay and Newmarket. Preliminary results from these five LDCs were issued to the five LDCs involved in the study in August 2013 and are now publically available on the OPA website. Preliminary results demonstrated load shifting behaviors from the residential customer class.

Three additional LDCs were added to the study in 2014 – Cambridge-North Dumphries, Powerstream and Sudbury. Preliminary results from this study are planned to be issued to the eight LDCs in September 2014. The OPA advised that the TOU study will be complete in the summer of 2015 and final verified savings will be available for LDCs to include in the 2014 Annual Report.

As of September 30, 2014, the OPA has not released any verified results of TOU savings to Hydro Ottawa. Therefore Hydro Ottawa is not able to provide any verified savings related to LDC's TOU program at this time. In the original business case, Hydro Ottawa was expecting approximately 17MW of savings from TOU based on the 2010 provincial business case estimate of 308 MW.) Without clear knowledge of the TOU impact, we are not able to provide accurate forecasts for TOU.

### 1.2.2 TOU PROGRAM DESCRIPTION

**Target Customer Type(s):** Residential and small business customers (up to 250,000 kWh per year)

**Initiative Frequency:** Year-Round

**Objectives:** TOU pricing is designed to incent the shifting of energy usage. Therefore peak demand reductions are expected, and energy conservation benefits may also be realized.

**Description**: In August of 2010, the OEB issued a final determination to mandate TOU pricing for Regulated Price Plan ("RPP") customers by June 2011, in order to support the Government's expectation for 3.6 million RPP consumers to be on TOU pricing by June 2011, and to ensure that smart meters funded at ratepayer expense are being used for their intended purpose.

The RPP TOU price is adjusted twice annually by the OEB. A summary of the RPP TOU pricing is provided below:

| RPP TOU | | Rates (cents/kWh) | |
|---|---|---|---|
| Effective Date | On Peak | Mid Peak | Off Peak |
| November 1, 2010 | 9.9 | 8.1 | 5.1 |
| May 1, 2011 | 10.7 | 8.9 | 5.9 |
| November 1, 2011 | 10.8 | 9.2 | 6.2 |
| May 1, 2012 | 11.7 | 10.0 | 6.5 |
| November 1, 2012 | 11.8 | 9.9 | 6.3 |
| May 1, 2013 | 12.4 | 10.4 | 6.7 |
| November 1, 2013 | 12.9 | 10.9 | 7.2 |

**Delivery:** The OEB set the rates; LDCs install and maintain the smart meters and convert customers to TOU billing.

**Initiative Activities/Progress:**

Hydro Ottawa began transitioning its RPP customers to TOU billing on May 1, 2010. At December 31st, 2013, 304,210 RPP customers were on TOU billing.

## 1.3 Hydro Ottawa's Application with the OEB

Hydro Ottawa did not submit a CDM program application to the OEB in 2013.

## 1.4 Hydro Ottawa's Application with the OPA's Conservation Fund

Hydro Ottawa did not submit a CDM program application to the OPA's Conservation Fund in 2013.

# 2 OPA-Contracted Province-Wide CDM Programs

## 2.1 Introduction

Effective February 10, 2011, Hydro Ottawa entered into an agreement with the OPA to deliver CDM programs extending from January 1, 2011 to December 31, 2014, which are listed below. Program details are included in Appendix A. In addition, results include projects started pre 2011 which were completed in 2011:

| Initiative | Schedule | Date schedule posted | Hydro Ottawa in Market Date |
|---|---|---|---|
| **Residential Programs** | | | |
| Appliance Retirement | Schedule B-1, Exhibit D | *Jan 26,2011* | *February 2011* |
| Appliance Exchange | Schedule B-1, Exhibit E | *Jan 26, 2011* | *May 2011* |
| HVAC Incentives | Schedule B-1, Exhibit B | *Jan 26, 2011* | *February 2011* |
| Conservation Instant Coupon Booklet | Schedule B-1, Exhibit A | *Jan 26, 2011* | *March 2011* |
| Bi-Annual Retailer Event | Schedule B-1, Exhibit C | *Jan 26, 2011* | *April 2011* |
| ~~Retailer Co-op~~ | n/a | *n/a* | *n/a* |
| Residential Demand Response | Schedule B-3 | *Aug 22, 2011* | *May 2012* |
| New Construction Program | Schedule B-2 | *Jan 26, 2011* | *Fall 2011* |
| Home Assistance Program | Schedule E-1 | *May 9, 2011* | *January 2012* |
| **Commercial & Institutional Programs** | | | |
| Efficiency: Equipment Replacement | Schedule C-2 | *Jan 26, 2011* | *February 2011* |
| Direct Install Lighting<br>• *General Service <50 kW* | Schedule C-3 | *Jan 26, 2011* | *March 2011* |
| Existing Building Commissioning Incentive | Schedule C-6 | *Feb 2011* | *March 2011* |
| New Construction and Major Renovation Initiative | Schedule C-4 | *Feb 2011* | *July 2011* |
| Energy Audit | Schedule C-1 | *Jan 26, 2011* | *March 2011* |
| Commercial Demand Response<br>• *General Service <50 kW* | Schedule B-3 | *Jan 26, 2011* | *May 2013* |
| **Industrial Programs -** General Service 50 kW & above | | | |
| Process & System Upgrades | Schedule D-1 | *May 31, 2011* | *February 2011* |
| Monitoring & Targeting | Schedule D-2 | *May 31, 2011* | *February 2011* |
| Energy Manager | Schedule D-3 | *May 31, 2011* | *August 2012* |
| Key Account Manager ("KAM") | Schedule D-4 | *May 31,2011* | *August 2012* |
| Efficiency Equipment Replacement Incentive<br>• (part of the C&I program schedule) | Schedule C-2 | *May 31, 2011* | *February 2011* |
| Demand Response 3 | Schedule D-6 | *May 31, 2011* | *October 2011* |

In addition, results were realized towards LDC's 2011-2014 target through the following pre-2011 programs:

- Electricity Retrofit Incentive Program
- High Performance New Construction
- Toronto Comprehensive

- Multifamily Energy Efficiency Rebates
- Data Centre Incentive Program
- EnWin Green Suites

As per the table below, several program initiatives are no longer available to customer or have not been launched in 2013.

| Not in Market | Objective | Status |
|---|---|---|
| **Residential Program** | | |
| Midstream Electronics | Encourages retailers to promote and sell high efficency televisions, and for distributors to distribute high efficiency set top boxes. | Did not launch and removed from Schedule in Q2, 2013. |
| Midstream Pool Equipment | Encourage pool installers to sell and install efficient pool pump equipment in residential in-ground pools. | Did not launch and removed from Schedule in Q2, 2013. |
| Home Energy Audit Tool | This is a provincial online audit tool to engage customers in conservation and help drive customer participation to CDM programs. | Did not launch and removed from Schedule in Q2, 2013. |
| **Commercial & Institutional Program** | | |
| Direct Service Space Cooling | Offers free servicing of air conditioning systems and refrigeration units for the purpose of achieving energy savings and demand reduction. | Did not launch in 2011/2012. As per the OPA there no plans to launch this Initiative in 2013. |
| Demand Response 1 ("DR1") | This initiative allows distribution customers to voluntarily reduce electricity demand during certain periods of the year pursuant to the DR 1 contract. The initiative provides DR payment for service for the actual electricity reduction provided during a demand response event. | No customer uptake for this initiative. As a result this Initiative was removed from the Schedule in Q4, 2012. |
| **Industrial Program** | | |
| DR1 | As above | No customer uptake for this initiative. Removed in Q4, 2012. |

The Master CDM Program Agreement includes program change management provision in Article 3. Collaboration between the OPA and the Local Distribution Companies (LDCs) commenced in 2011, and continued in 2012, as the change management process was implemented to enhance the saveONenergy program suite. The change management process allows for modifications to the Master Service Agreement and initiative Schedules. The program enhancements give LDCs additional tools and greater flexibility to deliver programs in a way that meets the needs of customers and further drives participation in the Initiatives.

## 2.2 Program Descriptions

Full OPA-Contracted Province-Wide CDM Program descriptions are available on the OPA's website at http://www.powerauthority.on.ca/ldc-province-wide-program-documents and additional initiative information can be found on the saveONenergy website at [https://saveONenergy.ca](https://saveONenergy.ca). The targeted customer types, objectives, and individual descriptions for each Program Initiative are detailed in Appendix A.

### 2.2.1 RESIDENTIAL PROGRAM

**Description:** Provides residential customers with programs and tools to help them understand and manage the amount of energy they use throughout their entire home and help the environment.

**Objective:** To provide incentives to both existing homeowners and developers/builders to motivate the installation of energy efficiency measures in both existing and new home construction.

**Discussion:**

The addition of LED measures to the Bi-Annual Retailer Event and to the Annual Coupon initiative in July 2013 has had a positive impact on customer participation. There were three LDC custom coded coupon options for LDCs to utilize in 2013. The Residential Demand Response program continues to be the largest contributor to demand savings in the Residential Program and has been generally well received by consumers. There were no savings associated with the Energy Display attributed to LDCs in the OPA's 2012 or 2013 verified results.

The Residential Program Portfolio is predominately a carryover of Initiatives from previous programs. It is mostly driven by retailers and contractors who many not have fully delivered what was anticipated. Three new initiatives (Midstream Electronics, Midstream Pool Equipment and Home Energy Audit Tool) were not launched and subsequently removed from the schedule in 2013 with no new additions.

Province-wide advertising was re-introduced in Q3 2013. This provided limited value due to the late market entry, especially for *peaksaver*PLUS.

Work to revitalize and increase the effectiveness and breadth of the Initiatives through the Residential Program continue to be a high priority. Opportunities within the Residential marketplace need to be identified, developed and offered to customers.

#### *2.2.1.1 Appliance Retirement Initiative (Exhibit D)*

**Initiative Activities/Progress:**

| | | | |
|---|---|---|---|
| Bill insert | Feb – Mar | multi program focus | all residential customers |
| Insert | Apr | multi program focus | daily newspaper |
| Event Team | promoted at over 100 community events | | |

| | |
|---|---|
| Print collateral | inclusion in the omnibus FOR HOME brochure |

**Additional Comments:**

- Due to the duration of the program, and the revised eligibility requirements to a minimum of 20 years old, this Initiative appears to have reached market saturation and has been under consideration for removal from the Portfolio.
- As participation is very responsive to province wide advertising, OPA province-wide advertising should continue to play a key role if the initiative continues.

#### *2.2.1.2 Appliance Exchange Initiative (Exhibit E)*

**Initiative Activities/Progress:**

**Additional Comments:**

- The design of the Initiatives, including eligible measures and incentives amounts are developed through the Residential Working Group. Retail Partner(s) are contracted by the OPA to deliver the initiatives province-wide. Individual LDCs have the opportunity to stage in-store events to drive the distribution of LDC coded Coupons and promotion of other programs in the portfolio
- The restrictive, limited and sometimes non-participation of local stores can diminish the savings potential for this Initiative.
- To date there has only been one retailer participant in the Appliance Exchange Initiative.
- Notification to LDCs regarding retailer participation and eligible measures continues to be delayed. Improved communications will aid in appropriate resource allocation and marketing of the Initiative.
- This Initiative may benefit from the disengagement of the retailer and allowing LDCs to conduct these events, possibly as part of a larger community engagement effort, with the backing of ARCA for appliance removal.
- The initiative appears to require more promotion from retailers.

#### *2.2.1.3 HVAC Incentives Initiative (Exhibit B)*

**Initiative Activities/Progress:**

| | | | |
|---|---|---|---|
| Bill insert | Feb – Mar | multi program focus | all residential customers |
| Insert | Apr | multi program focus | daily newspaper |
| Bill insert | Oct – Nov | all residential customers | |

| | | | |
|---|---|---|---|
| Radio | Spring / Fall | 10' tags on traffic and weather | |
| Print ads | Oct | community newspapers | |
| Event Team | promoted at over 100 community events | | |
| Print collateral | inclusion in the omnibus FOR HOME brochure | | |

**Additional Comments:**

- Incentive levels may not be sufficient to prompt customers to upgrade HVAC equipment prior to end of useful life. An Air Miles incentive was introduced in 2013 to try and encourage early replacement.
- This Initiative is contractor driven with LDCs responsible for marketing efforts to customers. More engagement with the HVAC contractor channel should be undertaken to drive a higher proportion of furnace and CAC sales to eligible units.
- In an effort to build capability, mandatory training has been instituted for all participating HVAC contractors. This could present a barrier for participation for some contractors as the application process already presents a restriction to contractor sales. It has been noted that there are approximately 4500-5000 HVAC contractors in the Province, however in 2013, only a total of 1,587 contractors completed the mandatory HVAC training and can participate in the program.
- There are cases where non-participating contractors are offering their own incentives (by discounting their installations to match value of the OPA incentive). As this occurs outside of the Initiative, savings are not credited to LDCs.
- Planned changes to the Schedule in 2014 will allow incentives for new installations, in addition to replacement units, may provide greater Initiative results.

#### *2.2.1.4 Conservation Instant Coupon Initiative (Exhibit A)*

**Initiative Activities/Progress:**

| | | | |
|---|---|---|---|
| Bill insert | Feb – Mar | multi program focus | all residential customers |
| Insert | Apr | multi program focus | daily newspaper |
| Bill insert | Mar – Apr | all residential customers | |
| Event Team | promoted at over 100 community events | | |
| Print collateral | inclusion in the omnibus FOR HOME brochure | | |
| Print collateral | individual coupons for distribution at events | | |

**Additional Comments:**

- The timeframe for retailer submission of redeemed coupons varies depending on the retailer and in some cases has been lengthy. The delays and incomplete results reporting limits the ability to react and respond to Initiative performance or changes in consumer behavior.
- Coupon booklets were not printed and mailed out in 2013 so coupons were not widely available to consumers without the ability to download and print online coupons. Consumers may not have been aware of the online coupons. The Initiative may benefit from province-wide marketing as a substitute to a mail out campaign.
- Program evolution, including new products and review of incentive pricing for the coupon Initiatives, should be a regular activity to ensure continued consumer interest.
- In 2013, LDCs were provided with 3 custom coded coupons. All coupons will be available with LDC custom coding in 2014 which allows LDCs to promote coupons based on local preferences.
- Consumer experience is not always consistent between and among participating retailers and this can impact coupon redemption rates. The challenges vary from not accepting coupons, to having a specific procedure to static lists of eligible products.

#### *2.2.1.5 Bi-Annual Retailer Event Initiative (Exhibit C)*

**Initiative Activities/Progress:**

| | | |
|---|---|---|
| Print ad | Apr + Oct | community newspapers |
| Print collateral | individual coupons for distribution at events | |

**Additional Comments:**

- This Initiative is strongly influenced by the retail participants and has no direct involvement from the LDCs.
- LDCs have the opportunity to stage in-store events to drive the distribution of LDC coded Coupons and promotion of other programs in the portfolio however this requires cooperation from the local retailer and LDC staff bandwidth.
- The Product list has changed very little over the past five years.
- Program evolution, including new products and review of incentive pricing for the coupon Initiatives, must be a regular activity to ensure continued consumer interest.
- The Product list could be distinctive from the Conservation Instant Coupon Initiative in order to gain more consumer interest and uptake.
- A review conducted by the Residential Working Group identified three areas of need for Initiative evolution: 1) introduction of product focused marketing; 2) enhanced product selection and 3) improved training for retailers as retail staff tend not to be knowledgeable regarding the products or promotion.

- This Initiative may benefit from a more exclusive relationship with a retailer appropriate to the program. There should be a value proposition for both the retailer and LDC.

#### ~~2.2.1.6 Retailer Co-op~~

**Initiative Activities/Progress:**

**Additional Comments:**

- This is a retailer Initiative with no direct benefit to the LDCs
- Limited engagement of local retailers can restrict the savings potential for this Initiative.
- The availability of retailer and/or LDC staff with product knowledge and the ability to conduct demonstration in store during the events would be an asset. This could be a valuable role for LDCs, however many LDCs are limited by available resources and unable to participate.

#### 2.2.1.7 New Construction Program (Schedule B-2)

**Initiative Activities/Progress:**

Print ad Greater Ottawa Home Builders Association annual directory and magazine

One-on-one outreach to local builders

**Additional Comments:**

- This Initiative provides incentives to home builders for incorporating energy efficiency into their buildings. To support this, LDCs need to provide education to the consumers regarding the importance of choosing the energy efficient builder upgrade options without an immediate benefit to the consumer.

- In 2012 the application process was streamlined, however continues to be too cumbersome for most builders. This combined with low incentives has resulted in this Initiative continuing to under-achieve.

- Administrative requirements, in particular individual home modeling, must align with perceived stakeholder payback.

- Applications are expected to increase in 2014 primarily because Hydro Ottawa has agreed to manage the application process for some of the larger builders. This is a temporary work-around to overcome the weak program design.

- This Initiative may benefit from collaboration with the Natural Gas utilities.

#### *2.2.1.8 Residential Demand Response Program (Schedule B-3)*

**Initiative Activities/Progress:**

| | | | |
|---|---|---|---|
| Direct mail | new participants, continuing participants | | |
| Television | specialty channel, local CTV | | |
| Video | target placement and You Tube | | |
| Bill insert | Feb – Mar | multi program focus | all residential customers |
| Insert | Apr | multi program focus | daily newspaper |
| Online | Apr – Dec | geo targeted local - TWN, Senators, CTV | |
| Print ad | June | daily newspaper gatefold | |
| Transit ads | Apr | bus exterior | |
| Print ads | Feb + Jul/Aug | community newspapers | |
| Print ads | Summer | specialty magazines | |
| Bill insert | Aug-Sep | all residential customers | |
| Street Team | May – Aug | deliver Energy Display to existing participants | |
| Event Team | promoted at over 100 community events | | |
| Print collateral | inclusion in the omnibus FOR HOME brochure | | |

**Additional Comments:**

- This is the main Initiative within the Residential portfolio that was to drive savings for LDCs, however the 2012 evaluation indicated savings realized from the In Home Display (IHD) were not statistically significant. LDCs were advised that the evaluation of the IHDs would continue with 2013 data. Data for the program EM&V was only reviewed in on geographic area within the province. Hydro Ottawa believes that because the Ottawa delivery model was strongly focused on the customer education, it will lead to significantly different results.

- Verified demand savings in 2012 from the load control devices were less than originally anticipated. This prompted an increase to the load cycling strategy in 2013 in order to increase savings closer to the original business case.

### 2.2.2 COMMERCIAL AND INSTITUTIONAL PROGRAM

**Description:** Provides commercial, institutional, agricultural and industrial organizations with energy-efficiency programs to help reduce their electrical costs while helping Ontario defer the need to build new generation and reduce its environmental footprint. This Initiative included programs to help fund energy audits, to replace energy-wasting equipment or to pursue new construction projects that exceed our existing codes and standards. Businesses can also pursue incentives for controlling and reducing their electricity demand at specific times.

**Targeted Customer Type(s):** Commercial, Institutional, Agricultural, Multi-family buildings, Industrial

**Objective:** Designed to assist building owners and operators as well as tenants and occupants in achieving demand and energy savings, and to facilitate a culture of conservation among these communities as well as the supply chains which serve them.

**Discussion:**

Throughout 2011 to 2013 the Commercial and Institutional (C&I) Working Group has strived to enhance the existing C&I programs and rectify identified program and system deficiencies. This has proven to be a challenging undertaking. Overbuilt governance, numerous initiative requirements, complex program structure and lengthy change management have restricted growth without providing the anticipated improved Measurement and Verification results. In addition, Evaluation, Measurement and Verification (EM&V) has not yet achieved transparency. LDCs are held accountable for these results but are not included in the EM&V process.

LDC program management has been hampered by varying rule interpretation, limited marketing ability, a somewhat inflexible online system of checks and balances and revolving OPA support personnel.

The C&I Working Group, working in cooperation with the OPA, continued to improve many of the issues which could be rectified. In particular, an accomplishment of 2012 was the advent of the expedited change management as means to accelerate certain program changes. 2013 saw the benefits of expedited change management process.

Looking ahead there is minimal opportunity to make valuable changes to the current program suite and have these changes reflected in LDC 2014 results. LDCs and the OPA should look beyond the current Initiatives and work to launch new programs, built on the strengths of the 2011-2014 programs, which will meet the needs of the industry and consumers.

#### *2.2.2.1 Efficiency: Equipment Replacement Incentive (ERII) (Schedule C-2)*

**Initiative Activities/Progress:**

| | |
|---|---|
| Inserts | local and geo targeted national newspapers |
| Radio | 10’ tags |
| Television | specialty channel |

| | |
|---|---|
| Video | target placement and You Tube, social media and online |
| Online | geo targeted media sites |
| Print ads | industry target magazines |
| Collateral | omnibus FOR BUSINESS brochure |

Channel Sales Strategy

**Additional Comments:**

- A large proportion of LDC savings are attributed to ERII.
- Capability building programs from Industrial programs have had very positive contributions to ERII program.
- This Initiative is limited by the state of the economy and the ability of commercial/institutional facility to complete capital upgrades.
- Applicants and Applicant Representatives continue to express dissatisfaction and difficulty with the online application system. This issue has been addressed by LDCs through application training workshops, Key Account Managers, channel partner/contractor training and LDC staff acting as customer Application Representatives. Although this has been an effective method of overcoming these issues and encouraging submissions, it also reveals the complexity and time consuming nature of the application process. As such, Applicant Representatives continue to influence the majority of applications submitted. Continued development of Channel Partners is essential to program success.
- Prescriptive and Engineered worksheets provide a much needed simplified application process for customers. However, the eligible measures need to be updated and expanded in both technology and incentive amounts to address changing product costs and evolution of the marketplace.
- A focus on demand incentives has limited some kWh project opportunities. In particular, night lighting projects have significant savings potential for customers but tend to have incentives of 10% of project cost or less.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.
- There is redundancy in the application process as customers may need to complete a worksheet and then enter most of that information over to the online application form. This can be cumbersome.
- Processing Head Office applications became much easier for the Lead LDC after Schedule changes came into effect in August 2013. The largest beneficiary was the customer who could now deal with one LDC for all of their provincial locations.
- The application process for Head Office projects requires improvement. Applicants still need to manually enter one application per facility associated with the project can be extremely onerous, often requiring a dedicated resource.
- Streamlining of the settlements systems resulted in significant improvement in the payment process in 2013.

#### *2.2.2.2 Direct Install Initiative (DIL) (Schedule C-3)*

**Initiative Activities/Progress:**

Video target placement and You Tube

Collateral customized sell sheets for contractors

Collateral omnibus FOR BUSINESS brochure

**Additional Comments:**

- LED lighting was introduced in 2013 as a new measure and has been well received by customers who may not have previously qualified for DIL eligible upgrades. This is an efficient product with a long estimated useful life.
- Cold start high output lighting was removed from the program. This particularly affected the farming customers who now have limited options within the program.
- The inclusion of a standard incentive for additional measures increased project size and drove higher energy and demand savings results in some situations. However, LDCs are unable to offer these standard incentives to prior participants. The ability to return to prior participants and offer a standard incentive on the remaining upgrades has potential to provide additional energy and demand savings
- Electrical contractor's margins have been reduced due to no labor rate increase, increase cost of materials, greater distances between retrofit and more door knocking required before a successful sale. This has led to a reduction in vendor channel participation in some regions.
- Measure incentives and additional funding for forklifts were introduced in September 2013 and were well received by installers.

#### *2.2.2.3 Existing Building Commissioning Incentive Initiative (Schedule C-6)*

**Initiative Activities/Progress:**

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Channel Sales Strategy

**Additional Comments:**

- Initiative name does not properly describe the Initiative.
- There was minimal participation for this Initiative. It is suspected that the lack of participation in the program is a result of the Initiative being limited to space cooling and a limited window of opportunity (cooling season) for participation.

- Participation is mainly channel partner driven.
- Customers would like to see the program expanded to include a broader range of measures for a more holistic approach to building re-commissioning. Chilled water systems used for other purposes should also be made an eligible measure.
- This initiative should be reviewed for incentive alignment with ERII. Currently a participant will not receive an incentive if the overall payback is less than 2 years.

#### *2.2.2.4 New Construction and Major Renovation Initiative (HPNC) (Schedule C-4)*

**Initiative Activities/Progress:**

Hydro Ottawa has Enbridge under contract as delivery agent for this program. Enbridge works in conjunction with the Hydro Ottawa sales team and engineering staff to deliver the program.

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Channel Sales Strategy

**Additional Comments**

- With the Ministerial Directive issued December 21, 2012, facilities with a completion date near the end of 2015 have some security that they will be compensated for choosing efficient measures. However, buildings that are in the planning phase with completion dates post-2015 may not participate due to funding and program uncertainty.
- Participants estimated completion dates tend to be inaccurate and are usually six months longer. This could result in diminished savings towards target when facilities are not substantially completed by December 31, 2014.
- The custom application process requires considerable customer support and skilled LDC staff. The effort required to participate through the custom stream exceeds the value of the incentive for many customers.
- There are no custom measure options for items that do not qualify under the prescriptive or engineered track as the custom path does not allow for individual measures, only whole building modeling.
- This Initiative has a very low net-to-gross ratio, which results in more than 50% of the proposed target savings being 'lost'. This factor may force LDCs to remove the program from portfolios in the future as the program delivers strong savings for the customer but minimal verified results from the OPA.
- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and a potential barrier to participation.

#### 2.2.2.5 *Energy Audit Initiative*

**Initiative Activities/Progress:**

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Channel Sales Strategy

**Additional Comments**

- The introduction of the new audit component for one system (i.e. compressed air), has increased customer participation.
- The energy audit Initiative is considered an 'enabling' Initiative and 'feeds into' other saveONenergy Initiatives.
- Evaluators in 2012 and 2013 recognized savings towards LDCs targets as a result of customers implementing low/no cost recommendations from their energy audits.
- Audit reports from consultants vary considerably and in some cases, while they adhere to the Initiative requirements, do not provide value for the Participant. A standard template with specific energy saving calculation requirements should be considered.
- Customers look to the LDCs to recommend audit companies. A centralized prequalified list provided by the OPA may be beneficial.
- Participation has been limited to one energy audit per customer which only allowed the customer to review and audit one area of their business. This has been revised in 2014 and LDCs are now able to consider additional customer participation when presented with a new scope of work.

### 2.2.3 INDUSTRIAL PROGRAM

**Description:** Large facilities are discovering the benefits of energy efficiency through the Industrial Programs which are designed to help identify and promote energy saving opportunities. It includes financial incentives and technical expertise to help organizations modernize systems for enhanced productivity and product quality, as wells as provide a substantial boost to energy productivity. This allows facilities to take control of their energy so they can create long-term competitive energy advantages which reach across the organization.

**Targeted Customer Type(s):** Industrial, Commercial, Institutional, Agricultural

**Objective:** To provide incentives to both existing and new industrial customers to motivate the installation of energy efficient measures and to promote participation in demand management.

**Discussion:**

The Industrial Program Portfolio has been able to provide significant incentives and valuable resources to large facilities to help them with energy efficiency upgrades and process system improvements. The Engineering Studies in particular as well as the Monitoring and Targeting initiative provide a unique opportunity for a customer to complete a comprehensive analysis of an energy intensive process that they otherwise may not undertake. The Energy Manager Initiative provides customers with a skilled individual whose only role is to assist them with conservation initiatives. To date these Energy Managers have played a key role in customer participation.

Due to the size, scope and long lead time of these Initiatives and associated projects, the Ministerial Directive provides some security for the continuation of the conservation programs and associated compensation for the participant; however the subsequent savings would not be attributed to an LDC's current target for projects that go into service after 2014.

Extensive legal documents, complex program structure and lengthy change management have restricted the change and growth of this Portfolio. While the expedited change management has benefited the Commercial Portfolio, the Industrial Portfolio has not seen the same results due to the narrow scope of the process. For 2013 the change to the threshold for small capital projects and the new small capital project agreement are expected to improve the number of projects and savings achieved within PSUI. Likewise, a decision to proceed with 2012 natural gas load displacement generation projects applications will also increase uptake although the limited time to bring new projects into service is a barrier.

#### *2.2.3.1 Process & Systems Upgrades Initiative (PSUI) (Schedule D-1)*

**Initiative Activities/Progress:**

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Channel Sales Strategy

**Additional Comments:**

- Numerous energy studies have been submitted and completed. This is a strong indication that there is the potential for large projects with corresponding energy savings. Many of these studies have been initiated through the Energy Manager and KAM resources.
- This Initiative is limited by the state of the economy and the ability of a facility to complete large capital upgrades.
- There is typically a long sales cycle for these projects, and then a long project development cycle. As such, limited results were generated in 2013. The majority of the results are expected in 2014 with a much reduced benefit to cumulative energy savings targets.
- Delays with processing funding payments have caused delayed payments to Participants beyond contract requirements. In some cases, LDCs have developed a separate side agreement between the LDC and Participant acknowledging that the Participant cannot be paid until the funds are received.
- The contract required for PSUI is a lengthy and complicated document. A key to making PSUI successful is a new agreement which is a simplified with less onerous conditions for the customer.

- To partially address this, changes were made to the ERII Initiative which allowed smaller projects to be directed to the Commercial stream. Most industrial projects to-date have been submitted as ERII projects due to less onerous contract and M&V requirements.

- A business case was submitted by the Industrial Working Group in July 2012 which would change the upper limit for a small project from 700 MWh to 1 million dollars in incentives. This would allow more projects to be eligible for the new small capital project agreement and increase participant uptake, while still protecting the ratepayer. This small capital project agreement was finalized in August 2013.

- While there is considerable customer interest in on-site Load Displacement (Co-Generation) projects, in 2012 the OPA was accepting waste heat/waste fuel projects only. Natural gas generation projects were on hold awaiting a decision on whether PSUI will fund these types of projects. In June 2013, a decision was made to allow natural gas load displacement generation projects to proceed under PSUI. It is expected that a number of projects will proceed although results may not be counted towards LDC targets due to in-service dates beyond 2014.

- The requirement to have a customer invoice the LDC for their incentive is very burdensome for the customer and results in a negative customer experience and another barrier to participation.

#### *2.2.3.2 Monitoring & Targeting Initiative (Schedule D-2)*

**Initiative Activities/Progress:**

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Channel Sales Strategy

**Additional Comments:**

- The M&T initiative is targeted at larger customers with the capacity to review the M&T data. This review requires the customer facility to employ an Energy Manager, or a person with equivalent qualifications, which has been a barrier for some customers. As such, a limited number of applications have been received to date.

- The savings target required for this Initiative can present a significant challenge for smaller customers.

- Changes were made to ERII in 2013 to allow smaller facilities to employ M&T systems.

#### *2.2.3.3 Energy Manager Initiative (Schedule D-3)*

**Initiative Activities/Progress:**

Hydro Ottawa added 3 new Embedded Energy Managers in 2013 and saw one EEM discontinued bringing the total number of Embedded Energy Managers to four. The Hydro Ottawa Roving Energy Manager continued in 2013.

**Additional Comments:**

- The Energy Managers have proven to be a popular and useful resource for larger customers.
- LDCs that are too small to qualify for their own REM are teaming up with other utilities to hire an REM to be shared by the group of utilities.
- Some LDCs and Customers are reporting difficulties in hiring capable Roving and Embedded Energy Managers (REM/EEM), in some instances taking up to 7 months to have a resource in place.
- New energy managers require training, time to familiarize with facilities and staff and require time to establish “credibility”. Energy Managers started filling their pipeline with projects in 2012 but few projects were implemented until 2013.

#### *2.2.3.4 Key Account Manager (Schedule D-4)*

**Initiative Activities/Progress:**

Hydro Ottawa had 1 Key Account Manager is 2013.

**Additional Comments**

- Customers appreciate dealing with a single contact to interface with an LDC, a resource that has both the technical and business background who can communicate easily with the customer and the LDC.
- Finding this type of skill set has been difficult. In addition, the short-term contract discourages some skilled applicants resulting in longer lead times to acquire the right resource.

#### *2.2.3.5 Demand Response 3 (D-6)*

**Initiative Activities/Progress:**

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Channel Sales Strategy

**Additional Comments:**

- Until early 2013 customer data was not provided on an individual customer basis due to contractual requirements with the aggregators. This limited LDCs' ability to effectively market to prospective participants and verify savings.
- No program improvements were made in 2013 however, it was accepted that prior participants who renew their DR3 contract within the 2011-2014 term will contribute to LDC targets.
- As of 2013, Aggregators were able to enter into contracts beyond 2014 which has allowed them to offer a more competitive contract price (5 year) than if limited to 1 or 2 year contracts.
- Metering and settlement requirements are expensive and complicated and can reduce customer compensation amounts, and present a barrier to smaller customers.
- Compensation amounts for new contracts and renewals have been reduced from the initial launch of this program (premium zones and 200 hour option have been discontinued) and subsequently there has been a corresponding decrease in renewal revenue.

### 2.2.4 LOW INCOME INITIATIVE (HOME ASSISTANCE PROGRAM) (Schedule E-1)

**Initiative Activities/Progress:**

A third party is contracted to deliver this program on behalf of Hydro Ottawa. Outreach to the three largest social housing providers has been the most effective to date. Over 1000 families benefited from this program in 2013.

**Additional Comments:**

- The process for enrolling in social housing was complicated and time consuming. This was addressed in late 2012 and showed some benefits in 2013 through changes to the participant agreements.
- The financial scope, complexity, and customer privacy requirements of this Initiative are challenging for LDCs and most have contracted this program out. Program design changes are expected to address these challenges.

### 2.2.5 PRE-2011 PROGRAMS

Savings were realized towards LDC's 2011-2014 target through pre-2011 programs. The targeted customer types, objectives, descriptions, and activities of these programs are detailed in Appendix B

# 3 2013 LDC CDM Results

## 3.1 Participation and Savings

Table 1: Hydro Hawkesbury Inc. Initiative and Program Level Net Savings by Year (Scenario 1)

| Initiative | Unit | Incremental Activity (new program activity occurring within the specified reporting period) | | | | Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) | | | | Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) | | | | Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW) | 2011-2014 Net Cumulative Energy Savings (kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2011* | 2012* | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2011 | 2012 | 2013 | 2014 | 2014 | 2014 |
| **Consumer Program** | | | | | | | | | | | | | | | |
| Appliance Retirement | Appliances | 29 | 13 | 9 | | 2 | 1 | 1 | | 12,263 | 5,304 | 3,836 | | 3 | 72,636 |
| Appliance Exchange | Appliances | 14 | 2 | 3 | | 1 | 0 | 1 | | 1,855 | 400 | 1,108 | | 1 | 10,121 |
| HVAC Incentives | Equipment | 15 | 32 | 29 | | 6 | 8 | 6 | | 12,690 | 14,153 | 11,762 | | 20 | 116,744 |
| Conservation Instant Coupon Booklet | Items | 755 | 43 | 484 | | 2 | 0 | 1 | | 27,819 | 1,949 | 10,743 | | 3 | 138,609 |
| Bi-Annual Retailer Event | Items | 1,327 | 1,479 | 1,317 | | 2 | 2 | 2 | | 40,962 | 37,329 | 23,946 | | 6 | 323,727 |
| Retailer Co-op | Items | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Residential Demand Response | Devices | 0 | 22 | 26 | | 0 | 10 | 13 | | 0 | 76 | 56 | | 0 | 133 |
| Residential Demand Response (IHD) | Devices | 0 | 19 | 23 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Residential New Construction | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Consumer Program Total** | | | | | | **14** | **21** | **23** | | **95,589** | **59,212** | **51,452** | | **34** | **661,970** |
| **Business Program** | | | | | | | | | | | | | | | |
| Retrofit | Projects | 6 | 11 | 8 | | 68 | 89 | 46 | | 470,057 | 471,791 | 210,279 | | 203 | 3,715,976 |
| Direct Install Lighting | Projects | 25 | 44 | 52 | | 59 | 39 | 66 | | 149,570 | 145,123 | 228,680 | | 144 | 1,434,088 |
| Building Commissioning | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| New Construction | Buildings | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Energy Audit | Audits | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Small Commercial Demand Response | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Small Commercial Demand Response (IHD) | Devices | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Demand Response 3 | Facilities | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Business Program Total** | | | | | | **127** | **128** | **113** | | **619,627** | **616,914** | **438,959** | | **347** | **5,150,064** |
| **Industrial Program** | | | | | | | | | | | | | | | |
| Process & System Upgrades | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Monitoring & Targeting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Energy Manager | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Retrofit | Projects | 1 | 0 | 0 | | 9 | 0 | 0 | | 104 | 0 | 0 | | 9 | 416 |
| Demand Response 3 | Facilities | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Industrial Program Total** | | | | | | **9** | **0** | **0** | | **104** | **0** | **0** | | **9** | **416** |
| **Home Assistance Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 39 | | 0 | 0 | 1 | | 0 | 0 | 18,172 | | 1 | 36,239 |
| **Home Assistance Program Total** | | | | | | **0** | **0** | **1** | | **0** | **0** | **18,172** | | **1** | **36,239** |
| **Aboriginal Program** | | | | | | | | | | | | | | | |
| Home Assistance Program | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Direct Install Lighting | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Aboriginal Program Total** | | | | | | **0** | **0** | **0** | | **0** | **0** | **0** | | **0** | **0** |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | | | | | |
| Electricity Retrofit Incentive Program | Projects | 1 | 0 | 0 | | 0 | 0 | 0 | | 1,838 | 0 | 0 | | 0 | 7,352 |
| High Performance New Construction | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 560 | 153 | 0 | | 0 | 2,700 |
| Toronto Comprehensive | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Multifamily Energy Efficiency Rebates | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| LDC Custom Programs | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Pre-2011 Programs completed in 2011 Total** | | | | | | **0** | **0** | **0** | | **2,398** | **153** | **0** | | **1** | **10,052** |
| **Other** | | | | | | | | | | | | | | | |
| Program Enabled Savings | Projects | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| Time-of-Use Savings | Homes | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 |
| **Other Total** | | | | | | **0** | **0** | **0** | | **0** | **0** | **0** | | **0** | **0** |
| **Adjustments to 2011 Verified Results** | | | | | | | **1** | **0** | | | **8,968** | **0** | | **1** | **35,495** |
| **Adjustments to 2012 Verified Results** | | | | | | | | **15** | | | | **79,889** | | **15** | **239,049** |
| **Energy Efficiency Total** | | | | | | **149** | **139** | **124** | | **717,718** | **676,202** | **508,526** | | **391** | **5,858,607** |
| **Demand Response Total (Scenario 1)** | | | | | | **0** | **10** | **13** | | **0** | **76** | **56** | | **0** | **133** |
| **Adjustments to Previous Years' Verified Results Total** | | | | | | **0** | **1** | **15** | | **0** | **8,968** | **79,889** | | **15** | **274,544** |
| **OPA-Contracted LDC Portfolio Total (inc. Adjustments)** | | | | | | **149** | **150** | **151** | | **717,718** | **685,247** | **588,471** | | **406** | **6,133,283** |
| | | | | | | | | | | | | | **Full OEB Target:** | **1,820** | **9,280,000** |
| | | | | | | | | | | | | | **% of Full OEB Target Achieved to Date (Scenario 1):** | **22.3%** | **66.1%** |

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

## Table 1: Summarized Program Results

| Program | Gross Savings | | Net Savings | | Contribution to Targets | |
|---|---|---|---|---|---|---|
| | Incremental Peak Demand Savings (MW) | Incremental Energy Savings (GWh) | Incremental Peak Demand Savings (MW) | Incremental Energy Savings (GWh) | Program-to-Date: Net Annual Peak Demand Savings (MW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (GWh) |
| Consumer Program Total | 15.014 | 8.364142 | 13.296 | 4.773328 | 6.849 | 66.002755 |
| Business Program Total | 10.352 | 44.181101 | 8.115 | 32.343568 | 15.748 | 215.787481 |
| Industrial Program Total | .309 | .912062 | .297 | .821286 | .142 | 3.478424 |
| Home Assistance Program Total | .032 | .384041 | .032 | .384041 | .058 | 1.724858 |
| Pre-2011 Programs completed in 2011 Total | .286 | 1.899180 | .286 | 1.899180 | 2.348 | 37.295803 |
| Other Adjustments | .751 | 3.557363 | .478 | 2.376882 | .256 | 8.069609 |
| **Total OPA Contracted Province-Wide CDM Programs** | **26.744** | **59.297889** | **22.503** | **42.598285** | **25.401** | **332.358930** |

## 3.2 Evaluation

See 3.4 Additional Comments

## 3.3 Spending

Table 3 and 4 summarize the total spending by initiative that Hydro Ottawa has incurred in 2013 and cumulatively since 2011. It is detailed by the Program Administration Budget (PAB), Participant Based Funding (PBF), Participant Incentives (PI) and Capability Building Funding (CBF).

**Table 3: 2013 Spending**

| Initiative | PAB | PBF | PI | CBF | TOTAL |
|---|---|---|---|---|---|
| Consumer Program | | | | | |
| Appliance Retirement | 46,122.79 | | | | 46,122.79 |
| Appliance Exchange | 34,322.24 | | | | 34,322.24 |
| HVAC Incentives | 140,717.57 | | | | 140,717.57 |
| Annual Coupons | 108,537.25 | | | | 108,537.25 |
| Bi-Annual Retailer Event | 68,644.49 | | | | 68,644.49 |
| Retailer Co-op | | | | | |
| Residential Demand Response | 1,288,978.75 | | 3,097,890.47 | | 4,386,869.22 |
| New Construction Program | 675.00 | | | | 675.00 |
| Business Program | | | | | |
| Equipment Replacement | 846,917.18 | | 4,149,733.16 | | 4,996,650.34 |
| Direct Installed Lighting | 779,918.48 | 238,385.00 | 1,228,177.20 | | 2,246,480.68 |
| Existing Building Commissioning Incentive | 67,526.20 | | | | 67,526.20 |
| New Construction and Major Renovation Initiative | 579,873.95 | | 601,776.25 | | 1,181,650.20 |
| Energy Audit | 68,837.87 | | 294,248.47 | | 363,086.34 |
| Small Commercial Demand Response | | | | | |
| Demand Response 3 | | | | | |
| Industrial Program | | | | | |
| Process & System Upgrades | 27,699.28 | | | | 27,699.28 |
| a) preliminary engineering study | | | | | |
| b) detailed engineering study | | | | | |
| c) program incentive | | | | | |
| Monitoring & Targeting | 27,544.29 | | | | 27,544.29 |
| Energy Manager | 18,279.51 | | | | 18,279.51 |
| Key Account Manager (“KAM”) | 4,167.09 | | | | 4,167.09 |
| Equipment Replacement | | | | | |
| Demand Response 3 | 92,398.32 | | | | 92,398.32 |
| Home Assistance Program | | | | | |
| Home Assistance | 264,888.09 | | 372,220.55 | | 637,108.64 |
| Initiatives Not In Market | | | | | |
| Midstream Electronics | | | | | |
| Midstream Pool Equipment | | | | | |
| Demand Service Space Cooling | | | | | |
| Demand Response 1 | 111,550.98 | | | | 111,550.98 |
| Home Energy Audit Tool | | | | | |
| TOTAL SPENDING | 4,577,599.33 | 238,385.00 | 9,744,046.10 | 0.00 | 14,560,030.43 |

**Table 4: Cumulative Spending (2011-2014)**

| Initiative | PAB | PBI | PI | CBF | TOTAL |
|---|---|---|---|---|---|
| Consumer Program | | | | | |
| Appliance Retirement | 256,560.19 | | | | 256,560.19 |
| Appliance Exchange | 96,310.19 | | | | 96,310.19 |
| HVAC Incentives | 367.493.25 | | | | 367,493.25 |
| Annual Coupons | 331,512.75 | | | | 331,512.75 |
| Bi-Annual Retailer Event | 213,045.76 | | | | 213,045.76 |
| Retailer Co-op | | | | | |
| Residential Demand Response | 2,636,921.53 | | 5,857,280.47 | | 8,494,202.00 |
| New Construction Program | 6,400.25 | | | | 6,400.25 |
| Business Program | | | | | |
| Equipment Replacement | 1,975,763.72 | | 9,356,562.45 | | 11,332,326.17 |
| Direct Installed Lighting | 1,530,976.50 | 699,461.00 | 3,080,806.95 | | 5,311,244.45 |
| Existing Building Commissioning Incentive | 158,607.95 | | | | 158,607.95 |
| New Construction and Major Renovation Initiative | 996,794.02 | | 631,256.15 | | 1,628,050.17 |
| Energy Audit | 166,658.95 | | 448,953.19 | | 615,612.14 |
| Small Commercial Demand Response | | | | | |
| Demand Response | | | | | |
| Industrial Program | | | | | |
| Process & System Upgrades | 56,853.80 | | | | 56,853.80 |
| a) preliminary engineering study | | | | | |
| b) detailed engineering study | | | | | |
| c) program incentive | | | | | |
| Monitoring & Targeting | 56,675.31 | | | | 56,675.31 |
| Energy Manager | 18,279.51 | | | | 18,279.51 |
| Key Account Manager ("KAM") | 5,235.22 | | | | 5,235.22 |
| Equipment Replacement Incentive | | | | | |
| Demand Response 3 | 226,432.30 | | | | 226,432.30 |
| Home Assistance Program | | | | | |
| Home Assistance Program | 703,490.29 | | 502,822.75 | | 1,206,313.04 |
| Pre 2011 Programs | | | | | |
| Electricity Retrofit Incentive Program | | | 3,188,459.61 | | 3,188,459.61 |
| High Performance New Construction | | | | | |
| Toronto Comprehensive | | | | | |
| Multifamily Energy Efficiency Rebates | | | | | |
| Data Centre Incentive Program | | | | | |
| EnWin Green Suites | | | | | |
| Initiatives Not In Market | | | | | |
| Midstream Electronics | | | | | |
| Midstream Pool Equipment | | | | | |
| Demand Service Space Cooling | 1,515.33 | | | | 1,515.33 |
| Demand Response 1 | 242,721.50 | | | | 242,721.50 |
| Home Energy Audit Tool | | | | | |
| TOTAL SPENDING | 10,048,248.32 | 699,461.00 | 23,066,141.57 | 0.00 | 33,813,850.89 |

## 3.4 Additional Comments

The design of OPA Province–Wide CDM Initiatives is not customer friendly and this has had an impact on Hydro Ottawa's CDM program results. However, many of these design flaws have been identified and are being corrected.

**Consumer Programs**

1. **Home Energy Audit Tool, Midstream Pool Equipment, Midstream Electronics Initiatives** were never launched and subsequently withdrawn with no new additions.

2. Due to the maturity of the **Appliance Retirement Initiative**, and the revised eligibility requirements to appliances at least 20 years old, this Initiative appears to have reached market saturation. It is currently under consideration for removal from the portfolio.

3. The **Appliance Exchange Initiative** is at the discretion of Participating Retailers. Only one retailer hosted a spring event in 2012. There was no fall event. The elimination of one event restricted participation and reduced results.

4. The **Instant Coupon Initiative** was ineffective for most of 2012 as the annual Instant coupons were not available to consumers until September 2012 and once they were offered, they were only available on line. For illustration purposes, Hydro Ottawa customers used 30,000 printed coupons in 2011 and only 1,700 online coupons in 2012.

5. The **Bi-Annual Retailer Event Initiative** is a contracted arrangement between the participating retailer and the OPA. LDCs have prescribed engagement opportunities with the participating retailers. The reporting of coupon redemption results is not timely due to the contracted reporting timelines.

6. The **New Construction Program** was burdened with a cumbersome administrative process that vastly outweighed the benefit to builders. Hydro Ottawa took on the administrative burden for the program on behalf of the local builders and has experienced some success with this program. We do not feel that this approach is sustainable and that there needs to be a streamlined process that builders will embrace.

7. Implementation of the **Residential Demand Response Program** was delayed until 2012 as changes to the provincial technical specifications were required to facilitate procurement. This program contributes heavily towards the Consumer Program overall results but constraints imposed by the program funding caps, technical specifications and real time data requirements should be reviewed to encourage a broader range of equipment, services and offerings for LDCs to maintain a relevant offer as this market evolves.

8. **In Home Displays (IHDs)** formed an important part of the residential offering for many customers. IHDs engage customers, which leads to a greater understanding of how and when electricity is being used in their homes. The OPA, for a second year in a row, has been unable to determine the savings value of IHDs through their EM&V process. The methodology for the

EM&V was conducted the GTA which restricted the findings. It is felt that the restrictive nature of the EM&V paints all LDCs with the same brush when many LDCs used completely different approaches to deploying IHDs. Some LDCs focused heavily on proper installation and customer education and others deployed a more generic approach. As a result, Hydro Ottawa has no savings to report for our efforts. This has a significant negative impact on our results based on the original business case for IHDs. Because there are no results to date and no certainty around future results, Hydro Ottawa is unsure if it should continue to pursue this program.

**Business Program**

The Business Program has been hampered by inconsistent interpretation of program rules and eligibility, limited effectiveness of provincial marketing efforts, dated technologies and measures, cumbersome online administration systems and time consuming change management processes.

1. In the case of the **Efficiency: Equipment Replacement Incentive (ERII)** the OPA centralized application system (CRM) requires significant back office LDC processing to help participants navigate the application process. Eligible measures need to be updated and expanded in both technology and incentive amounts to address changing product costs and technology evolution.

2. The **Direct Install Initiative (DIL) has been in market since 2009.** The early success of the program was encouraging; however the program has not remained up to date with market needs and conditions. The product list for the program must be updated with current technologies and should be monitored and adjusted regularly. Product costs have also increased over time, eroding the contractor profit margins. This has led to a severe reduction in their participation.

3. **Existing Building Commissioning Incentive Initiative** has had minimal participation as it mostly limited to space cooling

4. There is typically a long sales cycle (3-5 years) associated with any **New Construction and Major Renovation Initiative (HPNC).** These projects with their long project development cycle are impacted by the program end date and heavily discounted EMV results.

5. The **Direct Service Space Cooling Initiative** was never launched.

**Industrial Program**

The Industrial initiatives have not generated significant savings in the Ottawa market because the region has a very light industrial base. However, Hydro Ottawa has rolled out these initiatives where possible.

1. The **Monitoring & Targeting Initiative** is targeted at larger customers with the capacity to analyze and respond to the M&T data. This requires the customer facility to employ an Energy Manager, or a person with equivalent qualifications, which has been a barrier for some customers. As such, a limited number of applications have been received to date. This combined with the savings target required has limited the initiative uptake for smaller customers.

2. One of the most successful elements of the Industrial program has been the capability building enabled by the **Embedded Energy Manager (EEM), Roving Energy Manager (REM) and Key Account Manager (KAM Initiatives.** These resources are difficult to find and require time to establish

themselves but once in place, they have been very successful at identifying and delivering energy efficiency opportunities. To date, Hydro Ottawa has placed six EEMs, 1 REM and 1 KAM in specific key accounts.

3. The **Demand Response 1 Initiative ("DR1")** has had no customer uptake and was removed from the Schedule in Q4, 2012.

**Home Assistance Program**

The **Home Assistance Program** is only marginally cost effective and delivers exceedingly low results per participant. This ineffective program is not attractive to Social Housing providers as they perceive it to be time consuming and burdened with paperwork for minimal value.

**LRAM**

Hydro Ottawa is concerned that the issues that have been identified above, namely programs that have not materialized, were delayed or for which the results are still under review (for example TOU pricing and Residential IHD), can adversely affect an LDC's ability to be held whole in terms of lost revenue due to CDM. For those LDCs that claim a LRAM ex post, if the results are not available or are subsequently changed, then there is a disconnect between the lost revenue applied for and that actually lost and if there is a true up it would be done years after the lost revenue occurred.

For those utilities recovering the lost revenue through an ex ante adjustment to their load forecast, that adjustment normally reflects the anticipated CDM results based on expected programs and current EM&V methodologies. When program results do not match those anticipated then the utility is required to record the shortfall in the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) and may never be able to properly recover the appropriate lost revenue.

Hydro Ottawa's results for 2012 were limited as a result of the above-mentioned shortcomings of OPA Province–Wide CDM Initiatives. The lack of success through OPA Province–Wide CDM Initiatives is further diminished by the difficult processes and negative experience with Board Approved CDM programs by those LDCs making application.

These limitations are easily addressed with a change to the CDM funding and regulatory structure that aligns LDC accountability with the requisite control over program design and delivery. OPA may continue to contribute in an ongoing and valuable role as a service provider to the LDCs providing centralized services for analytics, research and evaluation, but, they must not be in command and control of LDC success. To be successful, LDCs must be given greater control over this important condition of their distribution licence.

# 4 Combined CDM Reporting Elements

## 4.1 Progress Towards CDM Targets

**Table 5: Net Peak Demand Savings at the End User Level (MW)**

| Implementation Period | Annual (MW) | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| 2011 – Verified by OPA | 12.7 | 8.9 | 8.9 | 8.3 |
| 2012 – Verified by OPA | -0.2 | 16.6 | 8.5 | 8.4 |
| 2013 – Verified by OPA | | 0.5 | 22.5 | 8.8 |
| 2014 | | | | |
| **Verified Net Annual Peak Demand Savings in 2014:** | | | | 25.4 |
| **HYDRO OTTAWA 2014 Annual CDM Capacity Target:** | | | | 85.3 |
| **Verified Portion of Peak Demand Savings Target Achieved (%):** | | | | **29.8%** |

**Table 6: Net Energy Savings at the End-User Level (GWh)**

| Implementation Period | Annual (GWh) | | | | Cumulative (GWh) |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2011-2014 |
| 2011 – Verified by OPA | 35.8 | 35.8 | 35.7 | 34.0 | 141.4 |
| 2012 – Verified by OPA | 0.2 | 35.1 | 34.9 | 34.4 | 104.6 |
| 2013 – Verified by OPA | | 2.4 | 42.6 | 41.4 | 86.4 |
| 2014 | | | | | |
| **Verified Net Cumulative Energy Savings 2011-2014:** | | | | | **332.4** |
| **HYDRO OTTAWA 2011-2014 Cumulative CDM Energy Target:** | | | | | **374.7** |
| **Verified Portion of Cumulative Energy Target Achieved (%):** | | | | | **88.7%** |

## 4.1 Variance from Strategy

There is no variance from our current strategy.

## 4.2 Outlook to 2014 and Strategy Modifications

There is no variance from our current strategy and we do not anticipate any modification to our strategy.

On March 31st, 2014 the Minister of Energy issued a directive entitled "Continuance of the OPA's Demand Response Program under IESO management" which effectively halts new customer enrollments in the DR3 program until the IESO has a program in market. This is estimated to be some time in 2015.

The DR3 Initiative is a significant contributor to helping LDCs achieve their demands savings target. The program has taken some time to get traction and LDCs have been diligently working with their customers to encourage participation in the DR3 program. LDC customers are now in a position where many of them have contracted with an Aggregator but will be unable to participate due to the inability of the Aggregator to receive new contract schedules resulting in the current "pipeline" of potential DR contributors being stranded.

The results reported for 2013 are lower than originally expected due to a number of factors. Major impacts include:

- no TOU results available and an expectation that any forthcoming results will be significantly lower than originally forecast.
- no results for IHDs
- removal of DR
- retrospective EM&V coming 1.5 years after the fact does not allow time to make adjustment

Our channels remain strong and engaged. We have made good inroads with some larger customers like the federal government. We continue to focus on moving conservation forward with our customers.

# 5 Conclusion

Over the course of 2013, Hydro Ottawa achieved 42.6 GWh in energy savings which represents 88.7% of the 2014 target. The Hydro Ottawa is reported to have saved 22.5 MW in peak demand savings which represents 29.8% of the 2014 target. Hydro Ottawa does not feel that this accurately represents our efforts as the peaksaver PLUS installs and the DR3 results from 2011 and 2012 are not included in this number.

These results are representative of a considerable effort expended by Hydro Ottawa, in cooperation with other LDCs, customers, channel partners and stakeholders to overcome many operational and structural issues that limited program effectiveness across all market sectors. This achievement is a success and the relationships built within the 2011-2014 CDM program term will aid results in a subsequent CDM term.

However, despite continuing improvements to existing programs Hydro Ottawa faces challenges in the remaining years of the current CDM framework. With the current slate of available OPA Programs, and the current forecast of implementation and projected savings, Hydro Ottawa expects to meet its 374.73 GWh consumption savings target but will be very challenged to meet its 85.26 MW demand savings target.

Looking ahead there is very limited time to make impactful changes to the current program portfolios and have these changes reflected in LDC 2014 results. However, LDCs and the OPA can build on the strengths and key successes of the 2011-2014 programs to launch new programs which will meet the needs of the industry and consumers.

# **Appendix A:** Initiative Descriptions

## Residential Program

### APPLIANCE RETIREMENT INITIATIVE (Exhibit D)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Year round

**Objectives:** Achieve energy and demand savings by permanently decommissioning certain older, inefficient refrigeration appliances.

**Description:** This is an energy efficiency Initiative that offers individuals and businesses free pick-up and decommissioning of old large refrigerators and freezers. Window air conditioners and portable dehumidifiers will also be picked up if a refrigerator or a freezer is being collected.

**Targeted End Uses:** Large refrigerators, large freezers, window air conditioners and portable dehumidifiers.

**Delivery**: OPA centrally contracts for the province-wide marketing, call centre, appliance pick-up and decommissioning process. LDC's provides local marketing and coordination with municipal pick-up where available.

**Additional Detail:** Schedule B-1, Exhibit D on the OPA extranet and saveONenergy website

**In Market Date:** February 2011

### APPLIANCE EXCHANGE INITIATIVE (Exhibit E)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Spring and Fall

**Objective:** The objective of this Initiative is to remove and permanently decommission older, inefficient window air conditioners and portable dehumidifiers that are in Ontario.

**Description:** This Initiative involves appliance exchange events. Exchange events are held at local retail locations and customers are encouraged to bring in their old room air conditioners (AC) and dehumidifiers in exchange for coupons/discounts towards the purchase of new energy efficient equipment. Window ACs were discontinued from the program in 2013.

**Targeted End Uses**: Window air conditioners and portable dehumidifiers

**Delivery**: OPA contracts with participating retailers for collection of eligible units. LDCs provide local marketing.

**Additional Detail:** Schedule B-1, Exhibit C on the OPA extranet and saveONenergy website

**In Market Date:** May 2011

### HVAC INCENTIVES INITIATIVE (Exhibit B)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to encourage the replacement of existing heating systems with high efficiency furnaces equipped with Electronically Commutated Motors (ECM), and to replace existing central air conditioners with ENERGY STAR qualified systems and products**.**

**Description:** This is an energy efficiency Initiative that provides rebates for the replacement of old heating or cooling systems with high efficiency furnaces (equipped with ECM) and ENERGY STAR® qualified central air conditioners by approved Heating, Refrigeration, and Air Conditioning Institute (HRAI) qualified contractors.

**Targeted End Uses:** Central air conditioners and furnaces

**Delivery:** OPA contracts centrally for delivery of the program. LDCs provide local marketing and encourage local contractors to participate in the Initiative.

**Additional Detail:** Schedule B-1, Exhibit B on the OPA extranet and SaveONenergy website

**In Market Date:** February 2011

### CONSERVATION INSTANT COUPON INITIATIVE (Exhibit A)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to encourage households to purchase energy efficient products by offering discounts.

**Description:** This Initiative provides customers with year round coupons. The coupons offer instant rebates towards the purchase of a variety of low cost, easy to install energy efficient measures and can be redeemed at participating retailers. Booklets were directly mailed to customers and were also available at point-of-purchase. Downloadable coupons were also available at www.saveoneenergy.ca.

**Targeted End Uses:** ENERGY STAR® qualified Standard Compact Fluorescent Lights ("CFLs"),ENERGY STAR® qualified Light Fixtures lighting control products, weather-stripping, hot water pipe wrap, electric water heater blanket, heavy duty plug-in Timers, Advanced power bars, clothesline, baseboard programmable thermostats.

**Delivery**: The OPA develops the electronic version of the coupons and posts them online for download. Three LDC specific coupons were made available for local marketing and utilization by LDCs. The OPA enters into agreements with retailers to honor the coupons.

**Additional Detail:** Schedule B-1, Exhibit A on the OPA extranet and saveONenergy website

**In Market Date:** March 2011

### BI-ANNUAL RETAILER EVENT INITIATIVE (Exhibit C)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Bi-annual events

**Objective:** The objective of this Initiative is to provide instant point of purchase discounts to individuals at participating retailers for a variety of energy efficient products.

**Description:** Twice a year (Spring and Fall), participating retailers host month-long rebate events. During the months of April and October, customers are encouraged to visit participating retailers where they can find coupons redeemable for instant rebates towards a variety of low cost, easy to install energy efficient measures.

**Targeted End Uses**: As per the Conservation Instant Coupon Initiative

**Delivery:** The OPA enters into arrangements with participating retailers to promote the discounted products, and to post and honor related coupons. LDCs also refer retailers to the OPA and market this initiative locally.

**Additional Detail:** Schedule B-1, Exhibit C on the OPA extranet and saveONenergy website

**In Market Date:** April 2011

### ~~RETAILER CO-OP~~

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Year Round

**Objective:** Hold promotional events to encourage customers to purchase energy efficiency measures (and go above-and-beyond the traditional Bi-Annual Coupon Events).

**Description:** The Retailer Co-op Initiative provides LDCs with the opportunity to work with retailers in their service area by holding special events at retail locations. These events are typically special promotions that encourage customers to purchase energy efficiency measures (and go above-and-beyond the traditional Bi-Annual Coupon Events).

**Targeted End Uses:** As per the Conservation Instant Coupon Initiative

**Delivery:** Retailers apply to the OPA for co-op funding to run special promotions that promote energy efficiency to customers in their stores. LDCs can refer retailers to the OPA. The OPA provides each LDC with a list of retailers who have qualified for Co-Op Funding as well as details of the proposed special events.

**In Market Date:** N/A

### NEW CONSTRUCTION PROGRAM (Schedule B-2)

**Target Customer Type(s):** Residential Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to provide incentives to participants for the purpose of promoting the construction of energy efficient residential homes in the Province of Ontario.

**Description:** This is an energy efficiency Initiative that provides incentives to homebuilders for constructing new homes that are efficient, smart, and integrated (applicable to new single family dwellings). Incentives are provided in two key categories as follows:

- Incentives for homebuilders who install electricity efficiency measures as determined by a prescriptive list or via a custom option.
- Incentives for homebuilders who meet or exceed aggressive efficiency standards using the EnerGuide performance rating system.

**Targeted End Uses:** All off switch, ECM motors, ENERGY STAR® qualified central a/c, lighting control products, lighting fixtures, EnerGuide 83 whole home, EnerGuide 85 whole homes

**Delivery:** Local engagement of builders will be the responsibility of the LDC and will be supported by OPA air coverage driving builders to their LDC for additional information.

**Additional Detail:** Schedule B-1, Exhibit C on the OPA extranet and saveONenergy website

**In Market Date:** Fall 2011

### RESIDENTIAL DEMAND RESPONSE PROGRAM (Schedule B-3)

**Target Customer Type(s):** Residential and Small Commercial Customers

**Initiative Frequency:** Year round

**Objective:** The objectives of this Initiative are to enhance the reliability of the IESO-controlled grid by accessing and aggregating specified residential and small commercial end uses for the purpose of load reduction, increasing consumer awareness of the importance of reducing summer demand and providing consumers their current electricity consumption and associated costs.

**Description:** In ***peaksaver***PLUS ™ participants are eligible to receive a free programmable thermostat or switch, including installation. Participants also receive access to price and real-time consumption information on an In Home Display (IHD).

**Targeted End Uses**: central air conditioning, electric hot water heaters and pool pumps

**Delivery**: LDC's recruit customers and procure technology

**Additional Detail:** Schedule B-1, Exhibit C on the OPA extranet and saveONenergy website

**In Market Date:** May 2012

## C&I Program

### EFFICIENCY: EQUIPMENT REPLACEMENT INCENTIVE (ERII) (Schedule C-2)

**Target Customer Type(s):** Commercial, Institutional, Agricultural and Industrial Customers

**Initiative Frequency:** Year round

**Objective**: The objective of this Initiative is to offer incentives to non-residential distribution customers to achieve reductions in electricity demand and consumption by upgrading to more energy efficient equipment for lighting, space cooling, ventilation and other measures.

**Description:** The Equipment Replacement Incentive Initiative (ERII) offers financial incentives to customers for the upgrade of existing equipment to energy efficient equipment. Upgrade projects can be classified into either: 1) prescriptive projects where prescribed measures replace associated required base case equipment; 2) engineered projects where energy and demand savings and incentives are calculated for associated measures; or 3) custom projects for other energy efficiency upgrades.

**Targeted End Uses:** lighting, space cooling, ventilation and other measures

**Delivery**: LDC delivered.

**Additional Detail:** Schedule C-2 on the OPA extranet and saveONenergy website

**In Market Date:** February 2011

## DIRECT INSTALL INITIATIVE (DIL) (Schedule C-3)

**Target Customer Type(s):** Small Commercial, Institutional, Agricultural facilities and multi-family buildings

**Initiative Frequency:** Year round

**Objective**: The objective of this Initiative is to offer a free installation of eligible lighting and water heating measures of up to $1,000 to eligible owners and tenants of small commercial, institutional and agricultural facilities and multi-family buildings, for the purpose of achieving electricity and peak demand savings.

**Description:** The Direct Installed Lighting Initiative targets customers in the General Service <50kW account category. This Initiative offers turnkey lighting and electric hot water heater measures with a value up to $1,000 at no cost to qualifying small businesses. In addition, standard prescriptive incentives are available for eligible equipment beyond the initial $1,000 limit.

**Target End Uses:** Lighting and electric water heating measures

**Delivery**: Participants can enroll directly with the LDC, or would be contacted by the LDC/LDC-designated representative.

**Additional Detail:** Schedule C-3 on the OPA extranet and saveONenergy website

**Initiative Activities/Progress:**

**In Market Date:** March 2011

## EXISTING BUILDING COMMISSIONING INCENTIVE INITIATIVE (Schedule C-6)

**Target Customer Type(s):** Commercial, Institutional, and Agricultural Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to offer incentives for optimizing (but not replacing) existing chilled water systems for space cooling in non-residential facilities for the purpose of achieving implementation phase energy savings, implementation phase demand savings, or both.

**Description:** This Initiative offers Participants incentives for the following:

- scoping study phase
- investigation phase
- implementation phase
- hand off/completion phase

**Targeted End Uses:** Chilled water systems for space cooling

**Delivery:** LDC delivered.

**Additional Detail:** Schedule C-6 on the OPA extranet and saveONenergy website Additional detail is available:

**Initiative Activities/Progress:**

**In Market Date:** March 2011

### NEW CONSTRUCTION AND MAJOR RENOVATION INITIATIVE (HPNC) (Schedule C-4)

**Target Customer Type(s):** Commercial, Institutional, Agricultural and Industrial Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to encourage builders/major renovators of commercial, institutional, and industrial buildings (including multi-family buildings and agricultural facilities) to reduce electricity demand and/or consumption by designing and building new buildings with more energy-efficient equipment and systems for lighting, space cooling, ventilation and other Measures.

**Description**: The New Construction initiative provides incentives for new buildings to exceed existing codes and standards for energy efficiency. The initiative uses both a prescriptive and custom approach.

**Targeted End Uses**: New building construction, building modeling, lighting, space cooling, ventilation and other Measures

**Delivery**: LDC delivers to customers and design decision makers.

**Additional Detail:** Schedule C-4 on the OPA extranet and saveONenergy website

**Initiative Activities/Progress**:

**In Market Date:** July 2011

### ENERGY AUDIT INITIATIVE (Schedule C-1)

**Target Customer Type(s):** Commercial, Institutional, Agricultural and Industrial Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this Initiative is to offer incentives to owners and lessees of commercial, institutional, multi-family buildings and agricultural facilities for the purpose of undertaking assessments to identify all possible opportunities to reduce electricity demand and consumption within their buildings or premises.

**Description:** This Initiative provides participants incentives for the completion of energy audits of electricity consuming equipment located in the facility. Energy audits include development of energy baselines, use assessments and performance monitoring and reporting.

**Targeted End Uses:** Various

**Delivery:** LDC delivered.

**Additional Detail:** Schedule C-1 on the OPA extranet Schedule C-1 and saveONenergy website

**In Market Date:** March 2011

## Industrial Program

### PROCESS & SYSTEMS UPGRADES INITIATIVE (PSUI) (Schedule D-1)

**Target Customer Type(s):** Industrial, Commercial, Institutional and Agricultural Customers

**Initiative Frequency:** Year round

**Objectives:** The objectives of this Initiative are to:

- Offer distribution customers capital incentives and enabling initiatives to assist with the implementation of large projects and project portfolios;
- Implement system optimization project in systems which are intrinsically complex and capital intensive; and
- Increase the capability of distribution customers to implement energy management and system optimization projects.

**Description:** PSUI is an energy management Initiative that includes three Initiatives: (preliminary engineering study, detailed engineering study, and project incentive Initiative). The incentives are available to large distribution connected customers with projects or portfolio projects that are expected to generate at least 350 MWh of annualized electricity savings or, in the case of Micro-Projects, 100 MWh of annualized electricity savings. The capital incentive for this Initiative is the lowest of:

a) $200/MWh of annualized electricity savings

b) 70% of projects costs

c) A one year pay back

**Targeted End Uses:** Process and systems

**Delivery:** LDC delivered with Key Account Management support, in some cases.

**Additional Detail:** Schedule D-1 on the OPA extranet and saveONenergy website

**In Market Date:** February 2011

### MONITORING & TARGETING INITIATIVE (Schedule D-2)

**Target Customer Type(s):** Industrial, Commercial, Institutional and Agricultural Customers

**Initiative Frequency:** Year round

**Objective:** This Initiative offers access to funding for the installation of Monitoring and Targeting systems in order to deliver a minimum savings target at the end of 24 months and sustained for the term of the M&T Agreement.

**Description:** This Initiative offers customers funding for the installation of a Monitoring and Targeting system to help them understand how their energy consumption might be reduced. A facility energy manager, who regularly oversees energy usage, will now be able to use historical energy consumption performance to analyze and set targets.

**Targeted End Uses:** Process and systems

**Delivery:** LDC delivered with Key Account Management support, in some cases.

**Additional Detail:** Schedule D-2 on the OPA extranet and saveONenergy website

**In Market Date:** February 2011

### ENERGY MANAGER INITIATIVE (Schedule D-3)

**Target Customer Type(s):** Industrial, Commercial, Institutional and Agricultural Customers

**Initiative Frequency:** Year round

**Objective:** The objective of this initiative is to provide customers and LDCs the opportunity to access funding for the engagement of energy managers in order to deliver a minimum annual savings target.

**Description:** This Initiative provides customers the opportunity to access funding to engage an on-site, full time embedded energy manager, or an off-site roving energy manager who is engaged by the LDC. The role of the energy manager is to take control of the facility's energy use by monitoring performance, leading awareness programs, and identifying opportunities for energy consumption improvement, and spearheading projects. Participants are funded 80% of the embedded energy manager's salary up to $100,000 plus 80% of the energy manager's actual reasonable expenses incurred up to $8,000 per year. Each embedded energy manager has a target of 300 kW/year of energy savings from one or more facilities. LDCs receive funding of up to $120,000 for a Roving Energy Manager plus $8,000 for expenses.

**Targeted End Uses:** Process and systems

**Delivery:** LDC delivered with Key Account Management support, in some cases.

**Additional Detail**: Schedule D-3 on the OPA extranet and saveONenergy website

**In Market Date:** August 2012

### KEY ACCOUNT MANAGER (KAM) (Schedule D-4)

**Target Customer Type(s):** Industrial, Commercial, Institutional and Agricultural Customers

**Initiative Frequency:** Year round

**Objective**: This initiative offers LDCs the opportunity to access funding for the employment of a KAM in order to support them in fulfilling their obligations related to the PSUI.

**Description:** This Initiative provides LDCs the opportunity to utilize a KAM to assist their customers. The KAM is considered to be a key element in assisting the consumer in overcoming traditional barriers related to energy management and help them achieve savings since the KAM can build relationships and become a significant resource of knowledge to the customer.

**Targeted End Uses:** Process and systems

**Delivery:** LDC delivered

**Additional Detail:** ScheduleD-4 on the OPA extranet.

**In Market Date:** August 2012

### DEMAND RESPONSE 3 (Schedule D-6)

**Target Customer Type(s):** Industrial, Commercial, Institutional and Agricultural Customers

**Initiative Frequency:** Year round

**Objective:** This Initiative provides for Demand Response ("DR") payments to contracted participants to compensate them for reducing their electricity consumption by a pre-defined amount during a DR event.

**Description:** Demand Response 3 ("DR3") is a demand response Initiative for commercial and industrial customers, of 50 kW or greater to reduce the amount of power being used during certain periods of the year. The DR3 Initiative is a contractual resource that is an economic alternative to procurement of new generation capacity. DR3 comes with specific contractual obligations requiring participants to reduce their use of electricity relative to a baseline when called upon. This Initiative makes payments for participants to be on standby and payments for the actual electricity reduction provided during a demand response event. Participants are scheduled to be on standby approximately 1,600 hours per calendar year for possible dispatch of up to 100 hours or 200 hours within that year depending on the contract.

**Targeted End Uses:** Commercial and Industrial Operations

**Delivery:** DR3 is delivered by Demand Response Providers ("DRPs"), under contract to the OPA. The OPA administers contracts with all DRPs and Direct Participants (who provide in excess of 5 MW of demand response capacity). OPA provides administration including settlement, measurement and verification, and dispatch. LDCs are responsible for local customer outreach and marketing efforts.

**Additional Detail:** Schedule D-6 available on the OPA and saveONenergy website

**In Market Date:** October 2011

It is noted that while the Schedule for this Initiative was not posted until May 2011, the Aggregators reported that they were able to enroll customers as of January 2011.

### LOW INCOME INITIATIVE (HOME ASSISTANCE PROGRAM) (Schedule E-1)

**Target Customer Type(s):** Income Qualified Residential Customers

**Initiative Frequency:** Year Round

**Objective**: The objective of this Initiative is to offer free installation of energy efficiency measures to income qualified households for the purpose of achieving electricity and peak demand savings.

**Description:** This is a turnkey Initiative for income qualified customers. It offers residents the opportunity to take advantage of free installation of energy efficient measures that improve the comfort of their home, increase efficiency, and help them save money. All eligible customers receive a Basic and Extended Measures Audit, while customers with electric heat also receive a Weatherization Audit. The Initiative is designed to coordinate efforts with gas utilities.

**Targeted End Uses**: End use measures based on results of audit (i.e. compact fluorescent light bulbs)

**Delivery:** LDC delivered.

**Additional Detail**: Schedule E available on the OPA extranet.

**In Market Date:** January 2012

# **Appendix B:** Pre-2011 Programs

## ELECTRICITY RETROFIT INCENTIVE PROGRAM

**Target Customer Type(s):** Commercial, Institutional, and Agricultural Customers

**Initiative Frequency:** Year Round

**Objective:** The objective of this Initiative is to offer incentives to non-residential distribution customers to achieve reductions in electricity demand and consumption by upgrading to more energy efficient equipment for lighting, space cooling, ventilation and other measures.

**Description:** The Equipment Replacement Incentive Program (ERIP) offered financial incentives to customers for the upgrade of existing equipment to energy efficient equipment. This program was available in 2010 and allowed customers up to 11 months following Pre-Approval to complete their projects. As a result, a number of projects Pre-Approved in 2010 were not completed and in-service until 2011. The electricity savings associated with these projects are attributed to 2011.

**Targeted End Uses**: Electricity savings measures

**Delivery**: LDC Delivered

## HIGH PERFORMANCE NEW CONSTRUCTION

**Target Customer Type(s):** Commercial, Institutional, and Agricultural Customers

**Initiative Frequency:** Year round

**Objective:** The High Performance New Construction Initiative provided incentives for new buildings to exceed existing codes and standards for energy efficiency. The Initiative uses both a prescriptive and custom approach and was delivered by Enbridge Gas under contract with the OPA (and subcontracted to Union Gas), which ran until December 2010.

**Description:** The objective of this Initiative is to encourage builders of commercial, institutional, and industrial buildings (including multi-family buildings and agricultural facilities) to reduce electricity demand and/or consumption by designing and building new buildings with more energy-efficient equipment and systems for lighting, space cooling, ventilation and other Measures.

**Targeted End Uses**: New Building construction, building modeling, lighting, space cooling, ventilation and other measures

**Delivery**: Through Enbridge Gas (and subcontracted to Union Gas)

## ~~TORONTO COMPREHENSIVE INITIATIVE~~

**Target Customer Type(s):** Commercial and Institutional Customers

**Initiative Frequency:** Year round

**Objective:**

**Description:** This Initiative is specific to Toronto Hydro's Service Area.

**Targeted End Uses**:

**Delivery**:

## MULTIFAMILY ENERGY EFFICIENCY REBATES

**Target Customer Type(s):** Residential Multi-unit buildings

**Initiative Frequency:** Year round

**Objective:** Improve energy efficiency of Multi-unit building

**Description:** OPA's Multifamily Energy Efficiency Rebates (MEER) Initiative applies to multifamily buildings of six units or more, including rental buildings, condominiums, and assisted social housing. The OPA contracted with GreenSaver to deliver the MEER Initiative outside of the Toronto Hydro service territory. Activities delivered in Toronto were contracted with the City.

Similar to ERII and ERIP, MEER provides financial incentives for prescriptive and custom measures, but also funds resident education. Unlike ERII, where incentives are paid by the LDC, all incentives through MEER are paid through the contracted partner (i.e. GreenSaver).

**Targeted End Uses**: Electricity saving measures

**Delivery**: OPA contracted with GreenSaver

## ~~DATA CENTRE INCENTIVE PROGRAM~~

**Target Customer Type(s):**

**Initiative Frequency:** Year round

**Objective:**

**Description:** This Initiative is specific to PowerStream's Service Area.

**Targeted End Uses**:

**Delivery**:

## ~~ENWIN GREEN SUITES~~

**Target Customer Type(s):**

**Initiative Frequency:** Year round

**Objective:**

**Description:** This Initiative is specific to EnWin's Service Area.

**Targeted End Uses**:

**Delivery**:

# LRAM VARIANCE ACCOUNT

## 1.0 INTRODUCTION

Hydro Ottawa Limited is seeking the recovery of the Lost Revenue Adjustment Mechanism ("LRAM") in the amount of ($679,243), including principle of ($678,660) and carrying charges of ($583). This includes the 2011, 2012 and 2013 Ontario Power Authority ("OPA") Conservation and Demand Management ("CDM") programs, cumulative to the year ending December 31, 2013; please see Attachment I-8(A) for further details.

## 2.0 Input Assumptions

Hydro Ottawa confirms it is using the most recent input assumptions available for calculating lost revenue at the time of filing this rate application. This includes the final 2013 verified results report from the OPA and Hydro Ottawa's Conservation and Demand Management 2013 Annual Report as Submitted to the OEB on September 30, 2014. Please refer to attachments D–5(A) and D–5(B) respectively.

## 3.0 CDM Evaluation report from the OPA

Hydro Ottawa confirms it has relied upon the most recent final CDM evaluation, the 2013 verified results report from the OPA to support the lost revenue calculations. Please refer to Attachment D-5(A) for a copy of this OPA report.

## 4.0 CDM Programs and initiatives by rate class

Table 1 below shows the Lost Revenue from 2011 to 2013 by rate class, the total lost revenue from 2011 to 2013 is $678,660.

**Table 1 – Lost Revenue by Year by Rate Class**

| | 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|
| Residential | $(187,041) | $ 170,928 | $ 61,248 | $ 45,135 |
| GS< 50 kW | (72,564) | (8,436) | (83,055) | (164,055) |
| Commercial | (172,163) | 606,207 | 327,092 | 761,136 |
| Unmetered | | 3,583 | 3,617 | 7,200 |
| Streetlighting | | 14,611 | 14,633 | 29,244 |
| **TOTAL** | **$(431,768)** | **$ 786,894** | **$ 323,534** | **$ 678,660** |

A list of all the CDM programs/initiatives by rate class indicating the energy savings (kWh) and peak demand (kW) savings assigned to the programs/initiatives, is available in Table 2. For descriptions on these initiatives, please see the OPA report in Attachment D–5(A).

## Table 2 – CDM Programs/Initiatives by Class by kWh/kW[1]

| Customer Class - Program / Initiative | Net Incremental Peak Demand Savings (kW) - 2011 | Net Incremental Peak Demand Savings (kW) - 2012 | Net Incremental Peak Demand Savings (kW) - 2013 | Net Incremental Energy Savings (kWh) - 2011 | Net Incremental Energy Savings (kWh) - 2012 | Net Incremental Energy Savings (kWh) - 2013 |
|---|---|---|---|---|---|---|
| **Residential** | | | | | | |
| Appliance Retirement | | | | 1,754,416 | 1,040,845 | 681,703 |
| Appliance Exchange | | | | 22,795 | 43,987 | 70,563 |
| HVAC Incentives | | | | 4,496,665 | 2,946,491 | 2,563,561 |
| Conservation Instant Coupon Booklet | | | | 1,120,034 | 78,235 | 431,268 |
| Bi-Annual Retailer Event | | | | 1,766,511 | 1,498,537 | 961,278 |
| Residential Demand Response | | | | 8,266 | 55,891 | 48,406 |
| Residential New Construction | | | | 0 | 0 | 16,548 |
| **Residential Program Total** | - | - | - | 9,168,688 | 5,663,987 | 4,773,328 |
| **GS< 50 kW** | | | | | | |
| Direct Install Lighting | | | | 0 | 0 | 0 |
| Small Commercial Demand Response | | | | 0 | 0 | 0 |
| **GS< 50 kW Total** | - | - | - | - | - | - |
| **Commercial** | | | | | | |
| Retrofit - Business | 35,933 | 66,187 | 58,770 | | | |
| New Construction | 0 | 163 | 1,500 | | | |
| Energy Audit | 311 | 1,553 | 5,076 | | | |
| Demand Response 3 - Business | 7,163 | 7,723 | 18,245 | | | |
| Energy Manager | 0 | 0 | 1,303 | | | |
| Retrofit - Industrial | 973 | | | | | |
| Demand Response 3 - Industrial | 0 | 503 | 2,266 | | | |
| Home Assistance Program | 0 | 316 | 380 | | | |
| Electricity Retrofit Incentive Program | 11,530 | 0 | 0 | | | |
| High Performance New Construction | 4,378 | 9,686 | 3,432 | | | |
| **Commercial Total** | 60,288 | 86,131 | 90,971 | - | - | - |
| **GRAND TOTAL** | **60,288** | **86,131** | **90,971** | **9,168,688** | **5,663,987** | **4,773,328** |

[1] Demand Response Activities due not Persist, therefore figures in Table 2 are not equal to cumulative totals in Table 3

## 5.0 Lost Revenue Calculations by Rate Class

Below in Table 3 is Hydro Ottawa's Lost Revenue by Class, broken down by demand (kW) and energy (kWh) for the years 2011 to 2013, the lost revenue totals shown include persistence. Hydro Ottawa used it's respective Board approved variable distribution charges in calculating the lost revenue.

**Table 3 – Lost Revenue by Class (2011 to 2013)**

| | | 2011 | | | 2012 | | | 2013 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Demand (kW) or Energy (kWh) | Units of Demand or Energy | Variable Rate | Lost Revenue | Units of Demand or Energy | Variable Rate | Lost Revenue | Units of Demand or Energy | Variable Rate | Lost Revenue |
| Residential | kWh | 9,168,688 | $0.0204 | $(187,041) | 14,824,409 | $0.0231 | $170,928 | 19,541,846 | $0.0228 | $61,248 |
| GS< 50 kW | kWh | 3,979,746 | $0.0182 | (72,564) | 7,408,550 | $0.0203 | (8,436) | 11,064,344 | $0.0204 | (83,055) |
| Commercial | kW | 60,288 | $2.8557 | (172,163) | 139,255 | $3.3690 | $606,207 | 222,001 | $3.3654 | $327,092 |
| Unmetered | kWh | | | | 0 | $0.0211 | $3,583 | 0 | $0.0213 | $3,617 |
| Streetlighting | kW | | | | 0 | $3.8880 | $14,611 | 0 | $3.8939 | $14,633 |
| TOTAL | | | | $(431,768) | | | $786,894 | | | $323,534 |

## 6.0 Carrying Charges on Lost Revenue

Hydro Ottawa confirms carrying charges are being requested on the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"). The interest rate used for the calculation of all carrying charges were as prescribed by the Board and published quarterly on its website, please refer to Exhibit I-1-1 for further details on the carrying charges.

## 7.0 Board Approved Programs

Hydro Ottawa did not undertake any Board-Approved CDM Programs from 2012 – 2014. All the CDM programs activities are OPA funded, thus as per section 6.1.1 of the Conservation and Demand Management Code, no separate third-party independent verification is required.

# COST OF CAPITAL AND CAPITAL STRUCTURE

Hydro Ottawa Limited (Hydro Ottawa) has prepared this document to provide an overview of its capital structure, financing approach, costs associated with short term and long term debt, and calculation of return on equity as required under section 2.8 of *Ontario Energy Board (OEB) Filing Requirements for Electricity Distribution Rate Applications (July 18, 2014).*

## 1.0 CAPITAL STRUCTURE

Hydro Ottawa's capital structure is set in accordance with the OEB guidelines provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities issued on December 11, 2009 (the "2009 Report)*. Hydro Ottawa targets a 60:40 debt to equity range as evidenced by Hydro Ottawa's past and current practices. The 60% debt component is made up of 56% long-term debt and 4% short term debt.

Appendix 2-OA "Capital Structure" outlines Hydro Ottawa's capital structure for the last Board approved year 2012 and the Test Years 2016 to 2020.

## 2.0 FINANCING APPROACH

Financing for Hydro Ottawa is received through its parent company, Hydro Ottawa Holding Inc. (Holding Company). All external debt is managed by the Holding Company as it maintains a strong investment grade credit rating at the parent company level for financing purposes. These credit ratings are required for the Holding Company to issue private debt issuances into the Canadian debt market to support its subsidiaries/affiliates financing requirements. Hydro Ottawa receives all of its financing from the Holding Company via intercompany loans on a "pass through" basis for the rates, terms, and conditions that the Holding Company receives from the external markets.

### 2.1 Credit Rating

The current credit ratings for the Holding Company by Standard and Poor's and Dominion Bond Rating Service are as follows:

| Rating Agency | Credit Rating |
|---|---|
| Dominion Bond Rating Service (DBRS) | A Stable |
| Standard and Poor's (S&P) | A Stable |

The most recent credit rating reports issued by DBRS and S&P are provided in Attachments A-4(D) and A-4(E) respectively.

### 2.2 Short Term Debt

The Holding Company maintains short term credit facilities to support the liquidity needs of Hydro Ottawa. These facilities are used to cover periodic working capital deficiencies, bridge financing requirements until long term debt is warranted, and to post required prudentials with the Independent Electricity System Operator.

The cost of short term financing is passed onto Hydro Ottawa on the same terms and conditions that the Holding Company receives from external markets through its credit facilities. Terms and conditions of short term borrowings are governed by the "Credit Agreement" dated January 1, 2009 which is filed in Attachment E-1(A).

For the purpose of the rate application, Hydro Ottawa has utilized the short term debt rate of 2.16% for the years 2016 through 2020, as provided in the letter dated November 20, 2014 outlining the Cost of Capital Parameter Updates for 2015 Applications. It is recognized that this rate will be updated at the time of the rate decision to reflect the deemed short term debt rate for 2016 rate applications to be published in November 2015. As described in the Executive Summary, it is Hydro Ottawa's intention to provide regulatory efficiency and rate stability by leaving this rate in effect until December 31, 2018, a 3-year period. In 2018, the short term rate would be reviewed and updated for the Cost of Capital Parameter Updates for 2019. This update would then remain in effect for the 2019 and 2020 rate years.

### 2.3 Long Term Debt

The Holding Company issues long term debt to support the financing requirements of Hydro Ottawa. Similar to short term financing, the costs associated with long term financing are also passed on to Hydro Ottawa on the same terms and conditions as the Holding Company receives from the external markets.

In the absence of associated external financing at the Holding Company level, long term debt is charged to Hydro Ottawa at the deemed cost of debt effective at the time of the fund transfer, as calculated per the 2009 Report. All debt using a deemed rate accumulates until the next external long term financing is conducted by the Holding Company, at which time the deemed rates are converted into the new rate, terms, and conditions as per the external bond issuance, which includes the actual cost of debt plus any incurred issuance costs. The issuance costs are amortized over a five year period which is consistent with the write-off for tax purposes.

By using this approach, Hydro Ottawa primarily relies on the embedded or actual cost of long term debt and only uses the deemed long term debt rate as a proxy to bridge the period between external financings.

The markets are not receptive to long term debt issuances under $100 million due to liquidity and listing requirements, and therefore smaller issuances, if attainable, would dictate premium pricing. As well, smaller and more frequent issuances will incur more costs than larger, less frequent issuances due to the fixed nature of most of the required issuance costs. The financing arrangement between Hydro Ottawa and the Holding Company is beneficial to both Hydro Ottawa and its ratepayers, as it allows Hydro Ottawa to follow the deemed capital structure and borrow in smaller tranches (without paying premiums) than it could otherwise be able to borrow in the financial markets.

The financial strength of the Holding Company and this type of financing arrangement optimizes Hydro Ottawa's borrowing requirements on both short term and long term financing. It provides financing to Hydro Ottawa in tranches that meets its capital structure requirements using both actual and deemed rates in an objective and transparent manner which minimizes borrowing costs for Hydro Ottawa and its ratepayers.

The current long term debt notes issued by Hydro Ottawa are included as Attachments E-1(B), (C), (D), (E), and (F).

### 2.4 Forecast Long Term Debt

Hydro Ottawa plans to issue further long term debt to support its on-going capital expenditure requirements. The forecasted additional borrowing requirement for Hydro Ottawa from 2015 to 2020 is as follows:

**Table 1 - Forecast Borrowing Requirements**

| Year | Amount |
|---|---|
| 2015 | $55 million |
| 2016 | $65 million |
| 2017 | $60 million |
| 2018 | $30 million |
| 2019 | $30 million |
| 2020 | $30 million |

### 2.5 Cost of Long Term Debt

The long term debt rate is calculated as the weighted average rate of existing debt and forecast debt planned to be issued from 2015 – 2020. The calculation to determine the forecast long term debt rate is comprised of 3 components:

1) The forecast Government of Canada 10-year bond yield;

2) The 30-year to 10-year Government of Canada bond yield spread, and
3) The Hydro Ottawa credit risk spread.

This emulates the calculation of the 2009 Report. Table 2 below summarizes the forecast Hydro Ottawa long term debt rate from 2016 to 2020.

The underlying forecast for the 10-year rate is as per the October 2014 Consensus Long Term Forecast (which is issued twice a year in October and April).

The 30-year Government of Canada bond yield is then calculated using the forecast 10-year bond yield plus 55bps, which is the 5-year historical average spread of the 30-year over 10-year Government of Canada bond yield as calculated per the 2009 Report.

The Hydro Ottawa historical credit spread is based on BMO Capital markets indicative spreads over the past 2.5-years for the Holding Company.

**Table 2 - Forecast Yield for 2015 to 2020 Long Term Debt Issuances**

| Year | Govt. of Canada 10-year Yield (based on October 2014 Consensus Forecast) | Historical Spread (30-year Govt. Yield over 10-year Govt. Yield) | Govt. of Canada 30-year Yield | Hydro Ottawa Historical Spread | Forecast Hydro Ottawa Yield |
|---|---|---|---|---|---|
| **2016** | 3.30%[1] | 55 bps | 3.85% | 152 bps | **5.37%** |
| **2017** | 3.90%[1] | 55 bps | 4.45% | 152 bps | **5.97%** |
| **2018** | 4.20%[1] | 55 bps | 4.75% | 152 bps | **6.27%** |
| **2019** | 4.40%[1] | 55 bps | 4.95% | 152 bps | **6.47%** |
| **2020** | 4.40%[1] | 55 bps | 4.95% | 152 bps | **6.47%** |

[1]Average for the year

As shown in Appendix 2-OB, the weighted cost of existing long term debt as of December 31, 2014 is 4.78%.

In February, 2015 the Holding Company issued two new tranches of debt comprised of tenures of 10 and 30 years. With this issuance, the Holding Company secured the lowest 10 and 30 year fixed coupons on record in the Canadian Corporate credit market. Hydro Ottawa has used these same rates for its financing requirements for 2015 and has reflected it in the weighted long term debt rates for 2015 to 2020.

For the purpose of the rate application, Hydro Ottawa has used the forecast weighted long term debt rate of 3.72% for 2016, 3.94% for 2017, 4.08% for 2018, 4.17% for 2019 and 4.23% for 2020. It is recognized that these rates will be updated at the time of the rate decision to reflect the then current weighted long term rate using the same foregoing approach and calculation.

As described in the Executive Summary, it is Hydro Ottawa's intention to provide regulatory efficiency by then leaving these rates in effect until December 31, 2018, a 3-year period. In 2018, the long term rate would be reviewed and updated following this same approach and to reflect any potential changes to the 2009 Report. This update would then remain in effect for the 2019 and 2020 rate years.

Appendix 2-OB "Debt Instruments" outlines the amounts and associated interest rates for all its long term debt instruments as well as the weighted long term debt rate for the historical, bridge and test years.

## 3.0 RETURN ON EQUITY

Hydro Ottawa has used the deemed ROE for 2015 cost of service applications of 9.30% as communicated through the November 20, 2014 Cost of Capital Parameters letter from the Board. It is recognized that this rate will be updated at the time of the rate decision to reflect the current rate in effect as per the calculations and terms outlined in the December 11, 2009 "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities".

As described in the Executive Summary, it is Hydro Ottawa's intention to provide regulatory efficiency by leaving this rate in effect until the end of 2018, a 3 year period. In 2018, the rate would be reviewed and updated for the Cost of Capital Parameters Updates for 2019. This update would remain in effect for the 2019 and 2020 rate years.

## 4.0 PREFERRED SHARES

Hydro Ottawa does not currently have any preferred shares issued nor has it forecasted for any issuance of preferred shares for the test years.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | E |
| **Tab:** | 1 |
| **Schedule:** | 1 |
| **Page:** | 1 |
| **Date:** | ORIGINAL |

# Appendix 2-OA
## Capital Structure and Cost of Capital

**This table must be completed for the last Board approved year and the test year.**

**Year:**

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $374,683,430 | 5.09% | $19,071,387 |
| 2 | Short-term Debt | 4.00% | (1) | $26,763,102 | 2.08% | $556,673 |
| 3 | **Total Debt** | 60.0% | | $401,446,532 | 4.89% | $19,628,059 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $267,631,021 | 9.42% | $25,210,842 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $267,631,021 | 9.42% | $25,210,842 |
| 7 | **Total** | 100.0% | | $669,077,553 | 6.70% | $44,838,901 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2012 (Actual)

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | | (%) | |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 52.80% | | $327,185,000 | 5.25% | $17,163,415 |
| 2 | Short-term Debt | 5.37% | (1) | $33,273,515 | 2.16% | $719,041 |
| 3 | **Total Debt** | 58.2% | | $360,458,515 | 4.96% | $17,882,456 |
| | **Equity** | | | | | |
| 4 | Common Equity | 41.83% | | $259,155,000 | 10.19% | $26,413,000 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 41.8% | | $259,155,000 | 10.19% | $26,413,000 |
| 7 | **Total** | 100.0% | | $619,613,515 | 7.15% | $44,295,456 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2016 (Test Year)

| Line No. | Particulars | Capitalization Ratio (%) | | | Cost Rate (%) | Return |
|---|---|---|---|---|---|---|
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $517,051,284 | 3.72% | $19,252,624 |
| 2 | Short-term Debt | 4.00% | (1) | $36,932,235 | 2.16% | $797,736 |
| 3 | **Total Debt** | 60.0% | | $553,983,519 | 3.62% | $20,050,360 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $369,322,346 | 9.30% | $34,346,978 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $369,322,346 | 9.30% | $34,346,978 |
| 7 | **Total** | 100.0% | | $923,305,865 | 5.89% | $54,397,338 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2017 (Test Year)

| Line No. | Particulars | Capitalization Ratio (%) | | | Cost Rate (%) | Return |
|---|---|---|---|---|---|---|
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $543,525,815 | 3.94% | $21,397,607 |
| 2 | Short-term Debt | 4.00% | (1) | $38,823,273 | 2.16% | $838,583 |
| 3 | **Total Debt** | 60.0% | | $582,349,088 | 3.82% | $22,236,190 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $388,232,725 | 9.30% | $36,105,643 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $388,232,725 | 9.30% | $36,105,643 |
| 7 | **Total** | 100.0% | | $970,581,813 | 6.01% | $58,341,833 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2018 (Test Year)

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | | (%) | |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $571,366,562 | 4.08% | $23,290,133 |
| 2 | Short-term Debt | 4.00% | (1) | $40,811,897 | 2.16% | $881,537 |
| 3 | **Total Debt** | 60.0% | | $612,178,459 | 3.95% | $24,171,670 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $408,118,973 | 9.30% | $37,955,064 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $408,118,973 | 9.30% | $37,955,064 |
| 7 | **Total** | 100.0% | | $1,020,297,432 | 6.09% | $62,126,734 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2019 (Test Year)

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | (%) | | | (%) | |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $588,405,524 | 4.17% | $24,560,548 |
| 2 | Short-term Debt | 4.00% | (1) | $42,028,966 | 2.16% | $907,826 |
| 3 | **Total Debt** | 60.0% | | $630,434,490 | 4.04% | $25,468,374 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $420,289,660 | 9.30% | $39,086,938 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $420,289,660 | 9.30% | $39,086,938 |
| 7 | **Total** | 100.0% | | $1,050,724,150 | 6.14% | $64,555,312 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

**Year:** 2020 (Test Year)

| Line No. | Particulars | Capitalization Ratio (%) | | | Cost Rate (%) | Return |
|---|---|---|---|---|---|---|
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $612,791,380 | 4.23% | $25,900,220 |
| 2 | Short-term Debt | 4.00% | (1) | $43,770,813 | 2.16% | $945,450 |
| 3 | **Total Debt** | 60.0% | | $656,562,193 | 4.09% | $26,845,670 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $437,708,128 | 9.30% | $40,706,856 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $437,708,128 | 9.30% | $40,706,856 |
| 7 | **Total** | 100.0% | | $1,094,270,321 | 6.17% | $67,552,526 |

**Notes**

**(1)** 4.0% unless an applicant has proposed or been approved for a different amount.

# Appendix 2-OB
## Debt Instruments

**This table must be completed for all required historical years, the bridge year and the test year.**

**Year** 2012

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | 10 yrs | $ 200,000,000 | 5.040% | $ 10,080,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | Deemed LT | $ 32,185,000 | 5.900% | $ 1,898,915 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 5.218% | $ 2,609,000 | |
| 4 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 21-Dec-09 | Deemed LT | $ 15,000,000 | 5.750% | $ 862,500 | |
| 5 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 30-Apr-10 | Deemed LT | $ 15,000,000 | 5.870% | $ 880,500 | |
| 6 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 5-Jul-11 | Deemed LT | $ 15,000,000 | 5.550% | $ 832,500 | |
| | | | | | | | | | | |
| Total | | | | | | | $ 327,185,000 | 5.246% | $ 17,163,415 | |

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

**Year** 2013

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | 10 years | $ 200,000,000 | 5.040% | $ 10,080,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 18,219,178 | 5.218% | $ 950,677 | $50M Note - rate change May 14, 2015 |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 31,780,822 | 4.968% | $ 1,578,871 | |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | Deemed LT | $ 11,727,685 | 5.900% | $ 691,933 | The cumulative deemed debt ($77.185M o/s end of 2012 and $30M issued on Feb 1, 2013) was converted into a single promissory note of $107.185M to reflect the actual HOHI bond issuance on May 14, 2015. |
| 5 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 21-Dec-09 | Deemed LT | $ 5,465,753 | 5.750% | $ 314,281 | |
| 6 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 30-Apr-10 | Deemed LT | $ 5,465,753 | 5.870% | $ 320,840 | |
| 7 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 5-Jul-11 | Deemed LT | $ 5,465,753 | 5.550% | $ 303,349 | |
| 8 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Feb-13 | Deemed LT | $ 8,383,562 | 4.220% | $ 353,786 | |
| 9 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 68,128,548 | 4.144% | $ 2,823,247 | |
| 10 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 10-Dec-13 | Deemed LT | $ 1,808,219 | 4.940% | $ 89,326 | $30M deemed debt - Effective 22 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 356,445,274 | 4.911% | $ 17,506,311 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

**Year** 2014

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | 10 years | $ 200,000,000 | 5.040% | $ 10,080,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 4.144% | $ 4,441,746 | |
| 4 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 10-Dec-13 | Deemed LT | $ 30,000,000 | 4.940% | $ 1,482,000 | |
| 5 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 28-Oct-14 | Deemed LT | $ 5,342,466 | 4.770% | $ 254,836 | $30M deemed debt - Effective 65 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 392,527,466 | 4.775% | $ 18,742,582 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any

3 Add more lines above row 12 if necessary.

**Year** 2015

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 4.144% | $ 4,441,746 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-05 | 10 years | $ 21,369,863 | 5.040% | $ 1,077,041 | The Feb 9.,2015 $200M maturity plus the cumulative deemed debt of $60M then outstanding ($260M total) were converted into two promissory notes of $138.7m and $121.3m on Feb 9, 2015 to reflect the actual HOHI bond issuance on a prorata basis for the two terms. |
| 4 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 10-Dec-13 | Deemed LT | $ 3,205,479 | 4.940% | $ 158,351 | |
| 5 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 28-Oct-14 | Deemed LT | $ 3,205,479 | 4.770% | $ 152,901 | |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 123,850,526 | 2.724% | $ 3,373,688 | |
| 7 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 108,368,652 | 3.769% | $ 4,084,414 | |
| 8 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 14,786,290 | 2.724% | $ 402,779 | $55M actual debt prorated for two terms - Effective 184 days |
| 9 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 12,939,737 | 3.769% | $ 487,699 | |
| | | | | | | | | | | |
| Total | | | | | | | $ 444,911,027 | 3.745% | $ 16,662,620 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

**Year** 2015 **2016**

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 4.144% | $ 4,441,746 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 138,667,000 | 2.724% | $ 3,777,289 | $260M actual debt |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 121,333,000 | 3.769% | $ 4,573,041 | |
| 5 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 29,331,500 | 2.724% | $ 798,990 | $55M actual debt |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 25,668,500 | 3.769% | $ 967,446 | |
| 7 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-16 | Deemed LT | $ 32,767,123 | 5.370% | $ 1,759,595 | $65M deemed debt - Effective 184 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 504,952,123 | 3.724% | $ 18,802,107 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

**Year** 2015 **2017**

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 4.144% | $ 4,441,746 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 138,667,000 | 2.724% | $ 3,777,289 | $260M actual debt |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 121,333,000 | 3.769% | $ 4,573,041 | |
| 5 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 29,331,500 | 2.724% | $ 798,990 | $55M actual debt |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 25,668,500 | 3.769% | $ 967,446 | |
| 7 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-16 | Deemed LT | $ 65,000,000 | 5.370% | $ 3,490,500 | |
| 8 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-17 | Deemed LT | $ 30,246,575 | 5.970% | $ 1,805,721 | $60M deemed debt - Effective 184 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 567,431,575 | 3.937% | $ 22,338,733 | |

**Notes**
1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

**Year** 2015 **2018**

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 39,056,452 | 4.144% | $ 1,618,499 | $107.185M Note - Rate changed during the year (issuance cost fully amortized) |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 68,128,548 | 3.991% | $ 2,719,010 | |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 138,667,000 | 2.724% | $ 3,777,289 | $260M actual debt |
| 5 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 121,333,000 | 3.769% | $ 4,573,041 | |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 29,331,500 | 2.724% | $ 798,990 | $55M actual debt |
| 7 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 25,668,500 | 3.769% | $ 967,446 | |
| 8 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-16 | Deemed LT | $ 65,000,000 | 5.370% | $ 3,490,500 | |
| 9 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-17 | Deemed LT | $ 60,000,000 | 5.970% | $ 3,582,000 | |
| 10 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-18 | Deemed LT | $ 15,123,288 | 6.270% | $ 948,230 | $30M deemed debt - Effective 184 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 612,308,288 | 4.076% | $ 24,959,006 | |

**Notes**
1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

**Year** 2015 **2019**

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 3.991% | $ 4,277,753 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 138,667,000 | 2.724% | $ 3,777,289 | $260M actual debt |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 121,333,000 | 3.769% | $ 4,573,041 | |
| 5 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 29,331,500 | 2.724% | $ 798,990 | $55M actual debt |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 25,668,500 | 3.769% | $ 967,446 | |
| 7 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-16 | Deemed LT | $ 65,000,000 | 5.370% | $ 3,490,500 | |
| 8 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-17 | Deemed LT | $ 60,000,000 | 5.970% | $ 3,582,000 | |
| 9 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-18 | Deemed LT | $ 30,000,000 | 6.270% | $ 1,881,000 | |
| 10 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-19 | Deemed LT | $ 15,123,288 | 6.470% | $ 978,477 | $30M deemed debt - Effective 184 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 642,308,288 | 4.174% | $ 26,810,496 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any

3 Add more lines above row 12 if necessary.

**Year** 2015 **2020**

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | Additional Comments, if any |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 20-Dec-06 | 30 years | $ 50,000,000 | 4.968% | $ 2,484,000 | |
| 2 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 14-May-13 | 30 years | $ 107,185,000 | 3.991% | $ 4,277,753 | |
| 3 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 10 years | $ 14,816,474 | 2.724% | $ 403,601 | $138.667M Note - Rate changed during the year (issuance cost fully amortized) |
| 4 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-20 | 10 years | $ 123,850,526 | 2.614% | $ 3,237,453 | |
| 5 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-15 | 30 years | $ 12,964,348 | 3.769% | $ 488,626 | $121.333M Note - Rate changed during the year (issuance cost fully amortized) |
| 6 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-20 | 30 years | $ 108,368,652 | 3.639% | $ 3,943,535 | |
| 7 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 10 years | $ 3,134,051 | 2.724% | $ 85,372 | $29.3315M Note - Rate changed during the year (issuance cost fully amortized) |
| 8 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-20 | 10 years | $ 26,197,449 | 2.614% | $ 684,801 | |
| 9 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-15 | 30 years | $ 2,742,662 | 3.769% | $ 103,371 | $25.6685M Note - Rate changed during the year (issuance cost fully amortized) |
| 10 | Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 9-Feb-20 | 30 years | $ 22,925,838 | 3.639% | $ 834,271 | |
| 11 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-16 | Deemed LT | $ 65,000,000 | 5.370% | $ 3,490,500 | |
| 12 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-17 | Deemed LT | $ 60,000,000 | 5.970% | $ 3,582,000 | |
| 13 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-18 | Deemed LT | $ 30,000,000 | 6.270% | $ 1,881,000 | |
| 14 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-19 | Deemed LT | $ 30,000,000 | 6.470% | $ 1,941,000 | |
| 15 | Grid Promissory Note | Hydo Ottawa Holding Inc. | Affiliated | Fixed Rate | 1-Jul-20 | Deemed LT | $ 15,123,288 | 6.470% | $ 978,477 | $30M deemed debt - Effective 184 days |
| | | | | | | | | | | |
| Total | | | | | | | $ 672,308,288 | 4.227% | $ 28,415,760 | |

**Notes**

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any

3 Add more lines above row 12 if necessary.

# AMENDMENT TO CREDIT AGREEMENT

**The Credit Agreement between Hydro Ottawa Holding Inc. and Hydro Ottawa Limited, dated January 1, 2009, is amended as follows:**

**3. <u>Administrative Fee</u>**

An administrative charge will be added to the rate of interest charged on Prime Rate Advances and Fixed Term Loans, payable to the Lender at the rate of 0.10% per annum.

**This clause is removed in its entirety.**

**All other sections of the Credit Agreement, including any subsequent amendments remain the same.**

**IN WITNESS WHEREOF the parties have executed this amendment January 31, 2014:**

**HYDRO OTTAWA HOLDING INC. / SOCIÉTÉDE PORTEFEUILLE D'HYDRO OTTAWA INC.**

**By:** ______________________
**J. Bryce Conrad**
**President and Chief Executive Officer**

**By:** ______________________
**Geoff Simpson**
**Chief Financial Officer**

**HYDRO OTTAWA LIMITED**

**By:** ______________________
**J. Bryce Conrad**
**President and Chief Executive Officer**

**By:** ______________________
**Geoff Simpson**
**Chief Financial Officer**

# CREDIT AGREEMENT

THIS AGREEMENT is made as of the 1st day of January 2009.

BETWEEN:

**HYDRO OTTAWA HOLDING INC./SOCIÉTÉ DE PORTEFEUILLE D'HYDRO OTTAWA INC.**

(hereinafter also referred to as the "Lender")

- and –

**HYDRO OTTAWA LIMITED**

(hereinafter also referred to as the "Borrower")

WHEREAS, the Lender has agreed to make available to the Borrower certain credits on the terms and conditions set out in this agreement.

NOW THEREFORE, in consideration of the covenants and agreements herein contained, the Parties agree as follows

1. **Definition**

Whenever used in this Agreement, unless there is something inconsistent in the subject matter or context, the following words and terms shall have the meaning as set out below:

(a) "Agreement" means this agreement, including any schedules and all instruments supplementing or amending or confirming this agreement;
(b) "Bank of Nova Scotia Credit Agreement" means an agreement between The Bank of Nova Scotia and Hydro Ottawa Holding Inc. evidenced by the most recent Commitment Letter;
(c) "Drawdown" means a borrowing of funds under the facility, a conversion or a rollover, as the context requires;
(d) "Event of Default" means any of the events described in section 7;
(e) "Fixed Term Loan" means an interest-bearing loan having a term of not less than 7 days and not more than 180 days having a rate of interest determined on the bases set out in this Agreement;
(f) "Permitted Encumbrance" means any of the following:

(i) purchase money security interests, capital leases and other encumbrances not exceeding in an aggregate amount of $5,000,000;

(ii) liens for taxes, payments in lieu of taxes, assessments, government charges or claims not yet due or for which instalments have been paid based on reasonable estimates pending final assessments, or if due, the validity of which is being contested in good faith, on in respect of which appropriate provision is made in consolidated financial statements of the Borrower;

(iii) a lien or deposit under workers' compensation, social security or similar legislation or deposits to secure public or statutory obligations;

(iv) a lien or deposit of cash or securities in connection with contracts, bids, tenders, leases or expropriation proceedings or to secure surety and appeal bonds not exceeding an aggregate amount of $1,000,000 at any time;

(v) a lien or privilege imposed by law, such as a builder's, carrier's, warehousemen's, landlord's mechanic's, supplier's or other similar liens and public, statutory and other like obligations incurred in the ordinary course of business;

(vi) a lien or right of distress reserved in or exercisable under any lease, for rent or for compliance with the terms of the lease;

(vii) undetermined or inchoate liens, rights of distress, privileges and charges incidental to current operations which have not at such time been filed or exercised or which relate to obligations not due or payable, or if due, the validity of which is being contested diligently and in good faith by appropriate proceedings;

(viii) reservations, limitations, provisos and conditions expressed in any original grants from the Crown or other grants of real or immovable property, or interests therein, which do not materially affect the use of the affected land for the purpose for which it is being used;

(ix) title defects, encroachments or irregularities or other matters relating to title which in the aggregate do not materially impair the use of the affected property for the purpose for which it is used;

(x) zoning, land use and building restrictions, by-laws, regulations and ordinances of federal, provincial, state, municipal and other governmental authorities, licences, easements, rights-of-way, rights in the nature of easements (including, without limiting the generality of the foregoing, licences, easements, rights-of-way and rights in the nature of easements for railways, sidewalks, public ways, sewers, drains, gas, steam and water mains or electric light and power, or telephone and telegraph conduits, poles, wires and cables) which do not materially impair the use of the affected land for the purpose for which it is being used;

(xi) any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, licence, franchise, grant or permit acquired by that person or by any statutory provision to terminate any lease, licence, franchise, grant or permit, or to require annual or other payments as a condition for the continuance thereof;

(xii) security given to a public utility or any municipality or governmental authority when required by such utility or authority in connection with the operations of that person in the ordinary course of business;
(xiii) security for costs of litigation where required by law; and
(xiv) attachments, judgements and other similar encumbrances arising in connection with court proceedings; provided that the encumbrances are in existence for less than 30 days after their creation or the execution or other enforcement of the encumbrances is effectively stayed or the claims so secured are being actively contested in good faith and by proper legal proceedings;

(g) "Prime Rate" means, at any time, the rate of interest expressed as an annual rate, established by The Bank of Nova Scotia Agreement from time to time as its reference "interest rate / fee" to determine the interest rates it will charge for loans in Canadian dollars; and

(h) "Prime Rate Advance" means an interest-bearing loan having a term not more than 180 days, for which the principal may be drawndown and upon which interest is calculated daily at the Prime Rate and repayable determined on the bases set out in this Agreement;

2. **<u>The Credit Facilities</u>**

(1) Upon the terms and subject to the conditions herein set forth, the Lender establishes in favour of the Borrower the following credit facility to be available to the Borrower in accordance with the provisions of this Agreement. The facility shall consist of a revolving demand facility of up to a maximum principal amount available within the Bank of Nova Scotia Credit Agreement.

(2) The total amount authorized for this credit facility is $90,000,000.00 CDN.

(3) The Borrower may avail the credit facility by way of direct advances through Prime Rate Advances. Changes in the Prime Rate shall cause an immediate adjustment to the interest rate applicable to an advance without the necessity of notice to the Borrower. The principal amounts of any Prime Rate Advances shall be repayable at any time on demand of the Lender and may be repaid by the Borrower at any time prior to such demand.

(4) The Borrower may avail the credit facility by way of Fixed Term Loans.

(5) The rate of interest on Fixed Term Loans shall be the Banker's Acceptance Fee charged pursuant to The Bank of Nova Scotia Credit Agreement, plus the Bankers Acceptance rate applicable to the date of the Drawdown as evidenced by a Bankers

Acceptance drawn by Hydro Ottawa Holding Inc. on that date, otherwise The Bank of Canada "Bankers Acceptances – 1 Month" rate will be used as posted on that date.

(6) Interest on loans and advances will be calculated on a daily basis and payable in arrears on a mutually agreed date.

(7) The Borrower may increase or decrease advances made by Prime Rate Advances or by Fixed Term Loan by making drawdowns, repayments or further drawdowns of the amount of advances that have been repaid. The Borrower may also convert a Prime Rate Advance to a Fixed Term Loan by notice to the Lender.

(8) On the date of maturity, the Borrower shall repay to the Lender the principal amount of Prime Rate Advances and Fixed Term Loans. The Borrower may request from the Lender and the Lender, in its sole discretion, may grant an extension of the maturity date of any Primary Rate Advances or Fixed Term Loans for a further period not to exceed 180 days.

(9) The Borrower may avail the credit facility by way of Standby Letters of Credit / Letters of Guarantee. The charge will be made pursuant to the Bank of Nova Scotia Credit Agreement "Commission" fee and will be payable upon issuance.

3. **<u>Administrative Fee</u>**

An administrative charge will be added to the rate of interest charged on Prime Rate Advances and Fixed Term Loans, payable to the Lender at the rate of 0.10% per annum.

4. **<u>Commitment Fee and Standby Fees</u>**

The Borrower shall pay a proportionate share of the commitment fee and standby fees payable per the terms of the Bank of Nova Scotia Credit Agreement.

5. **<u>Evidence of Indebtedness</u>**

The Lender shall open and maintain books of account evidencing all advances and all other amounts owing by the Borrower to the Lender hereunder. The information entered in the foregoing accounts shall constitute *prima facie* evidence of the obligations of the Borrower to the Lender and, in the absence of manifest error, are conclusive evidence of the advances made, repayments on account thereof and the indebtedness of the Borrower to the Lender. Upon request of the Borrower, the Lender shall advise the Borrower of entries made on the books of account.

6. **General Conditions**

The following conditions will apply until all debts and liabilities of the Borrower availed under the Credit Facilities have been discharged in full:

(a) The Borrower shall not encumber its assets in any manner other than by Permitted Encumbrances;

(b) The Borrower may not incur, assume or permit any debt to remain outstanding other than debt under this Agreement, other than:

(i) debt incurred from the Lender;

(ii) debt incurred in respect of purchase money security interests;

(iii) capital leases; and

(iv) other debt permitted by the Lender.

(c) The business activities of the Borrower shall be restricted to those permitted pursuant to section 73 of the *Ontario Energy Board Act, 1998*, so long as those restrictions on business activities continue to apply to the Borrower;

(d) The Borrower shall make due and timely payment of the obligations required to be paid by it hereunder;

(e) The Borrower shall provide notice to the Lender of any Event of Default;

(f) The Lender shall be under no obligation to provide a Prime Rate Advance, a Fixed Term Loan, or a Standby Letter of Credit / Letters of Guarantee following an Event of Default.

7. **Events of Default**

(1) The following shall constitute Events of Default for the purposes of this Agreement:

(a) The Borrower encumbering assets other than by Permitted Encumbrances;

(b) The Borrower fails to pay interest, principal or other amounts owing pursuant to this Agreement

(c) The Borrower is in breach of any conditions of this Agreement;

(d) Any actions by the Borrower which cause the Lender to be in default of its obligations under the Bank of Nova Scotia Credit Agreement;

(e) The Borrower is bankrupt, insolvent or liquidation proceedings or any other proceedings for the relief of creditors are instituted by or against the Borrower and are not dismissed within 60 days of such institution.

(2) Upon the occurrence of an Event of Default, at the option of the Lender, all amounts of Principal and Interest shall become immediately due and payable. The occurrence of an Event of Default shall relieve the Lender of all obligations to provide any further advances or loans to the Borrower.

8. **Indemnification**

The Borrower shall indemnify the Lender from any loss or expense incurred by the Lender as a result of any failure by the Borrower to fulfill its obligations under this Agreement, expense any loss or expense arising from the negligence or wilful misconduct of the Lender.

9. **Early Termination**

In the event of any change in control of the Borrower, the Lender may require that the Borrower pay the Principal and Interest payable within 30 days following a change of control of the Borrower. For the purpose of this sub-section control means with respect to the Borrower at any time (i) holding, as owner or other beneficiary – other than solely as beneficiary of an unrealized security interest – directly or indirectly, securities or ownership interests of the Borrower carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of the Borrower, or (ii) the exercise of de facto control of the Borrower, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

10. **Termination**

Unless otherwise extended by agreement of the parties, this facility shall terminate the date the Bank of Nova Scotia Credit Agreement is no longer in force. Prior to the termination of the facility, the Borrower shall pay to the Lender the Principal outstanding and any Interest payable.

11. **Notice**

Any demand, notice or communication to be made or given pursuant to this Agreement shall be in writing and may be made or given by personal delivery, by mail, by electronic mail addressed to the respective parties as follows:

To the Borrower:
Hydro Ottawa Limited
3025 Albion Road North
Ottawa, Ontario
K1G 3S4
Attention: Treasurer
Telephone: 613-738-5499 ext. 319
Electronic Mail: mikegrue@hydroottawa.com

To the Lender:
Hydro Ottawa Holding Inc.
3025 Albion Road North
Ottawa, Ontario
K1G 3S4
Attention: Treasurer
Telephone: 613-738-5499 ext. 319
Electronic mail: mikegrue@hydroottawa.com

Either party may from time to time notify the other party of any change to its address, telephone number or electronic mail contact.

12. **Successors and Assigns**

This Agreement shall be binding upon and enure to the benefit of the Lender, the Borrower and their successors and assigns, except that the Borrower shall not assign any rights or obligations with respect to this Agreement without the prior written consent of the Lender, which consent may be withheld or refused for any reason. The Lender may assign its rights and obligations with respect to this Agreement upon notice to the Borrower.

13. **Governing Law**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

14. **Severability**

Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall not invalidate the remaining provisions hereof and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

**IN WITNESS WHEREOF** the parties hereto have executed this Agreement.

**HYDRO OTTAWA HOLDING INC./ SOCIÉTÉDE PORTEFEUILLE D'HYDRO OTTAWA INC.**

By: ________________________
Rosemarie T. Leclair
President and Chief Executive Officer

By: ________________________
Alan Hoverd
Chief Financial Officer

**HYDRO OTTAWA LIMITED**

By: ________________________
Rosemarie T. Leclair
President and Chief Executive Officer

By: ________________________
Alan Hoverd
Chief Financial Officer

# GRID PROMISSORY NOTE

Effective the 14th day of May 2013.

As consideration for the funds received, **Hydro Ottawa Limited** (the "Borrower") unconditionally promises to pay to, or the order of, **Hydro Ottawa Holding Inc.** ("the "Lender"), in lawful money of Canada, the principal amount (the "Principal") advanced under this grid promissory note (the "Note) and interest ("Interest") thereon at a rate specified below upon the terms and subject to the conditions set forth below.

This Note is a negotiable instrument.

The following are the terms and conditions of the Note:

## 1. PRINCIPAL

(1) Advances of Principal may be made in tranches to meet **Hydro Ottawa Limited's** long term business requirements.

(2) The liability of the Borrower and of any guarantor of the Borrower ("Guarantor") or endorser in respect of Principal shall not exceed the outstanding amount of Principal.

(3) Advances shall be deemed conclusively to have been made to and for the benefit of the Borrower when,

(a) deposited or credited to the account of the Borrower by the Lender; or

(b) made in accordance with the instructions of the Borrower.

(4) All advances of Principal under this Note shall be evidenced by endorsement upon the grid attached to this Note as Schedule A (the "Grid").

(5) The Lender's Chief Financial Officer, President and Chief Executive Officer and Treasurer are authorized to endorse the Grid, including any continuation Grid that may be attached to this Note, the date and amount of each advance and together with the unpaid balance of the Principal and each endorsement shall be prima facie evidence of the amounts so advanced and the balance of principal outstanding under this Note.

## 2. INTEREST RATE

(1) Interest shall be payable upon the amounts advanced under this Note at a fixed rate of Interest payable monthly in arrears on a mutually agreed date. The rate established for long term debt will be:

a. a "deemed interest rate" which will be based on the underlying methodology outlined in the Ontario Energy Board's "Report of the Board" on the Cost of Capital for Ontario's Regulated Utilities EB-2009-0084 dated December 11, 2009. The rate will be determined from information available at the end of the month preceding the date of the advancement. The rate that is in effect when the advance was made will be used for the duration of the advance as per the Term and Repayment section.

3. **TERMS OF PAYMENT**

The Interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. **Hydro Ottawa Limited** shall pay to **Hydro Ottawa Holding Inc.**, on demand, Interest on overdue Interest at the rate described in section 2 hereof compounded on each date for the payment of Interest on this Note before and after judgment.

4. **REPAYMENT**

(1) **Hydro Ottawa Limited** may, at any time, repay in whole or in part the Principal and Interest outstanding under this Note.

(2) **Hydro Ottawa Holding Inc.** may, at any time, require that **Hydro Ottawa Limited** repay in whole or in part the Principal and Interest outstanding under this Note.

5. **SUBORDINATION**

The obligation of **Hydro Ottawa Limited** to pay the Principal amount or the amount remaining unpaid from time to time on this Note, together with Interest thereon in accordance with and pursuant to this Note is subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

6. **WAIVER OF NOTICE IN EVENT OF DEFAULT**

**Hydro Ottawa Limited** hereby waives presentment, protest and notice of any kind in the enforcement of this Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal amount on the amount remaining unpaid from time to time on this Note, or any payment of Interest thereon, is not made when due.

7. **RIGHTS AND REMEDIES IN EVENT OF DEFAULT**

The rights and remedies of **Hydro Ottawa Holding Inc.** under this Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc.**, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc.** which may be brought to recover any amounts due and payable under this Note. No delay or failure by **Hydro Ottawa Holding Inc.** in the enforcement of any covenant, promise or agreement of **Hydro**

**Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.**'s powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

8. **ASSIGNMENT**

This Note may not be assigned **by Hydro Ottawa Limited** without the written consent of **Hydro Ottawa Holding Inc.**

9. **GOVERNING LAW**

This Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

10. **CANCELLATION OF PREVIOUS NOTE**

This Note replaces the Note dated January 1, 2009 made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc.**

**IN WITNESS WHEREOF Hydro Ottawa Limited** has duly executed this Grid Promissory Note.

**HYDRO OTTAWA LIMITED**

Per: ____________________
Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Per: ____________________
Name: Geoff Simpson
Title: Chief Financial Officer

**Schedule A**

**Advances and Payment of Principal**

| Date | Amount of Advance | Amount of Principal Payment | Unpaid Balance | Interest Rate | Recorded By |
|---|---|---|---|---|---|
| Dec 10, 2013 | $30,000,000 | | $30,000,000 | 4.94% | [signature] |
| Oct 28/2014 | $30,000,000 | | $60,000,000 | 4.77% | [signature] |
| Feb 9/2015 | $ – | $60,000,000 | – | | [signature] |
| | | | | | |
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# PROMISSORY NOTE

| Principal: $50,000,000<br>lawful money of Canada | Effective May 14th, 2013 |
| --- | --- |

For value received, **Hydro Ottawa Limited**, hereby unconditionally promises to pay to the order of **Hydro Ottawa Holding Inc.** at Ottawa, Canada on December 19, 2036 (the "Due Date") the principal amount of fifty million dollars ($50,000,000) (the "Principal Amount") in lawful money of Canada and interest thereon upon the terms and subject to the conditions set forth below.

## 1. INTEREST RATE

The rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 4.968% per annum.

## 2. TERMS OF PAYMENT

The interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. **Hydro Ottawa Limited** shall pay to **Hydro Ottawa Holding Inc.**, on demand, interest on overdue interest at the rate described in section 1 hereof compounded on each date for the payment of interest on this Promissory Note before and after judgment.

## 3. REPAYMENT

(1) Subject to the terms and conditions set out in sub-section 3 (4) herein, **Hydro Ottawa Limited** may, at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note and interest owing under this Promissory Note.

(2) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable within 30 days following a change of control of **Hydro Ottawa Limited**. For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time:

a. holding, as owner or other beneficiary, other than solely as beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited** carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of **Hydro Ottawa Limited**, or

b. the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

**Hydro Ottawa Holding Inc.** shall provide **Hydro Ottawa Limited** with no less than twenty (20) days' prior notice of the requirement to repay Principal and interest.

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable in the event that **Hydro Ottawa Limited:**

a. disposes of substantially all of its property or assets;

b. fails to pay any principal, premium or interest on an indebtedness however incurred beyond any period of grace applicable to such indebtedness, where the amount of the indebtedness is $25 million or greater;

c. fails to perform or observe an agreement, term or condition contained in any agreement under which an indebtedness in the amount of $25 million or greater becomes due and payable; or

d. for any other reason causes the whole or any part of the Principal Amount to be repayable to **Hydro Ottawa Holding Inc.** in advance of the Due Date;

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(4) In the event that **Hydro Ottawa Limited** chooses to repay or is required to repay in whole or in part the Principal Amount remaining unpaid and accrued and unpaid interest in accordance with sub-sections 3 (1), (2) or (3) herein, **Hydro Ottawa Limited** shall:

a. Provide, where such repayment is initiated at the request of **Hydro Ottawa Limited,** at least fifty (50) days' prior notice in writing to **Hydro Ottawa Holding Inc.** setting out the proposed amount of the Principal Amount and accrued and unpaid interest that it proposes to pay and the date of such payment;

b. Pay to **Hydro Ottawa Holding Inc.** in respect of the Principal Amount and accrued and unpaid interest to be paid, an amount calculated and determined by **Hydro Ottawa Holding Inc.** in the same manner and subject to the same conditions (subject to any necessary changes) as the

Redemption Price respecting an equivalent payment of principal as is set out in the Series 2006 – 1 Supplemental Indenture dated as of December 20, 2006 between Hydro Ottawa Holding Inc. and BNY Trust Company of Canada;

c. Indemnify **Hydro Ottawa Holding Inc.**, in addition to the amount calculated and determined pursuant to sub-section 3 (4)(b) herein, for any damages, losses, liabilities, claims, demands, interest, charges, fines, penalties, assessments, judgments, costs and expenses suffered or asserted directly or indirectly arising from any payment made pursuant to sub-section 3 (1), (2) or (3) herein or any delay in providing such payment.

## 4. SUBORDINATION

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note, together with interest thereon in accordance with and pursuant to this Promissory Note is subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

## 5. WAIVER OF NOTICE IN EVENT OF DEFAULT

**Hydro Ottawa Limited** hereby waives presentment, protest and notice of any kind in the enforcement of this Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Promissory Note, or any payment of interest thereon is not made when due.

## 6. RIGHTS AND REMEDIES IN EVENT OF DEFAULT

The rights and remedies of **Hydro Ottawa Holding Inc**. under this Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc.**, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc**. which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc**. in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall discharge or release any person at any time liable for the payment of this

Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.'s** powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

7. **ASSIGNMENT**

This Promissory Note may not be assigned by **Hydro Ottawa Limited** without the written consent of **Hydro Ottawa Holding Inc.**

8. **GOVERNING LAW**

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9. **CANCELLATION OF PREVIOUS NOTE**

This interest bearing Promissory Note in the amount of fifty million dollars ($50,000,000) replaces the Demand Promissory Note dated **December 20, 2006** in the amount of fifty million dollars ($50,000,000) made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc.**

**IN WITNESS WHEREOF Hydro Ottawa Limited** has duly executed this Promissory Note.

**HYDRO OTTAWA LIMITED**

Per: ______________________
Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Per: ______________________
Name: Geoff Simpson
Title: Chief Financial Officer

# PROMISSORY NOTE

| | |
|---|---|
| Principal: $107,185,000<br>lawful money of Canada | Effective May 14th, 2013 |

For value received, **Hydro Ottawa Limited** hereby unconditionally promises to pay to the order of **Hydro Ottawa Holding Inc.** at Ottawa, Canada on May 14, 2043 (the "Due Date") the principal amount of one hundred seven million one hundred eighty five thousand dollars ($107,185,000) (the "Principal Amount") in lawful money of Canada and interest thereon upon the terms and subject to the conditions set forth below.

## 1. INTEREST RATE

The rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 4.144% per annum from May 14, 2013 to May 13, 2018 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.991% per annum from May 14, 2018 to May 13, 2043.

## 2. TERMS OF PAYMENT

The interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. **Hydro Ottawa Limited** shall pay to **Hydro Ottawa Holding Inc.**, on demand, interest on overdue interest at the rate described in section 1 hereof compounded on each date for the payment of interest on this Promissory Note before and after judgment.

## 3. REPAYMENT

(1) Subject to the terms and conditions set out in sub-section 3 (4) herein, **Hydro Ottawa Limited** may, at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note and interest owing under this Promissory Note.

(2) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable within 30 days following a change of control of **Hydro Ottawa Limited**. For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time:

a. holding, as owner or other beneficiary, other than solely as beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited** carrying votes or ownership interests

sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of **Hydro Ottawa Limited**, or

b. the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

**Hydro Ottawa Holding Inc.** shall provide **Hydro Ottawa Limited** with no less than twenty (20) days' prior notice of the requirement to repay Principal and interest.

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable in the event that **Hydro Ottawa Limited:**

a. disposes of substantially all of its property or assets;

b. fails to pay any principal, premium or interest on an indebtedness however incurred beyond any period of grace applicable to such indebtedness, where the amount of the indebtedness is $25 million or greater;

c. fails to perform or observe an agreement, term or condition contained in any agreement under which an indebtedness in the amount of $25 million or greater becomes due and payable; or

d. for any other reason causes the whole or any part of the Principal Amount to be repayable to **Hydro Ottawa Holding Inc.** in advance of the Due Date;

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(4) In the event that **Hydro Ottawa Limited** chooses to repay or is required to repay in whole or in part the Principal Amount remaining unpaid and accrued and unpaid interest in accordance with sub-sections 3 (1), (2) or (3) herein, **Hydro Ottawa Limited** shall:

a. Provide, where such repayment is initiated at the request of **Hydro Ottawa Limited,** at least fifty (50) days' prior notice in writing to **Hydro Ottawa Holding Inc.** setting out the proposed amount of the Principal Amount and accrued and unpaid interest that it proposes to pay and the date of such payment;

b. Pay to **Hydro Ottawa Holding Inc.** in respect of the Principal Amount and accrued and unpaid interest to be paid, an amount calculated and determined

by **Hydro Ottawa Holding Inc.** in the same manner and subject to the same conditions (subject to any necessary changes) as the Redemption Price respecting an equivalent payment of principal as is set out in the Series 2013 – 1 Supplemental Indenture dated as of May 14, 2013 between Hydro Ottawa Holding Inc. and BNY Trust Company of Canada;

c. Indemnify **Hydro Ottawa Holding Inc.**, in addition to the amount calculated and determined pursuant to sub-section 3 (4)(b) herein, for any damages, losses, liabilities, claims, demands, interest, charges, fines, penalties, assessments, judgments, costs and expenses suffered or asserted directly or indirectly arising from any payment made pursuant to sub-section 3 (1), (2) or (3) herein or any delay in providing such payment.

## 4. SUBORDINATION

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note, together with interest thereon in accordance with and pursuant to this Promissory Note is subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

## 5. WAIVER OF NOTICE IN EVENT OF DEFAULT

**Hydro Ottawa Limited** hereby waives presentment, protest and notice of any kind in the enforcement of this Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Promissory Note, or any payment of interest thereon is not made when due.

## 6. RIGHTS AND REMEDIES IN EVENT OF DEFAULT

The rights and remedies of **Hydro Ottawa Holding Inc**. under this Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc**., shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc**. which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc**. in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall

discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.'s** powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

7. **ASSIGNMENT**

This Promissory Note may not be assigned by **Hydro Ottawa Limited** without the written consent of **Hydro Ottawa Holding Inc.**

8. **GOVERNING LAW**

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9. **CANCELLATION OF PREVIOUS NOTE**

This interest bearing Promissory Note in the amount of one hundred seven million, one hundred eighty five thousand dollars ($107,185,000) replaces the Demand Promissory Note dated **July 1, 2005** in the amount of thirty two million, one hundred eighty five thousand dollars ($32,185,000) made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc**. and the Grid Promissory Note dated **January 1, 2009** in the amount of seventy five million dollars ($75,000,000) made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc.**

**IN WITNESS WHEREOF Hydro Ottawa Limited** has duly executed this Promissory Note.

**HYDRO OTTAWA LIMITED**

Per: ______________________
Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Per: ______________________
Name: Geoff Simpson
Title: Chief Financial Officer

# PROMISSORY NOTE

| Principal: \$138,667,000<br>lawful money of Canada | Effective February 9th, 2015 |
|---|---|

For value received, **Hydro Ottawa Limited** hereby unconditionally promises to pay to the order of **Hydro Ottawa Holding Inc.** at Ottawa, Canada on February 3, 2025 (the "Due Date") the principal amount of one hundred thirty eight million, six hundred sixty seven thousand dollars (\$138,667,000) (the "Principal Amount") in lawful money of Canada and interest thereon upon the terms and subject to the conditions set forth below.

## 1. INTEREST RATE

The rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.724% per annum from February 9, 2015 to February 3, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.614% per annum from February 4, 2020 to February 3, 2025.

## 2. TERMS OF PAYMENT

The interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. **Hydro Ottawa Limited** shall pay to **Hydro Ottawa Holding Inc.**, on demand, interest on overdue interest at the rate described in section 1 hereof compounded on each date for the payment of interest on this Promissory Note before and after judgment.

## 3. REPAYMENT

(1) Subject to the terms and conditions set out in sub-section 3 (4) herein, **Hydro Ottawa Limited** may, at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note and interest owing under this Promissory Note.

(2) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable within 30 days following a change of control of **Hydro Ottawa Limited**. For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time:

a. holding, as owner or other beneficiary, other than solely as beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited** carrying votes or ownership interests

sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of **Hydro Ottawa Limited**, or

b. the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

**Hydro Ottawa Holding Inc.** shall provide **Hydro Ottawa Limited** with no less than twenty (20) days' prior notice of the requirement to repay Principal and interest.

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable in the event that **Hydro Ottawa Limited:**

a. disposes of substantially all of its property or assets;

b. fails to pay any principal, premium or interest on an indebtedness however incurred beyond any period of grace applicable to such indebtedness, where the amount of the indebtedness is $25 million or greater;

c. fails to perform or observe an agreement, term or condition contained in any agreement under which an indebtedness in the amount of $25 million or greater becomes due and payable; or

d. for any other reason causes the whole or any part of the Principal Amount to be repayable to **Hydro Ottawa Holding Inc.** in advance of the Due Date;

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(4) In the event that **Hydro Ottawa Limited** chooses to repay or is required to repay in whole or in part the Principal Amount remaining unpaid and accrued and unpaid interest in accordance with sub-sections 3 (1), (2) or (3) herein, **Hydro Ottawa Limited** shall:

a. Provide, where such repayment is initiated at the request of **Hydro Ottawa Limited,** at least fifty (50) days' prior notice in writing to **Hydro Ottawa Holding Inc.** setting out the proposed amount of the Principal Amount and accrued and unpaid interest that it proposes to pay and the date of such payment;

b. Pay to **Hydro Ottawa Holding Inc.** in respect of the Principal Amount and accrued and unpaid interest to be paid, an amount calculated and determined

by **Hydro Ottawa Holding Inc.** in the same manner and subject to the same conditions (subject to any necessary changes) as the Redemption Price respecting an equivalent payment of principal as is set out in the Series 2015 – 1 Supplemental Indenture dated as of February 2, 2015 between Hydro Ottawa Holding Inc. and BNY Trust Company of Canada;

c. Indemnify **Hydro Ottawa Holding Inc.**, in addition to the amount calculated and determined pursuant to sub-section 3 (4)(b) herein, for any damages, losses, liabilities, claims, demands, interest, charges, fines, penalties, assessments, judgments, costs and expenses suffered or asserted directly or indirectly arising from any payment made pursuant to sub-section 3 (1), (2) or (3) herein or any delay in providing such payment.

4. **<u>SUBORDINATION</u>**

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note, together with interest thereon in accordance with and pursuant to this Promissory Note is subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

5. **<u>WAIVER OF NOTICE IN EVENT OF DEFAULT</u>**

**Hydro Ottawa Limited** hereby waives presentment, protest and notice of any kind in the enforcement of this Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Promissory Note, or any payment of interest thereon is not made when due.

6. **<u>RIGHTS AND REMEDIES IN EVENT OF DEFAULT</u>**

The rights and remedies of **Hydro Ottawa Holding Inc**. under this Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc**., shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc**. which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc**. in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall

discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.'s** powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

7. **ASSIGNMENT**

This Promissory Note may not be assigned by **Hydro Ottawa Limited** without the written consent of **Hydro Ottawa Holding Inc.**

8. **GOVERNING LAW**

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9. **CANCELLATION OF PREVIOUS NOTE**

This interest bearing Promissory Note in the amount of one hundred thirty eight million, six hundred sixty seven thousand dollars ($138,667,000) replaces 53.33% of the Promissory Note dated **May 14, 2013** in the amount of two hundred million dollars ($200,000,000) made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc**. which matured February 9, 2015, and 53.33% of the $60,000,000 outstanding as of February 9, 2015 on the Grid Promissory Note dated **May 14, 2013** made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc**.

**IN WITNESS WHEREOF Hydro Ottawa Limited** has duly executed this Promissory Note.

**HYDRO OTTAWA LIMITED**

Per: ______________________
Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Per: ______________________
Name: Geoff Simpson
Title: Chief Financial Officer

# PROMISSORY NOTE

| | |
|---|---|
| Principal: $121,333,000<br>lawful money of Canada | Effective February 9th, 2015 |

For value received, **Hydro Ottawa Limited** hereby unconditionally promises to pay to the order of **Hydro Ottawa Holding Inc.** at Ottawa, Canada on February 2, 2045 (the "Due Date") the principal amount of one hundred twenty one million, three hundred thirty three thousand dollars ($121,333,000) (the "Principal Amount") in lawful money of Canada and interest thereon upon the terms and subject to the conditions set forth below.

## 1. INTEREST RATE

The rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.769% per annum from February 9, 2015 to February 2, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.639% per annum from February 3, 2020 to February 2, 2045.

## 2. TERMS OF PAYMENT

The interest payable hereunder shall be calculated and payable monthly in arrears on the first day of each month, both before and after demand, default and judgment. **Hydro Ottawa Limited** shall pay to **Hydro Ottawa Holding Inc.**, on demand, interest on overdue interest at the rate described in section 1 hereof compounded on each date for the payment of interest on this Promissory Note before and after judgment.

## 3. REPAYMENT

(1) Subject to the terms and conditions set out in sub-section 3 (4) herein, **Hydro Ottawa Limited** may, at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note and interest owing under this Promissory Note.

(2) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable within 30 days following a change of control of **Hydro Ottawa Limited**. For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time:

a. holding, as owner or other beneficiary, other than solely as beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited** carrying votes or ownership interests

sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of **Hydro Ottawa Limited**, or

b. the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

**Hydro Ottawa Holding Inc.** shall provide **Hydro Ottawa Limited** with no less than twenty (20) days' prior notice of the requirement to repay Principal and interest.

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal Amount and interest payable in the event that **Hydro Ottawa Limited:**

a. disposes of substantially all of its property or assets;

b. fails to pay any principal, premium or interest on an indebtedness however incurred beyond any period of grace applicable to such indebtedness, where the amount of the indebtedness is $25 million or greater;

c. fails to perform or observe an agreement, term or condition contained in any agreement under which an indebtedness in the amount of $25 million or greater becomes due and payable; or

d. for any other reason causes the whole or any part of the Principal Amount to be repayable to **Hydro Ottawa Holding Inc.** in advance of the Due Date;

The amount to be repaid in respect of the Principal Amount and accrued and unpaid interest shall be determined in accordance with sub-section 3 (4) herein.

(4) In the event that **Hydro Ottawa Limited** chooses to repay or is required to repay in whole or in part the Principal Amount remaining unpaid and accrued and unpaid interest in accordance with sub-sections 3 (1), (2) or (3) herein, **Hydro Ottawa Limited** shall:

a. Provide, where such repayment is initiated at the request of **Hydro Ottawa Limited,** at least fifty (50) days' prior notice in writing to **Hydro Ottawa Holding Inc.** setting out the proposed amount of the Principal Amount and accrued and unpaid interest that it proposes to pay and the date of such payment;

b. Pay to **Hydro Ottawa Holding Inc.** in respect of the Principal Amount and accrued and unpaid interest to be paid, an amount calculated and determined

by **Hydro Ottawa Holding Inc.** in the same manner and subject to the same conditions (subject to any necessary changes) as the Redemption Price respecting an equivalent payment of principal as is set out in the Series 2015 – 2 Supplemental Indenture dated as of February 2, 2015 between Hydro Ottawa Holding Inc. and BNY Trust Company of Canada;

c. Indemnify **Hydro Ottawa Holding Inc.**, in addition to the amount calculated and determined pursuant to sub-section 3 (4)(b) herein, for any damages, losses, liabilities, claims, demands, interest, charges, fines, penalties, assessments, judgments, costs and expenses suffered or asserted directly or indirectly arising from any payment made pursuant to sub-section 3 (1), (2) or (3) herein or any delay in providing such payment.

4. **SUBORDINATION**

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note, together with interest thereon in accordance with and pursuant to this Promissory Note is subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

5. **WAIVER OF NOTICE IN EVENT OF DEFAULT**

**Hydro Ottawa Limited** hereby waives presentment, protest and notice of any kind in the enforcement of this Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Promissory Note, or any payment of interest thereon is not made when due.

6. **RIGHTS AND REMEDIES IN EVENT OF DEFAULT**

The rights and remedies of **Hydro Ottawa Holding Inc**. under this Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc.**, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc**. which may be brought to recover any amounts due and payable under this Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc**. in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall

discharge or release any person at any time liable for the payment of this Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.'s** powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

7. **ASSIGNMENT**

This Promissory Note may not be assigned by **Hydro Ottawa Limited** without the written consent of **Hydro Ottawa Holding Inc.**

8. **GOVERNING LAW**

This Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9. **CANCELLATION OF PREVIOUS NOTE**

This interest bearing Promissory Note in the amount of one hundred twenty one million, three hundred thirty three thousand dollars ($121,333,000) replaces 46.67% of the Promissory Note dated **May 14, 2013** in the amount of two hundred million dollars ($200,000,000) made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc**. which matured February 9, 2015, and 46.67% of the $60,000,000 outstanding as of February 9, 2015 on the Grid Promissory Note dated **May 14, 2013** made between **Hydro Ottawa Limited** and **Hydro Ottawa Holding Inc**.

**IN WITNESS WHEREOF Hydro Ottawa Limited** has duly executed this Promissory Note.

**HYDRO OTTAWA LIMITED**

Per: ______________________
Name: J. Bryce Conrad
Title: President and Chief Executive Officer

Per: ______________________
Name: Geoff Simpson
Title: Chief Financial Officer

# CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

## 1.0 INTRODUCTION

This Exhibit provides a summary of the revenue required by Hydro Ottawa Limited ("Hydro Ottawa") in 2016 through 2020 in order to continue delivering electricity safely and reliably. Hydro Ottawa's total Service Revenue Requirement is offset by revenues obtained by sources other than distribution rates, i.e. other revenue. The calculation of the revenue deficiency/sufficiency does not include the recovery of Deferral and Variance Accounts (Exhibit I-8-1) or Low Voltage Charges (Exhibit H-8-1). As directed in the Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications,* costs and revenues related to the cost of power are kept separate from the determination of the distribution revenue sufficiency/deficiency.

The revenue deficiency/sufficiency for 2016 through 2020 was calculated using the following inputs:

- 2015 approved rates,
- 2016 through 2020 load forecast and forecast of customers and connections, as developed using the methodology described in Exhibit C-1-1, and
- The 2016 through 2020 base revenue requirement calculated as shown in Table 1 below (more details for each year can be found in the Revenue Requirement WorkForms attached to this Exhibit).

The revenue deficiency/sufficiency was then determined by calculating what the revenue would have been with 2015 rates and the forecasted 2016 through 2020 load and customer numbers. As a result, revenue deficiency in Table 1 and the Revenue Requirement WorkForms produce a cumulative revenue requirement rather than a year over year revenue requirement. Hydro Ottawa compiled the analysis in this matter as the 2015 rates give a stable base to compare each year. In Table 1 a year over year revenue deficiency has also been provided.

**Table 1 – Revenue Sufficiency/Deficiency**

| | $000 | $000 | $000 | $000 | $000 |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| Return on Rate Base | 54,379 | 58,359 | 62,148 | 64,531 | 67,573 |
| Distribution Expenses (not including amortization) | 87,106 | 89,932 | 92,850 | 95,863 | 98,974 |
| Amortization | 40,826 | 44,145 | 47,047 | 48,949 | 50,295 |
| Payment in Lieu of Taxes | 4,958 | 4,799 | 6,074 | 8,473 | 7,587 |
| Service Revenue Requirement | 187,269 | 197,235 | 208,120 | 217,816 | 224,430 |
| Less Revenue Offsets | 11,700 | 11,565 | 11,722 | 11,802 | 11,898 |
| 2012 Base Revenue Requirement | 175,570 | 185,670 | 196,398 | 206,014 | 212,532 |
| Transformer Ownership Allowance | 1,125 | 1,114 | 1,109 | 1,106 | 1,105 |
| Revenue Requirement from Rates | 176,694 | 186,784 | 197,507 | 207,120 | 213,637 |
| Forecasted Load at 2015 Rates | 159,358 | 158,984 | 159,419 | 159,975 | 160,461 |
| **Cumulative Revenue Deficiency (over 2015)** | **(17,337)** | **(27,800)** | **(38,088)** | **(47,146)** | **(53,176)** |
| **Yearly Revenue Deficiency over 2015** | **(17,337)** | **(10,464)** | **(10,288)** | **(9,057)** | **(6,030)** |

Table 2 provides Revenue Deficiency based on previous Test Year rates against the current Test Years load forecast.

**Table 2 – Revenue Sufficiency/Deficiency using prior Test Year's Rates**

| | $000 | $000 | $000 | $000 | $000 |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| Total Revenue Requirement from Rates | 176,694 | 186,784 | 197,507 | 207,120 | 213,637 |
| Forecasted Load at Prior Years Rates | 159,360 | 176,407 | 187,467 | 198,471 | 208,158 |
| Yearly Revenue Deficiency | (17,334) | (10,377) | (10,040) | (8,650) | (5,479) |

Tables 3-7 provide the 2015-2020 year over year revenue deficiency/sufficiency amounts and major cost drivers as well as references to the Exhibits where further details on year over year variance and cost drivers can be attained.

**Table 3 –2015-2016 Revenue Deficiency - Amount & Drivers**

| $000 | 2015-2016 Revenue Deficiency & Drivers | | | | |
|---|---|---|---|---|---|
| | **2015** | **2016** | **Deficiency ($)** | **Drivers** | **Reference** |
| Return on Rate Base | 53,075 | 54,379 | 1,304 | • $46.8M additions<br>• $8.2M budgeted in CIP<br>• Higher WCA | B-1-1 |
| Distribution Expenses (not including amortization) | 83,656 | 87,106 | 3,450 | • Compensation increases<br>• Inflationary increases | D-1-3 |
| Amortization | 38,558 | 40,826 | 2,268 | • Increase in sustainment additions | D-3-1 |
| Payment in Lieu of Taxes | 0 | 4,958 | 4,958 | • Higher net income<br>• Less CCA deductions | D-4-1 |
| Service Revenue Requirement | 175,289 | 187,269 | 11,980 | | |
| Less Revenue Offsets | 8,847 | 11,700 | 2,852 | • Increases to retail, generation and specific service charges | C-2-1 |
| Base Revenue Requirement | 166,441 | 175,570 | 9,128 | | |
| Transformer Ownership Allowance | 1,168 | 1,125 | (43) | • Change in load | C-1-1 |
| Revenue Requirement from Rates | 167,609 | 176,694 | 9,085 | | |
| Forecasted Load at 2015 Rates | 159,745 | 159,358 | (387) | • Change in load | C-1-1 |
| **Cumulative Revenue Deficiency (over 2015)** | **(7,864)** | **(17,337)** | **(9,472)** | | |

### Table 4 –2016-2017 Revenue Deficiency - Amount & Drivers

| $000 | 2016-2017 Revenue Deficiency & Drivers | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | Deficiency ($) | Drivers | Reference |
| Return on Rate Base | 54,379 | 58,359 | 3,980 | • $42M in additions<br>• $4.1M more in CIP<br>• Higher WCA | B-1-1 |
| Distribution Expenses (not including amortization) | 87,106 | 89,932 | 2,827 | • Inflationary increases | D-1-3 |
| Amortization | 40,826 | 44,145 | 3,319 | • Increase due to sustainment assets and IT assets | D-3-1 |
| Payment in Lieu of Taxes | 4,958 | 4,799 | (160) | • No significant difference due to higher regulatory net income offset by increases to CCA deductions | D-4-1 |
| Service Revenue Requirement | 187,269 | 197,235 | 9,966 | | |
| Less Revenue Offsets | 11,700 | 11,565 | (134) | • Slight decline in late payment charges but offset by inflationary increase | C-2-1 |
| Base Revenue Requirement | 175,570 | 185,670 | 10,100 | | |
| Transformer Ownership Allowance | 1,125 | 1,114 | (10) | • Change in load | C-1-1 |
| Revenue Requirement from Rates | 176,694 | 186,784 | 10,090 | | |
| Forecasted Load at 2015 Rates | 159,358 | 158,984 | (374) | • Change in load | C-1-1 |
| **Cumulative Revenue Deficiency (over 2015)** | **(17,337)** | **(27,800)** | **(10,464)** | | |

### Table 5 –2017-2018 Revenue Deficiency - Amount & Drivers

| $000 | 2017-2018 Revenue Deficiency & Drivers | | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | Deficiency ($) | Drivers | Reference |
| Return on Rate Base | 58,359 | 62,148 | 3,789 | • $46.4 in additions<br>• $4.1M less in CIP<br>• Higher WCA | B-1-1 |
| Distribution Expenses (not including amortization) | 89,932 | 92,850 | 2,918 | • Inflationary increases | D-1-3 |
| Amortization | 44,145 | 47,047 | 2,902 | • Increase due to sustainment assets & other distribution assets | D-3-1 |
| Payment in Lieu of Taxes | 4,799 | 6,074 | 1,275 | • Higher net income<br>• Increase in accounting amortization add back | D-4-1 |
| Service Revenue Requirement | 197,235 | 208,120 | 10,885 | | |
| Less Revenue Offsets | 11,565 | 11,722 | 157 | • Inflationary increase as offset by interest earnings | C-2-1 |
| Base Revenue Requirement | 185,670 | 196,398 | 10,728 | | |
| Transformer Ownership Allowance | 1,114 | 1,109 | (5) | • Change in load | C-1-1 |
| Revenue Requirement from Rates | 186,784 | 197,507 | 10,723 | | |
| Forecasted Load at 2015 Rates | 158,984 | 159,419 | 435 | • Change in load | C-1-1 |
| **Cumulative Revenue Deficiency (over 2015)** | **(27,800)** | **(38,088)** | **(10,288)** | | |

**Table 6 –2018-2019 Revenue Deficiency - Amount & Drivers**

| $000 | 2018-2019 Revenue Deficiency & Drivers | | | | |
|---|---|---|---|---|---|
| | 2018 | 2019 | Deficiency ($) | Drivers | Reference |
| Return on Rate Base | 62,148 | 64,531 | 2,383 | • $18.9M in additions<br>• $29M more in CIP<br>• Lower WCA | B-1-1 |
| Distribution Expenses (not including amortization) | 92,850 | 95,863 | 3,013 | • Inflationary increases | D-1-3 |
| Amortization | 47,047 | 48,949 | 1,901 | • Increase due to sustainment assets | D-3-1 |
| Payment in Lieu of Taxes | 6,074 | 8,473 | 2,398 | • Slight increase to net income<br>• Increase in accounting amortization add back<br>• $4M less in CCA deductions | D-4-1 |
| Service Revenue Requirement | 208,120 | 217,816 | 9,696 | | |
| Less Revenue Offsets | 11,722 | 11,802 | 80 | • Inflationary increase as offset by interest earnings | C-2-1 |
| Base Revenue Requirement | 196,398 | 206,014 | 9,616 | | |
| Transformer Ownership Allowance | 1,109 | 1,106 | (3) | • Change in load | C-1-1 |
| Revenue Requirement from Rates | 197,507 | 207,120 | 9,613 | | |
| Forecasted Load at 2015 Rates | 159,419 | 159,975 | 556 | • Change in load | C-1-1 |
| **Cumulative Revenue Deficiency (over 2015)** | **(38,088)** | **(47,146)** | **(9,057)** | | |

**Table 7 –2019-2020 Revenue Deficiency - Amount & Drivers**

| $000 | 2019-2020 Revenue Deficiency & Drivers | | | | |
|---|---|---|---|---|---|
| | 2019 | 2020 | Deficiency ($) | Drivers | Reference |
| Return on Rate Base | 64,531 | 67,573 | 3,042 | • $62.6M in additions<br>• $18M less in CIP<br>• Higher WCA | B-1-1 |
| Distribution Expenses (not including amortization) | 95,863 | 98,974 | 3,111 | • Inflationary increases | D-1-3 |
| Amortization | 48,949 | 50,295 | 1,346 | • Increase due to sustainment assets | D-3-1 |
| Payment in Lieu of Taxes | 8,473 | 7,587 | (886) | • Decrease due to $5.3M in CCA deductions | D-4-1 |
| Service Revenue Requirement | 217,816 | 224,430 | 6,613 | | |
| Less Revenue Offsets | 11,802 | 11,898 | 96 | • Inflationary increase as offset by interest earnings | C-2-1 |
| Base Revenue Requirement | 206,014 | 212,532 | 6,518 | | |
| Transformer Ownership Allowance | 1,106 | 1,105 | (1) | • Change in load | C-1-1 |
| Revenue Requirement from Rates | 207,120 | 213,637 | 6,517 | | |
| Forecasted Load at 2015 Rates | 159,975 | 160,461 | 487 | • Change in load | C-1-1 |
| **Cumulative Revenue Deficiency (over 2015)** | **(47,146)** | **(53,176)** | **(6,030)** | | |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

**Version** 5.00

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | RegulatoryAffairs@HydroOttawa.com |



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers



**Notes:**

**(1)** Pale green cells represent inputs
**(2)** Pale green boxes at the bottom of each page are for additional notes
**(3)** Pale yellow cells represent drop-down lists
**(4)** ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
**(5)** ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Data Input [1]

| | | Initial Application | (2) | | (6) | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | |
| | Gross Fixed Assets (average) | $877,318,904 | | $ 877,318,904 | | $877,318,904 | |
| | Accumulated Depreciation (average) | ($93,370,568) | (5) | ($93,370,568) | | ($93,370,568) | |
| | Allowance for Working Capital: | | | | | | |
| | Controllable Expenses | $87,105,564 | | $ 87,105,564 | | $87,105,564 | |
| | Cost of Power | $894,285,487 | | $ 894,285,487 | | $894,285,487 | |
| | Working Capital Rate (%) | 14.20% | (9) | 14.20% | (9) | 14.20% | (9) |
| 2 | **Utility Income** | | | | | | |
| | Operating Revenues: | | | | | | |
| | Distribution Revenue at Current Rates | $158,233,086 | (10) | | | | |
| | Distribution Revenue at Proposed Rates | $175,569,610 | (11) | | | | |
| | Other Revenue: | | | | | | |
| | Specific Service Charges | $5,910,525 | | | | | |
| | Late Payment Charges | $898,752 | | | | | |
| | Other Distribution Revenue | $1,410,557 | | | | | |
| | Other Income and Deductions | $3,479,704 | | | | | |
| | Total Revenue Offsets | $11,699,538 | (7) | | | | |
| | Operating Expenses: | | | | | | |
| | OM+A Expenses | $85,017,720 | | $ 85,017,720 | | $85,017,720 | |
| | Depreciation/Amortization | $40,826,114 | | $ 40,826,114 | | $40,826,114 | |
| | Property taxes | $2,087,844 | | $ 2,087,844 | | $2,087,844 | |
| | Other expenses | | | | | | |

| | | | |
|---|---|---|---|
| **3** | **Taxes/PILs** | | |
| | Taxable Income: | | |
| | Adjustments required to arrive at taxable income | ($19,597,073) | **(3)** |
| | Utility Income Taxes and Rates: | | |
| | Income taxes (not grossed up) | $3,656,225 | |
| | Income taxes (grossed up) | $4,958,448 | |
| | Federal tax (%) | 15.00% | |
| | Provincial tax (%) | 11.26% | |
| | Income Tax Credits | ($217,500) | |
| **4** | **Capitalization/Cost of Capital** | | |
| | Capital Structure: | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | **(8)** |
| | Common Equity Capitalization Ratio (%) | 40.0% | |
| | Prefered Shares Capitalization Ratio (%) | | |
| | | 100.0% | |
| | Cost of Capital | | |
| | Long-term debt Cost Rate (%) | 3.72% | |
| | Short-term debt Cost Rate (%) | 2.16% | |
| | Common Equity Cost Rate (%) | 9.30% | |
| | Prefered Shares Cost Rate (%) | | |

**(8)** **(8)**

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Revenue at current rates minus Transformer Ownership Allowance

(11) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $176,694,250

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $877,318,904 | $ - | $877,318,904 | $ - | $877,318,904 |
| 2 | Accumulated Depreciation (average) | (3) | ($93,370,568) | $ - | ($93,370,568) | $ - | ($93,370,568) |
| 3 | Net Fixed Assets (average) | (3) | $783,948,336 | $ - | $783,948,336 | $ - | $783,948,336 |
| 4 | Allowance for Working Capital | (1) | $139,357,529 | $ - | $139,357,529 | $ - | $139,357,529 |
| 5 | **Total Rate Base** | | $923,305,865 | $ - | $923,305,865 | $ - | $923,305,865 |

(1) **Allowance for Working Capital - Derivation**

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $87,105,564 | $ - | $87,105,564 | $ - | $87,105,564 |
| 7 | Cost of Power | | $894,285,487 | $ - | $894,285,487 | $ - | $894,285,487 |
| 8 | Working Capital Base | | $981,391,050 | $ - | $981,391,050 | $ - | $981,391,050 |
| 9 | Working Capital Rate % | (2) | 14.20% | 0.00% | 14.20% | 0.00% | 14.20% |
| 10 | Working Capital Allowance | | $139,357,529 | $ - | $139,357,529 | $ - | $139,357,529 |

**Notes**
(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Utility Income

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $175,569,610 | ($175,569,610) | $ - | $ - | $ - |
| 2 | Other Revenue | (1) | $11,699,538 | ($11,699,538) | $ - | $ - | $ - |
| 3 | Total Operating Revenues | | $187,269,148 | ($187,269,148) | $ - | $ - | $ - |
| | **Operating Expenses:** | | | | | | |
| 4 | OM+A Expenses | | $85,017,720 | $ - | $85,017,720 | $ - | $85,017,720 |
| 5 | Depreciation/Amortization | | $40,826,114 | $ - | $40,826,114 | $ - | $40,826,114 |
| 6 | Property taxes | | $2,087,844 | $ - | $2,087,844 | $ - | $2,087,844 |
| 7 | Capital taxes | | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $127,931,678 | $ - | $127,931,678 | $ - | $127,931,678 |
| 10 | Deemed Interest Expense | | $20,032,044 | ($20,032,044) | $ - | $ - | $ - |
| 11 | Total Expenses (lines 9 to 10) | | $147,963,722 | ($20,032,044) | $127,931,678 | $ - | $127,931,678 |
| 12 | **Utility income before income taxes** | | $39,305,426 | ($167,237,104) | ($127,931,678) | $ - | ($127,931,678) |
| 13 | Income taxes (grossed-up) | | $4,958,448 | $ - | $4,958,448 | $ - | $4,958,448 |
| 14 | **Utility net income** | | $34,346,978 | ($167,237,104) | ($132,890,126) | $ - | ($132,890,126) |

**Notes**

## Other Revenues / Revenue Offsets

| Notes | | | | | | |
|---|---|---|---|---|---|---|
| **(1)** | Specific Service Charges | $5,910,525 | | $ - | | $ - |
| | Late Payment Charges | $898,752 | | $ - | | $ - |
| | Other Distribution Revenue | $1,410,557 | | $ - | | $ - |
| | Other Income and Deductions | $3,479,704 | | $ - | | $ - |
| | Total Revenue Offsets | $11,699,538 | $ - | $ - | $ - | $ - |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $34,346,978 | $ - | $ - |
| 2 | Adjustments required to arrive at taxable utility income | ($19,597,073) | $ - | ($19,597,073) |
| 3 | Taxable income | $14,749,905 | $ - | ($19,597,073) |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $3,656,225 | $3,656,225 | $3,656,225 |
| 6 | Total taxes | $3,656,225 | $3,656,225 | $3,656,225 |
| 7 | Gross-up of Income Taxes | $1,302,223 | $1,302,223 | $1,302,223 |
| 8 | Grossed-up Income Taxes | $4,958,448 | $4,958,448 | $4,958,448 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $4,958,448 | $4,958,448 | $4,958,448 |
| 10 | Other tax Credits | ($217,500) | ($217,500) | ($217,500) |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 15.00% | 15.00% | 15.00% |
| 12 | Provincial tax (%) | 11.26% | 11.26% | 11.26% |
| 13 | Total tax rate (%) | 26.26% | 26.26% | 26.26% |

**Notes**

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio (%) | Capitalization Ratio ($) | Cost Rate (%) | Return ($) |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $517,051,284 | 3.72% | $19,234,308 |
| 2 | Short-term Debt | 4.00% | $36,932,235 | 2.16% | $797,736 |
| 3 | **Total Debt** | 60.00% | $553,983,519 | 3.62% | $20,032,044 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $369,322,346 | 9.30% | $34,346,978 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $369,322,346 | 9.30% | $34,346,978 |
| 7 | **Total** | 100.00% | $923,305,865 | 5.89% | $54,379,022 |

| Line No. | Particulars | Capitalization Ratio (%) | Capitalization Ratio ($) | Cost Rate (%) | Return ($) |
|---|---|---|---|---|---|
| | **Debt** | | | | |
| 1 | Long-term Debt | 0.00% | $ - | 0.00% | $ - |
| 2 | Short-term Debt | 0.00% | $ - | 0.00% | $ - |
| 3 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 4 | Common Equity | 0.00% | $ - | 0.00% | $ - |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 7 | **Total** | 0.00% | $923,305,865 | 0.00% | $ - |

| Line No. | Particulars | Capitalization Ratio (%) | Capitalization Ratio ($) | Cost Rate (%) | Return ($) |
|---|---|---|---|---|---|
| | | **Per Board Decision** | | | |
| | **Debt** | | | | |
| 8 | Long-term Debt | 0.00% | $ - | 3.72% | $ - |
| 9 | Short-term Debt | 0.00% | $ - | 2.16% | $ - |
| 10 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 11 | Common Equity | 0.00% | $ - | 9.30% | $ - |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 14 | **Total** | 0.00% | $923,305,865 | 0.00% | $ - |

**Notes**

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| | | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates |
| 1 | Revenue Deficiency from Below | | $17,336,524 | | ($37,576,184) | | $127,931,678 |
| 2 | Distribution Revenue | $158,233,086 | $158,233,086 | $158,233,086 | $213,145,794 | $ - | ($127,931,678) |
| 3 | Other Operating Revenue Offsets - net | $11,699,538 | $11,699,538 | $ - | $ - | $ - | $ - |
| 4 | **Total Revenue** | $169,932,624 | $187,269,148 | $158,233,086 | $175,569,610 | $ - | $ - |
| 5 | Operating Expenses | $127,931,678 | $127,931,678 | $127,931,678 | $127,931,678 | $127,931,678 | $127,931,678 |
| 6 | Deemed Interest Expense | $20,032,044 | $20,032,044 | $ - | $ - | $ - | $ - |
| 8 | **Total Cost and Expenses** | $147,963,722 | $147,963,722 | $127,931,678 | $127,931,678 | $127,931,678 | $127,931,678 |
| 9 | **Utility Income Before Income Taxes** | $21,968,902 | $39,305,426 | $30,301,408 | $47,637,932 | ($127,931,678) | ($127,931,678) |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($19,597,073) | ($19,597,073) | ($19,597,073) | ($19,597,073) | $ - | $ - |
| 11 | **Taxable Income** | $2,371,829 | $19,708,353 | $10,704,335 | $28,040,859 | ($127,931,678) | ($127,931,678) |
| 12 | Income Tax Rate | 26.26% | 26.26% | 26.26% | 26.26% | 26.26% | 26.26% |
| 13 | **Income Tax on Taxable Income** | $622,907 | $5,175,948 | $2,811,248 | $7,364,290 | ($33,598,326) | ($33,598,326) |
| 14 | **Income Tax Credits** | ($217,500) | ($217,500) | ($217,500) | ($217,500) | $ - | $ - |
| 15 | **Utility Net Income** | $21,563,495 | $34,346,978 | $27,707,659 | ($132,890,126) | ($94,333,352) | ($132,890,126) |
| 16 | **Utility Rate Base** | $923,305,865 | $923,305,865 | $923,305,865 | $923,305,865 | $923,305,865 | $923,305,865 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **17** | Deemed Equity Portion of Rate Base | $369,322,346 | $369,322,346 | $ - | $ - | $ - | $ - |
| **18** | Income/(Equity Portion of Rate Base) | 5.84% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| **19** | Target Return - Equity on Rate Base | 9.30% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| **20** | Deficiency/Sufficiency in Return on Equity | -3.46% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **21** | Indicated Rate of Return | 4.51% | 5.89% | 3.00% | 0.00% | -10.22% | 0.00% |
| **22** | Requested Rate of Return on Rate Base | 5.89% | 5.89% | 0.00% | 0.00% | 0.00% | 0.00% |
| **23** | Deficiency/Sufficiency in Rate of Return | -1.38% | 0.00% | 3.00% | 0.00% | -10.22% | 0.00% |
| **24** | Target Return on Equity | $34,346,978 | $34,346,978 | $ - | $ - | $ - | $ - |
| **25** | Revenue Deficiency/(Sufficiency) | $12,783,483 | $0 | ($27,707,659) | $ - | $94,333,352 | $ - |
| **26** | **Gross Revenue Deficiency/(Sufficiency)** | $17,336,524 **(1)** | | ($37,576,184) **(1)** | | $127,931,678 **(1)** | |

**Notes:**
**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $85,017,720 | | $85,017,720 | | $85,017,720 | |
| 2 | Amortization/Depreciation | $40,826,114 | | $40,826,114 | | $40,826,114 | |
| 3 | Property Taxes | $2,087,844 | | $2,087,844 | | $2,087,844 | |
| 5 | Income Taxes (Grossed up) | $4,958,448 | | $4,958,448 | | $4,958,448 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $20,032,044 | | $ - | | $ - | |
| | Return on Deemed Equity | $34,346,978 | | $ - | | $ - | |
| 8 | **Service Revenue Requirement (before Revenues)** | $187,269,148 | | $132,890,126 | | $132,890,126 | |
| 9 | Revenue Offsets | $11,699,538 | | $ - | | $ - | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $175,569,610 | | $132,890,126 | | $132,890,126 | |
| 11 | Distribution revenue | $175,569,610 | (2) | $ - | | $ - | |
| 12 | Other revenue | $11,699,538 | | $ - | | $ - | |
| 13 | **Total revenue** | $187,269,148 | | $ - | | $ - | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $0 | **(1)** | ($132,890,126) | **(1)** | ($132,890,126) | **(1)** |

**Notes**

**(1)** Line 11 - Line 8

(2) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $176,694,250

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Tracking Form

**The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)**
**Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.**
**(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)**
**(2) Short description of change, issue, etc.**

**60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.**

### *Summary of Proposed Changes*

| | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | **Original Application** | $ 54,379,022 | 5.89% | $ 923,305,865 | $ 981,391,050 | $ 139,357,529 | $ 40,826,114 | $ 4,958,448 | $ 85,017,720 | $ 187,269,148 | $ 11,699,538 | $ 175,569,610 | $ 17,336,524 |
| 1 | | | | | | | | | | | | | |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | RegulatoryAffairs@HydroOttawa.com |



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers



**Notes:**

| | |
|---|---|
| **(1)** | Pale green cells represent inputs |
| **(2)** | Pale green boxes at the bottom of each page are for additional notes |
| **(3)** | Pale yellow cells represent drop-down lists |
| **(4)** | ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.*** |
| **(5)** | ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel*** |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Data Input (1)

| | | Initial Application | (2) | | (6) | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | |
| | Gross Fixed Assets (average) | $963,191,112 | | $ 963,191,112 | | $963,191,112 | |
| | Accumulated Depreciation (average) | ($134,843,112) | (5) | ($134,843,112) | | ($134,843,112) | |
| | Allowance for Working Capital: | | | | | | |
| | Controllable Expenses | $89,932,139 | | $ 89,932,139 | | $89,932,139 | |
| | Cost of Power | $911,714,427 | | $ 911,714,427 | | $911,714,427 | |
| | Working Capital Rate (%) | 14.20% | (9) | 14.20% | (9) | 14.20% | (9) |
| 2 | **Utility Income** | | | | | | |
| | Operating Revenues: | | | | | | |
| | Distribution Revenue at Current Rates | $157,869,752 | (10) | | | | |
| | Distribution Revenue at Proposed Rates | $185,669,946 | (11) | | | | |
| | Other Revenue: | | | | | | |
| | Specific Service Charges | $5,934,229 | | | | | |
| | Late Payment Charges | $720,000 | | | | | |
| | Other Distribution Revenue | $1,426,444 | | | | | |
| | Other Income and Deductions | $3,484,458 | | | | | |
| | Total Revenue Offsets | | (7) | | | | |
| | Operating Expenses: | | | | | | |
| | OM+A Expenses | $87,776,545 | | $ 87,776,545 | | $87,776,545 | |
| | Depreciation/Amortization | $44,145,078 | | $ 44,145,078 | | $44,145,078 | |
| | Property taxes | $2,155,595 | | $ 2,155,595 | | $2,155,595 | |
| | Other expenses | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **3** | **Taxes/PILs** | | | | | | |
| | Taxable Income: | | | | | | |
| | Adjustments required to arrive at taxable income | ($21,610,760) | **(3)** | $67,596,391 | | | |
| | Utility Income Taxes and Rates: | | | | | | |
| | Income taxes (not grossed up) | $3,538,644 | | | | | |
| | Income taxes (grossed up) | $4,798,717 | | | | | |
| | Federal tax (%) | 15.00% | | | | | |
| | Provincial tax (%) | 11.26% | | | | | |
| | Income Tax Credits | ($267,500) | | | | | |
| **4** | **Capitalization/Cost of Capital** | | | | | | |
| | Capital Structure: | | | | | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | | | | | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | **(8)** | | **(8)** | | **(8)** |
| | Common Equity Capitalization Ratio (%) | 40.0% | | | | | |
| | Prefered Shares Capitalization Ratio (%) | | | | | | |
| | | 100.0% | | | | | |
| | Cost of Capital | | | | | | |
| | Long-term debt Cost Rate (%) | 3.94% | | | | | |
| | Short-term debt Cost Rate (%) | 2.16% | | | | | |
| | Common Equity Cost Rate (%) | 9.30% | | | | | |
| | Prefered Shares Cost Rate (%) | | | | | | |

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Revenue at current rates minus Transformer Ownership Allowance

(11) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $186,784,378

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $963,191,112 | $ - | $963,191,112 | $ - | $963,191,112 |
| 2 | Accumulated Depreciation (average) | (3) | ($134,843,112) | $ - | ($134,843,112) | $ - | ($134,843,112) |
| 3 | Net Fixed Assets (average) | (3) | $828,348,000 | $ - | $828,348,000 | $ - | $828,348,000 |
| 4 | Allowance for Working Capital | (1) | $142,233,812 | $ - | $142,233,812 | $ - | $142,233,812 |
| 5 | **Total Rate Base** | | $970,581,813 | $ - | $970,581,813 | $ - | $970,581,813 |

(1) **Allowance for Working Capital - Derivation**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $89,932,139 | $ - | $89,932,139 | $ - | $89,932,139 |
| 7 | Cost of Power | | $911,714,427 | $ - | $911,714,427 | $ - | $911,714,427 |
| 8 | Working Capital Base | | $1,001,646,566 | $ - | $1,001,646,566 | $ - | $1,001,646,566 |
| 9 | Working Capital Rate % | (2) | 14.20% | 0.00% | 14.20% | 0.00% | 14.20% |
| 10 | Working Capital Allowance | | $142,233,812 | $ - | $142,233,812 | $ - | $142,233,812 |

**Notes**

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Utility Income

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $185,669,946 | ($185,669,946) | $ - | $ - | $ - |
| 2 | Other Revenue | (1) | $11,565,131 | ($11,565,131) | $ - | $ - | $ - |
| 3 | Total Operating Revenues | | $197,235,078 | ($197,235,078) | $ - | $ - | $ - |
| | **Operating Expenses:** | | | | | | |
| 4 | OM+A Expenses | | $87,776,545 | $ - | $87,776,545 | $ - | $87,776,545 |
| 5 | Depreciation/Amortization | | $44,145,078 | $ - | $44,145,078 | $ - | $44,145,078 |
| 6 | Property taxes | | $2,155,595 | $ - | $2,155,595 | $ - | $2,155,595 |
| 7 | Capital taxes | | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $134,077,217 | $ - | $134,077,217 | $ - | $134,077,217 |
| 10 | Deemed Interest Expense | | $22,253,500 | ($22,253,500) | $ - | $ - | $ - |
| 11 | Total Expenses (lines 9 to 10) | | $156,330,717 | ($22,253,500) | $134,077,217 | $ - | $134,077,217 |
| 12 | **Utility income before income taxes** | | $40,904,360 | ($174,981,578) | ($134,077,217) | $ - | ($134,077,217) |
| 13 | Income taxes (grossed-up) | | $4,798,717 | $ - | $4,798,717 | $ - | $4,798,717 |
| 14 | **Utility net income** | | $36,105,644 | ($174,981,578) | ($138,875,934) | $ - | ($138,875,934) |

| **Notes** | **Other Revenues / Revenue Offsets** | | | | | |
|---|---|---|---|---|---|---|
| **(1)** | Specific Service Charges | $5,934,229 | | $ - | | $ - |
| | Late Payment Charges | $720,000 | | $ - | | $ - |
| | Other Distribution Revenue | $1,426,444 | | $ - | | $ - |
| | Other Income and Deductions | $3,484,458 | | $ - | | $ - |
| | Total Revenue Offsets | $11,565,131 | $ - | $ - | $ - | $ - |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $36,105,643 | $ - | $ - |
| 2 | Adjustments required to arrive at taxable utility income | ($21,610,760) | $67,596,391 | ($21,610,760) |
| 3 | Taxable income | $14,494,883 | $67,596,391 | ($21,610,760) |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $3,538,644 | $3,538,644 | $3,538,644 |
| 6 | Total taxes | $3,538,644 | $3,538,644 | $3,538,644 |
| 7 | Gross-up of Income Taxes | $1,260,073 | $1,260,073 | $1,260,073 |
| 8 | Grossed-up Income Taxes | $4,798,717 | $4,798,717 | $4,798,717 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $4,798,717 | $4,798,717 | $4,798,717 |
| 10 | Other tax Credits | ($267,500) | ($267,500) | ($267,500) |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 15.00% | 15.00% | 15.00% |
| 12 | Provincial tax (%) | 11.26% | 11.26% | 11.26% |
| 13 | Total tax rate (%) | 26.26% | 26.26% | 26.26% |

**Notes**

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | Return |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $543,525,815 | 3.94% | $21,414,917 |
| 2 | Short-term Debt | 4.00% | $38,823,273 | 2.16% | $838,583 |
| 3 | **Total Debt** | 60.00% | $582,349,088 | 3.82% | $22,253,500 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $388,232,725 | 9.30% | $36,105,643 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $388,232,725 | 9.30% | $36,105,643 |
| 7 | **Total** | 100.00% | $970,581,813 | 6.01% | $58,359,143 |
| | | | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 0.00% | $ - | 0.00% | $ - |
| 2 | Short-term Debt | 0.00% | $ - | 0.00% | $ - |
| 3 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 4 | Common Equity | 0.00% | $ - | 0.00% | $ - |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 7 | **Total** | 0.00% | $970,581,813 | 0.00% | $ - |
| | | **Per Board Decision** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 8 | Long-term Debt | 0.00% | $ - | 3.94% | $ - |
| 9 | Short-term Debt | 0.00% | $ - | 2.16% | $ - |
| 10 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 11 | Common Equity | 0.00% | $ - | 9.30% | $ - |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 14 | **Total** | 0.00% | $970,581,813 | 0.00% | $ - |

**Notes**

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Deficiency/Sufficiency

| | | Initial Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| Line No. | Particulars | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates |
| 1 | Revenue Deficiency from Below | | $27,800,194 | | ($84,947) | | $158,147,559 |
| 2 | Distribution Revenue | $157,869,752 | $157,869,753 | $157,869,752 | $185,754,893 | $ - | ($158,147,559) |
| 3 | Other Operating Revenue Offsets - net | $11,565,131 | $11,565,131 | $ - | $ - | $ - | $ - |
| 4 | **Total Revenue** | $169,434,884 | $197,235,078 | $157,869,752 | $185,669,946 | $ - | $ - |
| 5 | Operating Expenses | $134,077,217 | $134,077,217 | $134,077,217 | $134,077,217 | $134,077,217 | $134,077,217 |
| 6 | Deemed Interest Expense | $22,253,500 | $22,253,500 | $ - | $ - | $ - | $ - |
| 8 | **Total Cost and Expenses** | $156,330,717 | $156,330,717 | $134,077,217 | $134,077,217 | $134,077,217 | $134,077,217 |
| 9 | **Utility Income Before Income Taxes** | $13,104,167 | $40,904,360 | $23,792,535 | $51,592,729 | ($134,077,217) | ($134,077,217) |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($21,610,760) | ($21,610,760) | $67,596,391 | $67,596,391 | $67,596,391 | $67,596,391 |
| 11 | **Taxable Income** | ($8,506,594) | $19,293,600 | $91,388,926 | $119,189,120 | ($66,480,826) | ($66,480,826) |
| 12 | Income Tax Rate | 26.26% | 26.26% | 26.26% | 26.26% | 26.26% | 26.26% |
| 13 | **Income Tax on Taxable Income** | ($2,233,707) | $5,066,217 | $23,997,394 | $31,297,317 | ($17,456,891) | ($17,456,891) |
| 14 | **Income Tax Credits** | ($267,500) | ($267,500) | ($267,500) | ($267,500) | $ - | $ - |
| 15 | **Utility Net Income** | $15,605,373 | $36,105,644 | $62,641 | ($138,875,934) | ($116,620,326) | ($138,875,934) |
| 16 | **Utility Rate Base** | $970,581,813 | $970,581,813 | $970,581,813 | $970,581,813 | $970,581,813 | $970,581,813 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 17 | Deemed Equity Portion of Rate Base | $388,232,725 | $388,232,725 | $ - | $ - | $ - | $ - |
| 18 | Income/(Equity Portion of Rate Base) | 4.02% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 19 | Target Return - Equity on Rate Base | 9.30% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 20 | Deficiency/Sufficiency in Return on Equity | -5.28% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 21 | Indicated Rate of Return | 3.90% | 6.01% | 0.01% | 0.00% | -12.02% | 0.00% |
| 22 | Requested Rate of Return on Rate Base | 6.01% | 6.01% | 0.00% | 0.00% | 0.00% | 0.00% |
| 23 | Deficiency/Sufficiency in Rate of Return | -2.11% | 0.00% | 0.01% | 0.00% | -12.02% | 0.00% |
| 24 | Target Return on Equity | $36,105,643 | $36,105,643 | $ - | $ - | $ - | $ - |
| 25 | Revenue Deficiency/(Sufficiency) | $20,500,270 | $0 | ($62,641) | $ - | $116,620,326 | $ - |
| 26 | **Gross Revenue Deficiency/(Sufficiency)** | $27,800,194 **(1)** | | ($84,947) **(1)** | | $158,147,559 **(1)** | |

**Notes:**

**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $87,776,545 | | $87,776,545 | | $87,776,545 | |
| 2 | Amortization/Depreciation | $44,145,078 | | $44,145,078 | | $44,145,078 | |
| 3 | Property Taxes | $2,155,595 | | $2,155,595 | | $2,155,595 | |
| 5 | Income Taxes (Grossed up) | $4,798,717 | | $4,798,717 | | $4,798,717 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $22,253,500 | | $ - | | $ - | |
| | Return on Deemed Equity | $36,105,643 | | $ - | | $ - | |
| 8 | **Service Revenue Requirement (before Revenues)** | $197,235,077 | | $138,875,934 | | $138,875,934 | |
| 9 | Revenue Offsets | $ - | | $ - | | $ - | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $197,235,077 | | $138,875,934 | | $138,875,934 | |
| 11 | Distribution revenue | $185,669,946 | (2) | $ - | | $ - | |
| 12 | Other revenue | $11,565,131 | | $ - | | $ - | |
| 13 | **Total revenue** | $197,235,078 | | $ - | | $ - | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $0 | (1) | ($138,875,934) | (1) | ($138,875,934) | (1) |

**Notes**

**(1)** Line 11 - Line 8

(2) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $186,784,378

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Tracking Form

**The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)**
**Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.**
**(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)**
**(2) Short description of change, issue, etc.**

**60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.**

### *Summary of Proposed Changes*

| | | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | | Original Application | $ 58,359,143 | 6.01% | $ 970,581,813 | $1,001,646,566 | $ 142,233,812 | $ 44,145,078 | $ 4,798,717 | $ 87,776,545 | $ 197,235,077 | $ 11,565,131 | $ 197,235,077 | $ 27,800,194 |
| 1 | | | | | | | | | | | | | | |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | RegulatoryAffairs@HydroOttawa.com |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers



**Notes:**

**(1)** Pale green cells represent inputs

**(2)** Pale green boxes at the bottom of each page are for additional notes

**(3)** Pale yellow cells represent drop-down lists

**(4)** ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

**(5)** ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Data Input [1]

| | | Initial Application | (2) | | (6) | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | |
| | Gross Fixed Assets (average) | $1,051,985,626 | | $1,051,985,626 | | $1,051,985,626 | |
| | Accumulated Depreciation (average) | ($179,426,302) | (5) | ($179,426,302) | | ($179,426,302) | |
| | Allowance for Working Capital: | | | | | | |
| | Controllable Expenses | $92,850,437 | | $ 92,850,437 | | $92,850,437 | |
| | Cost of Power | $947,558,773 | | $ 947,558,773 | | $947,558,773 | |
| | Working Capital Rate (%) | 14.20% | (9) | 14.20% | (9) | 14.20% | (9) |
| 2 | **Utility Income** | | | | | | |
| | Operating Revenues: | | | | | | |
| | Distribution Revenue at Current Rates | $158,309,877 | (10) | | | | |
| | Distribution Revenue at Proposed Rates | $196,398,374 | (11) | | | | |
| | Other Revenue: | | | | | | |
| | Specific Service Charges | $6,014,982 | | | | | |
| | Late Payment Charges | $720,000 | | | | | |
| | Other Distribution Revenue | $1,469,736 | | | | | |
| | Other Income and Deductions | $3,517,323 | | | | | |
| | Total Revenue Offsets | | (7) | | | | |
| | Operating Expenses: | | | | | | |
| | OM+A Expenses | $90,624,894 | | $ 90,624,894 | | $90,624,894 | |
| | Depreciation/Amortization | $47,047,409 | | $ 47,047,409 | | $47,047,409 | |
| | Property taxes | $2,225,544 | | $ 2,225,544 | | $2,225,544 | |
| | Other expenses | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **3** | **Taxes/PILs** | | | | | | |
| | Taxable Income: | | | | | | |
| | Adjustments required to arrive at taxable income | ($19,959,370) | **(3)** | $68,837,332 | | | |
| | Utility Income Taxes and Rates: | | | | | | |
| | Income taxes (not grossed up) | $4,476,359 | | | | | |
| | Income taxes (grossed up) | $6,074,211 | | | | | |
| | Federal tax (%) | 15.00% | | | | | |
| | Provincial tax (%) | 11.31% | | | | | |
| | Income Tax Credits | ($257,500) | | | | | |
| **4** | **Capitalization/Cost of Capital** | | | | | | |
| | Capital Structure: | | | | | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | | | | | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | **(8)** | | **(8)** | | **(8)** |
| | Common Equity Capitalization Ratio (%) | 40.0% | | | | | |
| | Prefered Shares Capitalization Ratio (%) | | | | | | |
| | | 100.0% | | | | | |
| | Cost of Capital | | | | | | |
| | Long-term debt Cost Rate (%) | 4.08% | | | | | |
| | Short-term debt Cost Rate (%) | 2.16% | | | | | |
| | Common Equity Cost Rate (%) | 9.30% | | | | | |
| | Prefered Shares Cost Rate (%) | | | | | | |

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Revenue at current rates minus Transformer Ownership Allowance

(11) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $197,507,477

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $1,051,985,626 | $ - | $1,051,985,626 | $ - | $1,051,985,626 |
| 2 | Accumulated Depreciation (average) | (3) | ($179,426,302) | $ - | ($179,426,302) | $ - | ($179,426,302) |
| 3 | Net Fixed Assets (average) | (3) | $872,559,324 | $ - | $872,559,324 | $ - | $872,559,324 |
| 4 | Allowance for Working Capital | (1) | $147,738,108 | $ - | $147,738,108 | $ - | $147,738,108 |
| 5 | **Total Rate Base** | | $1,020,297,432 | $ - | $1,020,297,432 | $ - | $1,020,297,432 |

### (1) Allowance for Working Capital - Derivation

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $92,850,437 | $ - | $92,850,437 | $ - | $92,850,437 |
| 7 | Cost of Power | | $947,558,773 | $ - | $947,558,773 | $ - | $947,558,773 |
| 8 | Working Capital Base | | $1,040,409,211 | $ - | $1,040,409,211 | $ - | $1,040,409,211 |
| 9 | Working Capital Rate % | (2) | 14.20% | 0.00% | 14.20% | 0.00% | 14.20% |
| 10 | Working Capital Allowance | | $147,738,108 | $ - | $147,738,108 | $ - | $147,738,108 |

**Notes**

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Utility Income

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $196,398,374 | ($196,398,374) | $ - | $ - | $ - |
| 2 | Other Revenue | (1) | $11,722,041 | ($11,722,041) | $ - | $ - | $ - |
| 3 | Total Operating Revenues | | $208,120,414 | ($208,120,414) | $ - | $ - | $ - |
| | **Operating Expenses:** | | | | | | |
| 4 | OM+A Expenses | | $90,624,894 | $ - | $90,624,894 | $ - | $90,624,894 |
| 5 | Depreciation/Amortization | | $47,047,409 | $ - | $47,047,409 | $ - | $47,047,409 |
| 6 | Property taxes | | $2,225,544 | $ - | $2,225,544 | $ - | $2,225,544 |
| 7 | Capital taxes | | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $139,897,846 | $ - | $139,897,846 | $ - | $139,897,846 |
| 10 | Deemed Interest Expense | | $24,193,293 | ($24,193,293) | $ - | $ - | $ - |
| 11 | Total Expenses (lines 9 to 10) | | $164,091,139 | ($24,193,293) | $139,897,846 | $ - | $139,897,846 |
| 12 | **Utility income before income taxes** | | $44,029,275 | ($183,927,122) | ($139,897,846) | $ - | ($139,897,846) |
| 13 | Income taxes (grossed-up) | | $6,074,211 | $ - | $6,074,211 | $ - | $6,074,211 |
| 14 | **Utility net income** | | $37,955,064 | ($183,927,122) | ($145,972,057) | $ - | ($145,972,057) |

**Notes**

## Other Revenues / Revenue Offsets

| Notes | | | | | | |
|---|---|---|---|---|---|---|
| **(1)** | Specific Service Charges | $6,014,982 | | $ - | | $ - |
| | Late Payment Charges | $720,000 | | $ - | | $ - |
| | Other Distribution Revenue | $1,469,736 | | $ - | | $ - |
| | Other Income and Deductions | $3,517,323 | | $ - | | $ - |
| | Total Revenue Offsets | $11,722,041 | $ - | $ - | $ - | $ - |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $37,955,064 | $ - | $ - |
| 2 | Adjustments required to arrive at taxable utility income | ($19,959,370) | $68,837,332 | ($19,959,370) |
| 3 | Taxable income | $17,995,695 | $68,837,332 | ($19,959,370) |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $4,476,359 | $4,476,359 | $4,476,359 |
| 6 | Total taxes | $4,476,359 | $4,476,359 | $4,476,359 |
| 7 | Gross-up of Income Taxes | $1,597,852 | $1,597,852 | $1,597,852 |
| 8 | Grossed-up Income Taxes | $6,074,211 | $6,074,211 | $6,074,211 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $6,074,211 | $6,074,211 | $6,074,211 |
| 10 | Other tax Credits | ($257,500) | ($257,500) | ($257,500) |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 15.00% | 15.00% | 15.00% |
| 12 | Provincial tax (%) | 11.31% | 11.31% | 11.31% |
| 13 | Total tax rate (%) | 26.31% | 26.31% | 26.31% |

**Notes**

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | Return |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $571,366,562 | 4.08% | $23,311,756 |
| 2 | Short-term Debt | 4.00% | $40,811,897 | 2.16% | $881,537 |
| 3 | **Total Debt** | 60.00% | $612,178,459 | 3.95% | $24,193,293 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $408,118,973 | 9.30% | $37,955,064 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $408,118,973 | 9.30% | $37,955,064 |
| 7 | **Total** | 100.00% | $1,020,297,432 | 6.09% | $62,148,357 |
| | | | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 0.00% | $ - | 0.00% | $ - |
| 2 | Short-term Debt | 0.00% | $ - | 0.00% | $ - |
| 3 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 4 | Common Equity | 0.00% | $ - | 0.00% | $ - |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 7 | **Total** | 0.00% | $1,020,297,432 | 0.00% | $ - |
| | | **Per Board Decision** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 8 | Long-term Debt | 0.00% | $ - | 4.08% | $ - |
| 9 | Short-term Debt | 0.00% | $ - | 2.16% | $ - |
| 10 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 11 | Common Equity | 0.00% | $ - | 9.30% | $ - |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 14 | **Total** | 0.00% | $1,020,297,432 | 0.00% | $ - |

**Notes**

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application: At Current Approved Rates | Initial Application: At Proposed Rates | At Current Approved Rates | At Proposed Rates | Per Board Decision: At Current Approved Rates | Per Board Decision: At Proposed Rates |
|---|---|---|---|---|---|---|---|
| 1 | Revenue Deficiency from Below | | $38,088,497 | | $5,810,282 | | $164,469,575 |
| 2 | Distribution Revenue | $158,309,877 | $158,309,877 | $158,309,877 | $190,588,091 | $ - | ($164,469,575) |
| 3 | Other Operating Revenue Offsets - net | $11,722,041 | $11,722,041 | $ - | $ - | $ - | $ - |
| 4 | **Total Revenue** | $170,031,918 | $208,120,414 | $158,309,877 | $196,398,374 | $ - | $ - |
| 5 | Operating Expenses | $139,897,846 | $139,897,846 | $139,897,846 | $139,897,846 | $139,897,846 | $139,897,846 |
| 6 | Deemed Interest Expense | $24,193,293 | $24,193,293 | $ - | $ - | $ - | $ - |
| 8 | **Total Cost and Expenses** | $164,091,139 | $164,091,139 | $139,897,846 | $139,897,846 | $139,897,846 | $139,897,846 |
| 9 | **Utility Income Before Income Taxes** | $5,940,779 | $44,029,275 | $18,412,031 | $56,500,528 | ($139,897,846) | ($139,897,846) |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($19,959,370) | ($19,959,370) | $68,837,332 | $68,837,332 | $68,837,332 | $68,837,332 |
| 11 | **Taxable Income** | ($14,018,591) | $24,069,906 | $87,249,363 | $125,337,859 | ($71,060,514) | ($71,060,514) |
| 12 | Income Tax Rate | 26.31% | 26.31% | 26.31% | 26.31% | 26.31% | 26.31% |
| 13 | **Income Tax on Taxable Income** | ($3,687,662) | $6,331,711 | $22,951,389 | $32,970,762 | ($18,692,830) | ($18,692,830) |
| 14 | **Income Tax Credits** | ($257,500) | ($257,500) | ($257,500) | ($257,500) | $ - | $ - |
| 15 | **Utility Net Income** | $9,885,941 | $37,955,064 | ($4,281,858) | ($145,972,057) | ($121,205,016) | ($145,972,057) |
| 16 | **Utility Rate Base** | $1,020,297,432 | $1,020,297,432 | $1,020,297,432 | $1,020,297,432 | $1,020,297,432 | $1,020,297,432 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **17** | Deemed Equity Portion of Rate Base | $408,118,973 | $408,118,973 | $ - | $ - | $ - | $ - |
| **18** | Income/(Equity Portion of Rate Base) | 2.42% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| **19** | Target Return - Equity on Rate Base | 9.30% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| **20** | Deficiency/Sufficiency in Return on Equity | -6.88% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **21** | Indicated Rate of Return | 3.34% | 6.09% | -0.42% | 0.00% | -11.88% | 0.00% |
| **22** | Requested Rate of Return on Rate Base | 6.09% | 6.09% | 0.00% | 0.00% | 0.00% | 0.00% |
| **23** | Deficiency/Sufficiency in Rate of Return | -2.75% | 0.00% | -0.42% | 0.00% | -11.88% | 0.00% |
| **24** | Target Return on Equity | $37,955,064 | $37,955,064 | $ - | $ - | $ - | $ - |
| **25** | Revenue Deficiency/(Sufficiency) | $28,069,124 | ($0) | $4,281,858 | $ - | $121,205,016 | $ - |
| **26** | **Gross Revenue Deficiency/(Sufficiency)** | $38,088,497 **(1)** | | $5,810,282 **(1)** | | $164,469,575 **(1)** | |

**Notes:**
**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $90,624,894 | | $90,624,894 | | $90,624,894 | |
| 2 | Amortization/Depreciation | $47,047,409 | | $47,047,409 | | $47,047,409 | |
| 3 | Property Taxes | $2,225,544 | | $2,225,544 | | $2,225,544 | |
| 5 | Income Taxes (Grossed up) | $6,074,211 | | $6,074,211 | | $6,074,211 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $24,193,293 | | $ - | | $ - | |
| | Return on Deemed Equity | $37,955,064 | | $ - | | $ - | |
| 8 | **Service Revenue Requirement (before Revenues)** | $208,120,415 | | $145,972,057 | | $145,972,057 | |
| 9 | Revenue Offsets | $ - | | $ - | | $ - | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $208,120,415 | | $145,972,057 | | $145,972,057 | |
| 11 | Distribution revenue | $196,398,374 | (2) | $ - | | $ - | |
| 12 | Other revenue | $11,722,041 | | $ - | | $ - | |
| 13 | **Total revenue** | $208,120,414 | | $ - | | $ - | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | ($0) | (1) | ($145,972,057) | (1) | ($145,972,057) | (1) |

**Notes**

**(1)** Line 11 - Line 8

(2) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $197,507,477

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Tracking Form

**The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)**
**Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.**
**(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)**
**(2) Short description of change, issue, etc.**

**60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.**

### *Summary of Proposed Changes*

| | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | Original Application | $ 62,148,357 | 6.09% | $1,020,297,432 | $1,040,409,211 | $ 147,738,108 | $ 47,047,409 | $ 6,074,211 | $ 90,624,894 | $ 208,120,415 | $ 11,722,041 | $ 208,120,415 | $ 38,088,497 |
| 1 | | | | | | | | | | | | | |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | RegulatoryAffairs@HydroOttawa.com |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers



**Notes:**

| | |
|---|---|
| **(1)** | Pale green cells represent inputs |
| **(2)** | Pale green boxes at the bottom of each page are for additional notes |
| **(3)** | Pale yellow cells represent drop-down lists |
| **(4)** | ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.*** |
| **(5)** | ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel*** |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Data Input (1)

| | | Initial Application | (2) | | | (6) | | Per Board Decision | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | | | |
| | Gross Fixed Assets (average) | $1,131,642,673 | | | $1,131,642,673 | | | $1,131,642,673 | |
| | Accumulated Depreciation (average) | ($226,411,300) | (5) | | ($226,411,300) | | | ($226,411,300) | |
| | Allowance for Working Capital: | | | | | | | | |
| | Controllable Expenses | $95,863,434 | | | $ 95,863,434 | | | $95,863,434 | |
| | Cost of Power | $928,733,588 | | | $ 928,733,588 | | | $928,733,588 | |
| | Working Capital Rate (%) | 14.20% | (9) | | 14.20% | (9) | | 14.20% | (9) |
| 2 | **Utility Income** | | | | | | | | |
| | Operating Revenues: | | | | | | | | |
| | Distribution Revenue at Current Rates | $158,868,175 | (10) | | | | | | |
| | Distribution Revenue at Proposed Rates | $206,014,098 | (11) | | | | | | |
| | Other Revenue: | | | | | | | | |
| | Specific Service Charges | $6,039,578 | | | | | | | |
| | Late Payment Charges | $720,000 | | | | | | | |
| | Other Distribution Revenue | $1,491,865 | | | | | | | |
| | Other Income and Deductions | $3,550,516 | | | | | | | |
| | Total Revenue Offsets | | (7) | | | | | | |
| | Operating Expenses: | | | | | | | | |
| | OM+A Expenses | $93,565,672 | | | $ 93,565,672 | | | $93,565,672 | |
| | Depreciation/Amortization | $48,948,694 | | | $ 48,948,694 | | | $48,948,694 | |
| | Property taxes | $2,297,762 | | | $ 2,297,762 | | | $2,297,762 | |
| | Other expenses | | | | | | | | |

| | | | |
|---|---|---|---|
| **3** | **Taxes/PILs** | | |
| | Taxable Income: | | |
| | Adjustments required to arrive at taxable income | ($14,483,338) | **(3)** |
| | Utility Income Taxes and Rates: | | |
| | Income taxes (not grossed up) | $6,239,454 | |
| | Income taxes (grossed up) | $8,472,655 | |
| | Federal tax (%) | 15.00% | |
| | Provincial tax (%) | 11.36% | |
| | Income Tax Credits | ($245,500) | |
| **4** | **Capitalization/Cost of Capital** | | |
| | Capital Structure: | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | **(8)** |
| | Common Equity Capitalization Ratio (%) | 40.0% | |
| | Prefered Shares Capitalization Ratio (%) | | |
| | | 100.0% | |
| | Cost of Capital | | |
| | Long-term debt Cost Rate (%) | 4.17% | |
| | Short-term debt Cost Rate (%) | 2.16% | |
| | Common Equity Cost Rate (%) | 9.30% | |
| | Prefered Shares Cost Rate (%) | | |

**(8)** **(8)**

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Revenue at current rates minus Transformer Ownership Allowance

(11) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $207,120,495

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $1,131,642,673 | | $ - | $1,131,642,673 | $ - | $1,131,642,673 |
| 2 | Accumulated Depreciation (average) | (3) | ($226,411,300) | | $ - | ($226,411,300) | $ - | ($226,411,300) |
| 3 | Net Fixed Assets (average) | (3) | $905,231,373 | | $ - | $905,231,373 | $ - | $905,231,373 |
| 4 | Allowance for Working Capital | (1) | $145,492,777 | | $ - | $145,492,777 | $ - | $145,492,777 |
| 5 | **Total Rate Base** | | $1,050,724,150 | | $ - | $1,050,724,150 | $ - | $1,050,724,150 |

(1) **Allowance for Working Capital - Derivation**

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $95,863,434 | $ - | $95,863,434 | $ - | $95,863,434 |
| 7 | Cost of Power | | $928,733,588 | $ - | $928,733,588 | $ - | $928,733,588 |
| 8 | Working Capital Base | | $1,024,597,022 | $ - | $1,024,597,022 | $ - | $1,024,597,022 |
| 9 | Working Capital Rate % | (2) | 14.20% | 0.00% | 14.20% | 0.00% | 14.20% |
| 10 | Working Capital Allowance | | $145,492,777 | $ - | $145,492,777 | $ - | $145,492,777 |

**Notes**

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Utility Income

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $206,014,098 | ($206,014,098) | $ - | $ - | $ - |
| 2 | Other Revenue | (1) | $11,801,959 | ($11,801,959) | $ - | $ - | $ - |
| 3 | Total Operating Revenues | | $217,816,057 | ($217,816,057) | $ - | $ - | $ - |
| | **Operating Expenses:** | | | | | | |
| 4 | OM+A Expenses | | $93,565,672 | $ - | $93,565,672 | $ - | $93,565,672 |
| 5 | Depreciation/Amortization | | $48,948,694 | $ - | $48,948,694 | $ - | $48,948,694 |
| 6 | Property taxes | | $2,297,762 | $ - | $2,297,762 | $ - | $2,297,762 |
| 7 | Capital taxes | | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $144,812,128 | $ - | $144,812,128 | $ - | $144,812,128 |
| 10 | Deemed Interest Expense | | $25,444,336 | ($25,444,336) | $ - | $ - | $ - |
| 11 | Total Expenses (lines 9 to 10) | | $170,256,464 | ($25,444,336) | $144,812,128 | $ - | $144,812,128 |
| 12 | **Utility income before income taxes** | | $47,559,593 | ($192,371,721) | ($144,812,128) | $ - | ($144,812,128) |
| 13 | Income taxes (grossed-up) | | $8,472,655 | $ - | $8,472,655 | $ - | $8,472,655 |
| 14 | **Utility net income** | | $39,086,939 | ($192,371,721) | ($153,284,783) | $ - | ($153,284,783) |

**Notes**

## Other Revenues / Revenue Offsets

| Notes | | | | | | |
|---|---|---|---|---|---|---|
| **(1)** | Specific Service Charges | $6,039,578 | | $ - | | $ - |
| | Late Payment Charges | $720,000 | | $ - | | $ - |
| | Other Distribution Revenue | $1,491,865 | | $ - | | $ - |
| | Other Income and Deductions | $3,550,516 | | $ - | | $ - |
| | Total Revenue Offsets | $11,801,959 | $ - | $ - | $ - | $ - |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $39,086,938 | $ - | $ - |
| 2 | Adjustments required to arrive at taxable utility income | ($14,483,338) | $ - | ($14,483,338) |
| 3 | Taxable income | $24,603,601 | $ - | ($14,483,338) |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $6,239,454 | $6,239,454 | $6,239,454 |
| 6 | Total taxes | $6,239,454 | $6,239,454 | $6,239,454 |
| 7 | Gross-up of Income Taxes | $2,233,201 | $2,233,201 | $2,233,201 |
| 8 | Grossed-up Income Taxes | $8,472,655 | $8,472,655 | $8,472,655 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $8,472,655 | $8,472,655 | $8,472,655 |
| 10 | Other tax Credits | ($245,500) | ($245,500) | ($245,500) |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 15.00% | 15.00% | 15.00% |
| 12 | Provincial tax (%) | 11.36% | 11.36% | 11.36% |
| 13 | Total tax rate (%) | 26.36% | 26.36% | 26.36% |

**Notes**

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | Return |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $588,405,524 | 4.17% | $24,536,510 |
| 2 | Short-term Debt | 4.00% | $42,028,966 | 2.16% | $907,826 |
| 3 | **Total Debt** | 60.00% | $630,434,490 | 4.04% | $25,444,336 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $420,289,660 | 9.30% | $39,086,938 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $420,289,660 | 9.30% | $39,086,938 |
| 7 | **Total** | 100.00% | $1,050,724,150 | 6.14% | $64,531,274 |
| | | | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 0.00% | $ - | 0.00% | $ - |
| 2 | Short-term Debt | 0.00% | $ - | 0.00% | $ - |
| 3 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 4 | Common Equity | 0.00% | $ - | 0.00% | $ - |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 7 | **Total** | 0.00% | $1,050,724,150 | 0.00% | $ - |
| | | **Per Board Decision** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 8 | Long-term Debt | 0.00% | $ - | 4.17% | $ - |
| 9 | Short-term Debt | 0.00% | $ - | 2.16% | $ - |
| 10 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 11 | Common Equity | 0.00% | $ - | 9.30% | $ - |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 14 | **Total** | 0.00% | $1,050,724,150 | 0.00% | $ - |

**Notes**

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| | | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates |
| 1 | Revenue Deficiency from Below | | $47,145,922 | | ($19,573,235) | | $144,812,128 |
| 2 | Distribution Revenue | $158,868,175 | $158,868,176 | $158,868,175 | $225,587,333 | $ - | ($144,812,128) |
| 3 | Other Operating Revenue Offsets - net | $11,801,959 | $11,801,959 | $ - | $ - | $ - | $ - |
| 4 | **Total Revenue** | $170,670,135 | $217,816,057 | $158,868,175 | $206,014,098 | $ - | $ - |
| 5 | Operating Expenses | $144,812,128 | $144,812,128 | $144,812,128 | $144,812,128 | $144,812,128 | $144,812,128 |
| 6 | Deemed Interest Expense | $25,444,336 | $25,444,336 | $ - | $ - | $ - | $ - |
| 8 | **Total Cost and Expenses** | $170,256,464 | $170,256,464 | $144,812,128 | $144,812,128 | $144,812,128 | $144,812,128 |
| 9 | **Utility Income Before Income Taxes** | $413,671 | $47,559,593 | $14,056,048 | $61,201,970 | ($144,812,128) | ($144,812,128) |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($14,483,338) | ($14,483,338) | ($14,483,338) | ($14,483,338) | $ - | $ - |
| 11 | **Taxable Income** | ($14,069,667) | $33,076,256 | ($427,290) | $46,718,632 | ($144,812,128) | ($144,812,128) |
| 12 | Income Tax Rate | 26.36% | 26.36% | 26.36% | 26.36% | 26.36% | 26.36% |
| 13 | **Income Tax on Taxable Income** | ($3,708,447) | $8,718,155 | ($112,624) | $12,313,978 | ($38,169,211) | ($38,169,211) |
| 14 | **Income Tax Credits** | ($245,500) | ($245,500) | ($245,500) | ($245,500) | $ - | $ - |
| 15 | **Utility Net Income** | $4,367,618 | $39,086,939 | $14,414,172 | ($153,284,783) | ($106,642,917) | ($153,284,783) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 16 | **Utility Rate Base** | $1,050,724,150 | $1,050,724,150 | $1,050,724,150 | $1,050,724,150 | $1,050,724,150 | $1,050,724,150 |
| 17 | Deemed Equity Portion of Rate Base | $420,289,660 | $420,289,660 | $ - | $ - | $ - | $ - |
| 18 | Income/(Equity Portion of Rate Base) | 1.04% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 19 | Target Return - Equity on Rate Base | 9.30% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 20 | Deficiency/Sufficiency in Return on Equity | -8.26% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 21 | Indicated Rate of Return | 2.84% | 6.14% | 1.37% | 0.00% | -10.15% | 0.00% |
| 22 | Requested Rate of Return on Rate Base | 6.14% | 6.14% | 0.00% | 0.00% | 0.00% | 0.00% |
| 23 | Deficiency/Sufficiency in Rate of Return | -3.30% | 0.00% | 1.37% | 0.00% | -10.15% | 0.00% |
| 24 | Target Return on Equity | $39,086,938 | $39,086,938 | $ - | $ - | $ - | $ - |
| 25 | Revenue Deficiency/(Sufficiency) | $34,719,321 | $0 | ($14,414,172) | $ - | $106,642,917 | $ - |
| 26 | **Gross Revenue Deficiency/(Sufficiency)** | $47,145,922 **(1)** | | ($19,573,235) **(1)** | | $144,812,128 **(1)** | |

**Notes:**
**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $93,565,672 | | $93,565,672 | | $93,565,672 | |
| 2 | Amortization/Depreciation | $48,948,694 | | $48,948,694 | | $48,948,694 | |
| 3 | Property Taxes | $2,297,762 | | $2,297,762 | | $2,297,762 | |
| 5 | Income Taxes (Grossed up) | $8,472,655 | | $8,472,655 | | $8,472,655 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $25,444,336 | | $ - | | $ - | |
| | Return on Deemed Equity | $39,086,938 | | $ - | | $ - | |
| 8 | **Service Revenue Requirement (before Revenues)** | $217,816,057 | | $153,284,783 | | $153,284,783 | |
| 9 | Revenue Offsets | $ - | | $ - | | $ - | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $217,816,057 | | $153,284,783 | | $153,284,783 | |
| 11 | Distribution revenue | $206,014,098 | (2) | $ - | | $ - | |
| 12 | Other revenue | $11,801,959 | | $ - | | $ - | |
| 13 | **Total revenue** | $217,816,057 | | $ - | | $ - | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $0 | (1) | ($153,284,783) | (1) | ($153,284,783) | (1) |

**Notes**

**(1)** Line 11 - Line 8

(2) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $207,120,495

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Tracking Form

**The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)**
**Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.**
**[1] Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)**
**[2] Short description of change, issue, etc.**

**60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.**

### *Summary of Proposed Changes*

| | | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | | Original Application | $ 64,531,274 | 6.14% | $1,050,724,150 | $1,024,597,022 | $ 145,492,777 | $ 48,948,694 | $ 8,472,655 | $ 93,565,672 | $ 217,816,057 | $ 11,801,959 | $ 217,816,057 | $ 47,145,922 |
| 1 | | | | | | | | | | | | | | |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | |
| **Assigned EB Number** | EB-2015-0004 |
| **Name and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | RegulatoryAffairs@HydroOttawa.com |



*While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.*

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers



**Notes:**

| | |
|---|---|
| **(1)** | Pale green cells represent inputs |
| **(2)** | Pale green boxes at the bottom of each page are for additional notes |
| **(3)** | Pale yellow cells represent drop-down lists |
| **(4)** | ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.*** |
| **(5)** | ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel*** |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Data Input (1)

| | | Initial Application | (2) | | (6) | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | |
| | Gross Fixed Assets (average) | $1,221,017,793 | | $1,221,017,793 | | $1,221,017,793 | |
| | Accumulated Depreciation (average) | ($275,019,996) | (5) | ($275,019,996) | | ($275,019,996) | |
| | Allowance for Working Capital: | | | | | | |
| | Controllable Expenses | $98,974,203 | | $ 98,974,203 | | $98,974,203 | |
| | Cost of Power | $945,198,501 | | $ 945,198,501 | | $945,198,501 | |
| | Working Capital Rate (%) | 14.20% | (9) | 14.20% | (9) | 14.20% | (9) |
| 2 | **Utility Income** | | | | | | |
| | Operating Revenues: | | | | | | |
| | Distribution Revenue at Current Rates | $159,356,002 | (10) | | | | |
| | Distribution Revenue at Proposed Rates | $212,531,699 | (11) | | | | |
| | Other Revenue: | | | | | | |
| | Specific Service Charges | $6,064,123 | | | | | |
| | Late Payment Charges | $720,000 | | | | | |
| | Other Distribution Revenue | $1,529,669 | | | | | |
| | Other Income and Deductions | $3,584,041 | | | | | |
| | Total Revenue Offsets | | (7) | | | | |
| | Operating Expenses: | | | | | | |
| | OM+A Expenses | $96,601,878 | | $ 96,601,878 | | $96,601,878 | |
| | Depreciation/Amortization | $50,294,804 | | $ 50,294,804 | | $50,294,804 | |
| | Property taxes | $2,372,325 | | $ 2,372,325 | | $2,372,325 | |
| | Other expenses | | | | | | |
| 3 | **Taxes/PILs** | | | | | | |
| | Taxable Income: | | | | | | |

| | | |
|---|---|---|
| Adjustments required to arrive at taxable income | ($18,604,719) | (3) |
| Utility Income Taxes and Rates: | | |
| Income taxes (not grossed up) | $5,588,566 | |
| Income taxes (grossed up) | $7,587,145 | |
| Federal tax (%) | 15.00% | |
| Provincial tax (%) | 11.34% | |
| Income Tax Credits | ($233,500) | |

## 4 Capitalization/Cost of Capital

| | | | | |
|---|---|---|---|---|
| Capital Structure: | | | | |
| Long-term debt Capitalization Ratio (%) | 56.0% | | | |
| Short-term debt Capitalization Ratio (%) | 4.0% | (8) | (8) | (8) |
| Common Equity Capitalization Ratio (%) | 40.0% | | | |
| Prefered Shares Capitalization Ratio (%) | 0.0% | | | |
| | 100.0% | | | |

| | |
|---|---|
| Cost of Capital | |
| Long-term debt Cost Rate (%) | 4.23% |
| Short-term debt Cost Rate (%) | 2.16% |
| Common Equity Cost Rate (%) | 9.30% |
| Prefered Shares Cost Rate (%) | 0.00% |

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Revenue at current rates minus Transformer Ownership Allowance

(11) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $213,637,062

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $1,221,017,793 | $ - | $1,221,017,793 | $ - | $1,221,017,793 |
| 2 | Accumulated Depreciation (average) | (3) | ($275,019,996) | $ - | ($275,019,996) | $ - | ($275,019,996) |
| 3 | Net Fixed Assets (average) | (3) | $945,997,797 | $ - | $945,997,797 | $ - | $945,997,797 |
| 4 | Allowance for Working Capital | (1) | $148,272,524 | $ - | $148,272,524 | $ - | $148,272,524 |
| 5 | **Total Rate Base** | | $1,094,270,321 | $ - | $1,094,270,321 | $ - | $1,094,270,321 |

### (1) Allowance for Working Capital - Derivation

| Line No. | Particulars | | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $98,974,203 | $ - | $98,974,203 | $ - | $98,974,203 |
| 7 | Cost of Power | | $945,198,501 | $ - | $945,198,501 | $ - | $945,198,501 |
| 8 | Working Capital Base | | $1,044,172,704 | $ - | $1,044,172,704 | $ - | $1,044,172,704 |
| 9 | Working Capital Rate % | (2) | 14.20% | 0.00% | 14.20% | 0.00% | 14.20% |
| 10 | Working Capital Allowance | | $148,272,524 | $ - | $148,272,524 | $ - | $148,272,524 |

**Notes**

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Utility Income

| Line No. | Particulars | Initial Application | | | | Per Board Decision |
|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | $212,531,699 | ($212,531,699) | $ - | $ - | $ - |
| 2 | Other Revenue (1) | $11,897,833 | ($11,897,833) | $ - | $ - | $ - |
| 3 | Total Operating Revenues | $224,429,532 | ($224,429,532) | $ - | $ - | $ - |
| | **Operating Expenses:** | | | | | |
| 4 | OM+A Expenses | $96,601,878 | $ - | $96,601,878 | $ - | $96,601,878 |
| 5 | Depreciation/Amortization | $50,294,804 | $ - | $50,294,804 | $ - | $50,294,804 |
| 6 | Property taxes | $2,372,325 | $ - | $2,372,325 | $ - | $2,372,325 |
| 7 | Capital taxes | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | $149,269,006 | $ - | $149,269,006 | $ - | $149,269,006 |
| 10 | Deemed Interest Expense | $26,866,525 | ($26,866,525) | $ - | $ - | $ - |
| 11 | Total Expenses (lines 9 to 10) | $176,135,531 | ($26,866,525) | $149,269,006 | $ - | $149,269,006 |
| 12 | **Utility income before income taxes** | $48,294,001 | ($197,563,007) | ($149,269,006) | $ - | ($149,269,006) |
| 13 | Income taxes (grossed-up) | $7,587,145 | $ - | $7,587,145 | $ - | $7,587,145 |
| 14 | **Utility net income** | $40,706,856 | ($197,563,007) | ($156,856,151) | $ - | ($156,856,151) |

**Notes**

## Other Revenues / Revenue Offsets

| Notes | | | | | | |
|---|---|---|---|---|---|---|
| **(1)** | Specific Service Charges | $6,064,123 | | $ - | | $ - |
| | Late Payment Charges | $720,000 | | $ - | | $ - |
| | Other Distribution Revenue | $1,529,669 | | $ - | | $ - |
| | Other Income and Deductions | $3,584,041 | | $ - | | $ - |
| | Total Revenue Offsets | $11,897,833 | $ - | $ - | $ - | $ - |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $40,706,856 | $ - | $ - |
| 2 | Adjustments required to arrive at taxable utility income | ($18,604,719) | $ - | ($18,604,719) |
| 3 | Taxable income | $22,102,137 | $ - | ($18,604,719) |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $5,588,566 | $5,588,566 | $5,588,566 |
| 6 | Total taxes | $5,588,566 | $5,588,566 | $5,588,566 |
| 7 | Gross-up of Income Taxes | $1,998,579 | $1,998,579 | $1,998,579 |
| 8 | Grossed-up Income Taxes | $7,587,145 | $7,587,145 | $7,587,145 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $7,587,145 | $7,587,145 | $7,587,145 |
| 10 | Other tax Credits | ($233,500) | ($233,500) | ($233,500) |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 15.00% | 15.00% | 15.00% |
| 12 | Provincial tax (%) | 11.34% | 11.34% | 11.34% |
| 13 | Total tax rate (%) | 26.34% | 26.34% | 26.34% |

**Notes**

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | Return |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $612,791,380 | 4.23% | $25,921,075 |
| 2 | Short-term Debt | 4.00% | $43,770,813 | 2.16% | $945,450 |
| 3 | **Total Debt** | 60.00% | $656,562,192 | 4.09% | $26,866,525 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $437,708,128 | 9.30% | $40,706,856 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $437,708,128 | 9.30% | $40,706,856 |
| 7 | **Total** | 100.00% | $1,094,270,321 | 6.18% | $67,573,381 |
| | | | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 0.00% | $ - | 0.00% | $ - |
| 2 | Short-term Debt | 0.00% | $ - | 0.00% | $ - |
| 3 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 4 | Common Equity | 0.00% | $ - | 0.00% | $ - |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 7 | **Total** | 0.00% | $1,094,270,321 | 0.00% | $ - |
| | | **Per Board Decision** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 8 | Long-term Debt | 0.00% | $ - | 4.23% | $ - |
| 9 | Short-term Debt | 0.00% | $ - | 2.16% | $ - |
| 10 | **Total Debt** | 0.00% | $ - | 0.00% | $ - |
| | **Equity** | | | | |
| 11 | Common Equity | 0.00% | $ - | 9.30% | $ - |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 0.00% | $ - | 0.00% | $ - |
| 14 | **Total** | 0.00% | $1,094,270,321 | 0.00% | $ - |

**Notes**

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| | | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates | At Current Approved Rates | At Proposed Rates |
| 1 | Revenue Deficiency from Below | | $53,175,698 | | ($17,057,405) | | $149,269,006 |
| 2 | Distribution Revenue | $159,356,002 | $159,356,002 | $159,356,002 | $229,589,104 | $ - | ($149,269,006) |
| 3 | Other Operating Revenue Offsets - net | $11,897,833 | $11,897,833 | $ - | $ - | $ - | $ - |
| 4 | **Total Revenue** | $171,253,835 | $224,429,532 | $159,356,002 | $212,531,699 | $ - | $ - |
| 5 | Operating Expenses | $149,269,006 | $149,269,006 | $149,269,006 | $149,269,006 | $149,269,006 | $149,269,006 |
| 6 | Deemed Interest Expense | $26,866,525 | $26,866,525 | $ - | $ - | $ - | $ - |
| 8 | **Total Cost and Expenses** | $176,135,531 | $176,135,531 | $149,269,006 | $149,269,006 | $149,269,006 | $149,269,006 |
| 9 | **Utility Income Before Income Taxes** | ($4,881,697) | $48,294,001 | $10,086,995 | $63,262,693 | ($149,269,006) | ($149,269,006) |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($18,604,719) | ($18,604,719) | ($18,604,719) | ($18,604,719) | $ - | $ - |
| 11 | **Taxable Income** | ($23,486,415) | $29,689,282 | ($8,517,723) | $44,657,974 | ($149,269,006) | ($149,269,006) |
| 12 | Income Tax Rate | 26.34% | 26.34% | 26.34% | 26.34% | 26.34% | 26.34% |
| 13 | **Income Tax on Taxable Income** | ($6,186,708) | $7,820,645 | ($2,243,708) | $11,763,645 | ($39,319,911) | ($39,319,911) |
| 14 | **Income Tax Credits** | ($233,500) | ($233,500) | ($233,500) | ($233,500) | $ - | $ - |
| 15 | **Utility Net Income** | $1,538,511 | $40,706,856 | $12,564,204 | ($156,856,151) | ($109,949,096) | ($156,856,151) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 16 | **Utility Rate Base** | $1,094,270,321 | $1,094,270,321 | $1,094,270,321 | $1,094,270,321 | $1,094,270,321 | $1,094,270,321 |
| 17 | Deemed Equity Portion of Rate Base | $437,708,128 | $437,708,128 | $ - | $ - | $ - | $ - |
| 18 | Income/(Equity Portion of Rate Base) | 0.35% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 19 | Target Return - Equity on Rate Base | 9.30% | 9.30% | 0.00% | 0.00% | 0.00% | 0.00% |
| 20 | Deficiency/Sufficiency in Return on Equity | -8.95% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 21 | Indicated Rate of Return | 2.60% | 6.18% | 1.15% | 0.00% | -10.05% | 0.00% |
| 22 | Requested Rate of Return on Rate Base | 6.18% | 6.18% | 0.00% | 0.00% | 0.00% | 0.00% |
| 23 | Deficiency/Sufficiency in Rate of Return | -3.58% | 0.00% | 1.15% | 0.00% | -10.05% | 0.00% |
| 24 | Target Return on Equity | $40,706,856 | $40,706,856 | $ - | $ - | $ - | $ - |
| 25 | Revenue Deficiency/(Sufficiency) | $39,168,345 | $0 | ($12,564,204) | $ - | $109,949,096 | $ - |
| 26 | **Gross Revenue Deficiency/(Sufficiency)** | $53,175,698 **(1)** | | ($17,057,405) **(1)** | | $149,269,006 **(1)** | |

**Notes:**
**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $96,601,878 | | $96,601,878 | | $96,601,878 | |
| 2 | Amortization/Depreciation | $50,294,804 | | $50,294,804 | | $50,294,804 | |
| 3 | Property Taxes | $2,372,325 | | $2,372,325 | | $2,372,325 | |
| 5 | Income Taxes (Grossed up) | $7,587,145 | | $7,587,145 | | $7,587,145 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $26,866,525 | | $ - | | $ - | |
| | Return on Deemed Equity | $40,706,856 | | $ - | | $ - | |
| 8 | **Service Revenue Requirement (before Revenues)** | $224,429,532 | | $156,856,151 | | $156,856,151 | |
| 9 | Revenue Offsets | $ - | | $ - | | $ - | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $224,429,532 | | $156,856,151 | | $156,856,151 | |
| 11 | Distribution revenue | $212,531,699 | (2) | $ - | | $ - | |
| 12 | Other revenue | $11,897,833 | | $ - | | $ - | |
| 13 | **Total revenue** | $224,429,532 | | $ - | | $ - | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $0 | (1) | ($156,856,151) | (1) | ($156,856,151) | (1) |

**Notes**
(1) Line 11 - Line 8
(2) Distrubution Revenue not including Transformer Ownership Allowance, Total Revenue Requirement is $213,637,062

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2015 Filers

## Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

### *Summary of Proposed Changes*

| | | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | | Original Application | $ 67,573,381 | 6.18% | $1,094,270,321 | $1,044,172,704 | $ 148,272,524 | $ 50,294,804 | $ 7,587,145 | $ 96,601,878 | $ 224,429,532 | $ 11,897,833 | $ 224,429,532 | $ 53,175,698 |
| 1 | | | | | | | | | | | | | | |

# COST ALLOCATION STUDY

Hydro Ottawa Limited ("Hydro Ottawa") engaged Elenchus to undertake a Cost Allocation Study using the Ontario Energy Board's ("the Board") approved model. Please find details of this study in attachment G-1(A), Elenchus' Report titled "Hydro Ottawa 2016-2020 CA – Custom IR". Hydro Ottawa has also included live Excel spreadsheets for each of its test years 2016 through 2020, excel file G-1 (B through F). PDF copies of the required pages are also available as attachments G-1 (B through F).

Per the Boards filing requirements Hydro Ottawa has completed Appendix 2-P it is attached to this exhibit in a PDF version.

Hydro Ottawa's Cost allocation study indicated that two rate classes required adjustments to bring them into the Board-approved ranges. Sentinel Lights was outside its lower range while Unmetered Scattered Load ("USL") was outside its upper range.

In Hydro Ottawa's 2012 rate application EB-2011-0054 is was stated that it was not possible to bring the Sentinel Lights class revenue to cost ratio to 80% without creating a large bill impact for the customer and proposed incremental increases. Hydro Ottawa proposes to continue to make incremental adjustment every year to the Sentinel Lights class as part of this application. Appendix 2-P outlines the yearly adjustments starting with an approximate 5% increase in 2016.

Hydro Ottawa has adjusted USL to bring this class into the Board-approved ranges. This was achieved by first increasing Sentinel Lights by approximately 5% and then proportioning the remaining revenue requirement among the other classes below 100% revenue to cost ratio.

Please refer to Appendix 2-P for final proposed revenue to cost ratio.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | G |
| **Tab:** | 1 |
| **Schedule:** | 1 |
| **Page:** | 1 |
| | |
| **Date:** | ORIGINAL |

# Appendix 2-P
# Cost Allocation

Please complete the following four tables.

**A) Allocated Costs**

| Classes | Costs Allocated from Previous Study | % | Costs Allocated in 2016 Test Year Study (Column 7A) | % | Costs Allocated in 2017 Test Year Study (Column 7A) | % | Costs Allocated in 2018 Test Year Study (Column 7A) | % | Costs Allocated in 2019 Test Year Study (Column 7A) | % | Costs Allocated in 2020 Test Year Study (Column 7A) | % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | $ 94,436,258 | 56.15% | $ 101,241,491 | 54.06% | $ 106,345,499 | 53.92% | $ 112,032,332 | 53.83% | $ 117,177,906 | 53.80% | $ 120,713,953 | 53.79% |
| GS < 50 kW | $ 19,093,962 | 11.35% | $ 19,819,301 | 10.58% | $ 20,764,678 | 10.53% | $ 21,741,761 | 10.45% | $ 22,589,550 | 10.37% | $ 23,125,641 | 10.30% |
| GS > 50 kW < GS 1,500 | $ 39,359,863 | 23.40% | $ 45,860,732 | 24.49% | $ 48,217,445 | 24.45% | $ 50,763,713 | 24.39% | $ 52,968,216 | 24.32% | $ 54,402,930 | 24.24% |
| GS > 1,500 '4,999 kW | $ 7,805,712 | 4.64% | $ 11,093,288 | 5.92% | $ 12,029,406 | 6.10% | $ 13,066,436 | 6.28% | $ 14,029,936 | 6.44% | $ 14,805,926 | 6.60% |
| Large User | $ 5,754,313 | 3.42% | $ 7,272,098 | 3.88% | $ 7,761,426 | 3.94% | $ 8,265,710 | 3.97% | $ 8,680,762 | 3.99% | $ 8,938,779 | 3.98% |
| Street Lighting | $ 1,183,502 | 0.70% | $ 1,393,557 | 0.74% | $ 1,492,351 | 0.76% | $ 1,590,510 | 0.76% | $ 1,677,974 | 0.77% | $ 1,730,916 | 0.77% |
| Sentinel Lighting | $ 10,894 | 0.01% | $ 9,263 | 0.00% | $ 8,940 | 0.00% | $ 8,558 | 0.00% | $ 8,092 | 0.00% | $ 7,476 | 0.00% |
| Unmetered Scattered Load (USL) | $ 470,639 | 0.28% | $ 517,197 | 0.28% | $ 548,385 | 0.28% | $ 579,662 | 0.28% | $ 607,594 | 0.28% | $ 625,501 | 0.28% |
| Standby | $ 58,465 | 0.03% | $ 62,223 | 0.03% | $ 66,948 | 0.03% | $ 71,732 | 0.03% | $ 76,027 | 0.03% | $ 78,410 | 0.03% |
| | | 0.00% | | 0.00% | | 0.00% | | 0.00% | | 0.00% | | 0.00% |
| | | 0.00% | | 0.00% | | 0.00% | | 0.00% | | 0.00% | | 0.00% |
| **Total** | $ 168,173,609 | 100.00% | $ 187,269,148 | 100.00% | $ 197,235,078 | 100.00% | $ 208,120,414 | 100.00% | $ 217,816,057 | 100.00% | $ 224,429,532 | 100.00% |

**Notes**

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage

**B) Calculated Class Revenues**

## 2016

| Classes (same as previous table) | Column 7B | Column 7C | Column 7D | Column 7E |
|---|---|---|---|---|
| | Load Forecast (LF) X current | L.F. X current approved rates | LF X proposed rates | Miscellaneous Revenue |
| Residential | $ 86,359,164 | $ 95,819,638 | $ 95,819,638 | $ 7,835,113 |
| GS < 50 kW | $ 20,171,698 | $ 22,381,467 | $ 22,381,467 | $ 1,244,861 |
| GS > 50 kW < GS 1,500 | $ 34,607,039 | $ 38,398,171 | $ 38,404,411 | $ 1,877,505 |
| GS > 1,500 '4,999 kW | $ 10,061,938 | $ 11,164,203 | $ 11,164,203 | $ 425,511 |
| Large User | $ 5,599,620 | $ 6,213,047 | $ 6,214,047 | $ 241,865 |
| Street Lighting | $ 872,268 | $ 967,824 | $ 967,982 | $ 52,382 |
| Sentinel Lighting | $ 3,902 | $ 4,330 | $ 4,751 | $ 807 |
| Unmetered Scattered Load (USL) | $ 549,494 | $ 609,690 | $ 601,871 | $ 18,765 |
| Standby | $ 10,131 | $ 11,240 | $ 11,240 | $ 2,729 |
| | | | | |
| 0 | | | | |
| **Total** | $ 158,235,254 | $ 175,569,610 | $ 175,569,610 | $ 11,699,538 |

## 2017

| Classes (same as previous table) | Column 7B | Column 7C | Column 7D | Column 7E |
|---|---|---|---|---|
| | Load Forecast (LF) X current | L.F. X current approved rates | LF X proposed rates | Miscellaneous Revenue |
| Residential | $ 86,397,220 | $ 101,610,008 | $ 101,651,762 | $ 7,737,562 |
| GS < 50 kW | $ 19,995,810 | $ 23,516,665 | $ 23,521,272 | $ 1,220,652 |
| GS > 50 kW < GS 1,500 | $ 34,281,385 | $ 40,317,638 | $ 40,295,883 | $ 1,854,678 |
| GS > 1,500 '4,999 kW | $ 10,164,325 | $ 11,954,055 | $ 11,944,686 | $ 433,003 |
| Large User | $ 5,594,105 | $ 6,579,113 | $ 6,575,306 | $ 244,169 |
| Street Lighting | $ 872,268 | $ 1,025,857 | $ 1,025,267 | $ 52,851 |
| Sentinel Lighting | $ 3,776 | $ 4,441 | $ 4,867 | $ 730 |
| Unmetered Scattered Load (USL) | $ 552,900 | $ 650,254 | $ 638,998 | $ 18,722 |
| Standby | $ 10,131 | $ 11,914 | $ 11,905 | $ 2,765 |
| 0 | | | | |
| 0 | | | | |
| **Total** | $ 157,871,920 | $ 185,669,946 | $ 185,669,946 | $ 11,565,131 |

## 2018

| Classes (same as previous table) | Column 7B | Column 7C | Column 7D | Column 7E |
|---|---|---|---|---|
| | Load Forecast (LF) X current | L.F. X current approved rates | LF X proposed rates | Miscellaneous Revenue |
| Residential | $ 87,038,947 | $ 107,978,566 | $ 108,025,504 | $ 7,848,216 |
| GS < 50 kW | $ 19,869,160 | $ 24,649,235 | $ 24,668,344 | $ 1,230,322 |
| GS > 50 kW < GS 1,500 | $ 34,078,185 | $ 42,276,633 | $ 42,258,136 | $ 1,870,670 |
| GS > 1,500 '4,999 kW | $ 10,293,812 | $ 12,770,272 | $ 12,747,778 | $ 448,049 |
| Large User | $ 5,589,542 | $ 6,934,260 | $ 6,924,176 | $ 248,503 |
| Street Lighting | $ 872,268 | $ 1,082,117 | $ 1,080,547 | $ 53,791 |
| Sentinel Lighting | $ 3,651 | $ 4,529 | $ 4,965 | $ 681 |
| Unmetered Scattered Load (USL) | $ 556,350 | $ 690,195 | $ 676,378 | $ 18,989 |
| Standby | $ 10,131 | $ 12,568 | $ 12,547 | $ 2,820 |
| 0 | | | | |
| 0 | | | | |
| **Total** | $ 158,312,045 | $ 196,398,374 | $ 196,398,374 | $ 11,722,041 |

**2019**

| Classes (same as previous table) | Column 7B<br>Load Forecast (LF) X current | Column 7C<br>L.F. X current approved rates | Column 7D<br>LF X proposed rates | Column 7E<br>Miscellaneous Revenue |
|---|---|---|---|---|
| Residential | $ 87,685,777 | $ 113,705,968 | $ 113,758,962 | $ 7,911,040 |
| GS < 50 kW | $ 19,773,873 | $ 25,641,643 | $ 25,676,389 | $ 1,232,430 |
| GS > 50 kW < GS 1,500 | $ 33,951,625 | $ 44,026,552 | $ 44,026,023 | $ 1,872,837 |
| GS > 1,500 '4,999 kW | $ 10,432,118 | $ 13,527,782 | $ 13,478,300 | $ 459,183 |
| Large User | $ 5,581,227 | $ 7,237,420 | $ 7,218,471 | $ 249,729 |
| Street Lighting | $ 872,268 | $ 1,131,109 | $ 1,128,045 | $ 54,190 |
| Sentinel Lighting | $ 3,525 | $ 4,571 | $ 4,983 | $ 628 |
| Unmetered Scattered Load (USL) | $ 559,799 | $ 725,916 | $ 709,828 | $ 19,076 |
| Standby | $ 10,131 | $ 13,137 | $ 13,098 | $ 2,847 |
| 0 | | | | |
| 0 | | | | |
| **Total** | $ 158,870,343 | $ 206,014,098 | $ 206,014,098 | $ 11,801,959 |

**2020**

| Classes (same as previous table) | Column 7B<br>Load Forecast (LF) X current | Column 7C<br>L.F. X current approved rates | Column 7D<br>LF X proposed rates | Column 7E<br>Miscellaneous Revenue |
|---|---|---|---|---|
| Residential | $ 88,188,231 | $ 117,614,269 | $ 117,718,137 | $ 7,980,775 |
| GS < 50 kW | $ 19,702,481 | $ 26,276,669 | $ 26,317,949 | $ 1,236,650 |
| GS > 50 kW < GS 1,500 | $ 33,865,217 | $ 45,165,128 | $ 45,181,271 | $ 1,880,321 |
| GS > 1,500 '4,999 kW | $ 10,582,413 | $ 14,113,479 | $ 14,008,944 | $ 471,730 |
| Large User | $ 5,570,474 | $ 7,429,191 | $ 7,398,161 | $ 251,119 |
| Street Lighting | $ 872,268 | $ 1,163,321 | $ 1,158,045 | $ 54,566 |
| Sentinel Lighting | $ 3,399 | $ 4,533 | $ 4,906 | $ 576 |
| Unmetered Scattered Load (USL) | $ 563,555 | $ 751,599 | $ 730,841 | $ 19,234 |
| Standby | $ 10,131 | $ 13,511 | $ 13,445 | $ 2,862 |
| 0 | | | | |
| 0 | | | | |
| **Total** | $ 159,358,170 | $ 212,531,699 | $ 212,531,699 | $ 11,897,833 |

**Notes:**

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

**C) Rebalancing Revenue-to-Cost (R/C) Ratios**

| Class | Previously Approved Ratios Most Recent Year: 2012 | 2016 Status Quo Ratios (7C + 7E) / (7A) | 2016 Proposed Ratios (7D + 7E) / (7A) | 2017 Status Quo Ratios (7C + 7E) / (7A) | 2017 Proposed Ratios (7D + 7E) / (7A) | 2018 Status Quo Ratios (7C + 7E) / (7A) | 2018 Proposed Ratios (7D + 7E) / (7A) | 2019 Status Quo Ratios (7C + 7E) / (7A) | 2019 Proposed Ratios (7D + 7E) / (7A) | 2020 Status Quo Ratios (7C + 7E) / (7A) | 2020 Proposed Ratios (7D + 7E) / (7A) | Policy Range |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | % | % | % | % | % | % | % | % | % | % | % | % |
| Residential | 97.00 | 102.38 | 102.38 | 102.82 | 102.86 | 103.39 | 103.43 | 103.79 | 103.83 | 104.04 | 104.13 | 85 - 115 |
| GS < 50 kW | 114.00 | 119.21 | 119.21 | 119.13 | 119.15 | 119.03 | 119.12 | 118.97 | 119.12 | 118.97 | 119.15 | 80 - 120 |
| GS > 50 kW < GS 1,500 | 95.00 | 87.82 | 87.84 | 87.46 | 87.42 | 86.97 | 86.93 | 86.65 | 86.65 | 86.48 | 86.51 | 80 - 120 |
| GS > 1,500 '4,999 kW | 120.00 | 104.48 | 104.48 | 102.97 | 102.90 | 101.16 | 100.99 | 99.69 | 99.34 | 98.51 | 97.80 | 80 - 120 |
| Large User | 107.00 | 88.76 | 88.78 | 87.91 | 87.86 | 86.90 | 86.78 | 86.25 | 86.03 | 85.92 | 85.57 | 85 - 115 |
| Street Lighting | 76.50 | 73.21 | 73.22 | 72.28 | 72.24 | 71.42 | 71.32 | 70.64 | 70.46 | 70.36 | 70.06 | 70 - 120 |
| Sentinel Lighting | 50.00 | 55.45 | 60.00 | 57.84 | 62.60 | 60.87 | 65.97 | 64.24 | 69.33 | 68.34 | 73.32 | 80 - 120 |
| Unmetered Scattered Load (USL) | 119.00 | 121.51 | 120.00 | 121.99 | 119.94 | 122.34 | 119.96 | 122.61 | 119.97 | 123.23 | 119.92 | 80 - 120 |
| Standby | 230.00 | 22.45 | 22.45 | 21.93 | 21.91 | 21.45 | 21.42 | 21.02 | 20.97 | 20.88 | 20.80 | N/A |
| | | | | | | | | | | | | |
| 0 | | | | | | | | | | | | |

**Notes**

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

**D) Proposed Revenue-to-Cost Ratios**

| Class | Proposed Revenue-to-Cost Ratios 2016 | 2017 | 2018 | 2019 | 2020 | Policy Range |
|---|---|---|---|---|---|---|
| | % | % | % | % | % | % |
| Residential | 102.38 | 102.86 | 103.43 | 103.83 | 104.13 | 85 - 115 |
| GS < 50 kW | 119.21 | 119.15 | 119.12 | 119.12 | 119.15 | 80 - 120 |
| GS > 50 kW < GS 1,500 | 87.84 | 87.42 | 86.93 | 86.65 | 86.51 | 80 - 120 |
| GS > 1,500 '4,999 kW | 104.48 | 102.90 | 100.99 | 99.34 | 97.80 | 80 - 120 |
| Large User | 88.78 | 87.86 | 86.78 | 86.03 | 85.57 | 85 - 115 |
| Street Lighting | 73.22 | 72.24 | 71.32 | 70.46 | 70.06 | 70 - 120 |
| Sentinel Lighting | 60.00 | 62.60 | 65.97 | 69.33 | 73.32 | 80 - 120 |
| Unmetered Scattered Load (USL) | 120.00 | 119.94 | 119.96 | 119.97 | 119.92 | 80 - 120 |
| Standby | 22.45 | 21.91 | 21.42 | 20.97 | 20.80 | N/A |
| | | | | | | 0 |
| 0 | | | | | | |

**Note**

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2014. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

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# Hydro Ottawa 2016-2020 CA - Custom IR

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Hydro Ottawa

17/04/2015

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# 1 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") has prepared its 2016-2020 Custom IR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the July 18, 2014 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements").

Section 2.10 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements on page 48 state:

> *A completed cost allocation study using the Board-approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Microsoft Excel spreadsheets. The most current update of the model (version 3.2) will be available on the Board's web site. Appendix 2-P must also be completed.* [1]

Hydro Ottawa asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation study for its 2016-2020 Custom IR rate application.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some revenue to cost ratio ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues.

## 1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on 2016-2020 forward test years, the primary purpose of the cost allocation study ("CA Study") is to determine the

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1 *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications (July 18, 2014), p. 48.*

2 John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Hydro Ottawa and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

3 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, Hydro Ottawa's prospective year CA Study for the 2016-2020 test years is based on an allocation of the 2016-2020 test year costs (i.e., the 2016-2020 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

## 1.2 HYDRO OTTAWA'S 2012 COST ALLOCATION

The last cost allocation study filed by Hydro Ottawa was in 2011 in Proceeding EB-2011-0054, was based on the v 2.0 Cost Allocation Model. The 2016-2020 models were performed in accordance with the internal documentation in the v 3.2 Cost Allocation Model (CA Model).

Hydro Ottawa's 2012 CA Study was prepared in accordance with the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[4] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report").

## 1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Hydro Ottawa CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2016-2020 Hydro Ottawa models by documenting each step taken in completing the model. Section 4 summarizes the results of the Hydro Ottawa CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model. Section 5 shows the fixed charge unit costs per month and

[4] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

the fixed charge boundary values as calculated in the cost allocation models for 2016 to 2020.

# 2 Overview of the Hydro Ottawa 2016-2020 CA Study

## 2.1 Model Run Included in the Hydro Ottawa Cost Allocation Study

Section 2.10.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- *The previously approved ratios most recently implemented by the distributor;*
- *The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and*
- *The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model.*

For clarity, the following designations are used.

- Ottawa-2012: The Hydro Ottawa 2012 revenue to cost ratios.
- Ottawa-2016: The version 3.2 CA Model with 2016 loads, costs, and revenues.
- Ottawa-2017: The version 3.2 CA Model with 2017 loads, costs, and revenues.
- Ottawa-2018: The version 3.2 CA Model with 2018 loads, costs, and revenues.
- Ottawa-2019: The version 3.2 CA Model with 2019 loads, costs, and revenues.
- Ottawa-2020: The version 3.2 CA Model with 2020 loads, costs, and revenues.

## 2.2 Load and Customer Information

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "If updated load profiles are not available, the load profiles of the classes may be the same as those provided by Hydro One for use in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes", (Section 2.10.1, p. 48)

The Hydro Ottawa 2016-2020 models have been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts: The 2016-2020 load forecast and customer counts by class being used by Ottawa in its application were also used for the 2016-2020 CA models.
- Hourly load profile: The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes except the Large Use class. Updating of the hourly load profiles for this class was necessary because of the small number of customers in this class. Furthermore, actual 2013 hourly load data are available for these classes (all customers have interval meters) and the hourly load data does not require weather adjustment, making it a straightforward task to determine the updated hourly load shape of these classes in a manner that is consistent with the Hydro One methodology.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2016-2020 models for the following reasons.

1. Elenchus has previously explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. It is Elenchus' opinion that there would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information may be available in the future.
4. Both time-of-use commodity pricing and changes to the design of distribution rates are influencing the hourly load profiles of the affected classes; however, it will not be practical to use smart meter data to update the load profiles of the weather sensitive classes until a sufficient number of years of data have been collected to determine demand on a weather normalized basis.

## 2.3 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of Hydro Ottawa, the financial information for the forecast years has been prepared at the USoA level with respect to capital assets; however, OM&A spending is expected to be more stable over the period of the Custom IR, and has been forecast at a less granular level.

# 3 Hydro Ottawa Cost Allocation Study Methodology

This section documents Elenchus' methodology for the Hydro Ottawa Cost Allocation Study, the 2016-2020 CA Models.

## 3.1 2016-2020 Hydro Ottawa CA Models

### 3.1.1 Hourly Load Profile (HONI File)

For the Hydro Ottawa CAIF, HONI provided data files with three worksheets that were to be used as input to the 2006 CAIF:

- Data Summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- Hourly Load Shape by Class: GWh by class for each hour in 2004.
- Input to Cost Allocation Model: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Hydro Ottawa hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2016-2020. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2016-2020 load forecast years while maintaining the hourly load shapes.

For the Large User customer class, 2013 actual interval hourly data was used, scaled to levels consistent with the 2016-2020 load forecast years while maintaining the hourly load shapes.

### 3.1.2 Demand Allocators (HONI File)

The demand allocators used in the Hydro Ottawa-2016-2020 CA models were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2016-2020 hourly load profiles resulting from the preceding step. Using the 2016-2020 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet.  The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

### 3.1.3 2016-2020 Demand Data (Hydro Ottawa-2016-2020 Models)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2016-2020 Hydro Ottawa CA Models. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values for GS > 50 to 1499, GS > 1500 to 4999, and Large User customer classes are not equal to the full class NCP values since not all customers in these customer classes use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

# 4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Hydro Ottawa cost allocation models are shown in Table 7, below.

**Table 7: Revenue to Cost Ratios**

| Customer Class | Ottawa-2012 | Ottawa-2016 Status Quo Rates | Ottawa-2017 Status Quo Rates | Board Target Range |
|---|---|---|---|---|
| Residential | 97.35 | 102.38 | 102.82 | 85-115 |
| GS < 50 kW | 114.70 | 119.21 | 119.13 | 80-120 |
| GS > 50 to 1,499 kW | 95.62 | 87.82 | 87.46 | 80-120 |
| GS > 1,500 to 4,999 kW | 114.41 | 104.48 | 102.97 | 85-115 |
| Large Use | 107.12 | 88.76 | 87.91 | 85-115 |
| Street Light | 75.04 | 73.21 | 72.28 | 70-120 |
| Sentinel | 41.00 | 55.45 | 57.84 | 80-120 |
| USL | 123.66 | 121.51 | 121.99 | 80-120 |
| Standby Power | 230.47 | 22.45 | 21.93 | 80-120 |
| Total | 100.00 | 100.00 | 100.00 | |

| Customer Class | Ottawa-2018 Status Quo Rates | Ottawa-2019 Status Quo Rates | Ottawa-2020 Status Quo Rates | Board Target Range |
|---|---|---|---|---|
| Residential | 103.39 | 103.79 | 104.04 | 85-115 |
| GS < 50 kW | 119.03 | 118.97 | 118.97 | 80-120 |
| GS > 50 to 1,499 kW | 86.97 | 86.65 | 86.48 | 80-120 |
| GS > 1,500 to 4,999 kW | 101.16 | 99.69 | 98.51 | 80-120 |
| Large Use | 86.90 | 86.25 | 85.92 | 85-115 |
| Street Light | 71.42 | 70.64 | 70.36 | 70-120 |
| Sentinel | 60.87 | 64.24 | 68.34 | 80-120 |
| USL | 122.34 | 122.61 | 123.23 | 80-120 |
| Standby Power | 21.45 | 21.02 | 20.88 | 80-120 |
| Total | 100.00 | 100.00 | 100.00 | |

The Hydro Ottawa-2016-2020 ratios (at Status Quo rates) reflect the impact of changes in throughput by class as well as changes in costs from 2012 through the 2016-2020 forecast test years.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

**Table 8: Revenue Responsibility by Rate Class**

| Customer Class | Ottawa-2012 | | Ottawa-2016 | | Ottawa-2017 | |
|---|---|---|---|---|---|---|
| | $ | % | $ | % | $ | % |
| Residential | 94,436,258 | 52.2 | 101,241,491 | 54.1 | 106,345,499 | 53.9 |
| GS < 50 kW | 19,093,962 | 11.4 | 19,819,301 | 10.6 | 20,746,678 | 10.5 |
| GS > 50 to 1,499 kW | 39,359,863 | 23.4 | 45,860,732 | 24.5 | 48,217,445 | 24.4 |
| GS > 1,500 to 4,999 kW | 7,805,712 | 4.6 | 11,093,288 | 5.9 | 12,029,406 | 6.1 |
| Large Use | 5,754,313 | 3.4 | 7,272,098 | 3.9 | 7,761,426 | 3.9 |
| Street Light | 1,183,502 | 0.7 | 1,393,557 | 0.7 | 1,492,351 | 0.8 |
| Sentinel | 10,894 | 0.0 | 9,263 | 0.0 | 8,940 | 0.0 |
| USL | 470,639 | 0.3 | 517,197 | 0.3 | 548,385 | 0.3 |
| Standby Power | 58,465 | 0.0 | 62,223 | 0.0 | 66,948 | 0.0 |
| Total | 168,173,609 | 100.0 | 187,269,148 | 100.0 | 195,013,622 | 100.0 |

| Customer Class | Ottawa-2018 | | Ottawa-2019 | | Ottawa-2020 | |
|---|---|---|---|---|---|---|
| | $ | % | $ | % | $ | % |
| Residential | 112,032,332 | 53.8 | 117,177,906 | 53.8 | 120,713,953 | 53.8 |
| GS < 50 kW | 21,741,761 | 10.4 | 22,589,550 | 10.4 | 23,125,641 | 10.3 |
| GS > 50 to 1,499 kW | 50,763,713 | 24.4 | 52,968,216 | 24.3 | 54,402,930 | 24.2 |
| GS > 1,500 to 4,999 kW | 13,066,436 | 6.3 | 14,029,936 | 6.4 | 14,805,926 | 6.6 |
| Large Use | 8,265,710 | 4.0 | 8,680,762 | 4.0 | 8,938,779 | 4.0 |
| Street Light | 1,590,510 | 0.8 | 1,677,974 | 0.8 | 1,730,916 | 0.8 |
| Sentinel | 8,558 | 0.0 | 8,092 | 0.0 | 7,476 | 0.0 |
| USL | 579,662 | 0.3 | 607,594 | 0.3 | 625,501 | 0.3 |
| Standby Power | 71,732 | 0.0 | 76,027 | 0.0 | 78,410 | 0.0 |
| Total | 208,120,414 | 100.0 | 217,816,057 | 100.0 | 224,429,532 | 100.0 |

# 5 FIXED CHARGE RATES

The Hydro Ottawa cost allocation model produced the following customer unit cost per month values:

**Table 9: 2016 Customer Unit Cost per Month**

| Customer Class | Avoided Cost | Directly Related | Minimum System with PLCC[5] Adjustment |
|---|---|---|---|
| Residential | 4.64 | 7.95 | 16.89 |
| GS < 50 kW | 7.33 | 11.71 | 25.24 |
| GS > 50 to 1,499 kW | 42.38 | 71.31 | 101.67 |
| GS > 1,500 to 4,999 kW | 175.80 | 300.66 | 534.95 |
| Large Use | 95.34 | 220.90 | 589.53 |
| Street Light | 0.22 | 0.50 | 8.84 |
| Sentinel | 1.86 | 3.71 | 13.66 |
| USL | -0.03 | -0.02 | 8.14 |
| Standby Power | 209.29 | 330.58 | 278.42 |

**Table 10: 2017 Customer Unit Cost per Month**

| Customer Class | Avoided Cost | Directly Related | Minimum System with PLCC Adjustment |
|---|---|---|---|
| Residential | 4.76 | 8.14 | 17.41 |
| GS < 50 kW | 7.54 | 11.99 | 25.96 |
| GS > 50 to 1,499 kW | 43.81 | 73.33 | 104.32 |
| GS > 1,500 to 4,999 kW | 180.99 | 308.19 | 551.64 |
| Large Use | 96.82 | 224.71 | 605.76 |
| Street Light | 0.23 | 0.51 | 9.18 |
| Sentinel | 1.92 | 3.81 | 14.25 |
| USL | -0.03 | -0.02 | 8.45 |
| Standby Power | 212.53 | 336.20 | 279.30 |

**Table 11: 2018 Customer Unit Cost per Month**

| Customer Class | Avoided Cost | Directly Related | Minimum System with PLCC Adjustment |
|---|---|---|---|
| Residential | 4.87 | 8.30 | 17.92 |
| GS < 50 kW | 7.71 | 12.23 | 26.64 |
| GS > 50 to 1,499 kW | 44.94 | 74.96 | 106.93 |
| GS > 1,500 to 4,999 kW | 183.53 | 312.61 | 569.99 |
| Large Use | 93.94 | 223.72 | 637.08 |
| Street Light | 0.23 | 0.52 | 9.53 |
| Sentinel | 1.95 | 3.87 | 14.79 |
| USL | -0.03 | -0.02 | 8.77 |
| Standby Power | 217.00 | 342.55 | 280.23 |

5 PLCC: ‘Peak Load Carrying Capacity’

**Table 12: 2019 Customer Unit Cost per Month**

| Customer Class | Avoided Cost | Directly Related | Minimum System with PLCC Adjustment |
|---|---|---|---|
| Residential | 4.97 | 8.46 | 18.37 |
| GS < 50 kW | 7.88 | 12.44 | 27.25 |
| GS > 50 to 1,499 kW | 46.14 | 76.56 | 109.38 |
| GS > 1,500 to 4,999 kW | 186.91 | 317.40 | 588.10 |
| Large Use | 96.11 | 227.28 | 667.05 |
| Street Light | 0.23 | 0.53 | 9.83 |
| Sentinel | 1.98 | 3.94 | 15.28 |
| USL | -0.03 | -0.02 | 9.04 |
| Standby Power | 221.47 | 348.42 | 281.17 |

**Table 13: 2020 Customer Unit Cost per Month**

| Customer Class | Avoided Cost | Directly Related | Minimum System with PLCC Adjustment |
|---|---|---|---|
| Residential | 5.06 | 8.59 | 18.64 |
| GS < 50 kW | 8.00 | 12.60 | 27.60 |
| GS > 50 to 1,499 kW | 47.00 | 77.84 | 111.03 |
| GS > 1,500 to 4,999 kW | 188.09 | 320.01 | 601.87 |
| Large Use | 93.51 | 226.11 | 679.50 |
| Street Light | 0.24 | 0.54 | 9.96 |
| Sentinel | 2.00 | 4.01 | 15.54 |
| USL | -0.03 | -0.02 | 9.14 |
| Standby Power | 224.56 | 352.79 | 283.57 |

In accordance with Board policy,[6] the following boundary values would apply for the fixed monthly service charge:

**Table 14: 2016 Fixed Charge Boundary Values**

| Customer Class | Cost Allocation | | Existing Rate | Boundary Values | |
|---|---|---|---|---|---|
| | Low | High | | Minimum | Maximum |
| Residential | 4.64 | 16.89 | 9.67 | 4.64 | 16.89 |
| GS < 50 kW | 7.33 | 25.24 | 16.72 | 7.33 | 25.24 |
| GS > 50 to 1,499 kW | 42.38 | 101.67 | 260.82 | 42.38 | 260.82 |
| GS > 1,500 to 4,999 kW | 175.80 | 534.95 | 4,193.93 | 175.80 | 4,193.93 |
| Large Use | 95.34 | 589.53 | 15,231.32 | 95.34 | 15,231.32 |
| Street Light | 0.22 | 8.84 | 0.57 | 0.22 | 8.84 |
| Sentinel | 1.86 | 13.66 | 2.62 | 1.86 | 13.66 |
| USL | -0.03 | 8.14 | 4.43 | -0.03 | 8.14 |
| Standby Power | 209.29 | 330.58 | 122.41 | 209.29 | 330.58 |

[6] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

## Table 15: 2017 Fixed Charge Boundary Values

| Customer Class | Cost Allocation | | Existing Rate | Boundary Values | |
|---|---|---|---|---|---|
| | Low | High | | Minimum | Maximum |
| Residential | 4.76 | 17.41 | 9.67 | 4.76 | 17.41 |
| GS < 50 kW | 7.54 | 25.96 | 16.72 | 7.54 | 25.96 |
| GS > 50 to 1,499 kW | 43.81 | 104.32 | 260.82 | 43.81 | 260.82 |
| GS > 1,500 to 4,999 kW | 180.99 | 551.64 | 4,193.93 | 180.99 | 4,193.93 |
| Large Use | 96.82 | 605.76 | 15,231.32 | 96.82 | 15,231.32 |
| Street Light | 0.23 | 9.18 | 0.57 | 0.23 | 9.18 |
| Sentinel | 1.92 | 14.25 | 2.62 | 1.92 | 14.25 |
| USL | -0.03 | 8.45 | 4.43 | -0.03 | 8.45 |
| Standby Power | 212.53 | 336.20 | 122.41 | 212.53 | 336.20 |

## Table 16: 2018 Fixed Charge Boundary Values

| Customer Class | Cost Allocation | | Existing Rate | Boundary Values | |
|---|---|---|---|---|---|
| | Low | High | | Minimum | Maximum |
| Residential | 4.87 | 17.92 | 9.67 | 4.87 | 17.92 |
| GS < 50 kW | 7.71 | 26.64 | 16.72 | 7.71 | 26.64 |
| GS > 50 to 1,499 kW | 44.94 | 106.93 | 260.82 | 44.94 | 260.82 |
| GS > 1,500 to 4,999 kW | 183.53 | 569.99 | 4,193.93 | 183.53 | 4,193.93 |
| Large Use | 93.94 | 637.08 | 15,231.32 | 93.94 | 15,231.32 |
| Street Light | 0.23 | 9.53 | 0.57 | 0.23 | 9.53 |
| Sentinel | 1.95 | 14.79 | 2.62 | 1.95 | 14.79 |
| USL | -0.03 | 8.77 | 4.43 | -0.03 | 8.77 |
| Standby Power | 217.00 | 342.55 | 122.41 | 217.00 | 342.55 |

## Table 17: 2019 Fixed Charge Boundary Values

| Customer Class | Cost Allocation | | Existing Rate | Boundary Values | |
|---|---|---|---|---|---|
| | Low | High | | Minimum | Maximum |
| Residential | 4.97 | 18.37 | 9.67 | 4.97 | 18.37 |
| GS < 50 kW | 7.88 | 27.25 | 16.72 | 7.88 | 27.25 |
| GS > 50 to 1,499 kW | 46.14 | 109.38 | 260.82 | 46.14 | 260.82 |
| GS > 1,500 to 4,999 kW | 186.91 | 588.10 | 4,193.93 | 186.91 | 4,193.93 |
| Large Use | 96.11 | 667.05 | 15,231.32 | 96.11 | 15,231.32 |
| Street Light | 0.23 | 9.83 | 0.57 | 0.23 | 9.83 |
| Sentinel | 1.98 | 15.28 | 2.62 | 1.98 | 15.28 |
| USL | -0.03 | 9.04 | 4.43 | -0.03 | 9.04 |
| Standby Power | 221.47 | 348.42 | 122.41 | 221.47 | 348.42 |

**Table 18: 2020 Fixed Charge Boundary Values**

| Customer Class | Cost Allocation | | Existing Rate | Boundary Values | |
|---|---|---|---|---|---|
| | Low | High | | Minimum | Maximum |
| Residential | 5.06 | 18.64 | 9.67 | 5.06 | 18.64 |
| GS < 50 kW | 8.00 | 27.60 | 16.72 | 8.00 | 27.60 |
| GS > 50 to 1,499 kW | 47.00 | 111.03 | 260.82 | 47.00 | 260.82 |
| GS > 1,500 to 4,999 kW | 188.09 | 601.87 | 4,193.93 | 188.09 | 4,193.93 |
| Large Use | 93.51 | 679.50 | 15,231.32 | 93.51 | 15,231.32 |
| Street Light | 0.24 | 9.96 | 0.57 | 0.24 | 9.96 |
| Sentinel | 2.00 | 15.54 | 2.62 | 2.00 | 15.54 |
| USL | -0.03 | 9.14 | 4.43 | -0.03 | 9.14 |
| Standby Power | 224.56 | 352.56 | 122.41 | 224.56 | 352.56 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.1 Revenue Worksheet - 2016-2020 Custom IR - 2016 Model

| | |
|---|---|
| **Total kWhs from Load Forecast** | 7,440,624,000 |
| **Total kWs from Load Forecast** | 10,124,953 |
| **Deficiency/sufficiency ( RRWF 8. cell F51)** | - 17,334,357 |
| **Miscellaneous Revenue (RRWF 5. cell F48)** | 11,699,538 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ID** | **Total** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| **Billing Data** | | | | | | | | | | | | | |
| Forecast kWh | **CEN** | 7,440,624,000 | 2,216,045,000 | 726,360,000 | 2,954,441,000 | 863,309,000 | 620,218,000 | 43,552,000 | 48,000 | 16,651,000 | | | |
| Forecast kW | **CDEM** | 10,124,953 | | | 7,027,979 | 1,847,365 | 1,121,449 | 123,144 | 216 | | | 4,800 | |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,499,198 | | | 1,756,995 | 461,841 | 280,362 | | | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | **CEN EWMP** | 7,440,624,000 | 2,216,045,000 | 726,360,000 | 2,954,441,000 | 863,309,000 | 620,218,000 | 43,552,000 | 48,000 | 16,651,000 | - | - | - |
| | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |
| Existing Distribution kWh Rate | | | $0.0234 | $0.0210 | | | | | | $0.0219 | | | |
| Existing Distribution kW Rate | | | | | $3.5691 | $3.4887 | $3.3129 | $3.9997 | $10.0361 | | $1.6337 | $1.4985 | $1.6629 |
| Existing TOA Rate | | | | | $0.45 | $0.45 | $0.45 | | | | | | |
| Additional Charges | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $159,359,893 | $86,359,164 | $20,171,698 | $35,397,687 | $10,269,766 | $5,725,783 | $872,268 | $3,902 | $549,494 | $0 | $10,131 | $0 |
| Transformer Ownership Allowance | | $1,124,639 | $0 | $0 | $790,648 | $207,829 | $126,163 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | **CREV** | $158,235,254 | $86,359,164 | $20,171,698 | $34,607,039 | $10,061,938 | $5,599,620 | $872,268 | $3,902 | $549,494 | $0 | $10,131 | $0 |

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# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.2 Customer Data Worksheet - 2016-2020 Custom IR - 2016 Model

| | ID | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billing Data** | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $2,000,008 | $1,354,005 | $422,002 | $150,001 | $74,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $884,964 | $658,889 | $119,577 | $93,649 | $12,109 | $102 | $156 | $104 | $377 | | | |
| Number of Bills | CNB | 3,903,839 | 3,568,119 | 294,147.00 | 39,545.00 | 912.00 | 132.00 | 180.00 | 660.00 | 120.00 | | 24 | |
| Number of Devices | | | | | | | | 55,516 | 55 | 3,477 | | | |
| Number of Connections (Unmetered) | CCON | 7,233 | | | | | | 3,701 | 55 | 3,477 | | | |
| Total Number of Customers | CCA | 325,320 | 297,343 | 24,512 | 3,295 | 76 | 11 | 15 | 55 | 10 | | 2 | |
| Bulk Customer Base | CCB | 325,320 | 297,343 | 24,512 | 3,295 | 76 | 11 | 15 | 55 | 10 | | 2 | |
| Primary Customer Base | CCP | 325,320 | 297,343 | 24,512 | 3,295 | 76 | 11 | 15 | 55 | 10 | | 2 | |
| Line Transformer Customer Base | CCLT | 324,897 | 297,343 | 24,512 | 2,923 | 33 | 5 | 15 | 55 | 10 | | | |
| Secondary Customer Base | CCS | 323,583 | 297,343 | 24,512 | 1,648 | | | 15 | 55 | 10 | | | |
| Weighted - Services | CWCS | 370,078 | 297,343 | 49,025 | 16,477 | - | - | 3,701 | 55 | 3,477 | - | - | - |
| Weighted Meter -Capital | CWMC | 60,568,577 | 44,025,138 | 9,147,451 | 6,505,988 | 760,000 | 110,000 | - | - | - | - | 20,000 | - |
| Weighted Meter Reading | CWMR | 500,674 | 297,343 | 24,512 | 159,869 | 16,182 | 2,342 | - | - | - | - | 426 | - |
| Weighted Bills | CWNB | 4,157,610 | 3,568,119 | 302,982 | 254,405 | 23,055 | 3,329 | 4,531 | 466 | 125 | - | 598 | - |

## Bad Debt Data

| | Year | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2010 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2011 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Three-year average** | | **2,000,008** | **1,354,005** | **422,002** | **150,001** | **74,000** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

## SSS Admin Charge Data

| | Year | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2012 | 979,657 | 895,929 | 74,332 | 9,078 | 226 | 35 | 56 | | 2 | | | |
| **Historic Year:** | 2013 | 896,212 | 819,690 | 67,433 | 8,586 | 214 | 30 | - 12 | | 270 | | | |
| **Historic Year:** | 2014 | 920,026 | 842,937 | 67,671 | 8,715 | 253 | 30 | 21 | | 398 | | | |
| **Three-year average** | | **1,147,299** | **852,852** | **210,480** | **58,794** | **24,897** | **32** | **22** | **-** | **224** | **-** | **-** | **-** |

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# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I8 Demand Data Worksheet - 2016-2020 Custom IR - 2016 Model

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Classes** | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 1,282,883 | 436,953 | 153,148 | 508,176 | 105,363 | 77,512 | - | - | 1,731 | | - | |
| Bulk Delivery CP | BCP1 | 1,282,883 | 436,953 | 153,148 | 508,176 | 105,363 | 77,512 | - | - | 1,731 | - | - | |
| Total Sytem CP | DCP1 | 1,282,883 | 436,953 | 153,148 | 508,176 | 105,363 | 77,512 | - | - | 1,731 | - | - | |
| **4 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 5,006,360 | 1,792,729 | 491,382 | 1,920,564 | 460,783 | 316,194 | 17,335 | 15 | 7,356 | | - | |
| Bulk Delivery CP | BCP4 | 5,006,360 | 1,792,729 | 491,382 | 1,920,564 | 460,783 | 316,194 | 17,335 | 15 | 7,356 | - | - | |
| Total Sytem CP | DCP4 | 5,006,360 | 1,792,729 | 491,382 | 1,920,564 | 460,783 | 316,194 | 17,335 | 15 | 7,356 | - | - | |
| **12 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 13,857,647 | 4,705,908 | 1,390,100 | 5,366,758 | 1,372,626 | 949,343 | 50,166 | 48 | 22,468 | | 230 | |
| Bulk Delivery CP | BCP12 | 13,857,647 | 4,705,908 | 1,390,100 | 5,366,758 | 1,372,626 | 949,343 | 50,166 | 48 | 22,468 | - | 230 | |
| Total Sytem CP | DCP12 | 13,857,647 | 4,705,908 | 1,390,100 | 5,366,758 | 1,372,626 | 949,343 | 50,166 | 48 | 22,468 | - | 230 | |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 1,457,990 | 497,262 | 153,148 | 527,926 | 156,830 | 105,588 | 13,805 | 14 | 2,265 | | 1,152 | |
| Primary NCP | PNCP1 | 1,457,990 | 497,262 | 153,148 | 527,926 | 156,830 | 105,588 | 13,805 | 14 | 2,265 | | 1,152 | |
| Line Transformer NCP | LTNCP1 | 1,245,101 | 497,262 | 153,148 | 459,296 | 69,005 | 49,626 | 13,805 | 14 | 2,265 | - | 680 | |
| Secondary NCP | SNCP1 | 930,458 | 497,262 | 153,148 | 263,963 | | | 13,805 | 14 | 2,265 | - | | |
| **4 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 5,665,114 | 1,961,254 | 576,965 | 2,050,013 | 604,725 | 406,005 | 53,358 | 54 | 8,906 | | 3,836 | |
| Primary NCP | PNCP4 | 5,665,114 | 1,961,254 | 576,965 | 2,050,013 | 604,725 | 406,005 | 53,358 | 54 | 8,906 | | 3,836 | |
| Line Transformer NCP | LTNCP4 | 4,878,062 | 1,961,254 | 576,965 | 1,818,362 | 266,079 | 190,823 | 53,358 | 54 | 8,906 | - | 2,263 | |
| Secondary NCP | SNCP4 | 3,625,543 | 1,961,254 | 576,965 | 1,025,007 | | | 53,358 | 54 | 8,906 | - | | |
| **12 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 15,671,749 | 5,439,974 | 1,578,908 | 5,753,087 | 1,642,061 | 1,094,028 | 130,015 | 131 | 25,887 | | 7,657 | |
| Primary NCP | PNCP12 | 15,671,749 | 5,439,974 | 1,578,908 | 5,753,087 | 1,642,061 | 1,094,028 | 130,015 | 131 | 25,887 | | 7,657 | |
| Line Transformer NCP | LTNCP12 | 13,421,320 | 5,439,974 | 1,578,908 | 5,005,186 | 722,507 | 514,194 | 130,015 | 131 | 25,887 | - | 4,517 | |
| Secondary NCP | SNCP12 | 10,051,460 | 5,439,974 | 1,578,908 | 2,876,544 | | | 130,015 | 131 | 25,887 | - | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet O1 Revenue to Cost Summary Worksheet - 2016-2020 Custom IR - 2016 Model

**Instructions:**
Please see the first tab in this workbook for detailed instructions

### Class Revenue, Cost Analysis, and Return on Rate Base

| Rate Base Assets | | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $158,235,254 | $86,359,164 | $20,171,698 | $34,607,039 | $10,061,938 | $5,599,620 | $872,268 | $3,902 | $549,494 | $0 | $10,131 | $0 |
| mi | Miscellaneous Revenue (mi) | $11,699,538 | $7,835,113 | $1,244,861 | $1,877,505 | $425,511 | $241,865 | $52,382 | $807 | $18,765 | $0 | $2,729 | $0 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | $169,934,792 | $94,194,277 | $21,416,559 | $36,484,544 | $10,487,449 | $5,841,485 | $924,651 | $4,709 | $568,259 | $0 | $12,859 | $0 |
| | Factor required to recover deficiency (1 + D) | 1.1095 | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $175,569,610 | $95,819,638 | $22,381,467 | $38,398,171 | $11,164,203 | $6,213,047 | $967,824 | $4,330 | $609,690 | $0 | $11,240 | $0 |
| | Miscellaneous Revenue (mi) | $11,699,538 | $7,835,113 | $1,244,861 | $1,877,505 | $425,511 | $241,865 | $52,382 | $807 | $18,765 | $0 | $2,729 | $0 |
| | **Total Revenue at Status Quo Rates** | $187,269,148 | $103,654,751 | $23,626,328 | $40,275,676 | $11,589,714 | $6,454,912 | $1,020,206 | $5,137 | $628,455 | $0 | $13,969 | $0 |
| | **Expenses** | | | | | | | | | | | | |
| di | Distribution Costs (di) | $28,347,308 | $13,699,008 | $2,965,336 | $7,940,251 | $2,000,911 | $1,353,291 | $272,717 | $1,384 | $103,323 | $0 | $11,088 | $0 |
| cu | Customer Related Costs (cu) | $17,064,637 | $13,856,084 | $1,705,783 | $1,284,236 | $184,533 | $16,086 | $13,280 | $1,365 | $366 | $0 | $2,903 | $0 |
| ad | General and Administration (ad) | $41,693,619 | $24,927,267 | $4,299,663 | $8,706,004 | $2,071,154 | $1,307,506 | $268,860 | $2,467 | $97,740 | $0 | $12,957 | $0 |
| dep | Depreciation and Amortization (dep) | $40,826,114 | $20,617,872 | $4,513,067 | $10,865,406 | $2,611,292 | $1,741,867 | $333,161 | $1,662 | $127,145 | $0 | $14,642 | $0 |
| INPUT | PILs (INPUT) | $4,958,448 | $2,351,583 | $529,413 | $1,425,998 | $353,089 | $238,436 | $42,245 | $199 | $15,762 | $0 | $1,724 | $0 |
| INT | Interest | $20,032,044 | $9,500,354 | $2,138,818 | $5,761,006 | $1,426,474 | $963,276 | $170,667 | $805 | $63,678 | $0 | $6,965 | $0 |
| | **Total Expenses** | $152,922,170 | $84,952,168 | $16,152,080 | $35,982,901 | $8,647,453 | $5,620,462 | $1,100,930 | $7,883 | $408,014 | $0 | $50,280 | $0 |
| | **Direct Allocation** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| NI | Allocated Net Income (NI) | $34,346,978 | $16,289,323 | $3,667,221 | $9,877,831 | $2,445,835 | $1,651,635 | $292,627 | $1,381 | $109,183 | $0 | $11,943 | $0 |
| | **Revenue Requirement (includes NI)** | $187,269,148 | $101,241,491 | $19,819,301 | $45,860,732 | $11,093,288 | $7,272,098 | $1,393,557 | $9,263 | $517,197 | $0 | $62,223 | $0 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $778,402,502 | $372,612,860 | $83,486,982 | $221,464,064 | $54,612,826 | $36,830,041 | $6,613,352 | $31,534 | $2,478,896 | $0 | $271,948 | $0 |
| gp | General Plant - Gross | $127,558,194 | $60,705,486 | $13,622,571 | $36,546,459 | $9,032,920 | $6,099,931 | $1,091,932 | $5,198 | $409,287 | $0 | $44,409 | $0 |
| accum dep | Accumulated Depreciation | ($105,581,138) | ($52,414,315) | ($11,633,056) | ($28,695,277) | ($6,967,577) | ($4,655,206) | ($853,823) | ($4,117) | ($320,059) | $0 | ($37,708) | $0 |
| co | Capital Contribution | ($16,431,222) | ($8,956,022) | ($1,772,105) | ($3,961,318) | ($890,594) | ($602,163) | ($168,640) | ($1,053) | ($73,305) | $0 | ($6,021) | $0 |
| | **Total Net Plant** | $783,948,336 | $371,948,009 | $83,704,392 | $225,353,927 | $55,787,575 | $37,672,603 | $6,682,820 | $31,562 | $2,494,819 | $0 | $272,628 | $0 |
| | **Directly Allocated Net Fixed Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| COP | Cost of Power (COP) | $894,285,487 | $268,175,263 | $87,229,363 | $353,899,725 | $103,407,625 | $74,290,052 | $5,250,740 | $6,257 | $2,026,462 | $0 | $0 | $0 |
| | OM&A Expenses | $87,105,564 | $52,482,359 | $8,970,782 | $17,930,491 | $4,256,598 | $2,676,883 | $554,858 | $5,216 | $201,429 | $0 | $26,948 | $0 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | *$981,391,050* | *$320,657,622* | *$96,200,145* | *$371,830,215* | *$107,664,223* | *$76,966,935* | *$5,805,597* | *$11,473* | *$2,227,891* | *$0* | *$26,948* | *$0* |
| | **Working Capital** | $139,357,529 | $45,533,382 | $13,660,421 | $52,799,891 | $15,288,320 | $10,929,305 | $824,395 | $1,629 | $316,360 | $0 | $3,827 | $0 |
| | **Total Rate Base** | $923,305,865 | $417,481,391 | $97,364,813 | $278,153,818 | $71,075,895 | $48,601,907 | $7,507,215 | $33,191 | $2,811,180 | $0 | $276,455 | $0 |
| | | Rate Base Input equals Output | | | | | | | | | | | |
| | **Equity Component of Rate Base** | $369,322,346 | $166,992,556 | $38,945,925 | $111,261,527 | $28,430,358 | $19,440,763 | $3,002,886 | $13,277 | $1,124,472 | $0 | $110,582 | $0 |
| | **Net Income on Allocated Assets** | $34,345,868 | $18,702,583 | $7,474,249 | $4,292,775 | $2,942,261 | $834,450 | ($80,724) | ($2,746) | $220,441 | $0 | ($37,420) | $0 |
| | **Net Income on Direct Allocation Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **Net Income** | $34,345,868 | $18,702,583 | $7,474,249 | $4,292,775 | $2,942,261 | $834,450 | ($80,724) | ($2,746) | $220,441 | $0 | ($37,420) | $0 |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | 102.38% | 119.21% | 87.82% | 104.48% | 88.76% | 73.21% | 55.45% | 121.51% | 0.00% | 22.45% | 0.00% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | ($17,334,357) | ($7,047,214) | $1,597,258 | ($9,376,188) | ($605,839) | ($1,430,613) | ($468,906) | ($4,554) | $51,062 | $0 | ($49,363) | $0 |
| | | Deficiency Input equals Output | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | $0 | $2,413,260 | $3,807,027 | ($5,585,056) | $496,426 | ($817,186) | ($373,351) | ($4,127) | $111,258 | $0 | ($48,253) | $0 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 9.30% | 11.20% | 19.19% | 3.86% | 10.35% | 4.29% | -2.69% | -20.68% | 19.60% | 0.00% | -33.84% | 0.00% |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016-2020 Custom IR - 2016 Model**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

| | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summary** | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| Customer Unit Cost per month - Avoided Cost | $4.64 | $7.33 | $42.38 | $175.80 | $95.34 | $0.22 | $1.86 | -$0.03 | 0 | $209.29 | 0 |
| Customer Unit Cost per month - Directly Related | $7.95 | $11.71 | $71.31 | $300.66 | $220.90 | $0.50 | $3.71 | -$0.02 | 0 | $330.58 | 0 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $16.89 | $25.24 | $101.67 | $534.95 | $589.53 | $8.84 | $13.66 | $8.14 | 0 | $278.42 | 0 |
| Existing Approved Fixed Charge | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet I6.1 Revenue Worksheet - 2016-2020 Custom IR - 2017 Model**

| | |
|---|---|
| **Total kWhs from Load Forecast** | 7,379,644,000 |

| | |
|---|---|
| **Total kWs from Load Forecast** | 10,034,217 |

| | |
|---|---|
| **Deficiency/sufficiency ( RRWF 8. cell F51)** | - 25,576,570 |

| | |
|---|---|
| **Miscellaneous Revenue (RRWF 5. cell F48)** | 11,565,131 |

| | | | January 1, 1900 | January 2, 1900 | January 3, 1900 | January 4, 1900 | January 6, 1900 | January 7, 1900 | January 8, 1900 | January 9, 1900 | January 11, 1900 | January 12, 1900 | January 13, 1900 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ID** | **Total** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| **Billing Data** | | | | | | | | | | | | | |
| Forecast kWh | **CEN** | 7,379,644,000 | 2,198,259,000 | 716,896,000 | 2,907,445,000 | 877,400,000 | 619,253,000 | 43,653,000 | 48,000 | 16,690,000 | | | |
| Forecast kW | **CDEM** | 10,034,217 | | | 6,908,640 | 1,877,691 | 1,119,726 | 123,144 | 216 | | | 4,800 | |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,476,514 | | | 1,727,160 | 469,423 | 279,932 | | | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | **CEN EWMP** | 7,379,644,000 | 2,198,259,000 | 716,896,000 | 2,907,445,000 | 877,400,000 | 619,253,000 | 43,653,000 | 48,000 | 16,690,000 | - | - | - |
| | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |
| Existing Distribution kWh Rate | | | $0.0234 | $0.0210 | | | | | | $0.0219 | | | |
| Existing Distribution kW Rate | | | | | $3.5691 | $3.4887 | $3.3129 | $3.9997 | $10.0361 | | $1.6337 | $1.4985 | $1.6629 |
| Existing TOA Rate | | | | | $0.45 | $0.45 | $0.45 | | | | | | |
| Additional Charges | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $158,986,352 | $86,397,220 | $19,995,810 | $35,058,607 | $10,375,565 | $5,720,075 | $872,268 | $3,776 | $552,900 | $0 | $10,131 | $0 |
| Transformer Ownership Allowance | | $1,114,431 | $0 | $0 | $777,222 | $211,240 | $125,969 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | **CREV** | $157,871,920 | $86,397,220 | $19,995,810 | $34,281,385 | $10,164,325 | $5,594,105 | $872,268 | $3,776 | $552,900 | $0 | $10,131 | $0 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.2 Customer Data Worksheet - 2016-2020 Custom IR - 2017 Model

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ID | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **Billing Data** | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $2,000,008 | $1,354,005 | $422,002 | $150,001 | $74,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $884,964 | $658,889 | $119,577 | $93,649 | $12,109 | $102 | $156 | $104 | $377 | | | |
| Number of Bills | CNB | 3,952,466 | 3,615,094 | 295,514.00 | 39,878.00 | 912.00 | 132.00 | 180.00 | 612.00 | 120.00 | | 24 | |
| Number of Devices | | | | | | | | 55,516 | 51 | 3,525 | | | |
| Number of Connections (Unmetered) | CCON | 7,277 | | | | | | 3,701 | 51 | 3,525 | | | |
| Total Number of Customers | CCA | 329,372 | 301,258 | 24,626 | 3,323 | 76 | 11 | 15 | 51 | 10 | | 2 | |
| Bulk Customer Base | CCB | 329,372 | 301,258 | 24,626 | 3,323 | 76 | 11 | 15 | 51 | 10 | | 2 | |
| Primary Customer Base | CCP | 329,372 | 301,258 | 24,626 | 3,323 | 76 | 11 | 15 | 51 | 10 | | 2 | |
| Line Transformer Customer Base | CCLT | 328,946 | 301,258 | 24,626 | 2,948 | 33 | 5 | 15 | 51 | 10 | | | |
| Secondary Customer Base | CCS | 327,622 | 301,258 | 24,626 | 1,662 | | | 15 | 51 | 10 | | | |
| Weighted - Services | CWCS | 374,403 | 301,258 | 49,252 | 16,616 | - | - | 3,701 | 51 | 3,525 | - | - | - |
| Weighted Meter -Capital | CWMC | 61,277,413 | 44,596,728 | 9,189,973 | 6,600,712 | 760,000 | 110,000 | - | - | - | - | 20,000 | - |
| Weighted Meter Reading | CWMR | 506,049 | 301,258 | 24,626 | 161,215 | 16,182 | 2,342 | - | - | - | - | 426 | - |
| Weighted Bills | CWNB | 4,208,102 | 3,615,094 | 304,390 | 256,548 | 23,055 | 3,329 | 4,531 | 432 | 125 | - | 598 | - |

## Bad Debt Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2010 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2011 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Three-year average** | | **2,000,008** | **1,354,005** | **422,002** | **150,001** | **74,000** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

## SSS Admin Charge Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2012 | 979,657 | 895,929 | 74,332 | 9,078 | 226 | 35 | 56 | | 2 | | | |
| **Historic Year:** | 2013 | 896,212 | 819,690 | 67,433 | 8,586 | 214 | 30 | - 12 | | 270 | | | |
| **Historic Year:** | 2014 | 920,026 | 842,937 | 67,671 | 8,715 | 253 | 30 | 21 | | 398 | | | |
| **Three-year average** | | **1,147,299** | **852,852** | **210,480** | **58,794** | **24,897** | **32** | **22** | **-** | **224** | **-** | **-** | **-** |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet I8 Demand Data Worksheet - 2016-2020 Custom IR - 2017 Model**

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| | | | January 1, 1900 | January 2, 1900 | January 3, 1900 | January 4, 1900 | January 6, 1900 | January 7, 1900 | January 8, 1900 | January 9, 1900 | January 11, 1900 | January 12, 1900 | January 13, 1900 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Classes** | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 1,270,901 | 433,446 | 151,153 | 500,093 | 107,082 | 77,391 | - | - | 1,736 | | - | |
| Bulk Delivery CP | BCP1 | 1,270,901 | 433,446 | 151,153 | 500,093 | 107,082 | 77,391 | - | - | 1,736 | - | - | |
| Total Sytem CP | DCP1 | 1,270,901 | 433,446 | 151,153 | 500,093 | 107,082 | 77,391 | - | - | 1,736 | - | - | |
| **4 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 4,962,106 | 1,778,343 | 484,980 | 1,890,014 | 468,304 | 315,703 | 17,376 | 14 | 7,373 | | - | |
| Bulk Delivery CP | BCP4 | 4,962,106 | 1,778,343 | 484,980 | 1,890,014 | 468,304 | 315,703 | 17,376 | 14 | 7,373 | - | - | |
| Total Sytem CP | DCP4 | 4,962,106 | 1,778,343 | 484,980 | 1,890,014 | 468,304 | 315,703 | 17,376 | 14 | 7,373 | - | - | |
| **12 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 13,737,495 | 4,668,145 | 1,371,988 | 5,281,389 | 1,395,030 | 947,866 | 50,282 | 45 | 22,520 | | 230 | |
| Bulk Delivery CP | BCP12 | 13,737,495 | 4,668,145 | 1,371,988 | 5,281,389 | 1,395,030 | 947,866 | 50,282 | 45 | 22,520 | - | 230 | |
| Total Sytem CP | DCP12 | 13,737,495 | 4,668,145 | 1,371,988 | 5,281,389 | 1,395,030 | 947,866 | 50,282 | 45 | 22,520 | - | 230 | |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 1,446,038 | 493,272 | 151,153 | 519,528 | 159,390 | 105,423 | 13,837 | 13 | 2,270 | | 1,152 | |
| Primary NCP | PNCP1 | 1,446,038 | 493,272 | 151,153 | 519,528 | 159,390 | 105,423 | 13,837 | 13 | 2,270 | | 1,152 | |
| Line Transformer NCP | LTNCP1 | 1,232,894 | 493,272 | 151,153 | 451,990 | 70,131 | 49,549 | 13,837 | 13 | 2,270 | - | 680 | |
| Secondary NCP | SNCP1 | 920,309 | 493,272 | 151,153 | 259,765 | | | 13,837 | 13 | 2,270 | - | | |
| **4 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 5,618,628 | 1,945,515 | 569,448 | 2,017,404 | 614,595 | 405,373 | 53,482 | 50 | 8,927 | | 3,836 | |
| Primary NCP | PNCP4 | 5,618,628 | 1,945,515 | 569,448 | 2,017,404 | 614,595 | 405,373 | 53,482 | 50 | 8,927 | | 3,836 | |
| Line Transformer NCP | LTNCP4 | 4,830,068 | 1,945,515 | 569,448 | 1,789,437 | 270,422 | 190,526 | 53,482 | 50 | 8,927 | - | 2,263 | |
| Secondary NCP | SNCP4 | 3,586,123 | 1,945,515 | 569,448 | 1,008,702 | | | 53,482 | 50 | 8,927 | - | | |
| **12 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 15,541,461 | 5,396,320 | 1,558,336 | 5,661,573 | 1,668,863 | 1,092,326 | 130,317 | 122 | 25,948 | | 7,657 | |
| Primary NCP | PNCP12 | 15,541,461 | 5,396,320 | 1,558,336 | 5,661,573 | 1,668,863 | 1,092,326 | 130,317 | 122 | 25,948 | | 7,657 | |
| Line Transformer NCP | LTNCP12 | 13,288,821 | 5,396,320 | 1,558,336 | 4,925,569 | 734,300 | 513,394 | 130,317 | 122 | 25,948 | - | 4,517 | |
| Secondary NCP | SNCP12 | 9,941,829 | 5,396,320 | 1,558,336 | 2,830,787 | | | 130,317 | 122 | 25,948 | - | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet O1 Revenue to Cost Summary Worksheet - 2016-2020 Custom IR - 2017 Model

**Instructions:**
**Please see the first tab in this workbook for detailed instructions**

**Class Revenue, Cost Analysis, and Return on Rate Base**

| Rate Base Assets | | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $157,871,920 | $86,397,220 | $19,995,810 | $34,281,385 | $10,164,325 | $5,594,105 | $872,268 | $3,776 | $552,900 | $0 | $10,131 | $0 |
| mi | Miscellaneous Revenue (mi) | $11,565,131 | $7,737,562 | $1,220,652 | $1,854,678 | $433,003 | $244,169 | $52,851 | $730 | $18,722 | $0 | $2,765 | $0 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | $169,437,051 | $94,134,781 | $21,216,462 | $36,136,063 | $10,597,328 | $5,838,274 | $925,119 | $4,506 | $571,622 | $0 | $12,896 | $0 |
| | Factor required to recover deficiency (1 + D) | 1.1761 | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $185,669,946 | $101,610,008 | $23,516,665 | $40,317,638 | $11,954,055 | $6,579,113 | $1,025,857 | $4,441 | $650,254 | $0 | $11,914 | $0 |
| | Miscellaneous Revenue (mi) | $11,565,131 | $7,737,562 | $1,220,652 | $1,854,678 | $433,003 | $244,169 | $52,851 | $730 | $18,722 | $0 | $2,765 | $0 |
| | **Total Revenue at Status Quo Rates** | $197,235,078 | $109,347,570 | $24,737,316 | $42,172,316 | $12,387,058 | $6,823,282 | $1,078,708 | $5,171 | $668,976 | $0 | $14,680 | $0 |
| | **Expenses** | | | | | | | | | | | | |
| di | Distribution Costs (di) | $29,267,179 | $14,131,285 | $3,048,685 | $8,153,970 | $2,120,604 | $1,408,781 | $284,184 | $1,309 | $106,685 | $0 | $11,675 | $0 |
| cu | Customer Related Costs (cu) | $17,618,384 | $14,319,552 | $1,751,482 | $1,323,589 | $189,173 | $16,413 | $13,547 | $1,292 | $374 | $0 | $2,962 | $0 |
| ad | General and Administration (ad) | $43,046,577 | $25,734,103 | $4,417,813 | $8,945,914 | $2,190,294 | $1,361,396 | $280,179 | $2,335 | $100,969 | $0 | $13,573 | $0 |
| dep | Depreciation and Amortization (dep) | $44,145,078 | $22,300,765 | $4,849,115 | $11,683,212 | $2,892,224 | $1,897,268 | $365,964 | $1,666 | $138,770 | $0 | $16,095 | $0 |
| INPUT | PILs (INPUT) | $4,798,717 | $2,268,739 | $508,881 | $1,376,051 | $352,326 | $233,833 | $41,673 | $178 | $15,317 | $0 | $1,720 | $0 |
| INT | Interest | $22,253,500 | $10,521,017 | $2,359,875 | $6,381,277 | $1,633,873 | $1,084,372 | $193,254 | $824 | $71,029 | $0 | $7,978 | $0 |
| | **Total Expenses** | $161,129,434 | $89,275,462 | $16,935,850 | $37,864,012 | $9,378,495 | $6,002,063 | $1,178,802 | $7,603 | $433,143 | $0 | $54,004 | $0 |
| | **Direct Allocation** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| NI | Allocated Net Income (NI) | $36,105,643 | $17,070,037 | $3,828,827 | $10,353,432 | $2,650,911 | $1,759,362 | $313,549 | $1,337 | $115,243 | $0 | $12,945 | $0 |
| | **Revenue Requirement (includes NI)** | $197,235,078 | $106,345,499 | $20,764,678 | $48,217,445 | $12,029,406 | $7,761,426 | $1,492,351 | $8,940 | $548,385 | $0 | $66,948 | $0 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $865,509,370 | $415,063,655 | $92,363,633 | $244,211,215 | $62,106,945 | $41,150,474 | $7,489,263 | $32,564 | $2,780,478 | $0 | $311,143 | $0 |
| gp | General Plant - Gross | $146,877,353 | $69,855,564 | $15,583,253 | $41,848,197 | $10,681,659 | $7,089,444 | $1,284,804 | $5,564 | $476,142 | $0 | $52,726 | $0 |
| accum dep | Accumulated Depreciation | ($154,225,719) | ($76,773,787) | ($16,898,539) | ($41,552,756) | ($10,378,824) | ($6,818,392) | ($1,267,335) | ($5,620) | ($474,661) | $0 | ($55,806) | $0 |
| co | Capital Contribution | ($29,813,003) | ($16,242,702) | ($3,201,006) | ($7,154,013) | ($1,659,707) | ($1,102,646) | ($306,998) | ($1,751) | ($133,140) | $0 | ($11,039) | $0 |
| | **Total Net Plant** | $828,348,000 | $391,902,729 | $87,847,341 | $237,352,642 | $60,750,073 | $40,318,881 | $7,199,734 | $30,757 | $2,648,819 | $0 | $297,024 | $0 |
| | **Directly Allocated Net Fixed Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| COP | Cost of Power (COP) | $911,714,427 | $273,437,511 | $88,495,848 | $358,000,053 | $108,031,563 | $76,246,717 | $5,408,923 | $6,381 | $2,087,431 | $0 | $0 | $0 |
| | OM&A Expenses | $89,932,139 | $54,184,941 | $9,217,980 | $18,423,473 | $4,500,071 | $2,786,591 | $577,910 | $4,936 | $208,027 | $0 | $28,210 | $0 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | *$1,001,646,566* | *$327,622,452* | *$97,713,828* | *$376,423,526* | *$112,531,634* | *$79,033,308* | *$5,986,833* | *$11,317* | *$2,295,458* | *$0* | *$28,210* | *$0* |
| | **Working Capital** | $142,233,812 | $46,522,388 | $13,875,364 | $53,452,141 | $15,979,492 | $11,222,730 | $850,130 | $1,607 | $325,955 | $0 | $4,006 | $0 |
| | **Total Rate Base** | $970,581,813 | $438,425,118 | $101,722,705 | $290,804,783 | $76,729,565 | $51,541,610 | $8,049,864 | $32,364 | $2,974,774 | $0 | $301,030 | $0 |
| | | Rate Base Input equals Output | | | | | | | | | | | |
| | **Equity Component of Rate Base** | $388,232,725 | $175,370,047 | $40,689,082 | $116,321,913 | $30,691,826 | $20,616,644 | $3,219,946 | $12,946 | $1,189,910 | $0 | $120,412 | $0 |
| | **Net Income on Allocated Assets** | $36,103,860 | $20,072,108 | $7,801,466 | $4,308,304 | $3,008,563 | $821,219 | ($100,094) | ($2,432) | $235,834 | $0 | ($41,108) | $0 |
| | **Net Income on Direct Allocation Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **Net Income** | $36,103,860 | $20,072,108 | $7,801,466 | $4,308,304 | $3,008,563 | $821,219 | ($100,094) | ($2,432) | $235,834 | $0 | ($41,108) | $0 |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | 102.82% | 119.13% | 87.46% | 102.97% | 87.91% | 72.28% | 57.84% | 121.99% | 0.00% | 21.93% | 0.00% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | ($27,798,026) | ($12,210,718) | $451,784 | ($12,081,381) | ($1,432,079) | ($1,923,151) | ($567,231) | ($4,434) | $23,237 | $0 | ($54,052) | $0 |
| | | Deficiency Input Does Not Equal Output | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | $0 | $3,002,071 | $3,972,638 | ($6,045,128) | $357,652 | ($938,143) | ($413,643) | ($3,769) | $120,591 | $0 | ($52,269) | $0 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 9.30% | 11.45% | 19.17% | 3.70% | 9.80% | 3.98% | -3.11% | -18.78% | 19.82% | 0.00% | -34.14% | 0.00% |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016-2020 Custom IR - 2017 Model**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

## Summary

| | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| Customer Unit Cost per month - Avoided Cost | $4.76 | $7.54 | $43.81 | $180.99 | $96.82 | $0.23 | $1.92 | -$0.03 | 0 | $212.53 | 0 |
| Customer Unit Cost per month - Directly Related | $8.14 | $11.99 | $73.33 | $308.19 | $224.71 | $0.51 | $3.81 | -$0.02 | 0 | $336.20 | 0 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $17.41 | $25.96 | $104.32 | $551.64 | $605.76 | $9.18 | $14.25 | $8.45 | 0 | $279.30 | 0 |
| Existing Approved Fixed Charge | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.1 Revenue Worksheet - 2016-2020 Custom IR - 2018 Model

| | |
|---|---|
| **Total kWhs from Load Forecast** | 7,366,004,000 |
| **Total kWs from Load Forecast** | 9,986,854 |
| **Deficiency/sufficiency ( RRWF 8. cell F51)** | - 38,086,329 |
| **Miscellaneous Revenue (RRWF 5. cell F48)** | 11,722,041 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ID** | **Total** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| **Billing Data** | | | | | | | | | | | | | |
| Forecast kWh | **CEN** | 7,366,004,000 | 2,206,411,000 | 709,791,000 | 2,875,422,000 | 895,369,000 | 618,467,000 | 43,765,000 | 48,000 | 16,731,000 | | | |
| Forecast kW | **CDEM** | 9,986,854 | | | 6,824,350 | 1,916,044 | 1,118,300 | 123,144 | 216 | | | 4,800 | |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,464,674 | | | 1,706,088 | 479,011 | 279,575 | | | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | **CEN EWMP** | 7,366,004,000 | 2,206,411,000 | 709,791,000 | 2,875,422,000 | 895,369,000 | 618,467,000 | 43,765,000 | 48,000 | 16,731,000 | - | - | - |
| | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |
| Existing Distribution kWh Rate | | | $0.0234 | $0.0210 | | | | | | $0.0219 | | | |
| Existing Distribution kW Rate | | | | | $3.5691 | $3.4887 | $3.3129 | $3.9997 | $10.0361 | | $1.6337 | $1.4985 | $1.6629 |
| Existing TOA Rate | | | | | $0.45 | $0.45 | $0.45 | | | | | | |
| Additional Charges | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $159,421,148 | $87,038,947 | $19,869,160 | $34,845,925 | $10,509,367 | $5,715,350 | $872,268 | $3,651 | $556,350 | $0 | $10,131 | $0 |
| Transformer Ownership Allowance | | $1,109,103 | $0 | $0 | $767,739 | $215,555 | $125,809 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | **CREV** | $158,312,045 | $87,038,947 | $19,869,160 | $34,078,185 | $10,293,812 | $5,589,542 | $872,268 | $3,651 | $556,350 | $0 | $10,131 | $0 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.2 Customer Data Worksheet - 2016-2020 Custom IR - 2018 Model

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ID | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **Billing Data** | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $2,000,008 | $1,354,005 | $422,002 | $150,001 | $74,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $884,964 | $658,889 | $119,577 | $93,649 | $12,109 | $102 | $156 | $104 | $377 | | | |
| Number of Bills | CNB | 4,000,741 | 3,661,730 | 296,863.00 | 40,216.00 | 912.00 | 132.00 | 180.00 | 564.00 | 120.00 | | 24 | |
| Number of Devices | | | | | | | | 55,516 | 47 | 3,573 | | | |
| Number of Connections (Unmetered) | CCON | 7,321 | | | | | | 3,701 | 47 | 3,573 | | | |
| Total Number of Customers | CCA | 333,395 | 305,144 | 24,739 | 3,351 | 76 | 11 | 15 | 47 | 10 | | 2 | |
| Bulk Customer Base | CCB | 333,395 | 305,144 | 24,739 | 3,351 | 76 | 11 | 15 | 47 | 10 | | 2 | |
| Primary Customer Base | CCP | 333,395 | 305,144 | 24,739 | 3,351 | 76 | 11 | 15 | 47 | 10 | | 2 | |
| Line Transformer Customer Base | CCLT | 332,966 | 305,144 | 24,739 | 2,973 | 33 | 5 | 15 | 47 | 10 | | | |
| Secondary Customer Base | CCS | 331,630 | 305,144 | 24,739 | 1,676 | | | 15 | 47 | 10 | | | |
| Weighted - Services | CWCS | 378,699 | 305,144 | 49,477 | 16,757 | - | - | 3,701 | 47 | 3,573 | - | - | - |
| Weighted Meter -Capital | CWMC | 61,981,642 | 45,164,084 | 9,232,122 | 6,695,436 | 760,000 | 110,000 | - | - | - | - | 20,000 | - |
| Weighted Meter Reading | CWMR | 511,414 | 305,144 | 24,739 | 162,581 | 16,182 | 2,342 | - | - | - | - | 426 | - |
| Weighted Bills | CWNB | 4,258,268 | 3,661,730 | 305,779 | 258,722 | 23,055 | 3,329 | 4,531 | 398 | 125 | - | 598 | - |

## Bad Debt Data

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2010 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2011 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Three-year average** | | **2,000,008** | **1,354,005** | **422,002** | **150,001** | **74,000** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

## SSS Admin Charge Data

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2012 | 979,657 | 895,929 | 74,332 | 9,078 | 226 | 35 | 56 | | 2 | | | |
| **Historic Year:** | 2013 | 896,212 | 819,690 | 67,433 | 8,586 | 214 | 30 | - 12 | | 270 | | | |
| **Historic Year:** | 2014 | 920,026 | 842,937 | 67,671 | 8,715 | 253 | 30 | 21 | | 398 | | | |
| **Three-year average** | | **1,147,299** | **852,852** | **210,480** | **58,794** | **24,897** | **32** | **22** | **-** | **224** | **-** | **-** | **-** |

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# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I8 Demand Data Worksheet - 2016-2020 Custom IR - 2018 Model

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| Customer Classes | | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 1,267,602 | 435,054 | 149,655 | 494,585 | 109,276 | 77,293 | - | - | 1,740 | | - | |
| Bulk Delivery CP | BCP1 | 1,267,602 | 435,054 | 149,655 | 494,585 | 109,276 | 77,293 | - | - | 1,740 | - | - | |
| Total Sytem CP | DCP1 | 1,267,602 | 435,054 | 149,655 | 494,585 | 109,276 | 77,293 | - | - | 1,740 | - | - | |
| **4 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 4,952,332 | 1,784,940 | 480,173 | 1,869,197 | 477,895 | 315,302 | 17,420 | 13 | 7,391 | | - | |
| Bulk Delivery CP | BCP4 | 4,952,332 | 1,784,940 | 480,173 | 1,869,197 | 477,895 | 315,302 | 17,420 | 13 | 7,391 | - | - | |
| Total Sytem CP | DCP4 | 4,952,332 | 1,784,940 | 480,173 | 1,869,197 | 477,895 | 315,302 | 17,420 | 13 | 7,391 | - | - | |
| **12 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 13,710,594 | 4,685,463 | 1,358,391 | 5,223,220 | 1,423,600 | 946,663 | 50,411 | 42 | 22,576 | | 230 | |
| Bulk Delivery CP | BCP12 | 13,710,594 | 4,685,463 | 1,358,391 | 5,223,220 | 1,423,600 | 946,663 | 50,411 | 42 | 22,576 | - | 230 | |
| Total Sytem CP | DCP12 | 13,710,594 | 4,685,463 | 1,358,391 | 5,223,220 | 1,423,600 | 946,663 | 50,411 | 42 | 22,576 | - | 230 | |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 1,443,818 | 495,101 | 149,655 | 513,806 | 162,654 | 105,290 | 13,873 | 12 | 2,276 | | 1,152 | |
| Primary NCP | PNCP1 | 1,443,818 | 495,101 | 149,655 | 513,806 | 162,654 | 105,290 | 13,873 | 12 | 2,276 | | 1,152 | |
| Line Transformer NCP | LTNCP1 | 1,229,661 | 495,101 | 149,655 | 447,011 | 71,567 | 49,486 | 13,873 | 12 | 2,276 | - | 680 | |
| Secondary NCP | SNCP1 | 917,820 | 495,101 | 149,655 | 256,903 | | | 13,873 | 12 | 2,276 | - | | |
| **4 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 5,610,210 | 1,952,732 | 563,804 | 1,995,184 | 627,182 | 404,858 | 53,619 | 46 | 8,949 | | 3,836 | |
| Primary NCP | PNCP4 | 5,610,210 | 1,952,732 | 563,804 | 1,995,184 | 627,182 | 404,858 | 53,619 | 46 | 8,949 | | 3,836 | |
| Line Transformer NCP | LTNCP4 | 4,817,385 | 1,952,732 | 563,804 | 1,769,728 | 275,960 | 190,284 | 53,619 | 46 | 8,949 | - | 2,263 | |
| Secondary NCP | SNCP4 | 3,576,742 | 1,952,732 | 563,804 | 997,592 | | | 53,619 | 46 | 8,949 | - | | |
| **12 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 15,516,859 | 5,416,339 | 1,542,892 | 5,599,216 | 1,703,041 | 1,090,940 | 130,651 | 112 | 26,011 | | 7,657 | |
| Primary NCP | PNCP12 | 15,516,859 | 5,416,339 | 1,542,892 | 5,599,216 | 1,703,041 | 1,090,940 | 130,651 | 112 | 26,011 | | 7,657 | |
| Line Transformer NCP | LTNCP12 | 13,253,921 | 5,416,339 | 1,542,892 | 4,871,318 | 749,338 | 512,742 | 130,651 | 112 | 26,011 | - | 4,517 | |
| Secondary NCP | SNCP12 | 9,915,614 | 5,416,339 | 1,542,892 | 2,799,608 | | | 130,651 | 112 | 26,011 | - | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet O1 Revenue to Cost Summary Worksheet - 2016-2020 Custom IR - 2018 Model

**Instructions:**
Please see the first tab in this workbook for detailed instructions

### Class Revenue, Cost Analysis, and Return on Rate Base

| Rate Base Assets | | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $158,312,045 | $87,038,947 | $19,869,160 | $34,078,185 | $10,293,812 | $5,589,542 | $872,268 | $3,651 | $556,350 | $0 | $10,131 | $0 |
| mi | Miscellaneous Revenue (mi) | $11,722,041 | $7,848,216 | $1,230,322 | $1,870,670 | $448,049 | $248,503 | $53,791 | $681 | $18,989 | $0 | $2,820 | $0 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | $170,034,086 | $94,887,162 | $21,099,482 | $35,948,855 | $10,741,861 | $5,838,045 | $926,059 | $4,331 | $575,339 | $0 | $12,951 | $0 |
| | Factor required to recover deficiency (1 + D) | 1.2406 | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $196,398,374 | $107,978,566 | $24,649,235 | $42,276,633 | $12,770,272 | $6,934,260 | $1,082,117 | $4,529 | $690,195 | $0 | $12,568 | $0 |
| | Miscellaneous Revenue (mi) | $11,722,041 | $7,848,216 | $1,230,322 | $1,870,670 | $448,049 | $248,503 | $53,791 | $681 | $18,989 | $0 | $2,820 | $0 |
| | **Total Revenue at Status Quo Rates** | $208,120,414 | $115,826,781 | $25,879,557 | $44,147,303 | $13,218,321 | $7,182,763 | $1,135,908 | $5,210 | $709,184 | $0 | $15,388 | $0 |
| | **Expenses** | | | | | | | | | | | | |
| di | Distribution Costs (di) | $30,216,898 | $14,621,579 | $3,123,653 | $8,354,668 | $2,241,806 | $1,457,397 | $294,373 | $1,231 | $110,009 | $0 | $12,182 | $0 |
| cu | Customer Related Costs (cu) | $18,190,101 | $14,797,938 | $1,798,612 | $1,364,399 | $193,961 | $16,750 | $13,822 | $1,214 | $381 | $0 | $3,023 | $0 |
| ad | General and Administration (ad) | $44,443,438 | $26,607,181 | $4,529,330 | $9,175,836 | $2,311,430 | $1,408,968 | $290,262 | $2,196 | $104,118 | $0 | $14,118 | $0 |
| dep | Depreciation and Amortization (dep) | $47,047,409 | $23,789,276 | $5,124,596 | $12,382,131 | $3,160,827 | $2,030,836 | $392,933 | $1,618 | $147,797 | $0 | $17,394 | $0 |
| INPUT | PILs (INPUT) | $6,074,211 | $2,868,390 | $637,988 | $1,735,001 | $459,280 | $298,425 | $53,343 | $205 | $19,352 | $0 | $2,227 | $0 |
| INT | Interest | $24,193,293 | $11,424,662 | $2,541,076 | $6,910,425 | $1,829,292 | $1,188,611 | $212,462 | $815 | $77,080 | $0 | $8,870 | $0 |
| | **Total Expenses** | $170,165,350 | $94,109,027 | $17,755,255 | $39,922,460 | $10,196,596 | $6,400,987 | $1,257,194 | $7,279 | $458,738 | $0 | $57,815 | $0 |
| | **Direct Allocation** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| NI | Allocated Net Income (NI) | $37,955,064 | $17,923,306 | $3,986,506 | $10,841,253 | $2,869,841 | $1,864,723 | $333,315 | $1,279 | $120,924 | $0 | $13,916 | $0 |
| | **Revenue Requirement (includes NI)** | $208,120,414 | $112,032,332 | $21,741,761 | $50,763,713 | $13,066,436 | $8,265,710 | $1,590,510 | $8,558 | $579,662 | $0 | $71,732 | $0 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $957,393,232 | $460,616,916 | $101,366,866 | $267,795,932 | $70,235,022 | $45,547,981 | $8,364,320 | $33,006 | $3,082,339 | $0 | $350,850 | $0 |
| gp | General Plant - Gross | $163,835,149 | $77,990,891 | $17,221,148 | $46,395,669 | $12,230,259 | $7,947,059 | $1,451,508 | $5,689 | $532,815 | $0 | $60,110 | $0 |
| accum dep | Accumulated Depreciation | ($206,506,577) | ($103,170,301) | ($22,439,174) | ($55,156,040) | ($14,181,492) | ($9,125,144) | ($1,711,790) | ($6,931) | ($640,350) | $0 | ($75,354) | $0 |
| co | Capital Contribution | ($42,162,480) | ($23,020,312) | ($4,494,072) | ($10,043,156) | ($2,402,547) | ($1,562,388) | ($433,740) | ($2,256) | ($188,351) | $0 | ($15,659) | $0 |
| | **Total Net Plant** | $872,559,324 | $412,417,195 | $91,654,767 | $248,992,404 | $65,881,243 | $42,807,509 | $7,670,299 | $29,509 | $2,786,452 | $0 | $319,948 | $0 |
| | **Directly Allocated Net Fixed Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| COP | Cost of Power (COP) | $947,558,773 | $285,391,883 | $91,246,474 | $368,891,926 | $114,864,148 | $79,341,238 | $5,642,837 | $6,519 | $2,173,747 | $0 | $0 | $0 |
| | OM&A Expenses | $92,850,437 | $56,026,698 | $9,451,594 | $18,894,904 | $4,747,196 | $2,883,115 | $598,457 | $4,641 | $214,508 | $0 | $29,323 | $0 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | *$1,040,409,211* | *$341,418,581* | *$100,698,068* | *$387,786,830* | *$119,611,345* | *$82,224,354* | *$6,241,294* | *$11,160* | *$2,388,255* | *$0* | *$29,323* | *$0* |
| | **Working Capital** | $147,738,108 | $48,481,439 | $14,299,126 | $55,065,730 | $16,984,811 | $11,675,858 | $886,264 | $1,585 | $339,132 | $0 | $4,164 | $0 |
| | **Total Rate Base** | $1,020,297,432 | $460,898,633 | $105,953,893 | $304,058,134 | $82,866,054 | $54,483,367 | $8,556,563 | $31,093 | $3,125,584 | $0 | $324,111 | $0 |
| | | Rate Base Input equals Output | | | | | | | | | | | |
| | **Equity Component of Rate Base** | $408,118,973 | $184,359,453 | $42,381,557 | $121,623,254 | $33,146,422 | $21,793,347 | $3,422,625 | $12,437 | $1,250,234 | $0 | $129,645 | $0 |
| | **Net Income on Allocated Assets** | $37,952,627 | $21,717,755 | $8,124,302 | $4,224,843 | $3,021,726 | $781,776 | ($121,287) | ($2,069) | $250,447 | $0 | ($44,865) | $0 |
| | **Net Income on Direct Allocation Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **Net Income** | $37,952,627 | $21,717,755 | $8,124,302 | $4,224,843 | $3,021,726 | $781,776 | ($121,287) | ($2,069) | $250,447 | $0 | ($44,865) | $0 |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | 103.39% | 119.03% | 86.97% | 101.16% | 86.90% | 71.42% | 60.87% | 122.34% | 0.00% | 21.45% | 0.00% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | ($38,086,329) | ($17,145,170) | ($642,279) | ($14,814,858) | ($2,324,575) | ($2,427,665) | ($664,450) | ($4,227) | ($4,323) | $0 | ($58,781) | $0 |
| | | Deficiency Input equals Output | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | ($0) | $3,794,449 | $4,137,796 | ($6,616,410) | $151,885 | ($1,082,947) | ($454,602) | ($3,349) | $129,522 | $0 | ($56,344) | $0 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 9.30% | 11.78% | 19.17% | 3.47% | 9.12% | 3.59% | -3.54% | -16.64% | 20.03% | 0.00% | -34.61% | 0.00% |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016-2020 Custom IR - 2018 Model**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

| | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summary** | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| Customer Unit Cost per month - Avoided Cost | $4.87 | $7.71 | $44.94 | $183.53 | $93.94 | $0.23 | $1.95 | -$0.03 | 0 | $217.00 | 0 |
| Customer Unit Cost per month - Directly Related | $8.30 | $12.23 | $74.96 | $312.61 | $223.72 | $0.52 | $3.87 | -$0.02 | 0 | $342.55 | 0 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $17.92 | $26.64 | $106.93 | $569.99 | $637.08 | $9.53 | $14.79 | $8.77 | 0 | $280.23 | 0 |
| Existing Approved Fixed Charge | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.1 Revenue Worksheet - 2016-2020 Custom IR - 2019 Model

| | |
|---|---|
| **Total kWhs from Load Forecast** | 7,364,071,000 |
| **Total kWs from Load Forecast** | 9,962,801 |
| **Deficiency/sufficiency ( RRWF 8. cell F51)** | - 41,952,858 |
| **Miscellaneous Revenue (RRWF 5. cell F48)** | 11,801,959 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ID** | **Total** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| **Billing Data** | | | | | | | | | | | | | |
| Forecast kWh | **CEN** | 7,364,071,000 | 2,214,984,000 | 704,193,000 | 2,852,593,000 | 914,569,000 | 617,036,000 | 43,876,000 | 48,000 | 16,772,000 | | | |
| Forecast kW | **CDEM** | 9,962,801 | | | 6,761,930 | 1,957,009 | 1,115,702 | 123,144 | 216 | | | 4,800 | |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,458,660 | | | 1,690,483 | 489,252 | 278,926 | | | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | **CEN EWMP** | 7,364,071,000 | 2,214,984,000 | 704,193,000 | 2,852,593,000 | 914,569,000 | 617,036,000 | 43,876,000 | 48,000 | 16,772,000 | - | - | - |
| | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |
| Existing Distribution kWh Rate | | | $0.0234 | $0.0210 | | | | | | $0.0219 | | | |
| Existing Distribution kW Rate | | | | | $3.5691 | $3.4887 | $3.3129 | $3.9997 | $10.0361 | | $1.6337 | $1.4985 | $1.6629 |
| Existing TOA Rate | | | | | $0.45 | $0.45 | $0.45 | | | | | | |
| Additional Charges | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $159,976,740 | $87,685,777 | $19,773,873 | $34,712,342 | $10,652,281 | $5,706,743 | $872,268 | $3,525 | $559,799 | $0 | $10,131 | $0 |
| Transformer Ownership Allowance | | $1,106,397 | $0 | $0 | $760,717 | $220,164 | $125,516 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | **CREV** | $158,870,343 | $87,685,777 | $19,773,873 | $33,951,625 | $10,432,118 | $5,581,227 | $872,268 | $3,525 | $559,799 | $0 | $10,131 | $0 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.2 Customer Data Worksheet - 2016-2020 Custom IR - 2019 Model

| | ID | Total | 1<br>Residential | 2<br>GS <50 | 3<br>GS 50 to 1,499 kW | 4<br>GS 1,500 to 4,999 kW | 6<br>Large Use | 7<br>Street Light | 8<br>Sentinel | 9<br>Unmetered Scattered Load | 11<br>Standby Power GS 50 to 1,499 kW | 12<br>Standby Power GS 1,500 to 4,999 kW | 13<br>Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billing Data** | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $2,000,008 | $1,354,005 | $422,002 | $150,001 | $74,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $884,964 | $658,889 | $119,577 | $93,649 | $12,109 | $102 | $156 | $104 | $377 | | | |
| Number of Bills | CNB | 4,048,512 | 3,707,875 | 298,195.00 | 40,558.00 | 912.00 | 132.00 | 180.00 | 516.00 | 120.00 | | 24 | |
| Number of Devices | | | | | | | | 55,516 | 43 | 3,621 | | | |
| Number of Connections (Unmetered) | CCON | 7,365 | | | | | | 3,701 | 43 | 3,621 | | | |
| Total Number of Customers | CCA | 337,376 | 308,990 | 24,850 | 3,380 | 76 | 11 | 15 | 43 | 10 | | 2 | |
| Bulk Customer Base | CCB | 337,376 | 308,990 | 24,850 | 3,380 | 76 | 11 | 15 | 43 | 10 | | 2 | |
| Primary Customer Base | CCP | 337,376 | 308,990 | 24,850 | 3,380 | 76 | 11 | 15 | 43 | 10 | | 2 | |
| Line Transformer Customer Base | CCLT | 336,944 | 308,990 | 24,850 | 2,998 | 33 | 5 | 15 | 43 | 10 | | | |
| Secondary Customer Base | CCS | 335,597 | 308,990 | 24,850 | 1,690 | | | 15 | 43 | 10 | | | |
| Weighted - Services | CWCS | 382,953 | 308,990 | 49,699 | 16,899 | - | - | 3,701 | 43 | 3,621 | - | - | - |
| Weighted Meter -Capital | CWMC | 62,682,668 | 45,725,600 | 9,273,525 | 6,793,543 | 760,000 | 110,000 | - | - | - | - | 20,000 | - |
| Weighted Meter Reading | CWMR | 516,753 | 308,990 | 24,850 | 163,964 | 16,182 | 2,342 | - | - | - | - | 426 | - |
| Weighted Bills | CWNB | 4,307,951 | 3,707,875 | 307,151 | 260,922 | 23,055 | 3,329 | 4,531 | 364 | 125 | - | 598 | - |

## Bad Debt Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2010 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2011 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Three-year average** | | **2,000,008** | **1,354,005** | **422,002** | **150,001** | **74,000** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

## SSS Admin Charge Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2012 | 979,657 | 895,929 | 74,332 | 9,078 | 226 | 35 | 56 | | 2 | | | |
| **Historic Year:** | 2013 | 896,212 | 819,690 | 67,433 | 8,586 | 214 | 30 | - 12 | | 270 | | | |
| **Historic Year:** | 2014 | 920,026 | 842,937 | 67,671 | 8,715 | 253 | 30 | 21 | | 398 | | | |
| **Three-year average** | | **1,147,299** | **852,852** | **210,480** | **58,794** | **24,897** | **32** | **22** | **-** | **224** | **-** | **-** | **-** |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet I8 Demand Data Worksheet - 2016-2020 Custom IR - 2019 Model**

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| | | | January 1, 1900 | January 2, 1900 | January 3, 1900 | January 4, 1900 | January 6, 1900 | January 7, 1900 | January 8, 1900 | January 9, 1900 | January 11, 1900 | January 12, 1900 | January 13, 1900 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Classes** | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 1,266,355 | 436,746 | 148,474 | 490,658 | 111,619 | 77,114 | - | - | 1,744 | | - | |
| Bulk Delivery CP | BCP1 | 1,266,355 | 436,746 | 148,474 | 490,658 | 111,619 | 77,114 | - | - | 1,744 | - | - | |
| Total Sytem CP | DCP1 | 1,266,355 | 436,746 | 148,474 | 490,658 | 111,619 | 77,114 | - | - | 1,744 | - | - | |
| **4 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 4,950,222 | 1,791,878 | 476,386 | 1,854,357 | 488,143 | 314,572 | 17,464 | 12 | 7,410 | | - | |
| Bulk Delivery CP | BCP4 | 4,950,222 | 1,791,878 | 476,386 | 1,854,357 | 488,143 | 314,572 | 17,464 | 12 | 7,410 | - | - | |
| Total Sytem CP | DCP4 | 4,950,222 | 1,791,878 | 476,386 | 1,854,357 | 488,143 | 314,572 | 17,464 | 12 | 7,410 | - | - | |
| **12 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 13,705,140 | 4,703,675 | 1,347,677 | 5,181,751 | 1,454,127 | 944,473 | 50,539 | 38 | 22,631 | | 230 | |
| Bulk Delivery CP | BCP12 | 13,705,140 | 4,703,675 | 1,347,677 | 5,181,751 | 1,454,127 | 944,473 | 50,539 | 38 | 22,631 | - | 230 | |
| Total Sytem CP | DCP12 | 13,705,140 | 4,703,675 | 1,347,677 | 5,181,751 | 1,454,127 | 944,473 | 50,539 | 38 | 22,631 | - | 230 | |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 1,443,767 | 497,026 | 148,474 | 509,727 | 166,142 | 105,046 | 13,908 | 11 | 2,282 | | 1,152 | |
| Primary NCP | PNCP1 | 1,443,767 | 497,026 | 148,474 | 509,727 | 166,142 | 105,046 | 13,908 | 11 | 2,282 | | 1,152 | |
| Line Transformer NCP | LTNCP1 | 1,228,317 | 497,026 | 148,474 | 443,462 | 73,102 | 49,372 | 13,908 | 11 | 2,282 | - | 680 | |
| Secondary NCP | SNCP1 | 916,565 | 497,026 | 148,474 | 254,864 | | | 13,908 | 11 | 2,282 | - | | |
| **4 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 5,610,179 | 1,960,323 | 559,357 | 1,979,344 | 640,631 | 403,922 | 53,755 | 42 | 8,971 | | 3,836 | |
| Primary NCP | PNCP4 | 5,610,179 | 1,960,323 | 559,357 | 1,979,344 | 640,631 | 403,922 | 53,755 | 42 | 8,971 | | 3,836 | |
| Line Transformer NCP | LTNCP4 | 4,812,109 | 1,960,323 | 559,357 | 1,755,678 | 281,877 | 189,844 | 53,755 | 42 | 8,971 | - | 2,263 | |
| Secondary NCP | SNCP4 | 3,572,120 | 1,960,323 | 559,357 | 989,672 | | | 53,755 | 42 | 8,971 | - | | |
| **12 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 15,515,671 | 5,437,392 | 1,530,723 | 5,554,762 | 1,739,561 | 1,088,415 | 130,983 | 103 | 26,075 | | 7,657 | |
| Primary NCP | PNCP12 | 15,515,671 | 5,437,392 | 1,530,723 | 5,554,762 | 1,739,561 | 1,088,415 | 130,983 | 103 | 26,075 | | 7,657 | |
| Line Transformer NCP | LTNCP12 | 13,239,399 | 5,437,392 | 1,530,723 | 4,832,643 | 765,407 | 511,556 | 130,983 | 103 | 26,075 | - | 4,517 | |
| Secondary NCP | SNCP12 | 9,902,658 | 5,437,392 | 1,530,723 | 2,777,381 | | | 130,983 | 103 | 26,075 | - | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet O1 Revenue to Cost Summary Worksheet - 2016-2020 Custom IR - 2019 Model**

**Instructions:**
**Please see the first tab in this workbook for detailed instructions**

**Class Revenue, Cost Analysis, and Return on Rate Base**

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Base Assets | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| crev | Distribution Revenue at Existing Rates | $158,870,343 | $87,685,777 | $19,773,873 | $33,951,625 | $10,432,118 | $5,581,227 | $872,268 | $3,525 | $559,799 | $0 | $10,131 | $0 |
| mi | Miscellaneous Revenue (mi) | $11,801,959 | $7,911,040 | $1,232,430 | $1,872,837 | $459,183 | $249,729 | $54,190 | $628 | $19,076 | $0 | $2,847 | $0 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | **$170,672,303** | **$95,596,817** | **$21,006,304** | **$35,824,462** | **$10,891,301** | **$5,830,956** | **$926,459** | **$4,153** | **$578,875** | **$0** | **$12,978** | **$0** |
| | Factor required to recover deficiency (1 + D) | 1.2967 | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $206,014,098 | $113,705,968 | $25,641,643 | $44,026,552 | $13,527,782 | $7,237,420 | $1,131,109 | $4,571 | $725,916 | $0 | $13,137 | $0 |
| | Miscellaneous Revenue (mi) | $11,801,959 | $7,911,040 | $1,232,430 | $1,872,837 | $459,183 | $249,729 | $54,190 | $628 | $19,076 | $0 | $2,847 | $0 |
| | **Total Revenue at Status Quo Rates** | **$217,816,057** | **$121,617,008** | **$26,874,074** | **$45,899,389** | **$13,986,965** | **$7,487,149** | **$1,185,299** | **$5,199** | **$744,992** | **$0** | **$15,984** | **$0** |
| | **Expenses** | | | | | | | | | | | | |
| di | Distribution Costs (di) | $31,197,437 | $15,119,889 | $3,202,453 | $8,572,257 | $2,367,689 | $1,503,269 | $304,627 | $1,149 | $113,418 | $0 | $12,685 | $0 |
| cu | Customer Related Costs (cu) | $18,780,370 | $15,291,556 | $1,847,227 | $1,406,872 | $198,902 | $17,099 | $14,105 | $1,134 | $389 | $0 | $3,086 | $0 |
| ad | General and Administration (ad) | $45,885,628 | $27,502,361 | $4,645,820 | $9,422,317 | $2,436,907 | $1,453,710 | $300,436 | $2,050 | $107,366 | $0 | $14,660 | $0 |
| dep | Depreciation and Amortization (dep) | $48,948,694 | $24,809,227 | $5,293,354 | $12,796,590 | $3,357,162 | $2,107,807 | $410,904 | $1,527 | $153,832 | $0 | $18,291 | $0 |
| INPUT | PILs (INPUT) | $8,472,655 | $3,998,747 | $882,118 | $2,410,536 | $657,962 | $417,677 | $75,194 | $259 | $26,994 | $0 | $3,169 | $0 |
| INT | Interest | $25,444,336 | $12,008,687 | $2,649,099 | $7,239,110 | $1,975,935 | $1,254,330 | $225,816 | $778 | $81,065 | $0 | $9,517 | $0 |
| | **Total Expenses** | **$178,729,119** | **$98,730,467** | **$18,520,071** | **$41,847,681** | **$10,994,556** | **$6,753,892** | **$1,331,082** | **$6,898** | **$483,065** | **$0** | **$61,408** | **$0** |
| | **Direct Allocation** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| NI | Allocated Net Income (NI) | $39,086,938 | $18,447,438 | $4,069,479 | $11,120,535 | $3,035,380 | $1,926,870 | $346,893 | $1,195 | $124,529 | $0 | $14,619 | $0 |
| | **Revenue Requirement (includes NI)** | $217,816,057 | $117,177,906 | $22,589,550 | $52,968,216 | $14,029,936 | $8,680,762 | $1,677,974 | $8,092 | $607,594 | $0 | $76,027 | $0 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $1,046,540,206 | $505,170,331 | $110,014,196 | $290,370,008 | $78,341,662 | $49,624,744 | $9,217,745 | $32,875 | $3,378,951 | $0 | $389,693 | $0 |
| gp | General Plant - Gross | $174,532,512 | $83,188,504 | $18,190,177 | $49,135,949 | $13,342,663 | $8,470,270 | $1,564,141 | $5,529 | $570,022 | $0 | $65,256 | $0 |
| accum dep | Accumulated Depreciation | ($261,683,191) | ($131,079,107) | ($28,214,604) | ($69,410,064) | ($18,340,904) | ($11,534,700) | ($2,183,943) | ($8,012) | ($815,615) | $0 | ($96,243) | $0 |
| co | Capital Contribution | ($54,158,154) | ($29,618,774) | ($5,732,975) | ($12,823,650) | ($3,156,574) | ($2,005,291) | ($556,134) | ($2,622) | ($241,993) | $0 | ($20,141) | $0 |
| | **Total Net Plant** | **$905,231,373** | **$427,660,954** | **$94,256,795** | **$257,272,244** | **$70,186,847** | **$44,555,023** | **$8,041,809** | **$27,771** | **$2,891,364** | **$0** | **$338,565** | **$0** |
| | **Directly Allocated Net Fixed Assets** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| COP | Cost of Power (COP) | $928,733,588 | $279,346,850 | $88,810,617 | $359,760,102 | $115,342,580 | $77,818,649 | $5,533,504 | $6,054 | $2,115,232 | $0 | $0 | $0 |
| | OM&A Expenses | $95,863,434 | $57,913,807 | $9,695,500 | $19,401,446 | $5,003,498 | $2,974,077 | $619,168 | $4,334 | $221,174 | $0 | $30,431 | $0 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | ***$1,024,597,022*** | ***$337,260,657*** | ***$98,506,117*** | ***$379,161,547*** | ***$120,346,078*** | ***$80,792,727*** | ***$6,152,672*** | ***$10,387*** | ***$2,336,406*** | ***$0*** | ***$30,431*** | ***$0*** |
| | **Working Capital** | **$145,492,777** | **$47,891,013** | **$13,987,869** | **$53,840,940** | **$17,089,143** | **$11,472,567** | **$873,679** | **$1,475** | **$331,770** | **$0** | **$4,321** | **$0** |
| | **Total Rate Base** | **$1,050,724,150** | **$475,551,968** | **$108,244,663** | **$311,113,183** | **$87,275,990** | **$56,027,590** | **$8,915,489** | **$29,246** | **$3,223,134** | **$0** | **$342,887** | **$0** |
| | | Rate Base Input equals Output | | | | | | | | | | | |
| | **Equity Component of Rate Base** | **$420,289,660** | **$190,220,787** | **$43,297,865** | **$124,445,273** | **$34,910,396** | **$22,411,036** | **$3,566,195** | **$11,698** | **$1,289,254** | **$0** | **$137,155** | **$0** |
| | **Net Income on Allocated Assets** | **$39,083,932** | **$22,886,541** | **$8,354,003** | **$4,051,708** | **$2,992,409** | **$733,257** | **($145,783)** | **($1,699)** | **$261,927** | **$0** | **($48,430)** | **$0** |
| | **Net Income on Direct Allocation Assets** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| | **Net Income** | **$39,083,932** | **$22,886,541** | **$8,354,003** | **$4,051,708** | **$2,992,409** | **$733,257** | **($145,783)** | **($1,699)** | **$261,927** | **$0** | **($48,430)** | **$0** |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | **100.00%** | **103.79%** | **118.97%** | **86.65%** | **99.69%** | **86.25%** | **70.64%** | **64.24%** | **122.61%** | 0.00% | 21.02% | 0.00% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | **($47,143,755)** | ($21,581,089) | ($1,583,246) | ($17,143,754) | ($3,138,635) | ($2,849,807) | ($751,515) | ($3,940) | ($28,719) | $0 | ($63,049) | $0 |
| | | Deficiency Input Does Not Equal Output | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | **($0)** | $4,439,103 | $4,284,524 | ($7,068,828) | ($42,971) | ($1,193,613) | ($492,675) | ($2,894) | $137,398 | $0 | ($60,043) | $0 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 9.30% | 12.03% | 19.29% | 3.26% | 8.57% | 3.27% | -4.09% | -14.52% | 20.32% | 0.00% | -35.31% | 0.00% |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016-2020 Custom IR - 2019 Model**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

| | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summary** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| Customer Unit Cost per month - Avoided Cost | $4.97 | $7.88 | $46.14 | $186.91 | $96.11 | $0.23 | $1.98 | -$0.03 | 0 | $221.47 | 0 |
| Customer Unit Cost per month - Directly Related | $8.46 | $12.44 | $76.56 | $317.40 | $227.28 | $0.53 | $3.94 | -$0.02 | 0 | $348.42 | 0 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $18.37 | $27.25 | $109.38 | $588.10 | $667.05 | $9.83 | $15.28 | $9.04 | 0 | $281.17 | 0 |
| Existing Approved Fixed Charge | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

**Sheet I6.1 Revenue Worksheet - 2016-2020 Custom IR - 2020 Model**

| | |
|---|---|
| **Total kWhs from Load Forecast** | 7,364,398,000 |
| **Total kWs from Load Forecast** | 9,953,606 |
| **Deficiency/sufficiency ( RRWF 8. cell F51)** | - 53,173,530 |
| **Miscellaneous Revenue (RRWF 5. cell F48)** | 11,897,833 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ID** | **Total** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| **Billing Data** | | | | | | | | | | | | | |
| Forecast kWh | **CEN** | 7,364,398,000 | 2,217,628,000 | 699,744,000 | 2,835,387,000 | 935,554,000 | 615,195,000 | 44,015,000 | 48,000 | 16,827,000 | | | |
| Forecast kW | **CDEM** | 9,953,606 | | | 6,711,579 | 2,001,525 | 1,112,342 | 123,144 | 216 | | | 4,800 | |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,456,362 | | | 1,677,895 | 500,381 | 278,086 | | | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | **CEN EWMP** | 7,364,398,000 | 2,217,628,000 | 699,744,000 | 2,835,387,000 | 935,554,000 | 615,195,000 | 44,015,000 | 48,000 | 16,827,000 | - | - | - |
| | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |
| Existing Distribution kWh Rate | | | $0.0234 | $0.0210 | | | | | | $0.0219 | | | |
| Existing Distribution kW Rate | | | | | $3.5691 | $3.4887 | $3.3129 | $3.9997 | $10.0361 | | $1.6337 | $1.4985 | $1.6629 |
| Existing TOA Rate | | | | | $0.45 | $0.45 | $0.45 | | | | | | |
| Additional Charges | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $160,463,532 | $88,188,231 | $19,702,481 | $34,620,270 | $10,807,584 | $5,695,612 | $872,268 | $3,399 | $563,555 | $0 | $10,131 | $0 |
| Transformer Ownership Allowance | | $1,105,363 | $0 | $0 | $755,053 | $225,172 | $125,138 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | **CREV** | $159,358,170 | $88,188,231 | $19,702,481 | $33,865,217 | $10,582,413 | $5,570,474 | $872,268 | $3,399 | $563,555 | $0 | $10,131 | $0 |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I6.2 Customer Data Worksheet - 2016-2020 Custom IR - 2020 Model

| | ID | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billing Data** | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $2,000,008 | $1,354,005 | $422,002 | $150,001 | $74,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $884,964 | $658,889 | $119,577 | $93,649 | $12,109 | $102 | $156 | $104 | $377 | | | |
| Number of Bills | CNB | 4,095,680 | 3,753,437 | 299,513.00 | 40,894.00 | 912.00 | 132.00 | 180.00 | 468.00 | 120.00 | | 24 | |
| Number of Devices | | | | | | | | 55,516 | 39 | 3,669 | | | |
| Number of Connections (Unmetered) | CCON | 7,409 | | | | | | 3,701 | 39 | 3,669 | | | |
| Total Number of Customers | CCA | 341,307 | 312,786 | 24,959 | 3,408 | 76 | 11 | 15 | 39 | 10 | | 2 | |
| Bulk Customer Base | CCB | 341,307 | 312,786 | 24,959 | 3,408 | 76 | 11 | 15 | 39 | 10 | | 2 | |
| Primary Customer Base | CCP | 341,307 | 312,786 | 24,959 | 3,408 | 76 | 11 | 15 | 39 | 10 | | 2 | |
| Line Transformer Customer Base | CCLT | 340,871 | 312,786 | 24,959 | 3,023 | 33 | 5 | 15 | 39 | 10 | | | |
| Secondary Customer Base | CCS | 339,514 | 312,786 | 24,959 | 1,704 | | | 15 | 39 | 10 | | | |
| Weighted - Services | CWCS | 387,154 | 312,786 | 49,919 | 17,039 | - | - | 3,701 | 39 | 3,669 | - | - | - |
| Weighted Meter -Capital | CWMC | 63,372,265 | 46,279,816 | 9,314,182 | 6,888,267 | 760,000 | 110,000 | - | - | - | - | 20,000 | - |
| Weighted Meter Reading | CWMR | 522,018 | 312,786 | 24,959 | 165,322 | 16,182 | 2,342 | - | - | - | - | 426 | - |
| Weighted Bills | CWNB | 4,356,999 | 3,753,437 | 308,509 | 263,084 | 23,055 | 3,329 | 4,531 | 330 | 125 | - | 598 | - |

## Bad Debt Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2010 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Historic Year:** | 2011 | 2,000,008 | 1,354,005 | 422,002 | 150,001 | 74,000 | | | | | | | |
| **Three-year average** | | **2,000,008** | **1,354,005** | **422,002** | **150,001** | **74,000** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

## SSS Admin Charge Data

| | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2012 | 979,657 | 895,929 | 74,332 | 9,078 | 226 | 35 | 56 | | 2 | | | |
| **Historic Year:** | 2013 | 896,212 | 819,690 | 67,433 | 8,586 | 214 | 30 | - 12 | | 270 | | | |
| **Historic Year:** | 2014 | 920,026 | 842,937 | 67,671 | 8,715 | 253 | 30 | 21 | | 398 | | | |
| **Three-year average** | | **1,147,299** | **852,852** | **210,480** | **58,794** | **24,897** | **32** | **22** | **-** | **224** | **-** | **-** | **-** |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet I8 Demand Data Worksheet - 2016-2020 Custom IR - 2020 Model

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| | | | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Classes** | | Total | Residential | GS <50 | GS 50 to 1,499 kW | GS 1,500 to 4,999 kW | Large Use | Street Light | Sentinel | Unmetered Scattered Load | Standby Power GS 50 to 1,499 kW | Standby Power GS 1,500 to 4,999 kW | Standby Power Large Use |
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 1,265,316 | 437,267 | 147,536 | 487,699 | 114,180 | 76,884 | - | - | 1,750 | | - | |
| Bulk Delivery CP | BCP1 | 1,265,316 | 437,267 | 147,536 | 487,699 | 114,180 | 76,884 | - | - | 1,750 | - | - | |
| Total Sytem CP | DCP1 | 1,265,316 | 437,267 | 147,536 | 487,699 | 114,180 | 76,884 | - | - | 1,750 | - | - | |
| **4 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 4,948,510 | 1,794,019 | 473,377 | 1,843,172 | 499,344 | 313,634 | 17,520 | 11 | 7,434 | | - | |
| Bulk Delivery CP | BCP4 | 4,948,510 | 1,794,019 | 473,377 | 1,843,172 | 499,344 | 313,634 | 17,520 | 11 | 7,434 | - | - | |
| Total Sytem CP | DCP4 | 4,948,510 | 1,794,019 | 473,377 | 1,843,172 | 499,344 | 313,634 | 17,520 | 11 | 7,434 | - | - | |
| **12 CP** | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 13,701,771 | 4,709,296 | 1,339,163 | 5,150,496 | 1,487,492 | 941,655 | 50,699 | 35 | 22,705 | | 230 | |
| Bulk Delivery CP | BCP12 | 13,701,771 | 4,709,296 | 1,339,163 | 5,150,496 | 1,487,492 | 941,655 | 50,699 | 35 | 22,705 | - | 230 | |
| Total Sytem CP | DCP12 | 13,701,771 | 4,709,296 | 1,339,163 | 5,150,496 | 1,487,492 | 941,655 | 50,699 | 35 | 22,705 | - | 230 | |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 1,443,898 | 497,620 | 147,536 | 506,652 | 169,954 | 104,733 | 13,952 | 10 | 2,289 | | 1,152 | |
| Primary NCP | PNCP1 | 1,443,898 | 497,620 | 147,536 | 506,652 | 169,954 | 104,733 | 13,952 | 10 | 2,289 | | 1,152 | |
| Line Transformer NCP | LTNCP1 | 1,226,878 | 497,620 | 147,536 | 440,787 | 74,779 | 49,224 | 13,952 | 10 | 2,289 | - | 680 | |
| Secondary NCP | SNCP1 | 914,734 | 497,620 | 147,536 | 253,327 | | | 13,952 | 10 | 2,289 | - | | |
| **4 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 5,610,740 | 1,962,665 | 555,823 | 1,967,405 | 655,330 | 402,716 | 53,925 | 38 | 9,000 | | 3,836 | |
| Primary NCP | PNCP4 | 5,610,740 | 1,962,665 | 555,823 | 1,967,405 | 655,330 | 402,716 | 53,925 | 38 | 9,000 | | 3,836 | |
| Line Transformer NCP | LTNCP4 | 4,806,425 | 1,962,665 | 555,823 | 1,745,088 | 288,345 | 189,277 | 53,925 | 38 | 9,000 | - | 2,263 | |
| Secondary NCP | SNCP4 | 3,565,155 | 1,962,665 | 555,823 | 983,703 | | | 53,925 | 38 | 9,000 | - | | |
| **12 NCP** | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 15,516,152 | 5,443,890 | 1,521,052 | 5,521,257 | 1,779,475 | 1,085,168 | 131,398 | 94 | 26,161 | | 7,657 | |
| Primary NCP | PNCP12 | 15,516,152 | 5,443,890 | 1,521,052 | 5,521,257 | 1,779,475 | 1,085,168 | 131,398 | 94 | 26,161 | | 7,657 | |
| Line Transformer NCP | LTNCP12 | 13,223,604 | 5,443,890 | 1,521,052 | 4,803,494 | 782,969 | 510,029 | 131,398 | 94 | 26,161 | - | 4,517 | |
| Secondary NCP | SNCP12 | 9,883,224 | 5,443,890 | 1,521,052 | 2,760,629 | | | 131,398 | 94 | 26,161 | - | | |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet O1 Revenue to Cost Summary Worksheet - 2016-2020 Custom IR - 2020 Model

**Instructions:**
Please see the first tab in this workbook for detailed instructions

### Class Revenue, Cost Analysis, and Return on Rate Base

| Rate Base Assets | | Total | 1 Residential | 2 GS <50 | 3 GS 50 to 1,499 kW | 4 GS 1,500 to 4,999 kW | 6 Large Use | 7 Street Light | 8 Sentinel | 9 Unmetered Scattered Load | 11 Standby Power GS 50 to 1,499 kW | 12 Standby Power GS 1,500 to 4,999 kW | 13 Standby Power Large Use |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $159,358,170 | $88,188,231 | $19,702,481 | $33,865,217 | $10,582,413 | $5,570,474 | $872,268 | $3,399 | $563,555 | $0 | $10,131 | $0 |
| mi | Miscellaneous Revenue (mi) | $11,897,833 | $7,980,775 | $1,236,650 | $1,880,321 | $471,730 | $251,119 | $54,566 | $576 | $19,234 | $0 | $2,862 | $0 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | $171,256,003 | **$96,169,006** | **$20,939,131** | **$35,745,538** | **$11,054,143** | **$5,821,593** | **$926,835** | **$3,975** | **$582,790** | **$0** | **$12,992** | **$0** |
| | Factor required to recover deficiency (1 + D) | 1.3337 | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $212,531,699 | $117,614,269 | $26,276,669 | $45,165,128 | $14,113,479 | $7,429,191 | $1,163,321 | $4,533 | $751,599 | $0 | $13,511 | $0 |
| | Miscellaneous Revenue (mi) | $11,897,833 | $7,980,775 | $1,236,650 | $1,880,321 | $471,730 | $251,119 | $54,566 | $576 | $19,234 | $0 | $2,862 | $0 |
| | **Total Revenue at Status Quo Rates** | $224,429,532 | **$125,595,044** | **$27,513,318** | **$47,045,449** | **$14,585,209** | **$7,680,310** | **$1,217,887** | **$5,109** | **$770,833** | **$0** | **$16,373** | **$0** |
| | **Expenses** | | | | | | | | | | | | |
| di | Distribution Costs (di) | $32,209,794 | $15,618,392 | $3,286,294 | $8,808,723 | $2,502,142 | $1,548,465 | $314,450 | $1,065 | $117,164 | $0 | $13,098 | $0 |
| cu | Customer Related Costs (cu) | $19,389,793 | $15,801,247 | $1,897,472 | $1,450,608 | $204,010 | $17,459 | $14,399 | $1,050 | $397 | $0 | $3,151 | $0 |
| ad | General and Administration (ad) | $47,374,616 | $28,407,403 | $4,768,483 | $9,690,861 | $2,571,567 | $1,498,346 | $310,066 | $1,899 | $110,880 | $0 | $15,110 | $0 |
| dep | Depreciation and Amortization (dep) | $50,294,804 | $25,564,527 | $5,409,926 | $13,055,502 | $3,512,568 | $2,150,194 | $423,413 | $1,414 | $158,377 | $0 | $18,883 | $0 |
| INPUT | PILs (INPUT) | $7,587,145 | $3,565,649 | $783,690 | $2,159,963 | $607,254 | $375,954 | $67,491 | $207 | $24,094 | $0 | $2,843 | $0 |
| INT | Interest | $26,866,525 | $12,626,172 | $2,775,092 | $7,648,554 | $2,150,322 | $1,331,276 | $238,990 | $732 | $85,318 | $0 | $10,069 | $0 |
| | **Total Expenses** | $183,722,676 | **$101,583,389** | **$18,920,957** | **$42,814,212** | **$11,547,862** | **$6,921,694** | **$1,368,810** | **$6,367** | **$496,231** | **$0** | **$63,154** | **$0** |
| | **Direct Allocation** | $0 | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| NI | Allocated Net Income (NI) | $40,706,856 | $19,130,563 | $4,204,684 | $11,588,719 | $3,258,064 | $2,017,085 | $362,106 | $1,109 | $129,270 | $0 | $15,256 | $0 |
| | **Revenue Requirement (includes NI)** | $224,429,532 | $120,713,953 | $23,125,641 | $54,402,930 | $14,805,926 | $8,938,779 | $1,730,916 | $7,476 | $625,501 | $0 | $78,410 | $0 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $1,142,410,295 | $551,403,217 | $119,336,173 | $315,785,070 | $87,573,426 | $54,087,767 | $10,077,631 | $32,195 | $3,688,732 | $0 | $426,085 | $0 |
| gp | General Plant - Gross | $188,854,630 | $89,800,030 | $19,533,703 | $53,101,919 | $14,839,711 | $9,187,474 | $1,698,398 | $5,366 | $617,285 | $0 | $70,744 | $0 |
| accum dep | Accumulated Depreciation | ($319,007,839) | ($159,876,862) | ($34,169,614) | ($84,261,753) | ($22,872,577) | ($14,030,560) | ($2,672,649) | ($8,799) | ($997,381) | $0 | ($117,644) | $0 |
| co | Capital Contribution | ($66,259,289) | ($36,252,767) | ($6,973,921) | ($15,624,217) | ($3,955,506) | ($2,449,512) | ($679,593) | ($2,878) | ($296,222) | $0 | ($24,673) | $0 |
| | **Total Net Plant** | $945,997,797 | **$445,073,617** | **$97,726,341** | **$269,001,019** | **$75,585,054** | **$46,795,169** | **$8,423,786** | **$25,884** | **$3,012,414** | **$0** | **$354,512** | **$0** |
| | **Directly Allocated Net Fixed Assets** | $0 | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| COP | Cost of Power (COP) | $945,198,501 | $284,625,934 | $89,810,054 | $363,913,458 | $120,075,563 | $78,958,442 | $5,649,194 | $6,161 | $2,159,695 | $0 | $0 | $0 |
| | OM&A Expenses | $98,974,203 | $59,827,042 | $9,952,249 | $19,950,193 | $5,277,718 | $3,064,270 | $638,915 | $4,014 | $228,442 | $0 | $31,359 | $0 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | *$1,044,172,704* | ***$344,452,976*** | ***$99,762,303*** | ***$383,863,651*** | ***$125,353,282*** | ***$82,022,712*** | ***$6,288,109*** | ***$10,174*** | ***$2,388,137*** | ***$0*** | ***$31,359*** | ***$0*** |
| | **Working Capital** | $148,272,524 | **$48,912,323** | **$14,166,247** | **$54,508,638** | **$17,800,166** | **$11,647,225** | **$892,912** | **$1,445** | **$339,115** | **$0** | **$4,453** | **$0** |
| | **Total Rate Base** | $1,094,270,321 | **$493,985,940** | **$111,892,588** | **$323,509,657** | **$93,385,220** | **$58,442,394** | **$9,316,698** | **$27,329** | **$3,351,530** | **$0** | **$358,965** | **$0** |
| | | Rate Base Input equals Output | | | | | | | | | | | |
| | **Equity Component of Rate Base** | $437,708,128 | **$197,594,376** | **$44,757,035** | **$129,403,863** | **$37,354,088** | **$23,376,958** | **$3,726,679** | **$10,932** | **$1,340,612** | **$0** | **$143,586** | **$0** |
| | **Net Income on Allocated Assets** | $40,703,476 | **$24,011,655** | **$8,592,361** | **$4,231,237** | **$3,037,347** | **$758,616** | **($150,923)** | **($1,257)** | **$274,602** | **$0** | **($50,162)** | **$0** |
| | **Net Income on Direct Allocation Assets** | $0 | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| | **Net Income** | $40,703,476 | **$24,011,655** | **$8,592,361** | **$4,231,237** | **$3,037,347** | **$758,616** | **($150,923)** | **($1,257)** | **$274,602** | **$0** | **($50,162)** | **$0** |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | **104.04%** | **118.97%** | **86.48%** | **98.51%** | **85.92%** | **70.36%** | **68.34%** | **123.23%** | 0.00% | 20.88% | 0.00% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | ($53,173,530) | ($24,544,947) | ($2,186,510) | ($18,657,393) | ($3,751,783) | ($3,117,186) | ($804,081) | ($3,501) | ($42,711) | $0 | ($65,417) | $0 |
| | | Deficiency Input equals Output | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | $0 | $4,881,091 | $4,387,677 | ($7,357,482) | ($220,717) | ($1,258,469) | ($513,029) | ($2,367) | $145,332 | $0 | ($62,037) | $0 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 9.30% | 12.15% | 19.20% | 3.27% | 8.13% | 3.25% | -4.05% | -11.50% | 20.48% | 0.00% | -34.94% | 0.00% |

Ontario Energy Board

# 2015 Cost Allocation Model

**EB-2015-0004**

## Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2016-2020 Custom IR - 2020 Model

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

| | 1 | 2 | 3 | 4 | 6 | 7 | 8 | 9 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summary** | **Residential** | **GS <50** | **GS 50 to 1,499 kW** | **GS 1,500 to 4,999 kW** | **Large Use** | **Street Light** | **Sentinel** | **Unmetered Scattered Load** | **Standby Power GS 50 to 1,499 kW** | **Standby Power GS 1,500 to 4,999 kW** | **Standby Power Large Use** |
| Customer Unit Cost per month - Avoided Cost | $5.06 | $8.00 | $47.00 | $188.09 | $93.51 | $0.24 | $2.00 | -$0.03 | 0 | $224.56 | 0 |
| Customer Unit Cost per month - Directly Related | $8.59 | $12.60 | $77.84 | $320.01 | $226.11 | $0.54 | $4.01 | -$0.02 | 0 | $352.79 | 0 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $18.64 | $27.60 | $111.03 | $601.87 | $679.50 | $9.96 | $15.54 | $9.14 | 0 | $283.57 | 0 |
| Existing Approved Fixed Charge | $9.67 | $16.72 | $260.82 | $4,193.93 | $15,231.32 | $0.57 | $2.62 | $4.43 | $122.41 | $122.41 | $122.41 |

# UNMETERED LOADS

Hydro Ottawa Limited ("Hydro Ottawa') is aware of a study being undertaken by Navigant Consulting Limited ("Navigant") and related working group activities examining unmetered loads as initiated by the Ontario Energy Board (OEB) pursuant to the proceeding EB-2012-0383 Review of Cost Allocation Policy for Unmetered Loads. Based on the record of the proceeding, the Navigant study and a revised cost allocation model are expected to be completed prior to the 2016 Board filing requirements release. Should the cost allocation model be updated with the 2016 filing requirements, Hydro Ottawa intends to review the model for any material impacts to the Company's current proposed cost to revenue allocation ratios.

# FIXED/VARIABLE PROPORTION

## 1.0 INTRODUCTION

This Exhibit explains how the proposed rates have been designed in order to collect the requested revenue requirement from 2016 through 2020. The current 2015 and proposed 2016 through 2020 Tariff of Rates and Charges are provided in Exhibit H-10-1. Bill Impacts can be found in Exhibit H-12-1.

Hydro Ottawa Limited ("Hydro Ottawa") is requesting approval of a Base Revenue Requirement in 2016 of $175,570k and Transformer Ownership Credit of $1,125k for total revenue from distribution rates of $176,694k. Please see Table 1 for the requested revenue from distribution rates from 2016 through 2020.

**Table 1 - Revenue from Distribution Rates[1]**

| | 2016<br>**$000** | 2017<br>**$000** | 2018<br>**$000** | 2019<br>**$000** | 2020<br>**$000** |
|---|---|---|---|---|---|
| Base Revenue Requirement | 175,570 | 185,670 | 196,398 | 206,014 | 212,532 |
| Transformer Ownership Credit | 1,125 | 1,114 | 1,109 | 1,106 | 1,105 |
| **Revenue from distribution rates** | **176,694** | **186,784** | **197,507** | **207,120** | **213,637** |

Please see Exhibit F-1-1 for the compilation of revenue required from distribution rates and calculation of revenue deficiency.

## 2.0 FIXED/VARIABLE PROPORTION

The current fixed/variable ratio split was approved as part of Hydro Ottawa's 2012 rate application EB-2011-0054. As part of this application Hydro Ottawa has started to apply the Ontario Energy Board's ("the Board") principles in its Draft Report on Rate Design for

[1] Totals may not match due to rounding

Electricity Distributors (EB-2012-0410). On April 2, 2015 the Board released the Board Policy, A New Distribution Rate Design for Residential Electricity Customers. Hydro Ottawa will wait until the Board's Working Groups has put forth its recommendations prior to incorporating these directions. Table 2 provides Hydro Ottawa's current and proposed fixed/variable ratio split.

**Table 2 - Current and Proposed Fixed/Variable Split**

| | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fixed % | Variable % | Fixed % | Variable % | Fixed % | Variable % | Fixed % | Variable % | Fixed % | Variable % | Fixed % | Variable % |
| Residential | 37.8% | 62.2% | 45.6% | 54.4% | 50.7% | 49.3% | 55.9% | 44.1% | 61.9% | 38.1% | 66.2% | 33.8% |
| GS <50 | 22.7% | 77.3% | 29.9% | 70.1% | 34.9% | 65.1% | 40.0% | 60.0% | 45.0% | 55.0% | 50.1% | 49.9% |
| GS 50 to 1,499 kW | 28.3% | 71.7% | 29.3% | 70.7% | 34.5% | 65.5% | 39.3% | 60.7% | 44.4% | 55.6% | 49.0% | 51.0% |
| GS 1,500 to 4,999 kW | 37.3% | 62.7% | 37.3% | 62.7% | 37.3% | 62.7% | 39.4% | 60.6% | 44.3% | 55.7% | 49.3% | 50.7% |
| Large Use | 33.8% | 66.2% | 35.2% | 64.8% | 35.3% | 64.7% | 39.3% | 60.7% | 44.2% | 55.8% | 49.1% | 50.9% |
| Street Light | 43.5% | 56.5% | 44.7% | 55.3% | 45.5% | 54.5% | 46.2% | 53.8% | 47.3% | 52.7% | 46.0% | 54.0% |
| Sentinel | 50.8% | 49.2% | 45.1% | 54.9% | 40.8% | 59.2% | 45.4% | 54.6% | 44.0% | 56.0% | 45.3% | 54.7% |
| Unmetered Scattered Load | 30.1% | 69.9% | 32.9% | 67.1% | 38.1% | 61.9% | 44.4% | 55.6% | 45.9% | 54.1% | 45.2% | 54.8% |
| Standby Power | 2.2% | 97.8% | 28.8% | 71.2% | 28.8% | 71.2% | 28.7% | 71.3% | 29.1% | 70.9% | 29.5% | 70.5% |

Hydro Ottawa moved each customer class closer to a 50/50 variable/fixed split, with the exception of the Residential and Unmetered Classes. The Residential Class was adjusted with the Board's April 2015 Report in mind and therefore goes beyond a 50% fixed component. Per Exhibit G-1-2 Hydro Ottawa is waiting for the final Navigant Consulting Limited Report to the Board prior to making any adjustments to the variable/fixed split.

Table 3 Provides Hydro Ottawa's current and proposed fixed and variable charges.

**Table 3 - Current and Proposed Fixed and Variable Charges**

| | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fixed $ | Variable $/kWh or KW | Fixed $ | Variable $/kWh or KW | Fixed $ | Variable $/kWh or KW | Fixed $ | Variable $/kWh or KW | Fixed $ | Variable $/kWh or KW | Fixed $ | Variable $/kWh or KW |
| Residential | 9.67 | 0.0234 | 12.25 | 0.0235 | 14.25 | 0.0228 | 16.50 | 0.0216 | 19.00 | 0.0196 | 20.75 | 0.0180 |
| GS <50 | 16.72 | 0.0210 | 22.75 | 0.0216 | 27.75 | 0.0214 | 33.25 | 0.0208 | 38.75 | 0.0201 | 44.00 | 0.0188 |
| GS 50 to 1,499 kW | 260.82 | 3.5691 | 290.00 | 3.9454 | 355.00 | 3.8962 | 420.00 | 3.8299 | 490.00 | 3.6842 | 550.00 | 3.4930 |
| GS 1,500 to 4,999 kW | 4,193.93 | 3.4887 | 4,650.00 | 3.8602 | 4,975.00 | 4.0575 | 5,600.00 | 4.1002 | 6,650.00 | 3.9007 | 7,700.00 | 3.6031 |
| Large Use | 15,231.32 | 3.3129 | 16,900.00 | 3.6644 | 17,900.00 | 3.8746 | 21,000.00 | 3.8254 | 24,600.00 | 3.6719 | 28,000.00 | 3.4408 |
| Street Light | 0.57 | 3.9997 | 0.65 | 4.3442 | 0.70 | 4.5389 | 0.75 | 4.7173 | 0.80 | 4.8325 | 0.80 | 5.0761 |
| Sentinel | 2.62 | 10.0361 | 3.25 | 12.0650 | 3.25 | 13.3241 | 4.00 | 12.5418 | 4.25 | 12.9159 | 4.75 | 12.4211 |
| Unmetered Scattered Load | 4.43 | 0.0219 | 4.75 | 0.0242 | 5.75 | 0.0237 | 7.00 | 0.0225 | 7.50 | 0.0229 | 7.50 | 0.0238 |
| Standby Power GS 50 to 1,499 kW | 122.41 | 1.6337 | 135.00 | 1.8171 | 143.00 | 1.9245 | 150.00 | 2.0320 | 159.00 | 2.1082 | 165.00 | 2.1544 |
| Standby Power GS 1,500 to 4,999 kW | 122.41 | 1.4985 | 135.00 | 1.6668 | 143.00 | 1.7652 | 150.00 | 1.8639 | 159.00 | 1.9337 | 165.00 | 1.9761 |
| Standby Power Large Use | 122.41 | 1.6629 | 135.00 | 1.8496 | 143.00 | 1.9589 | 150.00 | 2.0683 | 159.00 | 2.1458 | 165.00 | 2.1929 |

Table 4 to 8 provide comparisons of current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study.

**Table 4 - 2015 Current and 2016 Proposed Fixed Charge ($) Comparison to Cost Allocation Floor and Ceiling**

| Customer Class | Cost Allocation | | 2015 Rate | 2016 Proposed Rate |
|---|---|---|---|---|
| | Floor | Ceiling | | |
| Residential | 4.64 | 16.89 | 9.67 | 12.25 |
| GS < 50 kW | 7.33 | 25.24 | 16.72 | 22.75 |
| GS > 50 to 1,499 kW | 42.38 | 101.67 | 260.82 | 290.00 |
| GS > 1,500 to 4,999 kW | 175.80 | 534.95 | 4,193.93 | 4,650.00 |
| Large Use | 95.34 | 589.53 | 15,231.32 | 16,900.00 |
| Street Light | 0.22 | 8.84 | 0.57 | 0.65 |
| Sentinel | 1.86 | 13.66 | 2.62 | 3.25 |
| Unmetered Scattered Load | (0.03) | 8.14 | 4.43 | 4.75 |
| Standby Power | 209.29 | 330.58 | 122.41 | 135.00 |

**Table 5 - 2015 Current and 2017 Proposed Fixed Charge ($) Comparison to Cost Allocation Floor and Ceiling**

| Customer Class | Cost Allocation | | 2015 Rate | 2017 Proposed Rate |
|---|---|---|---|---|
| | Floor | Ceiling | | |
| Residential | 4.76 | 17.41 | 9.67 | 14.25 |
| GS < 50 kW | 7.54 | 25.96 | 16.72 | 27.75 |
| GS > 50 to 1,499 kW | 43.81 | 104.32 | 260.82 | 355.00 |
| GS > 1,500 to 4,999 kW | 180.99 | 551.64 | 4,193.93 | 4,975.00 |
| Large Use | 96.82 | 605.76 | 15,231.32 | 17,900.00 |
| Street Light | 0.23 | 9.18 | 0.57 | 0.70 |
| Sentinel | 1.92 | 14.25 | 2.62 | 3.25 |
| Unmetered Scattered Load | (0.03) | 8.45 | 4.43 | 5.75 |
| Standby Power | 212.53 | 336.20 | 122.41 | 143 |

**Table 6 - 2015 Current and 2018 Proposed Fixed Charge ($) Comparison to Cost Allocation Floor and Ceiling**

| Customer Class | Cost Allocation | | 2015 Rate | 2018 Proposed Rate |
|---|---|---|---|---|
| | Floor | Ceiling | | |
| Residential | 4.87 | 17.92 | 9.67 | 16.50 |
| GS < 50 kW | 7.71 | 26.64 | 16.72 | 33.25 |
| GS > 50 to 1,499 kW | 44.94 | 106.93 | 260.82 | 420.00 |
| GS > 1,500 to 4,999 kW | 183.53 | 569.99 | 4,193.93 | 5,600.00 |
| Large Use | 93.94 | 637.08 | 15,231.32 | 21,000.00 |
| Street Light | 0.23 | 9.53 | 0.57 | 0.75 |
| Sentinel | 1.95 | 14.79 | 2.62 | 4.00 |
| Unmetered Scattered Load | (0.03) | 8.77 | 4.43 | 7.00 |
| Standby Power | 217.00 | 342.55 | 122.41 | 150.00 |

**Table 7 - 2015 Current and 2019 Proposed Fixed Charge ($) Comparison to Cost Allocation Floor and Ceiling**

| Customer Class | Cost Allocation | | 2015 Rate | 2019 Proposed Rate |
|---|---|---|---|---|
| | Floor | Ceiling | | |
| Residential | 4.97 | 18.37 | 9.67 | 19.00 |
| GS < 50 kW | 7.88 | 27.25 | 16.72 | 38.75 |
| GS > 50 to 1,499 kW | 46.14 | 109.38 | 260.82 | 490.00 |
| GS > 1,500 to 4,999 kW | 186.91 | 588.10 | 4,193.93 | 6,650.00 |
| Large Use | 96.11 | 667.05 | 15,231.32 | 24,600.00 |
| Street Light | 0.23 | 9.83 | 0.57 | 0.80 |
| Sentinel | 1.98 | 15.28 | 2.62 | 4.25 |
| Unmetered Scattered Load | (0.03) | 9.04 | 4.43 | 7.50 |
| Standby Power | 221.47 | 348.42 | 122.41 | 159.00 |

**Table 8 - 2015 Current and 2020 Proposed Fixed Charge ($) Comparison to Cost Allocation Floor and Ceiling**

| Customer Class | Cost Allocation | | 2015 Rate | 2020 Proposed Rate |
|---|---|---|---|---|
| | Floor | Ceiling | | |
| Residential | 5.06 | 18.64 | 9.67 | 20.75 |
| GS < 50 kW | 8.00 | 27.60 | 16.72 | 44.00 |
| GS > 50 to 1,499 kW | 47.00 | 111.03 | 260.82 | 550.00 |
| GS > 1,500 to 4,999 kW | 188.09 | 601.87 | 4,193.93 | 7,700.00 |
| Large Use | 93.51 | 679.50 | 15,231.32 | 28,000.00 |
| Street Light | 0.24 | 9.96 | 0.57 | 0.80 |
| Sentinel | 2.00 | 15.54 | 2.62 | 4.75 |
| Unmetered Scattered Load | (0.03) | 9.14 | 4.43 | 7.50 |
| Standby Power | 224.56 | 352.79 | 122.41 | 165.00 |

## 3.0 TRANSFORMER OWNERSHIP CREDIT

Hydro Ottawa is not proposing any change to the current Transformer Ownership Credit (“TOC”) of $0.45/kW for customers who own their transformers.

# RATE DESIGN POLICY CONSULTATION

## 1.0 INTRODUCTION

As part of this application Hydro Ottawa Limited ("Hydro Ottawa") is not proposing the implementation of a fully fixed rate. Hydro Ottawa is however looking at its fixed and variable split in order to move all rate classes into a similar fixed and variable split. Please refer to Exhibit H-1-1.

On April 2, 2015 the Ontario Energy Board ("the Board") released the Board Policy[1], A New Distribution Rate Design for Residential Electricity Customers. At this time, as the implementation details and filing guidelines have not been released, Hydro Ottawa will wait until the Board's Working Groups has put forth it's recommends prior to incorporating the directions.

[1] EB-2012-0410, Board Policy: A New Distribution Rate Design for Residential Electricity Customers, April 2, 2015

# RETAIL TRANSMISSION SERVICE RATES

## 1.0 INTRODUCTION

The Ontario Energy Board (the “Board”) issued a revision to Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates (the “Guideline”), which outlined information that the Board requires electricity distributors to file to adjust their retail transmission service rates (“RTSR”). Subsequently, the Board also provided a filing model which distributors are required to complete and file, 2015_RTSR Adjustment Work Form – version 4.0 issued by the Board June 26, 2014.

## 2.0 REVISED 2016 THROUGH 2020 RTSR

Hydro Ottawa Limited (“Hydro Ottawa”) proposes to use the Retail Transmission Service rates (“RTSRs”) for its 2016 rates as calculated by the Board RTSRs model. Currently the 2013 billing determinants are the most recently reported in the Reporting and Record Keeping Requirements (“RRR’s”). When the 2016 RTSR model is available the 2014 billing determinants will have been filed in the RRR’s. For the purpose of this filing, including bill impacts, Hydro Ottawa has used the 2015 approved RTSRs and will update the application based on the 2016 RTSR model when available. This is also the approach taken for calculation of the working capital allowance.

Hydro Ottawa has attached the 2015 RTRS Model in PDF format as part of this Exhibit and has also provided a live Excel version.

Hydro Ottawa is proposing to update the RTSRs on an annual basis, 2017 through 2020, based on Board Approved adjustments to the Hydro One Uniform Transmission Rates (“UTRs”) using the RTSR model. For the purpose of this rate application, including bill impacts, Hydro Ottawa has used the 2015 approved RTSRs for 2017 through 2020.

Given Hydro One UTRs are not typically approved in time for adjusting Hydro Ottawa's rates on January 1, Hydro Ottawa is proposing to set each year's RTSRs using the previous year's UTRs. Hydro Ottawa is proposing that the differences from the new yearly rates be captured in Uniform System of Accounts 1584 – RSVA Network and 1586 – RSVA Connection for future disposition.

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# 2015 RTSR Workform for Electricity Distributors

| | |
|---|---|
| Utility Name | |
| Service Territory | |
| Assigned EB Number | |
| Name and Title | |
| Phone Number | |
| Email Address | |
| Date | |
| Last COS Re-based Year | |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

# RTSR Workform for Electricity Distributors (2014 Filers)

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# 2015 RTSR Workform for Electricity Distributors

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

| Rate Class | Unit | RTSR-Network | RTSR-Connection |
|---|---|---|---|
| Residential | kWh | $ 0.0080 | $ 0.0042 |
| General Service Less Than 50 kW | kWh | $ 0.0072 | $ 0.0040 |
| General Service 50 to 1,499 kW | kW | $ 3.0087 | $ 1.6116 |
| General Service 1,500 to 4,999 kW | kW | $ 3.1240 | $ 1.7223 |
| Large Use > 5000 kW | kW | $ 3.4630 | $ 1.9395 |
| Unmetered Scattered Load | kWh | $ 0.0072 | $ 0.0040 |
| Sentinel Lighting | kW | $ 2.2210 | $ 1.1972 |
| Street Lighting | kW | $ 2.2323 | $ 1.2222 |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |
| Choose Rate Class | | | |

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# 2015 RTSR Workform for Electricity Distributors

**In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.**

| Rate Class | Unit | Non-Loss Adjusted Metered kWh | Non-Loss Adjusted Metered kW | Applicable Loss Factor | Load Factor | Loss Adjusted Billed kWh | Billed kW |
|---|---|---|---|---|---|---|---|
| **Residential** | **kWh** | 2,256,501,094 | | 1.0358 | | 2,337,283,833 | - |
| **General Service Less Than 50 kW** | **kWh** | 720,479,340 | | 1.0358 | | 746,272,500 | - |
| **General Service 50 to 1,499 kW** | **kW** | 3,006,131,060 | 7,292,973 | | **56.50%** | 3,006,131,060 | 7,292,973 |
| **General Service 1,500 to 4,999 kW** | **kW** | 857,551,218 | 1,866,871 | | **62.96%** | 857,551,218 | 1,866,871 |
| **Large Use > 5000 kW** | **kW** | 613,513,830 | 1,135,342 | | **74.06%** | 613,513,830 | 1,135,342 |
| **Unmetered Scattered Load** | **kWh** | 17,054,550 | | 1.0358 | | 17,665,103 | - |
| **Sentinel Lighting** | **kW** | 49,020 | 139 | | **48.34%** | 49,020 | 139 |
| **Street Lighting** | **kW** | 44,767,415 | 123,947 | | **49.50%** | 44,767,415 | 123,947 |

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# 2015 RTSR Workform for Electricity Distributors

| Uniform Transmission Rates | Unit | Effective January 1, 2013 | Effective January 1, 2014 | Effective January 1, 2015 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | $ 3.63 | $ 3.82 | $ 3.82 |
| Line Connection Service Rate | kW | $ 0.75 | $ 0.82 | $ 0.82 |
| Transformation Connection Service Rate | kW | $ 1.85 | $ 1.98 | $ 1.98 |

| Hydro One Sub-Transmission Rates | Unit | Effective January 1, 2013 | Effective January 1, 2014 | Effective January 1, 2015 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | $ 3.18 | $ 3.23 | $ 3.23 |
| Line Connection Service Rate | kW | $ 0.70 | $ 0.65 | $ 0.65 |
| Transformation Connection Service Rate | kW | $ 1.63 | $ 1.62 | $ 1.62 |
| Both Line and Transformation Connection Service Rate | kW | $ 2.33 | $ 2.27 | $ 2.27 |

| If needed , add extra host here (I) | Unit | Effective January 1, 2013 | Effective January 1, 2014 | Effective January 1, 2015 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | | | |
| Line Connection Service Rate | kW | | | |
| Transformation Connection Service Rate | kW | | | |
| Both Line and Transformation Connection Service Rate | kW | $ - | $ - | $ - |

| If needed , add extra host here (II) | Unit | Effective January 1, 2013 | Effective January 1, 2014 | Effective January 1, 2015 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | | | |
| Line Connection Service Rate | kW | | | |
| Transformation Connection Service Rate | kW | | | |
| Both Line and Transformation Connection Service Rate | kW | $ - | $ - | $ - |

| Hydro One Sub-Transmission Rate Rider 9A | Unit | Effective January 1, 2013 | Effective January 1, 2014 | Effective January 1, 2015 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| RSVA Transmission network – 4714 – which affects 1584 | kW | $ - | $ 0.1465 | |
| RSVA Transmission connection – 4716 – which affects 1586 | kW | $ - | $ 0.0667 | |
| RSVA LV – 4750 – which affects 1550 | kW | $ - | $ 0.0475 | |
| RARA 1 – 2252 – which affects 1590 | kW | $ - | $ 0.0419 | |
| RARA 1 – 2252 – which affects 1590 (2008) | kW | $ - | -$ 0.0270 | |
| RARA 1 – 2252 – which affects 1590 (2009) | kW | $ - | -$ 0.0006 | |
| Hydro One Sub-Transmission Rate Rider 9A | kW | $ - | $ 0.2750 | $ - |

| | | Historical 2013 | Current 2014 | Forecast 2015 |
|---|---|---|---|---|
| Low Voltage Switchgear Credit (if applicable, enter as a negative value) | $ | -$ 2,857,673 | -$ 2,972,507 | -$ 3,067,809 |

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# 2015 RTSR Workform for Electricity Distributors

**In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data".**
**For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.**

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,218,199 | $3.63 | $ 4,422,062 | 1,177,522 | $0.75 | $ 883,142 | 968,649 | $1.85 | $ 1,792,001 | $ 2,675,142 |
| February | 1,135,290 | $3.63 | $ 4,121,103 | 1,133,245 | $0.75 | $ 849,934 | 908,867 | $1.85 | $ 1,681,404 | $ 2,531,338 |
| March | 1,042,555 | $3.63 | $ 3,784,475 | 1,048,715 | $0.75 | $ 786,536 | 808,843 | $1.85 | $ 1,496,360 | $ 2,282,896 |
| April | 966,942 | $3.63 | $ 3,509,999 | 957,709 | $0.75 | $ 718,282 | 764,901 | $1.85 | $ 1,415,067 | $ 2,133,349 |
| May | 1,201,785 | $3.63 | $ 4,362,480 | 1,137,282 | $0.75 | $ 852,962 | 903,936 | $1.85 | $ 1,672,282 | $ 2,525,243 |
| June | 1,149,937 | $3.63 | $ 4,174,271 | 1,179,995 | $0.75 | $ 884,996 | 932,554 | $1.85 | $ 1,725,225 | $ 2,610,221 |
| July | 1,248,438 | $3.64 | $ 4,543,903 | 1,307,047 | $0.75 | $ 981,547 | 1,056,856 | $1.85 | $ 1,955,184 | $ 2,936,730 |
| August | 1,125,855 | $3.63 | $ 4,086,854 | 1,154,868 | $0.75 | $ 866,151 | 925,649 | $1.85 | $ 1,712,451 | $ 2,578,602 |
| September | 1,055,493 | $3.63 | $ 3,831,440 | 1,053,960 | $0.75 | $ 790,470 | 825,534 | $1.85 | $ 1,527,238 | $ 2,317,708 |
| October | 935,675 | $3.63 | $ 3,396,500 | 920,724 | $0.75 | $ 690,543 | 743,976 | $1.85 | $ 1,376,356 | $ 2,066,899 |
| November | 1,068,027 | $3.63 | $ 3,876,938 | 1,030,389 | $0.75 | $ 772,792 | 835,885 | $1.85 | $ 1,546,387 | $ 2,319,179 |
| December | 1,183,613 | $3.63 | $ 4,296,515 | 1,128,105 | $0.75 | $ 846,079 | 921,513 | $1.85 | $ 1,704,799 | $ 2,550,878 |
| **Total** | 13,331,809 | $ 3.63 | $ 48,406,540 | 13,229,561 | $ 0.75 | $ 9,923,432 | 10,597,163 | $ 1.85 | $ 19,604,752 | $ 29,528,184 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 92,944 | $3.18 | $ 295,562 | 917 | $0.70 | $ 642 | 92,027 | $1.66 | $ 152,957 | $ 153,599 |
| February | 82,359 | $3.18 | $ 261,902 | 849 | $0.70 | $ 594 | 82,295 | $1.66 | $ 136,827 | $ 137,422 |
| March | 70,488 | $3.18 | $ 224,152 | 720 | $0.70 | $ 504 | 72,104 | $1.67 | $ 120,077 | $ 120,581 |
| April | 66,801 | $3.18 | $ 212,426 | 3,854 | $0.70 | $ 2,698 | 66,127 | $1.63 | $ 107,787 | $ 110,484 |
| May | 90,015 | $3.18 | $ 286,249 | 3,751 | $0.70 | $ 2,626 | 89,343 | $1.63 | $ 145,629 | $ 148,255 |
| June | 90,879 | $3.18 | $ 288,994 | 4,039 | $0.70 | $ 2,828 | 90,172 | $1.63 | $ 146,981 | $ 149,809 |
| July | 98,267 | $3.18 | $ 312,488 | 4,587 | $0.70 | $ 3,211 | 97,535 | $1.63 | $ 158,982 | $ 162,193 |
| August | 79,841 | $3.18 | $ 253,895 | 5,000 | $0.70 | $ 3,500 | 79,852 | $1.63 | $ 130,159 | $ 133,659 |
| September | 71,837 | $3.18 | $ 228,441 | 4,796 | $0.70 | $ 3,357 | 72,748 | $1.63 | $ 118,580 | $ 121,936 |
| October | 75,053 | $3.18 | $ 238,669 | 4,963 | $0.70 | $ 3,474 | 76,159 | $1.63 | $ 124,139 | $ 127,612 |
| November | 81,617 | $3.18 | $ 259,543 | 4,435 | $0.70 | $ 3,104 | 83,522 | $1.63 | $ 136,141 | $ 139,245 |
| December | 94,893 | $3.19 | $ 302,735 | 5,068 | $0.69 | $ 3,495 | 97,504 | $1.63 | $ 158,730 | $ 162,225 |
| **Total** | 994,994 | $ 3.18 | $ 3,165,055 | 42,979 | $ 0.70 | $ 30,032 | 999,388 | $ 1.64 | $ 1,636,988 | $ 1,667,020 |

| Add Extra Host Here (I) (if needed) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| February | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| March | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| April | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| May | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| June | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| July | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| August | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| September | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| October | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| November | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| December | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Add Extra Host Here (II) (if needed) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| February | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| March | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| April | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| May | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| June | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| July | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| August | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| September | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| October | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| November | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| December | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,311,143 | $3.60 | $ 4,717,624 | 1,178,439 | $0.75 | $ 883,783 | 1,060,676 | $1.83 | $ 1,944,958 | $ 2,828,741 |
| February | 1,217,649 | $3.60 | $ 4,383,004 | 1,134,094 | $0.75 | $ 850,528 | 991,162 | $1.83 | $ 1,818,231 | $ 2,668,759 |
| March | 1,113,043 | $3.60 | $ 4,008,626 | 1,049,435 | $0.75 | $ 787,040 | 880,947 | $1.83 | $ 1,616,436 | $ 2,403,477 |
| April | 1,033,743 | $3.60 | $ 3,722,425 | 961,563 | $0.75 | $ 720,979 | 831,028 | $1.83 | $ 1,522,854 | $ 2,243,833 |
| May | 1,291,800 | $3.60 | $ 4,648,729 | 1,141,033 | $0.75 | $ 855,587 | 993,279 | $1.83 | $ 1,817,911 | $ 2,673,498 |
| June | 1,240,816 | $3.60 | $ 4,463,265 | 1,184,034 | $0.75 | $ 887,824 | 1,022,726 | $1.83 | $ 1,872,206 | $ 2,760,030 |
| July | 1,346,705 | $3.61 | $ 4,856,391 | 1,311,634 | $0.75 | $ 984,757 | 1,154,391 | $1.83 | $ 2,114,166 | $ 3,098,923 |
| August | 1,205,696 | $3.60 | $ 4,340,749 | 1,159,868 | $0.75 | $ 869,651 | 1,005,501 | $1.83 | $ 1,842,609 | $ 2,712,260 |
| September | 1,127,330 | $3.60 | $ 4,059,881 | 1,058,756 | $0.75 | $ 793,827 | 898,282 | $1.83 | $ 1,645,818 | $ 2,439,644 |
| October | 1,010,728 | $3.60 | $ 3,635,170 | 925,687 | $0.75 | $ 694,017 | 820,135 | $1.83 | $ 1,500,494 | $ 2,194,511 |
| November | 1,149,644 | $3.60 | $ 4,136,481 | 1,034,824 | $0.75 | $ 775,896 | 919,407 | $1.83 | $ 1,682,528 | $ 2,458,424 |
| December | 1,278,506 | $3.60 | $ 4,599,250 | 1,133,173 | $0.75 | $ 849,574 | 1,019,017 | $1.83 | $ 1,863,529 | $ 2,713,103 |
| **Total** | 14,326,803 | $ 3.60 | $ 51,571,595 | 13,272,540 | $ 0.75 | $ 9,953,464 | 11,596,551 | $ 1.83 | $ 21,241,740 | $ 31,195,204 |

Ontario Energy Board

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# 2015 RTSR Workform for Electricity Distributors

**The purpose of this sheet is to calculate the expected billing when current 2014 Uniform Transmission Rates are applied against historical 2013 transmission units.**

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,218,199 | $ 3.8200 | $ 4,653,520 | 1,177,522 | $ 0.8200 | $ 965,568 | 968,649 | $ 1.9800 | $ 1,917,925 | $ 2,883,493 |
| February | 1,135,290 | $ 3.8200 | $ 4,336,808 | 1,133,245 | $ 0.8200 | $ 929,261 | 908,867 | $ 1.9800 | $ 1,799,557 | $ 2,728,818 |
| March | 1,042,555 | $ 3.8200 | $ 3,982,560 | 1,048,715 | $ 0.8200 | $ 859,946 | 808,843 | $ 1.9800 | $ 1,601,509 | $ 2,461,455 |
| April | 966,942 | $ 3.8200 | $ 3,693,718 | 957,709 | $ 0.8200 | $ 785,321 | 764,901 | $ 1.9800 | $ 1,514,504 | $ 2,299,825 |
| May | 1,201,785 | $ 3.8200 | $ 4,590,819 | 1,137,282 | $ 0.8200 | $ 932,571 | 903,936 | $ 1.9800 | $ 1,789,793 | $ 2,722,365 |
| June | 1,149,937 | $ 3.8200 | $ 4,392,759 | 1,179,995 | $ 0.8200 | $ 967,596 | 932,554 | $ 1.9800 | $ 1,846,457 | $ 2,814,053 |
| July | 1,248,438 | $ 3.8200 | $ 4,769,033 | 1,307,047 | $ 0.8200 | $ 1,071,779 | 1,056,856 | $ 1.9800 | $ 2,092,575 | $ 3,164,353 |
| August | 1,125,855 | $ 3.8200 | $ 4,300,766 | 1,154,868 | $ 0.8200 | $ 946,992 | 925,649 | $ 1.9800 | $ 1,832,785 | $ 2,779,777 |
| September | 1,055,493 | $ 3.8200 | $ 4,031,983 | 1,053,960 | $ 0.8200 | $ 864,247 | 825,534 | $ 1.9800 | $ 1,634,557 | $ 2,498,805 |
| October | 935,675 | $ 3.8200 | $ 3,574,279 | 920,724 | $ 0.8200 | $ 754,994 | 743,976 | $ 1.9800 | $ 1,473,072 | $ 2,228,066 |
| November | 1,068,027 | $ 3.8200 | $ 4,079,863 | 1,030,389 | $ 0.8200 | $ 844,919 | 835,885 | $ 1.9800 | $ 1,655,052 | $ 2,499,971 |
| December | 1,183,613 | $ 3.8200 | $ 4,521,402 | 1,128,105 | $ 0.8200 | $ 925,046 | 921,513 | $ 1.9800 | $ 1,824,596 | $ 2,749,642 |
| **Total** | 13,331,809 | $ 3.82 | $ 50,927,510 | 13,229,561 | $ 0.82 | $ 10,848,240 | 10,597,163 | $ 1.98 | $ 20,982,383 | $ 31,830,623 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 92,944 | $ 3.3765 | $ 313,825 | 917 | $ 0.7167 | $ 657 | 92,027 | $ 1.6200 | $ 149,084 | $ 149,741 |
| February | 82,359 | $ 3.3765 | $ 278,085 | 849 | $ 0.7167 | $ 608 | 82,295 | $ 1.6200 | $ 133,318 | $ 133,926 |
| March | 70,488 | $ 3.3765 | $ 238,003 | 720 | $ 0.7167 | $ 516 | 72,104 | $ 1.6200 | $ 116,808 | $ 117,325 |
| April | 66,801 | $ 3.3765 | $ 225,554 | 3,854 | $ 0.7167 | $ 2,762 | 66,127 | $ 1.6200 | $ 107,126 | $ 109,888 |
| May | 90,015 | $ 3.3765 | $ 303,936 | 3,751 | $ 0.7167 | $ 2,688 | 89,343 | $ 1.6200 | $ 144,736 | $ 147,424 |
| June | 90,879 | $ 3.3765 | $ 306,853 | 4,039 | $ 0.7167 | $ 2,895 | 90,172 | $ 1.6200 | $ 146,079 | $ 148,973 |
| July | 98,267 | $ 3.3765 | $ 331,799 | 4,587 | $ 0.7167 | $ 3,288 | 97,535 | $ 1.6200 | $ 158,007 | $ 161,294 |
| August | 79,841 | $ 3.3765 | $ 269,583 | 5,000 | $ 0.7167 | $ 3,584 | 79,852 | $ 1.6200 | $ 129,360 | $ 132,944 |
| September | 71,837 | $ 3.3765 | $ 242,558 | 4,796 | $ 0.7167 | $ 3,437 | 72,748 | $ 1.6200 | $ 117,852 | $ 121,289 |
| October | 75,053 | $ 3.3765 | $ 253,416 | 4,963 | $ 0.7167 | $ 3,557 | 76,159 | $ 1.6200 | $ 123,378 | $ 126,935 |
| November | 81,617 | $ 3.3765 | $ 275,580 | 4,435 | $ 0.7167 | $ 3,179 | 83,522 | $ 1.6200 | $ 135,306 | $ 138,484 |
| December | 94,893 | $ 3.3765 | $ 320,406 | 5,068 | $ 0.7167 | $ 3,632 | 97,504 | $ 1.6200 | $ 157,956 | $ 161,589 |
| **Total** | 994,994 | $ 3.38 | $ 3,359,597 | 42,979 | $ 0.72 | $ 30,803 | 999,388 | $ 1.62 | $ 1,619,009 | $ 1,649,812 |

| Add Extra Host Here (I) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| February | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| March | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| April | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| May | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| June | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| July | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| August | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| September | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| October | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| November | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| December | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Add Extra Host Here (II) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| February | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| March | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| April | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| May | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| June | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| July | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| August | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| September | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| October | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| November | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| December | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,311,143 | $3.79 | $ 4,967,346 | 1,178,439 | $0.82 | $ 966,225 | 1,060,676 | $1.95 | $ 2,067,009 | $ 3,033,234 |
| February | 1,217,649 | $3.79 | $ 4,614,893 | 1,134,094 | $0.82 | $ 929,869 | 991,162 | $1.95 | $ 1,932,875 | $ 2,862,744 |
| March | 1,113,043 | $3.79 | $ 4,220,563 | 1,049,435 | $0.82 | $ 860,462 | 880,947 | $1.95 | $ 1,718,318 | $ 2,578,780 |
| April | 1,033,743 | $3.79 | $ 3,919,272 | 961,563 | $0.82 | $ 788,084 | 831,028 | $1.95 | $ 1,621,630 | $ 2,409,713 |
| May | 1,291,800 | $3.79 | $ 4,894,754 | 1,141,033 | $0.82 | $ 935,260 | 993,279 | $1.95 | $ 1,934,529 | $ 2,869,789 |
| June | 1,240,816 | $3.79 | $ 4,699,612 | 1,184,034 | $0.82 | $ 970,491 | 1,022,726 | $1.95 | $ 1,992,536 | $ 2,963,026 |
| July | 1,346,705 | $3.79 | $ 5,100,832 | 1,311,634 | $0.82 | $ 1,075,066 | 1,154,391 | $1.95 | $ 2,250,582 | $ 3,325,648 |
| August | 1,205,696 | $3.79 | $ 4,570,349 | 1,159,868 | $0.82 | $ 950,575 | 1,005,501 | $1.95 | $ 1,962,145 | $ 2,912,721 |
| September | 1,127,330 | $3.79 | $ 4,274,541 | 1,058,756 | $0.82 | $ 867,684 | 898,282 | $1.95 | $ 1,752,409 | $ 2,620,094 |
| October | 1,010,728 | $3.79 | $ 3,827,695 | 925,687 | $0.82 | $ 758,551 | 820,135 | $1.95 | $ 1,596,450 | $ 2,355,001 |
| November | 1,149,644 | $3.79 | $ 4,355,443 | 1,034,824 | $0.82 | $ 848,098 | 919,407 | $1.95 | $ 1,790,358 | $ 2,638,455 |
| December | 1,278,506 | $3.79 | $ 4,841,808 | 1,133,173 | $0.82 | $ 928,678 | 1,019,017 | $1.95 | $ 1,982,552 | $ 2,911,231 |
| **Total** | 14,326,803 | $ 3.79 | $ 54,287,108 | 13,272,540 | $ 0.82 | $ 10,879,043 | 11,596,551 | $ 1.95 | $ 22,601,391 | $ 33,480,434 |

Ontario Energy Board

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# 2015 RTSR Workform for Electricity Distributors

**The purpose of this sheet is to calculate the expected billing when forecasted 2015 Uniform Transmission Rates are applied against historical 2013 transmission units.**

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,218,199 | $ 3.8200 | $ 4,653,520 | 1,177,522 | $ 0.8200 | $ 965,568 | 968,649 | $ 1.9800 | $ 1,917,925 | $ 2,883,493 |
| February | 1,135,290 | $ 3.8200 | $ 4,336,808 | 1,133,245 | $ 0.8200 | $ 929,261 | 908,867 | $ 1.9800 | $ 1,799,557 | $ 2,728,818 |
| March | 1,042,555 | $ 3.8200 | $ 3,982,560 | 1,048,715 | $ 0.8200 | $ 859,946 | 808,843 | $ 1.9800 | $ 1,601,509 | $ 2,461,455 |
| April | 966,942 | $ 3.8200 | $ 3,693,718 | 957,709 | $ 0.8200 | $ 785,321 | 764,901 | $ 1.9800 | $ 1,514,504 | $ 2,299,825 |
| May | 1,201,785 | $ 3.8200 | $ 4,590,819 | 1,137,282 | $ 0.8200 | $ 932,571 | 903,936 | $ 1.9800 | $ 1,789,793 | $ 2,722,365 |
| June | 1,149,937 | $ 3.8200 | $ 4,392,759 | 1,179,995 | $ 0.8200 | $ 967,596 | 932,554 | $ 1.9800 | $ 1,846,457 | $ 2,814,053 |
| July | 1,248,438 | $ 3.8200 | $ 4,769,033 | 1,307,047 | $ 0.8200 | $ 1,071,779 | 1,056,856 | $ 1.9800 | $ 2,092,575 | $ 3,164,353 |
| August | 1,125,855 | $ 3.8200 | $ 4,300,766 | 1,154,868 | $ 0.8200 | $ 946,992 | 925,649 | $ 1.9800 | $ 1,832,785 | $ 2,779,777 |
| September | 1,055,493 | $ 3.8200 | $ 4,031,983 | 1,053,960 | $ 0.8200 | $ 864,247 | 825,534 | $ 1.9800 | $ 1,634,557 | $ 2,498,805 |
| October | 935,675 | $ 3.8200 | $ 3,574,279 | 920,724 | $ 0.8200 | $ 754,994 | 743,976 | $ 1.9800 | $ 1,473,072 | $ 2,228,066 |
| November | 1,068,027 | $ 3.8200 | $ 4,079,863 | 1,030,389 | $ 0.8200 | $ 844,919 | 835,885 | $ 1.9800 | $ 1,655,052 | $ 2,499,971 |
| December | 1,183,613 | $ 3.8200 | $ 4,521,402 | 1,128,105 | $ 0.8200 | $ 925,046 | 921,513 | $ 1.9800 | $ 1,824,596 | $ 2,749,642 |
| **Total** | 13,331,809 | $ 3.82 | $ 50,927,510 | 13,229,561 | $ 0.82 | $ 10,848,240 | 10,597,163 | $ 1.98 | $ 20,982,383 | $ 31,830,623 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 92,944 | $ 3.2300 | $ 300,209 | 917 | $ 0.6500 | $ 596 | 92,027 | $ 1.6200 | $ 149,084 | $ 149,680 |
| February | 82,359 | $ 3.2300 | $ 266,020 | 849 | $ 0.6500 | $ 552 | 82,295 | $ 1.6200 | $ 133,318 | $ 133,870 |
| March | 70,488 | $ 3.2300 | $ 227,676 | 720 | $ 0.6500 | $ 468 | 72,104 | $ 1.6200 | $ 116,808 | $ 117,276 |
| April | 66,801 | $ 3.2300 | $ 215,767 | 3,854 | $ 0.6500 | $ 2,505 | 66,127 | $ 1.6200 | $ 107,126 | $ 109,631 |
| May | 90,015 | $ 3.2300 | $ 290,748 | 3,751 | $ 0.6500 | $ 2,438 | 89,343 | $ 1.6200 | $ 144,736 | $ 147,174 |
| June | 90,879 | $ 3.2300 | $ 293,539 | 4,039 | $ 0.6500 | $ 2,625 | 90,172 | $ 1.6200 | $ 146,079 | $ 148,704 |
| July | 98,267 | $ 3.2300 | $ 317,402 | 4,587 | $ 0.6500 | $ 2,982 | 97,535 | $ 1.6200 | $ 158,007 | $ 160,988 |
| August | 79,841 | $ 3.2300 | $ 257,886 | 5,000 | $ 0.6500 | $ 3,250 | 79,852 | $ 1.6200 | $ 129,360 | $ 132,610 |
| September | 71,837 | $ 3.2300 | $ 232,034 | 4,796 | $ 0.6500 | $ 3,117 | 72,748 | $ 1.6200 | $ 117,852 | $ 120,969 |
| October | 75,053 | $ 3.2300 | $ 242,421 | 4,963 | $ 0.6500 | $ 3,226 | 76,159 | $ 1.6200 | $ 123,378 | $ 126,604 |
| November | 81,617 | $ 3.2300 | $ 263,623 | 4,435 | $ 0.6500 | $ 2,883 | 83,522 | $ 1.6200 | $ 135,306 | $ 138,188 |
| December | 94,893 | $ 3.2300 | $ 306,504 | 5,068 | $ 0.6500 | $ 3,294 | 97,504 | $ 1.6200 | $ 157,956 | $ 161,251 |
| **Total** | 994,994 | $ 3.23 | $ 3,213,831 | 42,979 | $ 0.65 | $ 27,936 | 999,388 | $ 1.62 | $ 1,619,009 | $ 1,646,945 |

| Add Extra Host Here (I) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| February | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| March | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| April | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| May | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| June | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| July | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| August | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| September | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| October | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| November | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| December | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Add Extra Host Here (II) | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| February | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| March | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| April | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| May | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| June | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| July | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| August | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| September | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| October | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| November | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| December | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 1,311,143 | $ 3.78 | $ 4,953,729 | 1,178,439 | $ 0.82 | $ 966,164 | 1,060,676 | $ 1.95 | $ 2,067,009 | $ 3,033,173 |
| February | 1,217,649 | $ 3.78 | $ 4,602,827 | 1,134,094 | $ 0.82 | $ 929,813 | 991,162 | $ 1.95 | $ 1,932,875 | $ 2,862,687 |
| March | 1,113,043 | $ 3.78 | $ 4,210,236 | 1,049,435 | $ 0.82 | $ 860,414 | 880,947 | $ 1.95 | $ 1,718,318 | $ 2,578,732 |
| April | 1,033,743 | $ 3.78 | $ 3,909,486 | 961,563 | $ 0.82 | $ 787,826 | 831,028 | $ 1.95 | $ 1,621,630 | $ 2,409,456 |
| May | 1,291,800 | $ 3.78 | $ 4,881,567 | 1,141,033 | $ 0.82 | $ 935,009 | 993,279 | $ 1.95 | $ 1,934,529 | $ 2,869,538 |
| June | 1,240,816 | $ 3.78 | $ 4,686,299 | 1,184,034 | $ 0.82 | $ 970,221 | 1,022,726 | $ 1.95 | $ 1,992,536 | $ 2,962,757 |
| July | 1,346,705 | $ 3.78 | $ 5,086,436 | 1,311,634 | $ 0.82 | $ 1,074,760 | 1,154,391 | $ 1.95 | $ 2,250,582 | $ 3,325,342 |
| August | 1,205,696 | $ 3.78 | $ 4,558,653 | 1,159,868 | $ 0.82 | $ 950,242 | 1,005,501 | $ 1.95 | $ 1,962,145 | $ 2,912,387 |
| September | 1,127,330 | $ 3.78 | $ 4,264,017 | 1,058,756 | $ 0.82 | $ 867,365 | 898,282 | $ 1.95 | $ 1,752,409 | $ 2,619,774 |
| October | 1,010,728 | $ 3.78 | $ 3,816,700 | 925,687 | $ 0.82 | $ 758,220 | 820,135 | $ 1.95 | $ 1,596,450 | $ 2,354,670 |
| November | 1,149,644 | $ 3.78 | $ 4,343,486 | 1,034,824 | $ 0.82 | $ 847,802 | 919,407 | $ 1.95 | $ 1,790,358 | $ 2,638,160 |
| December | 1,278,506 | $ 3.78 | $ 4,827,906 | 1,133,173 | $ 0.82 | $ 928,340 | 1,019,017 | $ 1.95 | $ 1,982,552 | $ 2,910,893 |
| **Total** | 14,326,803 | $ 3.78 | $ 54,141,341 | 13,272,540 | $ 0.82 | $ 10,876,176 | 11,596,551 | $ 1.95 | $ 22,601,391 | $ 33,477,568 |

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# 2015 RTSR Workform for Electricity Distributors

**The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.**

| Rate Class | Unit | Current RTSR-Network | | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | | Billed Amount % | Current Wholesale Billing | | Proposed RTSR Network |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | $ | 0.0080 | 2,337,283,833 | - | $ | 18,698,271 | 33.3% | $ | 18,067,691 | $0.0077 |
| General Service Less Than 50 kW | kWh | $ | 0.0072 | 746,272,500 | - | $ | 5,373,162 | 9.6% | $ | 5,191,958 | $0.0070 |
| General Service 50 to 1,499 kW | kW | $ | 3.0087 | 3,006,131,060 | 7,292,973 | $ | 21,942,368 | 39.1% | $ | 21,202,385 | $2.9072 |
| General Service 1,500 to 4,999 kW | kW | $ | 3.1240 | 857,551,218 | 1,866,871 | $ | 5,832,105 | 10.4% | $ | 5,635,423 | $3.0186 |
| Large Use > 5000 kW | kW | $ | 3.4630 | 613,513,830 | 1,135,342 | $ | 3,931,689 | 7.0% | $ | 3,799,097 | $3.3462 |
| Unmetered Scattered Load | kWh | $ | 0.0072 | 17,665,103 | - | $ | 127,189 | 0.2% | $ | 122,899 | $0.0070 |
| Sentinel Lighting | kW | $ | 2.2210 | 49,020 | 139 | $ | 309 | 0.0% | $ | 298 | $2.1461 |
| Street Lighting | kW | $ | 2.2323 | 44,767,415 | 123,947 | $ | 276,687 | 0.5% | $ | 267,356 | $2.1570 |
| | | | | | | $ | 56,181,779 | | | | |

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# 2015 RTSR Workform for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

| Rate Class | Unit | Current RTSR-Connection | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | Billed Amount % | Current Wholesale Billing | Proposed RTSR Connection |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | $ 0.0042 | 2,337,283,833 | - | $ 9,816,592 | 32.5% | $ 9,918,439 | $0.0042 |
| General Service Less Than 50 kW | kWh | $ 0.0040 | 746,272,500 | - | $ 2,985,090 | 9.9% | $ 3,016,060 | $0.0040 |
| General Service 50 to 1,499 kW | kW | $ 1.6116 | 3,006,131,060 | 7,292,973 | $ 11,753,355 | 38.9% | $ 11,875,296 | $1.6283 |
| General Service 1,500 to 4,999 kW | kW | $ 1.7223 | 857,551,218 | 1,866,871 | $ 3,215,312 | 10.6% | $ 3,248,671 | $1.7402 |
| Large Use > 5000 kW | kW | $ 1.9395 | 613,513,830 | 1,135,342 | $ 2,201,996 | 7.3% | $ 2,224,841 | $1.9596 |
| Unmetered Scattered Load | kWh | $ 0.0040 | 17,665,103 | - | $ 70,660 | 0.2% | $ 71,394 | $0.0040 |
| Sentinel Lighting | kW | $ 1.1972 | 49,020 | 139 | $ 166 | 0.0% | $ 168 | $1.2096 |
| Street Lighting | kW | $ 1.2222 | 44,767,415 | 123,947 | $ 151,488 | 0.5% | $ 153,060 | $1.2349 |
| | | | | | $ 30,194,660 | | | |

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# 2015 RTSR Workform for Electricity Distributors

**The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.**

| Rate Class | Unit | Adjusted RTSR-Network | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | Billed Amount % | Forecast Wholesale Billing | Proposed RTSR Network |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | $0.0077 | 2,337,283,833 | - | 18,067,691.09 | 33.3% | $ 18,019,177 | $0.0077 |
| General Service Less Than 50 kW | kWh | $0.0070 | 746,272,500 | - | $ 5,191,958 | 9.6% | $ 5,178,017 | $0.0069 |
| General Service 50 to 1,499 kW | kW | $2.9072 | 3,006,131,060 | 7,292,973 | $ 21,202,385 | 39.1% | $ 21,145,454 | $2.8994 |
| General Service 1,500 to 4,999 kW | kW | $3.0186 | 857,551,218 | 1,866,871 | $ 5,635,423 | 10.4% | $ 5,620,292 | $3.0105 |
| Large Use > 5000 kW | kW | $3.3462 | 613,513,830 | 1,135,342 | $ 3,799,097 | 7.0% | $ 3,788,896 | $3.3372 |
| Unmetered Scattered Load | kWh | $0.0070 | 17,665,103 | - | $ 122,899 | 0.2% | $ 122,569 | $0.0069 |
| Sentinel Lighting | kW | $2.1461 | 49,020 | 139 | $ 298 | 0.0% | $ 298 | $2.1403 |
| Street Lighting | kW | $2.1570 | 44,767,415 | 123,947 | $ 267,356 | 0.5% | $ 266,638 | $2.1512 |
| | | | | | $ 54,287,108 | | | |

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# 2015 RTSR Workform for Electricity Distributors

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

| Rate Class | Unit | Adjusted RTSR-Connection | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | Billed Amount % | Forecast Wholesale Billing | Proposed RTSR Connection |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | $ 0.0042 | 2,337,283,833 | - | $ 9,918,439 | 32.5% | $ 9,886,523 | $ 0.0042 |
| General Service Less Than 50 kW | kWh | $ 0.0040 | 746,272,500 | - | $ 3,016,060 | 9.9% | $ 3,006,355 | $ 0.0040 |
| General Service 50 to 1,499 kW | kW | $ 1.6283 | 3,006,131,060 | 7,292,973 | $ 11,875,296 | 38.9% | $ 11,837,083 | $ 1.6231 |
| General Service 1,500 to 4,999 kW | kW | $ 1.7402 | 857,551,218 | 1,866,871 | $ 3,248,671 | 10.6% | $ 3,238,217 | $ 1.7346 |
| Large Use > 5000 kW | kW | $ 1.9596 | 613,513,830 | 1,135,342 | $ 2,224,841 | 7.3% | $ 2,217,682 | $ 1.9533 |
| Unmetered Scattered Load | kWh | $ 0.0040 | 17,665,103 | - | $ 71,394 | 0.2% | $ 71,164 | $ 0.0040 |
| Sentinel Lighting | kW | $ 1.2096 | 49,020 | 139 | $ 168 | 0.0% | $ 168 | $ 1.2057 |
| Street Lighting | kW | $ 1.2349 | 44,767,415 | 123,947 | $ 153,060 | 0.5% | $ 152,567 | $ 1.2309 |
| | | | | | $ 30,507,928 | | | |

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# 2015 RTSR Workform for Electricity Distributors

Please enter the following Proposed RTS rates into your rates model.

| Rate Class | Unit | Proposed RTSR Network | Proposed RTSR Connection |
|---|---|---|---|
| Residential | kWh | $ 0.0077 | $ 0.0042 |
| General Service Less Than 50 kW | kWh | $ 0.0069 | $ 0.0040 |
| General Service 50 to 1,499 kW | kW | $ 2.8994 | $ 1.6231 |
| General Service 1,500 to 4,999 kW | kW | $ 3.0105 | $ 1.7346 |
| Large Use > 5000 kW | kW | $ 3.3372 | $ 1.9533 |
| Unmetered Scattered Load | kWh | $ 0.0069 | $ 0.0040 |
| Sentinel Lighting | kW | $ 2.1403 | $ 1.2057 |
| Street Lighting | kW | $ 2.1512 | $ 1.2309 |

# RETAIL SERVICE CHARGES

## 1.0 INTRODUCTION

Retail service charges apply to services provided by a distributor to retailers or customers with respect to the supply of competitive electricity through Retailer contracts, in accordance with the Retail Settlement Code ("RSC"). Currently, Hydro Ottawa applies the retail service rates and charges, in accordance with Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

Variances between the charges applied to retailers and the direct costs associated with the provision of these services are recorded in the Board established variance accounts 1518 Retail Cost Variance Retail and 1548 Retail Cost Variance STR, in accordance with Section 12.2.5 of the 2006 Electricity Distribution Rate Handbook.

As outlined in Exhibit H-7-1, Section 4.0, Hydro Ottawa is proposing changes to the current retail rates and charges in 2016, with modest adjustments for inflation between the years 2017 to 2020.

Recognizing the Board's plan to undertake a review of all Specific Service Charges in 2015[1], Hydro Ottawa undertook a review of service charges, as part of this Application, and is requesting a modest adjustment, as an interim step towards improving business efficiencies and appropriate cost recovery.

Hydro Ottawa has not informed Retailers of the proposed rates; however, plans to do so, as part of the standard notification process that will follow the submission of this Application.

[1] EB-2014-0365, Wireless Attachment Consultation, December 11, 2014. Pg. 3.

## WHOLESALE MARKET SERVICE RATE

As part of this application, Hydro Ottawa Limited ("Hydro Ottawa'") has used the Ontario Energy Board's ("the Board") generic Wholesale Market Service Rate of $0.0044 per kilowatt hour and the Rural and Remote Rate Protection of $0.0013 per kilowatt hour to bill its customers. Therefore, a total combined rate of $0.0057 per kilowatt hour is being used.

Hydro Ottawa is not proposing a distributor specific rate.

Hydro Ottawa proposes to update these rates in accordance with any Board approved rate changes during the 2016 through 2020 period.

## SMART METERING CHARGE

On March 28, 2013, the Ontario Energy Board ("the Board") issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering charge of $0.79 per month for Residential and General Service < 50kW customers effective May 1, 2013.

Hydro Ottawa Limited ("Hydro Ottawa") has reflected this charge in their application. As the Smart Metering Charge is currently in effect until October 31, 2018, Hydro Ottawa has only included the charge until October 31, 2018.

# SERVICE CHARGES

## 1.0 INTRODUCTION

As part of this application, Hydro Ottawa Limited ("Hydro Ottawa") is proposing to revise some previously established service charges, introduce additional service charges, eliminate some existing service charges and rename certain service charges to more accurately reflect the services provided. Service charges apply to services that are over and above Hydro Ottawa's standard level of service offerings and may result from a customer's action or inaction. The revenue from these charges offset the total revenue requirement.

During 2014, Hydro Ottawa undertook a review of many routine service charges to ensure they reflected the associated costs of providing services. In addition, the costs for new services requested by customers were also appropriately determined. Finally, Hydro Ottawa assessed certain repeated requests by a small number of customers which result in resources being expended by Hydro Ottawa. Service charges are proposed for such requests to encourage efficient use of Hydro Ottawa's resources.

The following, currently approved, service charges will not be revised or eliminated as part of this application:

i. Arrears Certificate (proposed terminology "Account Certificate");
ii. Duplicate Invoices from Previous Billing;
iii. Credit Reference/Credit Check;
iv. Unprocessed Payment Charge;
v. Account Set-up/Change of Occupancy Charge;
vi. Disconnect/Reconnect Charge (all 4 categories).

With regard to the disconnect/reconnect charge, Hydro Ottawa seeks approval to apply the currently approved rate(s) for the provision of service calls and disconnecting/reconnecting services which may result from occupancy changes, as outlined in Sections 6.4 and 6.1, respectively. As such, these current rates will apply between the years 2016 to 2020.

Hydro Ottawa proposes to increase some existing service charges, as well as, introduce new service charges. No existing service charges have been reduced. Unless otherwise indicated, the proposed rate changes and additions shall be adjusted for the years 2017 and 2020 by formulaic inflationary increases.

## 2.0 SUMMARY OF PROPOSED REVISED AND NEW SERVICE CHARGES

Tables 1 and 2 below summarize the proposed revised and new service charges, respectively, for the years 2016 through 2020. All of the proposed service charges are to be included in Hydro Ottawa's tariff sheet.

## Table 1 – Revised Service Charges

| Service Charges – Revised | 2012-2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Special Billing Service (formerly Other Billing Information Request), per hour | $15.00 | $95.00 | $97.00 | $100.00 | $102.00 | $104.00 |
| Temporary service install & remove – overhead – no transformer | $500.00 | $797.00 | $813.00 | $830.00 | $848.00 | $866.00 |
| Temporary service install & remove – underground – no transformer | $500.00 | $1,156.00 | $1,180.00 | $1,205.00 | $1,230.00 | $1,256.00 |
| Temporary service install & remove – overhead – with transformer | $500.00 | $2,840.00 | $2,900.00 | $2,961.00 | $3,023.00 | $3,087.00 |
| Specific Charge for Access to the Power Poles | $22.35/pole | $57.00 | $57.00 | $58.00 | $58.00 | $58.00 |
| Dry Core Transformer Charge – Demand | Attachment H-7(A) | Attachment H-7(A) | Attachment H-7(A) | Attachment H-7(A) | Attachment H-7(A) | Attachment H-7(A) |
| Standard Charge, per Retailer | $100.00 | $117.00 | $122.00 | $129.00 | $135.00 | $140.00 |
| Monthly Fixed Charge, per Retailer | $20.00 | $24.00 | $25.00 | $26.00 | $27.00 | $28.00 |
| Monthly Variable Charge, per Customer, per Retailer | $0.50 | $0.60 | $0.60 | $0.65 | $0.65 | $0.70 |
| Monthly Billing Charge ("DCB"), per Customer, per Retailer | $0.30 | $0.35 | $0.35 | $0.40 | $0.40 | $0.40 |
| Service Transaction Requests ("STR" ) Fee, per request | $0.25 | $0.30 | $0.30 | $0.30 | $0.35 | $0.35 |
| Service Transaction Requests ("STR") Fee, per process | $0.50 | $0.60 | $0.60 | $0.65 | $0.65 | $0.70 |
| Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly MicroFIT monthly account management charge) | $5.40 | $18.00 | $18.00 | $19.00 | $19.00 | $19.00 |

**Table 2 – New Service Charges**

| Service Charges – New | 2012-2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Disconnect/Reconnect at meter – regular hours (under account administration – new account) | | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 |
| Disconnect/Reconnect at meter – after regular hours (under account administration section – new account) | | $185.00 | $185.00 | $185.00 | $185.00 | $185.00 |
| Interval Meter – Field Reading | | $347.00 | $355.00 | $362.00 | $370.00 | $378.00 |
| High Bill Investigation – If billing is correct | | $213.00 | $218.00 | $222.00 | $227.00 | $232.00 |
| Service Call – Customer missed appointment (Regular Hours) | | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 |
| Service Call – Customer missed appointment (After Regular Hours) | | $185.00 | $185.00 | $185.00 | $185.00 | $185.00 |
| Energy Resource Facility Administration Charge – Without Account Set Up (one-time) | | $127.00 | $130.00 | $133.00 | $135.00 | $138.00 |
| Energy Resource Facility Administration Charge – With Account Set Up (one-time) | | $157.00 | $160.00 | $163.00 | $165.00 | $168.00 |
| FIT Energy Resource Facility Monthly Account Management Charge | | $119.00 | $121.00 | $124.00 | $126.00 | $129.00 |
| HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge | | $259.00 | $264.00 | $270.00 | $276.00 | $281.00 |

## 3.0 REVISED SERVICE CHARGES

Hydro Ottawa is proposing to revise a number of Specific, Retailer and Generator charges.

### 3.1 Special Billing Service (formerly Request for other Billing Information)

This proposed charge applies to all requests for billing information that involves sourcing, compiling and presenting several months or years of billing information for customers or their agents. Services of this nature were historically charged the $15.00 "Request for other Billing Information" charge. Typically, these services vary in terms of resource effort and time; therefore, the proposed charge is based upon Hydro Ottawa's work for others hourly labour rate. A one-hour minimum is proposed for all related services.

Services in excess of one-hour would be billed in 15-minute increments, thereafter. This approach ensures that the associated costs are captured and appropriately recovered. As noted in Section 7.2, Hydro Ottawa proposes to eliminate the "Request for other Billing Information" charge description and replace it with the "Special Billing Service" charge.

### 3.2 Temporary Services

Hydro Ottawa requests approval for three (3) temporary electricity service charges to reflect the actual costs associated with the provision of an overhead service with and without a transformer, as well as, the provision of an underground service. Historically, Hydro Ottawa has been applying the OEB-approved $500 service charge, regardless of service type. An analysis of the types of temporary services commonly provided and associated costs determined that the generic rate was no longer sufficient. The proposed rates have been developed in accordance with the Electricity Distribution Rate Handbook ("EDRH") methodology.

### 3.3 Specific Charge for Access to the Power Poles

As of yearend 2013, Hydro Ottawa had seven companies attaching to Hydro Ottawa poles. Telecom cables and street lighting represented the majority of attachments; however, Bell Canada and Hydro One ("HONI") also had attachments. With the exception of HONI, which applies its own OEB-approved rate, the remaining companies pay the current, province-wide annual pole charge of $22.35 per pole. This rate has applied for more than 10 years and no longer reflects the direct and indirect costs associated with maintaining third-party attachments. A review and analysis of the Access to Power Poles charge has resulted in a proposed rate of $57 for 2016, which will be adjusted for inflation on an annual basis between the years 2017 and 2020.

A detailed history and analysis of the proposed revised rate is set out in Attachment H-7(A). The proposed rate pertains to wire attachments, only.

### 3.4 Dry Core Transformers

The dry core transformer charge is applied to recover energy lost in the operation of a dry core transformer. A specific charge is calculated for each transformer size. A detailed analysis indicated that the existing charges are no longer sufficient. Hydro Ottawa is, therefore, requesting the approval of revised rates for the 26 dry core transformer sizes within Hydro Ottawa's service area, for each of the years 2016 through 2020 as outlined in Appendix H-7(A). On an annual basis, these proposed rates will be further adjusted to reflect any related changes in RPP and Hydro One rates.

## 4.0 REVISED RETAIL SERVICE CHARGES

Hydro Ottawa has been applying the Retail Service Charges set by the OEB, since the competitive electricity market opened in May, 2002. A detailed review and analysis of costs associated with serving this market has resulted in modest adjustments for each of the years 2016 through 2020.

The proposed 2016 rates are based upon the 2013 to 2015 IRM rate increases, plus the estimated 2016 percentage increase in revenue requirement. The 2017 to 2020 rate increases are based upon the estimated percentage increase in revenue requirement for those years.

## 5.0 REVISED GENERATOR CHARGES

### 5.1 Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly Micro-FIT Service charge)

The Micro-FIT monthly service charge of $5.40 is an Ontario Energy Board ("the Board") approved province-wide charge. A review and analysis of the associated costs providing monthly services to Micro-FIT and Micro-Net-Metering customers has resulted in proposed increases ranging from $18 to $19, per month, in the years 2016 to 2020.

## 6.0 NEW SERVICE CHARGES

### 6.1 Disconnect/Reconnect at Meter – New Account (Regular and After Hours)

In response to the Boards customer service rules regarding the opening and closing of customer accounts (EB-2007-0722), Hydro Ottawa's business practices were augmented to disconnect services in situations where the financially-responsible account holder is unknown or does not confirm account responsibility within the prescribed 15 calendar day period, where Hydro Ottawa is advised by a third-party (ref: Sections 2.8.1 and 2.8.2 of the DSC).

Applying the service charges associated with disconnection and reconnection for non-payment of account (at meter), Hydro Ottawa seeks approval to apply the same service charge where a responsible account holder is not confirmed and disconnection proceeds. These service charges would be reflected under the Customer Administration category.

### 6.2 Interval Meter Field Reading Charge

As outlined in Section 2.3.7.2 of Hydro Ottawa's Conditions of Service, interval-metered customers are responsible for providing a dedicated telephone line for remote meter data interrogation. Should this dedicated telephone line become defective, the customer shall be responsible for arranging the necessary repairs within 7 business days upon being notified by Hydro Ottawa. After this timeframe, should the defect remain and require Hydro Ottawa to visit the metering site to obtain a scheduled reading, an interval meter field reading charge will apply to each related visit. This proposed charge is intended to promote timely telephone communication line repairs and, when necessary, recover the costs associated with interval metering field readings due to unresolved telephone line defects.

### 6.3 High Bill Investigation Charge

This proposed charge is intended to recover the direct costs associated with offsite high bill investigations, when all other means of addressing customer high bill concerns have not been satisfactory to the customer. If, as a result of an onsite investigation, it is determined that the billing amount was inaccurate, this charge would be waived.

**6.4 Service Call – Customer Missed Appointment (Regular and After Hours)**

This charge is proposed for all scheduled appointments, wherein, Hydro Ottawa personnel arrive at the agreed-upon time, but, work cannot proceed due to the absence of the customer or designated party. This charge would not apply where the customer makes a reasonable attempt to advise Hydro Ottawa, in advance, that the appointment cannot be kept, in sufficient time for Hydro Ottawa personnel to be redeployed. The costs associated with missed appointments by customers are similar to those associated with disconnection and reconnection for non-payment of account. Therefore, the currently approved charges for disconnection and reconnection for non-payment (at meter) during and after regular hours are similarly proposed for scheduled appointments that are attended by Hydro Ottawa personnel, however, insufficient or no notice is provided by the customer or designated party that the scheduled appointment can no longer be kept.

**6.5 Energy Resource Facility Administration Charge**

This proposed charge applies to all energy resource facilities when there is an assignment of contracts which require legal services and service entrance assessments on the part of Hydro Ottawa. This charge would apply to any new generation facility associated with a new or existing generation account, regardless of size. Where a generation account does not already exist, the OEB-approved Account Set-Up charge will also be applied. This charge does not apply to micro-FIT and micro-net-metering generators.

**6.6 FIT Energy Resource Facility Monthly Account Management Charge**

This proposed charge is applicable to the services provided to FIT Energy Resource Facilities on a monthly basis with respect to settlement. Currently there are no associated charges for the provision of Finance, Accounting, Billing and Metering services.

### 6.7 HCI, RESOP & Other Energy Resource Facility Monthly Account Management Charge

This proposed charge is applicable to the services provided to HCI, RESOP & Other Energy Resource Facilities on a monthly basis with respect to settlement. Currently there are no associated charges for the provision of Finance, Accounting, Billing and Metering services.

## 7.0 REVISED SERVICE CHARGE DESCRIPTIONS

### 7.1 Account Certificate (formerly Arrears Certificate)

Hydro Ottawa is currently authorized to charge for the production of an Arrears Certificate. Typically, such requests are made prior to closing a real estate transaction. Some requests may also involve inquiries regarding Hydro Ottawa property easements. To accurately reflect the potential provision of arrears and/or easement information, Hydro Ottawa proposes to replace the existing “Arrears Certificate” description with “Account Certificate”. No change in the approved charge is requested at this time.

### 7.2 Special Billing Service (formerly Request for Other Billing Information)

As noted in Section 3.1, Hydro Ottawa proposes to eliminate the “Request for other Billing Information” terminology and replace it with the proposed “Special Billing Service” description to accurately reflect the variety of services requests and provided by Billing.

### 7.3 Micro-FIT & Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly Micro-FIT Service)

As noted in Section 5.1, Hydro Ottawa proposes to replace the monthly “Micro-FIT Service” charge description with the “Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge” to more accurately reflect the facilities for which this charge would apply.

## 8.0 SERVICE CHARGE CALCULATIONS

In accordance with the methodology outlined in the Electricity Distribution Rate Handbook (“EDRH”), the 2016 service charge calculations are provided in Attachment H-7(A).

## 9.0 SERVICE CHARGE REVENUES

A schedule of the associated revenues from all specific service charges between 2016 and 2020 is provided in Exhibit C-2-2.

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE: FIT, MICROFIT, HCI, RESOP & OTHER MONTHLY ACOUNT MANAGEMENT CHARGE**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge | $18 | 1,000 | $18,000 |
| FIT Monthly Account Management Charge | $119 | 125 | $14,875 |
| HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge | $259 | 36 | $9,324 |

SPECIFIC SERVICE CHARGES

PROPOSED NEW CHARGE: Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge

| | | Rate/Hr | Hours/Month | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| L | Direct Labour (inside staff) Straight Time: Billing Agent @ 3 days/month | $95.00 | 24.00 | | $2,280.00 |
| A | Direct Labour (inside staff) Straight Time: Senior MDS Analyst @ 4.2 days/month | $95.00 | 33.60 | | $3,192.00 |
| B | Direct Labour (inside staff) Straight Time: Finance @ 3.8 days/month | $95.00 | 30.40 | | $2,888.00 |
| O | Direct Labour (inside staff) Straight Time: Accounts Payables @ 0.8 days/month | $95.00 | 6.40 | | $608.00 |
| U | ***Sub-total Labour Hours Cost/month*** | | | | ***$8,968.00*** |
| R | ***Number of Accounts as of Aug 2014*** | ***543*** | | | |
| | ***Average Total Labour Cost (Labour Hrs Cost over # of accounts)*** | | ***94.40*** | | ***$16.52*** |
| O | Vehicle Time | N/A | | | |
| T | | | | | |
| H | Other: Materials - Postage @ $0.85/ acct | $0.85 | | | $0.85 |
| E | Contract | N/A | | | |
| R | Other: | N/A | | | |
| | ***Total Other*** | | | ***0.00*** | ***$0.85*** |
| ***Average Monthly Cost per Account*** | | | | | ***$17.37*** |
| **Specific Service Charge Value Requested - Rounded up to nearest $** | | | | | **$18.00** |

SPECIFIC SERVICE CHARGES

**PROPOSED NEW CHARGE:** **FIT Monthly Account Management Charge**

| | | Rate/Hr | Hours/ Month | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| L | Direct Labour (inside staff) Straight Time: Senior MDS Analyst @ 2.8 days/month | $95.00 | 22.40 | | $2,128.00 |
| A | Direct Labour (inside staff) Straight Time: Finance @ 5.2 days/month | $95.00 | 41.60 | | $3,952.00 |
| B | Direct Labour (inside staff) Straight Time: Accounts Payables @ 0.5 days/month | $95.00 | 4.00 | | $380.00 |
| O | ***Sub-total Labour Hours Cost/month*** | | | | ***$6,460.00*** |
| U | | | | | |
| R | ***Number of Accounts as of Aug 2014*** | ***55*** | | | |
| | ***Average Total Labour Cost (Labour Hrs Cost over # of accounts)*** | | ***68.00*** | | ***$117.45*** |
| O | Small Vehicle Time | N/A | | | |
| T | | | | | |
| H | Other: Materials - Postage @ $0.85/ acct | $0.85 | | | $0.85 |
| E | Contract | N/A | | | |
| R | Other: | | | | $0.00 |
| | ***Total Other*** | | | ***0.00*** | ***$0.85*** |
| ***Total Cost per account*** | | | | | ***$118.30*** |
| **Specific Service Charge Value Requested - Rounded up to nearest $** | | | | | **$119.00** |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE:** **HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge**

| | | Rate/Hr | Hours/ Month | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time: Finance @ 1.5 days/month | 95.00 | 12.00 | | $1,140.00 |
| **A** | Direct Labour (inside staff) Straight Time: Accounts Payables @ 0.2 days/month | 95.00 | 1.60 | | $152.00 |
| **B** | ***Sub-total Labour Hours Cost/month*** | | | | ***$1,292.00*** |
| **O** | | | | | |
| **U** | ***Number of Accounts as of Aug 2015*** | ***5*** | | | |
| **R** | | | | | |
| | ***Average Total Labour Cost (Labour Hrs Cost over # of accounts)*** | | ***13.60*** | | ***$258.40*** |
| **O** | Small Vehicle Time | N/A | | | |
| **T** | | | | | |
| **H** | Other: Material | N/A | | | |
| **E** | Contract | N/A | | | |
| **R** | Other | N/A | | | |
| | ***Total Other*** | ***0.00*** | ***0.00*** | ***0.00*** | ***$0.00*** |
| ***Total Cost*** | | | | | ***$258.40*** |
| **Specific Service Charge Value Requested - Rounded up to nearest $** | | | | | **$259.00** |

**SPECIFIC SERVICE CHARGES TO APPENDIX G**

**PROPOSED NEW CHARGE: Energy Resource Facility Administration Charge**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| Energy Resource Facility Administration Charge - with account set up | $157 | 5 | $785.00 |
| Energy Resource Facility Administration Charge - without account set up | $127 | 6 | $762.00 |

**PROPOSED CHARGE TO APPENDIX G**

**PROPOSED NEW CHARGE: Energy Resource Facility Administration Charge**

**IF AN HOL ACCOUNT HASN'T BEEN SET-UP. ADMINISTRATIVE CHARGE WILL BE REDUCED BY THE ACCOUNT SET-UP FEE ($30 BASED ON APPROVED OEB RATE)**

| | | | Rate/Hr | Hours | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff): Asset Planning - Receive & review assignment request (15 min), prepare assignment instrument and new payment form (15 min) | | $95.00 | 0.50 | | $47.50 |
| **A** | Direct Labour (inside staff): Legal Dept - Review assignment instrument (20 min) | | $95.00 | 0.33 | | $31.67 |
| **B** | Direct Labour (inside staff): Asset Planning - Issue assignment instrument & new payment form to client, process/assess completed assignment from client; obtain OPA approval where necessary, complete assignment process up to just before account set-up (30 min) | | $95.00 | 0.50 | | $47.50 |
| **O** | | | | | | |
| **U** | | | | | | |
| **R** | | | | | | |
| | | | | | | |
| | ***Total Labour Cost*** | | | | | ***$126.67*** |
| **O** | | | | | | |
| **T** | | | | | | |
| **H** | **Other:** | Material | N/A | | | |
| **E** | | Contract | N/A | | | |
| **R** | | ***Other: Account Revision*** | $30.00 | | | |
| | | ***Total Other*** | ***$30.00*** | | | **$30.00** |
| ***Total Cost*** | | | | | | ***$156.67*** |
| **Specific Service Charge Value Requested - Rounded up to nearest $** | | | | | | **$157** |

**SPECIFIC SERVICE CHARGES: TO APPENDIX G**

**PROPOSED NEW CHARGE: INTERVAL METER - FIELD READING CHARGE**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| Interval Meter Field Reading Charge | $347 | 0 | $0.00 |

**PROPOSED CHARGE TO APPENDIX G**

**PROPOSED NEW CHARGE: INTERVAL METER - FIELD READING CHARGE**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time: MDS - Managing "missed calls" lists, updating records, importing manual data files and data validation. Exporting data to creat CC&B import files. Managing LPSS missing data records | $95.00 | 1.0 | | $95.00 |
| **A** | Direct Labour (field staff) Straight Time: Meter Technican travel, on site manual data collection #1 (Performed after on-site initial site visit) | $95.00 | 1.5 | | $142.50 |
| **B** | Direct Labour (field staff) Straight Time: Meter Technican travel, on site for phone line re-instatement # 2 (Second trip after phone line fixed) | $95.00 | 1.0 | | $95.00 |
| **O** | | | | | |
| **U** | | | | | |
| **R** | | | | | |
| | ***Total Labour Cost*** | | | | ***$332.50*** |
| **O** | Small Vehicle Time: Small Van (Meter Tech) | $5.64 | 2.5 | | $14.10 |
| **T** | | | | | |
| **H** | Other: Material | | | | |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***$14.10*** |
| ***Total Cost*** | | | | | ***$346.60*** |
| **Proposed a reduced Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **$347** |

**SPECIFIC SERVICE CHARGES:**

**PROPOSED NEW CHARGE:**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| **High Bill Investigation** | $213.00 | 70 | $14,910.00 |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE: High Bill Investigation**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time | | | | |
| **A** | Direct Labour (inside staff) Overtime | | | | |
| **B** | Direct Labour (field staff) Straight Time | 95.00 | 2.00 | | 190.00 |
| **O** | Direct Labour (field staff) Overtime | | | | |
| **U** | Other Labour (Specify) | | | | |
| **R** | Payroll Burden % > included in rates | | | | |
| | ***Total Labour Cost*** | | | | ***190.00*** |
| **O** | Small Vehicle Time | 11.00 | 2.00 | | 22.00 |
| **T** | Large Vehicle Time | | | | 0.00 |
| **H** | Other: Material | | | | |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***22.00*** |
| ***Total Cost*** | | | | | ***212.00*** |
| **Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **212.00** |

**SPECIFIC SERVICE CHARGES:**

**PROPOSED NEW CHARGE:**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| Special Billing Services | $95.00 | 70 | $6,650.00 |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE: Special Billing Services**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time | | | | |
| **A** | Direct Labour (inside staff) Overtime | | | | |
| **B** | Direct Labour (field staff) Straight Time | 95.00 | 1.00 | | 95.00 |
| **O** | Direct Labour (field staff) Overtime | | | | |
| **U** | Other Labour (Specify) | | | | |
| **R** | Payroll Burden % > included in rates | | | | |
| | ***Total Labour Cost*** | | | | ***95.00*** |
| **O** | Small Vehicle Time | | | | 0.00 |
| **T** | Large Vehicle Time | | | | 0.00 |
| **H** | Other: Material | | | | |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***0.00*** |
| ***Total Cost*** | | | | | ***95.00*** |
| **Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **95.00** |

**SPECIFIC SERVICE CHARGES:**

**PROPOSED NEW CHARGE:**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| basic temp service + OH + no tx | $797.00 | 70 | $55,790.00 |
| basic temp service + UG + no tx | $1,156.00 | 10 | $11,560.00 |
| basic temp service + OH + tx | $2,840.00 | 25 | $71,000.00 |
| | | | |
| | | | |
| | | | |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE:** **Basic temporary service - overhead & no transformer**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time | | | | |
| **A** | Direct Labour (inside staff) Overtime | | | | |
| **B** | Direct Labour (field staff) Straight Time | 95.00 | 4.00 | | 380.00 |
| **O** | Direct Labour (field staff) Overtime | | | | |
| **U** | Other Labour (Specify) | | | | |
| **R** | Payroll Burden % > included in rates | | | | |
| | ***Total Labour Cost*** | | | | ***380.00*** |
| **O** | Small Vehicle Time | 12.00 | | | |
| **T** | Large Vehicle Time | 45.00 | 2.00 | | 90.00 |
| **H** | Other: Material | 302.33 | | | 302.33 |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***392.33*** |
| ***Total Cost*** | | | | | ***772.33*** |
| **Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **772.00** |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE:** **Basic temporary service - underground & no transformer**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time | | | | |
| **A** | Direct Labour (inside staff) Overtime | | | | |
| **B** | Direct Labour (field staff) Straight Time | 95.00 | 6.00 | | 570.00 |
| **O** | Direct Labour (field staff) Overtime | | | | |
| **U** | Other Labour (Specify) | | | | |
| **R** | Payroll Burden % > included in rates | | | | |
| | ***Total Labour Cost*** | | | | ***570.00*** |
| **O** | Small Vehicle Time | 12.00 | | | |
| **T** | Large Vehicle Time | 45.00 | 3.00 | | 135.00 |
| **H** | Other: Material | 417.28 | | | 417.28 |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***552.28*** |
| ***Total Cost*** | | | | | ***1,122.28*** |
| **Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **1,122.00** |

**SPECIFIC SERVICE CHARGES**

**PROPOSED NEW CHARGE:** **Basic temporary service - overhead & transformer**

| | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost |
|---|---|---|---|---|---|
| **L** | Direct Labour (inside staff) Straight Time | | | | |
| **A** | Direct Labour (inside staff) Overtime | | | | |
| **B** | Direct Labour (field staff) Straight Time | 95.00 | 8.00 | | 760.00 |
| **O** | Direct Labour (field staff) Overtime | | | | |
| **U** | Other Labour (Specify) | | | | |
| **R** | Payroll Burden % > included in rates | | | | |
| | ***Total Labour Cost*** | | | | ***760.00*** |
| **O** | Small Vehicle Time | 12.00 | | | |
| **T** | Large Vehicle Time | 45.00 | 4.00 | | 180.00 |
| **H** | Other: Material | 1,770.00 | | | 1,770.00 |
| **E** | Contract | | | | |
| **R** | Other | | | | |
| | ***Total Other*** | | | | ***1,950.00*** |
| ***Total Cost*** | | | | | ***2,710.00*** |
| **Specific Service Charge Value Requested - Rounded to nearest $** | | | | | **2,710.00** |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2012[1]

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2011-0054

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $4.44 | $0.08744 | | $2.85 | |
| 25 KVA 1 PH | 150 | 900 | $0.71 | $7.95 | $8.66 | $0.46 | $9.12 |
| 37.5 KVA 1 PH | 200 | 1200 | $0.95 | $10.60 | $11.55 | $0.61 | $12.16 |
| 50 KVA 1 PH | 250 | 1600 | $1.21 | $13.33 | $14.54 | $0.78 | $15.32 |
| 75 KVA 1 PH | 350 | 1900 | $1.62 | $18.37 | $19.99 | $1.04 | $21.03 |
| 100 KVA 1 PH | 400 | 2600 | $1.95 | $21.36 | $23.31 | $1.25 | $24.56 |
| 150 KVA 1 PH | 525 | 3500 | $2.58 | $28.11 | $30.69 | $1.66 | $32.35 |
| 167 KVA 1 PH | 650 | 4400 | $3.21 | $34.86 | $38.07 | $2.06 | $40.13 |
| 200 KVA 1 PH | 696 | 4700 | $3.43 | $37.32 | $40.75 | $2.20 | $42.96 |
| 225 KVA 1 PH | 748 | 5050 | $3.69 | $40.11 | $43.80 | $2.37 | $46.16 |
| 250 KVA 1 PH | 800 | 5400 | $3.95 | $42.89 | $46.84 | $2.53 | $49.37 |
| | | | | | | | |
| *15 KVA 3 PH | 125 | 650 | $0.57 | $6.54 | $7.11 | $0.37 | $7.47 |
| *45 KVA 3 PH | 300 | 1800 | $1.43 | $15.89 | $17.32 | $0.92 | $18.24 |
| *75 KVA 3 PH | 400 | 2400 | $1.90 | $21.19 | $23.09 | $1.22 | $24.31 |
| *112.5 KVA 3 PH | 600 | 3400 | $2.81 | $31.62 | $34.42 | $1.80 | $36.22 |
| *150 KVA 3 PH | 700 | 4500 | $3.40 | $37.34 | $40.74 | $2.18 | $42.92 |
| *225 KVA 3 PH | 900 | 5300 | $4.26 | $47.60 | $51.85 | $2.73 | $54.58 |
| *300 KVA 3 PH | 1100 | 6300 | $5.16 | $58.02 | $63.18 | $3.31 | $66.49 |
| *500 KVA 3 PH | 1500 | 9700 | $7.30 | $80.06 | $87.36 | $4.69 | $92.05 |
| *750 KVA 3 PH | 2100 | 12000 | $9.84 | $110.74 | $120.59 | $6.32 | $126.90 |
| *1000 KVA 3 PH | 2600 | 15000 | $12.22 | $137.23 | $149.45 | $7.84 | $157.30 |
| *1500 KVA 3 PH | 4000 | 22000 | $18.54 | $210.21 | $228.76 | $11.90 | $240.66 |
| *2000 KVA 3 PH | 4800 | 24000 | $21.68 | $250.21 | $271.89 | $13.92 | $285.81 |
| *2500 KVA 3 PH | 5700 | 26000 | $25.15 | $295.00 | $320.15 | $16.15 | $336.30 |

[1] *Rates in place from January 1, 2012 to December 31, 2015*

# DRAFT - TARIFF OF RATES AND CHARGES

**Effective and Implementation Date January 1, 2016**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8899 | $ 0.1146 | | $ 3.8233 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.61 | $ 11.82 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.82 | $ 15.76 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.04 | $ 19.86 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.39 | $ 27.26 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.68 | $ 31.83 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.22 | $ 41.92 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.76 | $ 52.01 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.96 | $ 55.67 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.07 | $ 52.58 | $ 56.65 | $ 3.18 | $ 59.83 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.40 | $ 63.98 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.49 | $ 9.69 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.23 | $ 23.64 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.64 | $ 31.52 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.42 | $ 46.96 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.75 | $ 48.96 | $ 52.70 | $ 2.93 | $ 55.63 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.67 | $ 70.76 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.44 | $ 86.20 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.91 | $ 8.44 | $ 178.34 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.83 | $ 11.06 | $ 226.89 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.78 | $ 12.41 | $ 256.19 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.22 | $ 302.52 | $ 323.74 | $ 16.59 | $ 340.33 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 19.78 | $ 407.44 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.25 | $ 23.76 | $ 490.00 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.02 | $ 579.49 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.01 | $ 635.31 | $ 679.32 | $ 34.41 | $ 713.72 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.55 | $ 733.92 | $ 784.48 | $ 39.53 | $ 824.00 |

# DRAFT - TARIFF OF RATES AND CHARGES

## Effective and Implementation Date January 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8889 | $ 0.1146 | | $ 3.9427 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.63 | $ 11.84 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.84 | $ 15.78 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.08 | $ 19.89 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.44 | $ 27.30 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.73 | $ 31.89 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.29 | $ 41.99 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.85 | $ 52.09 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 3.05 | $ 55.76 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.28 | $ 59.92 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.51 | $ 64.09 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.51 | $ 9.71 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.27 | $ 23.68 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.69 | $ 31.57 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.49 | $ 47.03 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 3.02 | $ 55.72 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.78 | $ 70.87 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.58 | $ 86.33 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.70 | $ 178.61 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 11.40 | $ 227.23 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.80 | $ 256.57 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.73 | $ 17.11 | $ 340.84 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 20.40 | $ 408.06 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 24.50 | $ 490.74 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.89 | $ 580.36 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 35.48 | $ 714.79 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 40.76 | $ 825.23 |

## DRAFT - TARIFF OF RATES AND CHARGES
**Effective and Implementation Date January 1, 2018**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.9185 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.63 | $ 11.83 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.84 | $ 15.78 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.07 | $ 19.88 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.43 | $ 27.30 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.72 | $ 31.87 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.28 | $ 41.97 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.83 | $ 52.07 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 3.03 | $ 55.74 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.26 | $ 59.90 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.48 | $ 64.07 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.50 | $ 9.70 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.26 | $ 23.67 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.68 | $ 31.56 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.48 | $ 47.02 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 3.00 | $ 55.70 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.76 | $ 70.85 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.55 | $ 86.31 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.65 | $ 178.55 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 11.33 | $ 227.16 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.72 | $ 256.49 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.73 | $ 17.00 | $ 340.74 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 20.28 | $ 407.93 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 24.35 | $ 490.59 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.71 | $ 580.18 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 35.26 | $ 714.57 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 40.51 | $ 824.98 |

# DRAFT - TARIFF OF RATES AND CHARGES

**Effective and Implementation Date January 1, 2019**

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.7523 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.60 | $ 11.81 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.80 | $ 15.74 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.03 | $ 19.84 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.37 | $ 27.23 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.65 | $ 31.80 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.18 | $ 41.88 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.71 | $ 51.95 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.90 | $ 55.61 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.12 | $ 59.77 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.34 | $ 63.92 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.48 | $ 9.68 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.21 | $ 23.61 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.61 | $ 31.49 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.37 | $ 46.91 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 2.87 | $ 55.57 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.60 | $ 70.69 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.36 | $ 86.11 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.28 | $ 178.19 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 10.85 | $ 226.68 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.18 | $ 255.95 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.74 | $ 16.28 | $ 340.02 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 19.42 | $ 407.07 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 23.32 | $ 489.56 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 27.50 | $ 578.96 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 33.77 | $ 713.08 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 38.79 | $ 823.26 |

# DRAFT - TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.5123 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.56 | $ 11.77 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.75 | $ 15.69 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 0.96 | $ 19.77 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.28 | $ 27.15 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.54 | $ 31.70 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.04 | $ 41.74 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.54 | $ 51.78 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.72 | $ 55.43 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 2.92 | $ 59.57 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.12 | $ 63.71 |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.45 | $ 9.65 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.13 | $ 23.54 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.51 | $ 31.38 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.22 | $ 46.76 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 2.69 | $ 55.39 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.37 | $ 70.46 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.08 | $ 85.83 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 7.75 | $ 177.66 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 10.16 | $ 225.98 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 11.40 | $ 255.17 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.74 | $ 15.24 | $ 338.97 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 18.17 | $ 405.83 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 21.82 | $ 488.06 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 25.74 | $ 577.21 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 31.61 | $ 710.92 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.55 | $ 733.92 | $ 784.47 | $ 36.31 | $ 820.78 |

**SPECIFIC SERVICE CHARGES:**

**PROPOSED NEW CHARGE:**

| NEW & UPDATED SPECIFIC SERVICE CHARGES | 2016 Rate | 2016 Forecast Volume | 2016 Forecast Revenue |
|---|---|---|---|
| Pole Attachments | $57.00 | 56,347 | $3,211,779.00 |

SPECIFIC SERVICE CHARGES

**PROPOSED NEW CHARGE:** Pole Attachments

| | | | Rate/ Amount | Hours/ Units | O/T Factor | Calculated Cost 2013 |
|---|---|---|---|---|---|---|
| **Admin** | Invoicing | | 95.00 | 16.00 | | 1,520.00 |
| | GIS Tracking | | 95.00 | 167.00 | | 15,865.00 |
| | Permit | | 95.00 | | | 123,906.00 |
| | Poles with attachments | 35,663 | | | | |
| | ***Total Admin per Pole with attachments per year*** | | | | | ***3.96*** |
| **LIP-Pole replacement** | **Field Varificantion** | | | | | |
| | Labour | | 95.00 | 1.00 | | 95.00 |
| | Small Vehicle Time | | 5.80 | 1.00 | | 5.80 |
| | Sub-total per field Verification | | | | | 100.80 |
| | Poles replaced with attacments | 808 | | | | |
| | | Cost of Field verification | | | | 81,410.21 |
| | | | | | | |
| | **Returning Crew** | | | | | |
| | Labour | | 95.00 | 2.00 | | 190.00 |
| | Small Vehicle Time | | 44.00 | 1.00 | | 44.00 |
| | Sub-total | | | | | 234.00 |
| | Poles replaced with attacments | 808 | | | | |
| | | Cost of Returning Crew | | | | 188,987.99 |
| | | | | | | |
| | **Total LIP-Pole replacement** | | | | | ***270,398.21*** |
| | | | | | | |
| **LIP-Field Verification** | **Wires Down** | | | | | |
| | Labour | | 95.00 | 1.00 | | 95.00 |
| | Small Vehicle Time | | 33.00 | 1.00 | | 33.00 |
| | Sub-total | | | | | 128.00 |
| | Reported wires down | 115 | | | | |
| | | Cost per wire down reported | | | | **14,720.00** |
| | | | | | | |
| **LIP-Field Verification** | **Tree on Wires** | | | | | |
| | Labour | | 95.00 | 1.00 | | 95.00 |
| | Small Vehicle Time | | 5.80 | 1.00 | | 5.80 |
| | Sub-total | | | | | 100.80 |
| | Reported wires on tree | 251 | | | | |
| | | Cost per tree on wire reported | | | | **25,300.80** |
| | | | | | | |
| | **Total Cost due to Loss In Productivity** | | | | | **310,419.01** |
| | **Poles with attachments** | **35,663** | | | | |
| | ***Total LIP per Pole with attachments per year*** | | | | | ***8.70*** |
| | | | | | | |
| **Net Embedded Cost er Pole** (Used to Calculate Capital Carrying Costs) | | | | | | 1,678.00 |
| | | | | | | |
| **Depreciation Expense per Pole** | | | | | | 43.29 |
| | | | | | | |
| **Pole Maintenance Expense per Pole** | | | | | | 12.61 |
| | | | | | | |
| **Capital Carrying Costs per Pole** | | | | | | 112.43 |
| | | | | | | |
| | **Total Indirect Costs per pole** | | | | | **168.33** |
| **Allocation Factor** | Based on 2 third party attachers | **25.9%** | | | | |
| | ***Total Indirect Costs per Pole with attachments per year*** | | | | | ***43.60*** |
| | | | | | | |
| ***Total Cost per Pole with attachments per year*** | | | | | | ***56.26*** |

# LOW VOLTAGE SERVICE RATES

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") receives low voltage ("LV") charges from Hydro One Networks Inc. ("Hydro One") for a number of Shared Distribution Stations, Specific Lines and Shared Lines. The Ontario Energy Board's (the "Board") Decision dated March 21, 2006 (EB-2005-0529) determined that it was appropriate for an embedded Local Distribution Company ("LDC"), or an LDC with embedded distribution points (such as Hydro Ottawa), to establish and maintain a variance account for LV charges from its host LDC.

In a June 13, 2006 memo, the Board notified LDCs that Account 4750, Charges - LV and Account 4075, Billed - LV and Account 1550 – LV Variance Account had been added to the Uniform System of Accounts ("USofA"). As a result, effective May 1, 2006 Account 1550 has been used to record the net of the amounts recorded in Accounts 4750 (amount charged by Hydro One for low voltage services) and 4075 (amount customers are billed for low voltage services). In 2008 Hydro Ottawa removed the LV charges from the distribution revenue requirement and proposed that a separate charge be calculated to recover the LV charges from the customer. These separate charges were approved by the Board as part of the EB-2007-0713 Decision, issued on March 17, 2008. The current low voltage rates are shown below in Table 1.

**Table 1 – Low Voltage Charges as of January 1, 2015**

| Class | Per | LV Charge |
|---|---|---|
| Residential | kWh | $0.00006 |
| General Service < 50 kW | kWh | $0.00006 |
| General Service 50 to 1,499 kW | kW | $0.02354 |
| General Service 1,500 to 4,999 kW | kW | $0.02516 |
| Large Use (> 5000 kW) | kW | $0.02833 |
| Unmetered Scattered Load | kWh | $0.00006 |
| Sentinel Lights | kW | $0.01785 |
| Street Lighting | kW | $0.01749 |

## 2.0 PROPOSED LV CHARGES FOR 2016 THROUGH 2020

In Table 2 below are the actual LV Charges for 2012 and 2013 and the forecasted LV Charges for 2014 and 2015.

**Table 2 – LV Charges 2012 to 2015**

| | 2012 Actual $000 | 2013 Actual $000 | 2014 Forecast $000 | 2015 Forecast $000 |
|---|---|---|---|---|
| LV Charges | $452 | $458 | $451 | $453 |

An average of the total actual LV Charge for 2012 and 2013 was the basis for the 2016 through 2020 forecast. As the dollar value was used it was not necessary to forecast the 2016 through 2020 billing determinants for LV charges.

The LV charge has been allocated to the customer classes based on the class percentage of Retail Transmission Connection dollars (using 2015 rates), as shown in Tables 3 through 7.

**Table 3 – 2016 Calculation of LV Charge**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| | **2015 Retail Transmission Connection Rate ($) kWh/kW** | **2016 Charge Determinant (kWh or kW)** | **A * B Basis for Allocation[1]** | **Allocation %** | **Allocated $** | **2016 Rate /kWh or kW** |
| Residential | $0.0042 | 2,216,045,000 | $9,307,389 | 31.84% | $144,858 | $0.00007 |
| General Service < 50 kW | $0.0040 | 726,360,000 | $2,905,440 | 9.94% | $45,220 | $0.00006 |
| General Service 50 to 1,499 kW | $1.6232 | 7,027,979 | $11,407,816 | 39.02% | $177,549 | $0.02526 |
| General Service 1,500 to 4,999 kW | $1.7347 | 1,847,365 | $3,204,624 | 10.96% | $49,876 | $0.02700 |
| Large Use (> 5000 kW) | $1.9535 | 1,121,449 | $2,190,751 | 7.49% | $34,096 | $0.03040 |
| Unmetered Scattered Load | $0.0040 | 16,651,000 | $66,604 | 0.23% | $1,037 | $0.00006 |
| Sentinel Lighting | $1.2058 | 216 | $260 | 0.00% | $4 | $0.01877 |
| Street Lighting | $1.2310 | 123,144 | $151,590 | 0.52% | $2,359 | $0.01916 |
| TOTAL | | | $29,234,474 | | $455,000 | |

**Table 4 – 2017 Calculation of LV Charge**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| | 2015 Retail Transmission Connection Rate ($) kWh/kW | 2017 Charge Determinant (kWh or kW) | A * B Basis for Allocation[1] | Allocation % | Allocated $ | 2017 Rate /kWh or kW |
| Residential | $0.0042 | 2,198,259,000 | $9,232,688 | 31.86% | $144,970 | $0.00007 |
| General Service < 50 kW | $0.0040 | 716,896,000 | $2,867,584 | 9.90% | $45,026 | $0.00006 |
| General Service 50 to 1,499 kW | $1.6232 | 6,908,640 | $11,214,104 | 38.70% | $176,081 | $0.02549 |
| General Service 1,500 to 4,999 kW | $1.7347 | 1,877,691 | $3,257,231 | 11.24% | $51,144 | $0.02724 |
| Large Use (> 5000 kW) | $1.9535 | 1,119,726 | $2,187,385 | 7.55% | $34,346 | $0.03067 |
| Unmetered Scattered Load | $0.0040 | 16,690,000 | $66,760 | 0.23% | $1,048 | $0.00006 |
| Sentinel Lighting | $1.2058 | 216 | $260 | 0.00% | $4 | $0.01893 |
| Street Lighting | $1.2310 | 123,144 | $151,590 | 0.52% | $2,380 | $0.01933 |
| TOTAL | | | $28,977,602 | | $455,000 | |

**Table 5 – 2018 Calculation of LV Charge**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| | 2015 Retail Transmission Connection Rate ($) kWh/kW | 2018 Charge Determinant (kWh or kW) | A * B Basis for Allocation[1] | Allocation % | Allocated $ | 2018 Rate /kWh or kW |
| Residential | $0.0042 | 2,206,411,000 | $9,266,926 | 32.05% | $145,845 | $0.00007 |
| General Service < 50 kW | $0.0040 | 709,791,000 | $2,839,164 | 9.82% | $44,683 | $0.00006 |
| General Service 50 to 1,499 kW | $1.6232 | 6,824,350 | $11,077,285 | 38.32% | $174,337 | $0.02555 |
| General Service 1,500 to 4,999 kW | $1.7347 | 1,916,044 | $3,323,762 | 11.50% | $52,310 | $0.02730 |
| Large Use (> 5000 kW) | $1.9535 | 1,118,300 | $2,184,599 | 7.56% | $34,382 | $0.03074 |
| Unmetered Scattered Load | $0.0040 | 16,731,000 | $66,924 | 0.23% | $1,053 | $0.00006 |
| Sentinel Lighting | $1.2058 | 216 | $260 | 0.00% | $4 | $0.01898 |
| Street Lighting | $1.2310 | 123,144 | $151,590 | 0.52% | $2,386 | $0.01937 |
| TOTAL | | | $28,910,510 | | $455,000 | |

**Table 6 – 2019 Calculation of LV Charge**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| | **2015 Retail Transmission Connection Rate ($) kWh/kW** | **2019 Charge Determinant (kWh or kW)** | **A * B Basis for Allocation[1]** | **Allocation %** | **Allocated $** | **2019 Rate /kWh or kW** |
| Residential | $0.0042 | 2,214,984,000 | $9,302,933 | 32.20% | $146,521 | $0.00007 |
| General Service < 50 kW | $0.0040 | 704,193,000 | $2,816,772 | 9.75% | $44,364 | $0.00006 |
| General Service 50 to 1,499 kW | $1.6232 | 6,761,930 | $10,975,965 | 37.99% | $172,871 | $0.02557 |
| General Service 1,500 to 4,999 kW | $1.7347 | 1,957,009 | $3,394,824 | 11.75% | $53,468 | $0.02732 |
| Large Use (> 5000 kW) | $1.9535 | 1,115,702 | $2,179,524 | 7.54% | $34,327 | $0.03077 |
| Unmetered Scattered Load | $0.0040 | 16,772,000 | $67,088 | 0.23% | $1,057 | $0.00006 |
| Sentinel Lighting | $1.2058 | 216 | $260 | 0.00% | $4 | $0.01899 |
| Street Lighting | $1.2310 | 123,144 | $151,590 | 0.52% | $2,388 | $0.01939 |
| TOTAL | | | $28,888,956 | | $455,000 | |

**Table 7 – 2020 Calculation of LV Charge**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| **2020** | **2015 Retail Transmission Connection Rate ($) kWh/kW** | **2020 Charge Determinant (kWh or kW)** | **A * B Basis for Allocation[1]** | **Allocation %** | **Allocated $** | **2020 Rate /kWh or kW** |
| Residential | $0.0042 | 2,217,628,000 | $9,314,038 | 32.26% | $146,785 | $0.00007 |
| General Service < 50 kW | $0.0040 | 699,744,000 | $2,798,976 | 9.69% | $44,111 | $0.00006 |
| General Service 50 to 1,499 kW | $1.6232 | 6,711,579 | $10,894,235 | 37.73% | $171,688 | $0.02558 |
| General Service 1,500 to 4,999 kW | $1.7347 | 2,001,525 | $3,472,045 | 12.03% | $54,718 | $0.02734 |
| Large Use (> 5000 kW) | $1.9535 | 1,112,342 | $2,172,960 | 7.53% | $34,245 | $0.03079 |
| Unmetered Scattered Load | $0.0040 | 16,827,000 | $67,308 | 0.23% | $1,061 | $0.00006 |
| Sentinel Lighting | $1.2058 | 216 | $260 | 0.00% | $4 | $0.01900 |
| Street Lighting | $1.2310 | 123,144 | $151,590 | 0.53% | $2,389 | $0.01940 |
| TOTAL | | | $28,871,413 | | $455,000 | |

# LOSS ADJUSTMENT FACTORS

## 1.0 DISTRIBUTION LOSSES

Table 1 below provides losses as a percentage of purchases for the previous five years. Hydro Ottawa Limited's ("Hydro Ottawa") losses have not been greater than 5% in the past five years. Hydro Ottawa contains no distributors embedded in its area and is not an embedded distributor itself; however it does have a number of delivery points embedded in Hydro One Network Inc.'s service territory.

***Table 1 – Losses as a % of Purchases for Previous Five Years***

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Electricity Purchases (MWh) | 7,784,723 | 7,839,865 | 7,853,159 | 7,856,204 | 7,722,152 |
| Electricity Sales (MWh) | 7,560,847 | 7,594,977 | 7,607,711 | 7,570,226 | 7,519,454 |
| Losses (MWh) | 223,876 | 244,888 | 245,447 | 285,978 | 202,698 |
| Losses % | 2.88% | 3.12% | 3.13% | 3.64% | 2.62% |

## 2.0 LOSS ADJUSTMENT FACTORS

Hydro Ottawa's current loss adjustment factors, which have been approved by the Ontario Energy Board (the "Board") as part of the EB-2011-0054 Decision, are shown below:

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0358 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0170 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0254 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0069 |

Hydro Ottawa has completed Appendix 2-R of the Board's Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, July 18, 2014, which is also attached as a PDF to this Exhibit.

As a result of the updated calculation in Appendix 2-R, Hydro Ottawa is requesting approval of the following revised loss factors, for Secondary and Primary Metered Customers:

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
| **Exhibit:** | H |
| **Tab:** | 9 |
| **Schedule:** | 1 |
| **Page:** | 1 |
| | |
| **Date:** | ORIGINAL |

# Appendix 2-R
# Loss Factors

| | | Historical Years | | | | | 5-Year Average |
|---|---|---|---|---|---|---|---|
| | | 2009 | 2010 | 2011 | 2012 | 2013 | |
| | ***Losses Within Distributor's System*** | | | | | | |
| **A(1)** | "Wholesale" kWh delivered to distributor (higher value) | 7,784,723,200 | 7,839,865,242 | 7,853,158,848 | 7,856,203,955 | 7,722,151,641 | 7811220577 |
| **A(2)** | "Wholesale" kWh delivered to distributor (lower value) | 7,739,120,106 | 7,793,416,883 | 7,806,353,006 | 7,808,192,459 | 7,675,507,526 | 7,764,517,996 |
| **B** | Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s) | 637,811,922 | 689,846,705 | 666,105,214 | 650,508,627 | 617,344,861 | 652,323,466 |
| **C** | Net "Wholesale" kWh delivered to distributor = **A(2) - B** | 7,101,308,184 | 7,103,570,178 | 7,140,247,792 | 7,157,683,832 | 7,058,162,665 | 7,112,194,530 |
| **D** | "Retail" kWh delivered by distributor | 7,560,846,876 | 7,594,977,085 | 7,607,711,356 | 7,570,226,415 | 7,519,454,130 | 7570643172 |
| **E** | Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s) | 633,982,714 | 685,666,594 | 662,045,474 | 646,432,433 | 613,513,830 | 648,328,209 |
| **F** | Net "Retail" kWh delivered by distributor = **D - E** | 6,926,864,162 | 6,909,310,491 | 6,945,665,882 | 6,923,793,982 | 6,905,940,300 | 6,922,314,963 |
| **G** | Loss Factor in Distributor's system = **C / F** | 1.0252 | 1.0281 | 1.0280 | 1.0338 | 1.0220 | 1.0274 |
| | ***Losses Upstream of Distributor's System*** | | | | | | |
| **H** | Supply Facilities Loss Factor | 1.0060 | 1.0061 | 1.0061 | 1.0063 | 1.0062 | 1.0062 |
| | ***Total Losses*** | | | | | | |
| **I** | Total Loss Factor = **G x H** | 1.0314 | 1.0344 | 1.0343 | 1.0403 | 1.0284 | 1.0338 |

***Notes***

**A(1)** If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

**A(2)** If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

**B** If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

**D** kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

**G** and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

**H** If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

# CURRENT AND PROPOSED TARIFF OF RATES AND CHARGES

Hydro Ottawa Limited's ("Hydro Ottawa") 2015 tariff of rates and charges is provided as attachment H-10(A). Hydro Ottawa's 2016 through 2020 proposed tariff of rates and charges is provided in Appendix 2-Z and included as PDF's to this exhibit.

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 12.25 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0235 |
| Low Voltage Service Rate | $/kWh | 0.00007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kWh | (0.0006) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 22.75 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0216 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kWh | (0.0009) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 290.00 |
| Distribution Volumetric Rate | $/kW | 3.9454 |
| Low Voltage Service Rate | $/kW | 0.02526 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kW | (0.0010) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kW | (0.4122) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 4,650.00 |
| Distribution Volumetric Rate | $/kW | 3.8602 |
| Low Voltage Service Rate | $/kW | 0.0270 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kW | (0.0001) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kW | (0.4598) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 16,900.00 |
| Distribution Volumetric Rate | $/kW | 3.6644 |
| Low Voltage Service Rate | $/kW | 0.0304 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kW | (0.00002) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kW | (0.5443) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this

### APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.75 |
| Distribution Volumetric Rate | $/kWh | 0.0242 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kWh | (0.0010) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 135.00 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.6668 |

### MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate
Rural or Remote Electricity Rate Protection Charge (RRRP)
Standard Supply Service - Administrative Charge (if applicable)

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 3.25 |
| Distribution Volumetric Rate | $/kW | 12.0650 |
| Low Voltage Service Rate | $/kW | 0.01877 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kW | (0.2038) |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.65 |
| Distribution Volumetric Rate | $/kW | 4.3442 |
| Low Voltage Service Rate | $/kW | 0.01916 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective until December 31, 2016 | $/kW | (0.0001) |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2016 | $/kW | (0.3479) |
| Rate Rider for Global Adjustment Account | $/kWh | (0.0003) |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## Micro-FIT and Micro-Net-Metering SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 18.0000 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## FIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's FIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 119.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## HCI, RESOP, Other Energy Resource SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's HCI, RESOP and Other Energy Resource programs and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 259.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month
Primary Metering Allowance for transformer losses – applied to measured demand and energy

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Special Billing Service Per Hour (Min 1 hour, 15 min incremental billing thereafter) | $ | 95.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Reconnect at Meter - Regular Hours (Under Account Administration - New Account) | $ | 65.00 |
| Reconnect at Meter - After Regular Hours (Under Account Administration - New Account) | $ | 185.00 |
| Interval Meter - Field Reading | $ | 347.00 |
| High Bill Investigation - If Billing is Correct | $ | 213.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late Payment – per month | % | 1.5000 |
| Late Payment – per annum | % | 19.5600 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary Service – Install & remove – overhead – no transformer | $ | 797.00 |
| Temporary Service – Install & remove – underground – no transformer | $ | 1,156.00 |
| Temporary Service – Install & remove – overhead – with transformer | $ | 2,840.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 57.00 |
| Dry core transformer distribution charge | Per Attached Table | |
| Service Call - Customer Missed Appointment - during regular hours | $ | 65.00 |
| Service Call - Customer Missed Appointment - after regular hours | $ | 185.00 |
| Energy Resource Facility Administration Charge - Without Account Set Up (One Time) | $ | 127.00 |
| Energy Resource Facility Administration Charge - With Account Set Up (One Time) | $ | 157.00 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 117.00 |
| Monthly Fixed Charge, per retailer | $ | 24.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.6000 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.3500 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.3500) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.30 |
| Processing fee, per request, applied to the requesting party | $ | 0.60 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

# DRAFT - TARIFF OF RATES AND CHARGES

## Effective and Implementation Date January 1, 2016

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8899 | $ 0.1146 | | $ 3.8233 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.61 | $ 11.82 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.82 | $ 15.76 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.04 | $ 19.86 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.39 | $ 27.26 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.68 | $ 31.83 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.22 | $ 41.92 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.76 | $ 52.01 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.96 | $ 55.67 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.07 | $ 52.58 | $ 56.65 | $ 3.18 | $ 59.83 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.40 | $ 63.98 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.49 | $ 9.69 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.23 | $ 23.64 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.64 | $ 31.52 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.42 | $ 46.96 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.75 | $ 48.96 | $ 52.70 | $ 2.93 | $ 55.63 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.67 | $ 70.76 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.44 | $ 86.20 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.91 | $ 8.44 | $ 178.34 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.83 | $ 11.06 | $ 226.89 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.78 | $ 12.41 | $ 256.19 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.22 | $ 302.52 | $ 323.74 | $ 16.59 | $ 340.33 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 19.78 | $ 407.44 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.25 | $ 23.76 | $ 490.00 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.02 | $ 579.49 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.01 | $ 635.31 | $ 679.32 | $ 34.41 | $ 713.72 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.55 | $ 733.92 | $ 784.48 | $ 39.53 | $ 824.00 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are

### APPLICATION

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 14.25 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0228 |
| Low Voltage Service Rate | $/kWh | 0.00007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 27.75 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0214 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 355.00 |
| Distribution Volumetric Rate | $/kW | 3.8962 |
| Low Voltage Service Rate | $/kW | 0.02549 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,975.00 |
| Distribution Volumetric Rate | $/kW | 4.0575 |
| Low Voltage Service Rate | $/kW | 0.02724 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 17,900.00 |
| Distribution Volumetric Rate | $/kW | 3.8746 |
| Low Voltage Service Rate | $/kW | 0.03067 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 5.75 |
| Distribution Volumetric Rate | $/kWh | 0.0237 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 143.00 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.7652 |

## MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate
Rural or Remote Electricity Rate Protection Charge (RRRP)
Standard Supply Service - Administrative Charge (if applicable)

# SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 3.25 |
| Distribution Volumetric Rate | $/kW | 13.3241 |
| Low Voltage Service Rate | $/kW | 0.01893 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.70 |
| Distribution Volumetric Rate | $/kW | 4.5389 |
| Low Voltage Service Rate | $/kW | 0.01933 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Micro-FIT and Micro-Net-Metering SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 18.0000 |

## MONTHLY RATES AND CHARGES - Regulatory Component

# FIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's FIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

## MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 121.00 |

## MONTHLY RATES AND CHARGES - Regulatory Component

## HCI, RESOP, Other Energy Resource SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's HCI, RESOP and Other Energy Resource programs and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 264.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

## ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month
Primary Metering Allowance for transformer losses – applied to measured demand and energy

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

| | | |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Special Billing Service Per Hour (Min 1 hour, 15 min incremental billing thereafter) | $ | 97.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Reconnect at Meter - Regular Hours (Under Account Administration - New Account) | $ | 65.00 |
| Reconnect at Meter - After Regular Hours (Under Account Administration - New Account) | $ | 185.00 |
| Interval Meter - Field Reading | $ | 355.00 |
| High Bill Investigation - If Billing is Correct | $ | 218.00 |
| **Non-Payment of Account** | | |
| Late Payment – per month | % | 1.5000 |
| Late Payment – per annum | % | 19.5600 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |
| **Other** | | |
| Temporary Service – Install & remove – overhead – no transformer | $ | 813.00 |
| Temporary Service – Install & remove – underground – no transformer | $ | 1,180.00 |
| Temporary Service – Install & remove – overhead – with transformer | $ | 2,900.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 57.00 |
| Dry core transformer distribution charge | Per Attached Table | |
| Service Call - Customer Missed Appointment - during regular hours | $ | 65.00 |
| Service Call - Customer Missed Appointment - after regular hours | $ | 185.00 |
| Energy Resource Facility Administration Charge - Without Account Set Up (One Time) | $ | 130.00 |
| Energy Resource Facility Administration Charge - With Account Set Up (One Time) | $ | 160.00 |

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 122.00 |
| Monthly Fixed Charge, per retailer | $ | 25.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.6000 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.3500 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.3500) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.30 |
| Processing fee, per request, applied to the requesting party | $ | 0.60 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

# DRAFT - TARIFF OF RATES AND CHARGES

## Effective and Implementation Date January 1, 2017

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8889 | $ 0.1146 | | $ 3.9427 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.63 | $ 11.84 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.84 | $ 15.78 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.08 | $ 19.89 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.44 | $ 27.30 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.73 | $ 31.89 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.29 | $ 41.99 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.85 | $ 52.09 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 3.05 | $ 55.76 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.28 | $ 59.92 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.51 | $ 64.09 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.51 | $ 9.71 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.27 | $ 23.68 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.69 | $ 31.57 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.49 | $ 47.03 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 3.02 | $ 55.72 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.78 | $ 70.87 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.58 | $ 86.33 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.70 | $ 178.61 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 11.40 | $ 227.23 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.80 | $ 256.57 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.73 | $ 17.11 | $ 340.84 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 20.40 | $ 408.06 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 24.50 | $ 490.74 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.89 | $ 580.36 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 35.48 | $ 714.79 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 40.76 | $ 825.23 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 16.50 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0216 |
| Low Voltage Service Rate | $/kWh | 0.00007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 33.25 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0208 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 420.00 |
| Distribution Volumetric Rate | $/kW | 3.8299 |
| Low Voltage Service Rate | $/kW | 0.02555 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5,600.00 |
| Distribution Volumetric Rate | $/kW | 4.1002 |
| Low Voltage Service Rate | $/kW | 0.0273 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 21,000.00 |
| Distribution Volumetric Rate | $/kW | 3.8254 |
| Low Voltage Service Rate | $/kW | 0.03074 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this

### APPLICATION

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 7.00 |
| Distribution Volumetric Rate | $/kWh | 0.0225 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 150.00 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.8639 |

### MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate
Rural or Remote Electricity Rate Protection Charge (RRRP)
Standard Supply Service - Administrative Charge (if applicable)

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.00 |
| Distribution Volumetric Rate | $/kW | 12.5418 |
| Low Voltage Service Rate | $/kW | 0.01898 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.75 |
| Distribution Volumetric Rate | $/kW | 4.7173 |
| Low Voltage Service Rate | $/kW | 0.01937 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## Micro-FIT and Micro-Net-Metering SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 19.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## FIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's FIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 124.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## HCI, RESOP, Other Energy Resource SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's HCI, RESOP and Other Energy Resource programs and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 270.00 |

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

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**EB-2015-0004**

## ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month
Primary Metering Allowance for transformer losses – applied to measured demand and energy

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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| | | |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Special Billing Service Per Hour (Min 1 hour, 15 min incremental billing thereafter) | $ | 100.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Reconnect at Meter - Regular Hours (Under Account Administration - New Account) | $ | 65.00 |
| Reconnect at Meter - After Regular Hours (Under Account Administration - New Account) | $ | 185.00 |
| Interval Meter - Field Reading | $ | 362.00 |
| High Bill Investigation - If Billing is Correct | $ | 222.00 |
| **Non-Payment of Account** | | |
| Late Payment – per month | % | 1.5000 |
| Late Payment – per annum | % | 19.5600 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |
| **Other** | | |
| Temporary Service – Install & remove – overhead – no transformer | $ | 830.00 |
| Temporary Service – Install & remove – underground – no transformer | $ | 1,205.00 |
| Temporary Service – Install & remove – overhead – with transformer | $ | 2,961.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 58.00 |
| Dry core transformer distribution charge | Per Attached Table | |
| Service Call - Customer Missed Appointment - during regular hours | $ | 65.00 |
| Service Call - Customer Missed Appointment - after regular hours | $ | 185.00 |
| Energy Resource Facility Administration Charge - Without Account Set Up (One Time) | $ | 133.00 |
| Energy Resource Facility Administration Charge - With Account Set Up (One Time) | $ | 163.00 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 129.00 |
| Monthly Fixed Charge, per retailer | $ | 26.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.6500 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.4000 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.4000) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.30 |
| Processing fee, per request, applied to the requesting party | $ | 0.65 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

# DRAFT - TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2018

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.9185 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.63 | $ 11.83 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.84 | $ 15.78 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.07 | $ 19.88 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.43 | $ 27.30 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.72 | $ 31.87 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.28 | $ 41.97 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.83 | $ 52.07 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 3.03 | $ 55.74 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.26 | $ 59.90 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.48 | $ 64.07 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.50 | $ 9.70 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.26 | $ 23.67 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.68 | $ 31.56 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.48 | $ 47.02 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 3.00 | $ 55.70 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.76 | $ 70.85 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.55 | $ 86.31 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.65 | $ 178.55 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 11.33 | $ 227.16 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.72 | $ 256.49 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.73 | $ 17.00 | $ 340.74 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 20.28 | $ 407.93 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 24.35 | $ 490.59 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 28.71 | $ 580.18 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 35.26 | $ 714.57 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 40.51 | $ 824.98 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 19.00 |
| Distribution Volumetric Rate | $/kWh | 0.0196 |
| Low Voltage Service Rate | $/kWh | 0.00007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 38.75 |
| Distribution Volumetric Rate | $/kWh | 0.0201 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

x

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 490.00 |
| Distribution Volumetric Rate | $/kW | 3.6842 |
| Low Voltage Service Rate | $/kW | 0.02557 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |

x

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 6,650.00 |
| Distribution Volumetric Rate | $/kW | 3.9007 |
| Low Voltage Service Rate | $/kW | 0.02732 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24,600.00 |
| Distribution Volumetric Rate | $/kW | 3.6719 |
| Low Voltage Service Rate | $/kW | 0.03077 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

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**EB-2015-0004**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 7.50 |
| Distribution Volumetric Rate | $/kWh | 0.0229 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

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**EB-2015-0004**

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 159.00 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.9337 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate
Rural or Remote Electricity Rate Protection Charge (RRRP)
Standard Supply Service - Administrative Charge (if applicable)

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.25 |
| Distribution Volumetric Rate | $/kW | 12.9159 |
| Low Voltage Service Rate | $/kW | 0.01899 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

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**EB-2015-0004**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor’s Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.80 |
| Distribution Volumetric Rate | $/kW | 4.8325 |
| Low Voltage Service Rate | $/kW | 0.01939 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |

x

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## Micro-FIT and Micro-Net-Metering SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 19.00 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## FIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's FIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 126.00 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## HCI, RESOP, Other Energy Resource SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's HCI, RESOP and Other Energy Resource programs and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 276.00 |

X

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2019

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month
Primary Metering Allowance for transformer losses – applied to measured demand and energy

## SPECIFIC SERVICE CHARGES

### APPLICATION

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No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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| | | |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Special Billing Service Per Hour (Min 1 hour, 15 min incremental billing thereafter) | $ | 102.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Reconnect at Meter - Regular Hours (Under Account Administration - New Account) | $ | 65.00 |
| Reconnect at Meter - After Regular Hours (Under Account Administration - New Account) | $ | 185.00 |
| Interval Meter - Field Reading | $ | 370.00 |
| High Bill Investigation - If Billing is Correct | $ | 227.00 |
| **Non-Payment of Account** | | |
| Late Payment – per month | % | 1.5000 |
| Late Payment – per annum | % | 19.5600 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |
| **Other** | | |
| Temporary Service – Install & remove – overhead – no transformer | $ | 848.00 |
| Temporary Service – Install & remove – underground – no transformer | $ | 1,230.00 |
| Temporary Service – Install & remove – overhead – with transformer | $ | 3,023.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 58.00 |
| Dry core transformer distribution charge | Per Attached Table | |
| Service Call - Customer Missed Appointment - during regular hours | $ | 65.00 |
| Service Call - Customer Missed Appointment - after regular hours | $ | 185.00 |
| Energy Resource Facility Administration Charge - Without Account Set Up (One Time) | $ | 135.00 |
| Energy Resource Facility Administration Charge - With Account Set Up (One Time) | $ | 165.00 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2019

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**EB-2015-0004**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 135.00 |
| Monthly Fixed Charge, per retailer | $ | 27.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.6500 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.4000 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.4000) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.35 |
| Processing fee, per request, applied to the requesting party | $ | 0.65 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

# DRAFT - TARIFF OF RATES AND CHARGES

## Effective and Implementation Date January 1, 2019

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EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.7523 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.60 | $ 11.81 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.80 | $ 15.74 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 1.03 | $ 19.84 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.37 | $ 27.23 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.65 | $ 31.80 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.18 | $ 41.88 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.71 | $ 51.95 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.90 | $ 55.61 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 3.12 | $ 59.77 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.34 | $ 63.92 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.48 | $ 9.68 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.21 | $ 23.61 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.61 | $ 31.49 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.37 | $ 46.91 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 2.87 | $ 55.57 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.60 | $ 70.69 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.36 | $ 86.11 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 8.28 | $ 178.19 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 10.85 | $ 226.68 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 12.18 | $ 255.95 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.74 | $ 16.28 | $ 340.02 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 19.42 | $ 407.07 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 23.32 | $ 489.56 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 27.50 | $ 578.96 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 33.77 | $ 713.08 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.54 | $ 733.92 | $ 784.47 | $ 38.79 | $ 823.26 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

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**EB-2015-0004**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 20.75 |
| Distribution Volumetric Rate | $/kWh | 0.0180 |
| Low Voltage Service Rate | $/kWh | 0.00007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 44.00 |
| Distribution Volumetric Rate | $/kWh | 0.0188 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

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**EB-2015-0004**

## GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 550.00 |
| Distribution Volumetric Rate | $/kW | 3.4930 |
| Low Voltage Service Rate | $/kW | 0.02558 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |

x

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2020

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**EB-2015-0004**

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 7,700.00 |
| Distribution Volumetric Rate | $/kW | 3.6031 |
| Low Voltage Service Rate | $/kW | 0.02734 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

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**EB-2015-0004**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 28,000.00 |
| Distribution Volumetric Rate | $/kW | 3.4408 |
| Low Voltage Service Rate | $/kW | 0.03079 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
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EB-2015-0004

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this

### APPLICATION

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 7.50 |
| Distribution Volumetric Rate | $/kWh | 0.0238 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
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EB-2015-0004

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 165.00 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.9761 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate
Rural or Remote Electricity Rate Protection Charge (RRRP)
Standard Supply Service - Administrative Charge (if applicable)

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.75 |
| Distribution Volumetric Rate | $/kW | 12.4211 |
| Low Voltage Service Rate | $/kW | 0.0190 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.80 |
| Distribution Volumetric Rate | $/kW | 5.0761 |
| Low Voltage Service Rate | $/kW | 0.0194 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |

x

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## Micro-FIT and Micro-Net-Metering SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 19.00 |

X

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## FIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's FIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 129.00 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## HCI, RESOP, Other Energy Resource SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's or Independent Electricity System Operator's HCI, RESOP and Other Energy Resource programs and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 281.00 |

x

### MONTHLY RATES AND CHARGES - Regulatory Component

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

## ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month
Primary Metering Allowance for transformer losses – applied to measured demand and energy

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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| | | |
|---|---|---|
| **Customer Administration** | | |
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Special Billing Service Per Hour (Min 1 hour, 15 min incremental billing thereafter) | $ | 104.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Reconnect at Meter - Regular Hours (Under Account Administration - New Account) | $ | 65.00 |
| Reconnect at Meter - After Regular Hours (Under Account Administration - New Account) | $ | 185.00 |
| Interval Meter - Field Reading | $ | 378.00 |
| High Bill Investigation - If Billing is Correct | $ | 232.00 |
| **Non-Payment of Account** | | |
| Late Payment – per month | % | 1.5000 |
| Late Payment – per annum | % | 19.5600 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |
| **Other** | | |
| Temporary Service – Install & remove – overhead – no transformer | $ | 866.00 |
| Temporary Service – Install & remove – underground – no transformer | $ | 1,256.00 |
| Temporary Service – Install & remove – overhead – with transformer | $ | 3,087.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 58.00 |
| Dry core transformer distribution charge | Per Attached Table | |
| Service Call - Customer Missed Appointment - during regular hours | $ | 65.00 |
| Service Call - Customer Missed Appointment - after regular hours | $ | 185.00 |
| Energy Resource Facility Administration Charge - Without Account Set Up (One Time) | $ | 138.00 |
| Energy Resource Facility Administration Charge - With Account Set Up (One Time) | $ | 168.00 |

# Hydro Ottawa Limited
# TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2015-0004**

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 140.00 |
| Monthly Fixed Charge, per retailer | $ | 28.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.7000 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.4000 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.4000) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.35 |
| Processing fee, per request, applied to the requesting party | $ | 0.70 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0163 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0234 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0062 |

# DRAFT - TARIFF OF RATES AND CHARGES
## Effective and Implementation Date January 1, 2020

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2015-0004

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $ 4.8890 | $ 0.1146 | | $ 3.5123 | |
| 25 KVA 1 PH, 1.2kV BIL | 150 | 900 | $ 0.79 | $ 10.42 | $ 11.20 | $ 0.56 | $ 11.77 |
| 37.5 KVA 1 PH, 1.2kV BIL | 200 | 1200 | $ 1.05 | $ 13.89 | $ 14.94 | $ 0.75 | $ 15.69 |
| 50 KVA 1 PH, 1.2kV BIL | 250 | 1600 | $ 1.34 | $ 17.48 | $ 18.81 | $ 0.96 | $ 19.77 |
| 75 KVA 1 PH, 1.2kV BIL | 350 | 1900 | $ 1.78 | $ 24.09 | $ 25.87 | $ 1.28 | $ 27.15 |
| 100 KVA 1 PH, 1.2kV BIL | 400 | 2600 | $ 2.15 | $ 28.01 | $ 30.15 | $ 1.54 | $ 31.70 |
| 150 KVA 1 PH, 1.2kV BIL | 525 | 3500 | $ 2.84 | $ 36.86 | $ 39.70 | $ 2.04 | $ 41.74 |
| 167 KVA 1 PH, 1.2kV BIL | 650 | 4400 | $ 3.54 | $ 45.71 | $ 49.24 | $ 2.54 | $ 51.78 |
| 200 KVA 1 PH, 1.2kV BIL | 696 | 4700 | $ 3.78 | $ 48.93 | $ 52.71 | $ 2.72 | $ 55.43 |
| 225 KVA 1 PH, 1.2kV BIL | 748 | 5050 | $ 4.06 | $ 52.58 | $ 56.65 | $ 2.92 | $ 59.57 |
| 250 KVA 1 PH, 1.2kV BIL | 800 | 5400 | $ 4.35 | $ 56.24 | $ 60.58 | $ 3.12 | $ 63.71 |
| | | | | | | | |
| *15 KVA 3 PH, 1.2kV BIL | 125 | 650 | $ 0.63 | $ 8.57 | $ 9.20 | $ 0.45 | $ 9.65 |
| *45 KVA 3 PH, 1.2kV BIL | 300 | 1800 | $ 1.57 | $ 20.84 | $ 22.41 | $ 1.13 | $ 23.54 |
| *75 KVA 3 PH, 1.2kV BIL | 400 | 2400 | $ 2.10 | $ 27.78 | $ 29.88 | $ 1.51 | $ 31.38 |
| *112.5 KVA 3 PH, 1.2kV BIL | 600 | 3400 | $ 3.09 | $ 41.45 | $ 44.54 | $ 2.22 | $ 46.76 |
| *150 KVA 3 PH, 1.2kV BIL | 700 | 4500 | $ 3.74 | $ 48.96 | $ 52.70 | $ 2.69 | $ 55.39 |
| *225 KVA 3 PH, 1.2kV BIL | 900 | 5300 | $ 4.69 | $ 62.40 | $ 67.09 | $ 3.37 | $ 70.46 |
| *300 KVA 3 PH, 1.2kV BIL | 1100 | 6300 | $ 5.68 | $ 76.07 | $ 81.75 | $ 4.08 | $ 85.83 |
| *500 KVA 3 PH, 95kV BIL | 2400 | 7600 | $ 10.79 | $ 159.11 | $ 169.90 | $ 7.75 | $ 177.66 |
| *750 KVA 3 PH, 95kV BIL | 3000 | 12000 | $ 14.14 | $ 201.68 | $ 215.82 | $ 10.16 | $ 225.98 |
| *1000 KVA 3 PH, 95kV BIL | 3400 | 13000 | $ 15.87 | $ 227.90 | $ 243.77 | $ 11.40 | $ 255.17 |
| *1500 KVA 3 PH, 95kV BIL | 4500 | 18000 | $ 21.21 | $ 302.52 | $ 323.74 | $ 15.24 | $ 338.97 |
| *2000 KVA 3 PH, 95kV BIL | 5400 | 21000 | $ 25.30 | $ 362.36 | $ 387.66 | $ 18.17 | $ 405.83 |
| *2500 KVA 3 PH, 95kV BIL | 6500 | 25000 | $ 30.38 | $ 435.86 | $ 466.24 | $ 21.82 | $ 488.06 |
| *3000 KVA 3PH, 95kV BIL | 7700 | 29000 | $ 35.83 | $ 515.64 | $ 551.47 | $ 25.74 | $ 577.21 |
| *3750 KVA 3PH, 95kV BIL | 9500 | 35000 | $ 44.00 | $ 635.31 | $ 679.31 | $ 31.61 | $ 710.92 |
| *5000 KVA 3PH, 95kV BIL | 11000 | 39000 | $ 50.55 | $ 733.92 | $ 784.47 | $ 36.31 | $ 820.78 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## RESIDENTIAL SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triple or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customes. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 9.67 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0234 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0042 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 16.72 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0210 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## GENERAL SERVICE 50 TO 1,499 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,500 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 260.82 |
| Distribution Volumetric Rate | $/kW | 3.5691 |
| Low Voltage Service Rate | $/kW | 0.02354 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6232 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## GENERAL SERVICE 1,500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to non residential accounts whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 1,500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4,193.93 |
| Distribution Volumetric Rate | $/kW | 3.4887 |
| Low Voltage Service Rate | $/kW | 0.02516 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.0186 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7347 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

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EB-2014-0085

## LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 15,231.32 |
| Distribution Volumetric Rate | $/kW | 3.3129 |
| Low Voltage Service Rate | $/kW | 0.02833 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.3462 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9535 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 120/240 volts single phase whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Qualification for this classification is at the discretion of Hydro Ottawa as defined in its Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.43 |
| Distribution Volumetric Rate | $/kWh | 0.0219 |
| Low Voltage Service Rate | $/kWh | 0.00006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0040 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation equal to or greater than 500 kW and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component (Approved on an Interim Basis)

| | | |
|---|---|---|
| Service Charge | $ | 122.41 |
| Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility). | | |
| General Service 50 to 1,499 kW customer | $/kW | 1.6337 |
| General Service 1,500 to 4,999 kW customer | $/kW | 1.4985 |
| General Service Large Use customer | $/kW | 1.6629 |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.62 |
| Distribution Volumetric Rate | $/kW | 10.0361 |
| Low Voltage Service Rate | $/kW | 0.01785 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1461 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2058 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting controlled by photocells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessements or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 0.57 |
| Distribution Volumetric Rate | $/kW | 3.9997 |
| Low Voltage Service Rate | $/kW | 0.01749 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.1570 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2310 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0013 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2015

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EB-2014-0085

## MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distrubition system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Hydro Ottawa Limited
## TARIFF OF RATES AND CHARGES
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EB-2014-0085

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.45) |
| Primary Metering Allowance for transformer losses – applied to measured demand and energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Duplicate Invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Credit Reference/credit check (plus credit agency costs) | $ | 15.00 |
| Unprocessed Payment Charge (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late Payment – per month | % | 1.50 |
| Late Payment – per annum | % | 19.56 |
| Collection of account charge – no disconnection | $ | 30.00 |
| Disconnect/Reconnect at meter – during regular hours | $ | 65.00 |
| Disconnect/Reconnect at meter – after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole – after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary Service – Install & remove – overhead – no transformer | $ | 500.00 |
| Specific Charge for Access to the Power Poles - $/pole/year | $ | 22.35 |
| Dry core transformer distribution charge | As per Attached Table | |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

## RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 100.00 |
| Monthly Fixed Charge, per retailer | $ | 20.00 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 0.50 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.30 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.30) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.25 |
| Processing fee, per request, applied to the requesting party | $ | 0.50 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 2.00 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0358 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | 1.0170 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0254 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | 1.0069 |

# Hydro Ottawa Limited

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2015

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

EB-2014-0085

**Dry Core Transformer Charges**

| Transformers | No Load Loss (W) | Load Loss (W) | Cost of Transmission and LV per kW | Cost of Energy and Wholesale Market per kWh | Total Monthly cost of power | Cost of Distribution per kW | Total |
|---|---|---|---|---|---|---|---|
| Rates | | | $4.44 | $0.09 | | $2.85 | |
| 25 KVA 1 PH | 150 | 900 | $0.71 | $7.95 | $8.66 | $0.46 | $9.12 |
| 37.5 KVA 1 PH | 200 | 1200 | $0.95 | $10.60 | $11.55 | $0.61 | $12.16 |
| 50 KVA 1 PH | 250 | 1600 | $1.21 | $13.33 | $14.54 | $0.78 | $15.32 |
| 75 KVA 1 PH | 350 | 1900 | $1.62 | $18.37 | $19.99 | $1.04 | $21.03 |
| 100 KVA 1 PH | 400 | 2600 | $1.95 | $21.36 | $23.31 | $1.25 | $24.56 |
| 150 KVA 1 PH | 525 | 3500 | $2.58 | $28.11 | $30.69 | $1.66 | $32.35 |
| 167 KVA 1 PH | 650 | 4400 | $3.21 | $34.86 | $38.07 | $2.06 | $40.13 |
| 200 KVA 1 PH | 696 | 4700 | $3.43 | $37.32 | $40.75 | $2.20 | $42.96 |
| 225 KVA 1 PH | 748 | 5050 | $3.69 | $40.11 | $43.80 | $2.37 | $46.16 |
| 250 KVA 1 PH | 800 | 5400 | $3.95 | $42.89 | $46.84 | $2.53 | $49.37 |
| *15 KVA 3 PH | 125 | 650 | $0.57 | $6.54 | $7.11 | $0.37 | $7.47 |
| *45 KVA 3 PH | 300 | 1800 | $1.43 | $15.89 | $17.32 | $0.92 | $18.24 |
| *75 KVA 3 PH | 400 | 2400 | $1.90 | $21.19 | $23.09 | $1.22 | $24.31 |
| *112.5 KVA 3 PH | 600 | 3400 | $2.81 | $31.62 | $34.42 | $1.80 | $36.22 |
| *150 KVA 3 PH | 700 | 4500 | $3.40 | $37.34 | $40.74 | $2.18 | $42.92 |
| *225 KVA 3 PH | 900 | 5300 | $4.26 | $47.60 | $51.85 | $2.73 | $54.58 |
| *300 KVA 3 PH | 1100 | 6300 | $5.16 | $58.02 | $63.18 | $3.31 | $66.49 |
| *500 KVA 3 PH | 1500 | 9700 | $7.30 | $80.06 | $87.36 | $4.69 | $92.05 |
| *750 KVA 3 PH | 2100 | 12000 | $9.84 | $110.74 | $120.59 | $6.32 | $126.90 |
| *1000 KVA 3 PH | 2600 | 15000 | $12.22 | $137.23 | $149.45 | $7.84 | $157.30 |
| *1500 KVA 3 PH | 4000 | 22000 | $18.54 | $210.21 | $228.76 | $11.90 | $240.66 |
| *2000 KVA 3 PH | 4800 | 24000 | $21.68 | $250.21 | $271.89 | $13.92 | $285.81 |
| *2500 KVA 3 PH | 5700 | 26000 | $25.15 | $295.00 | $320.15 | $16.15 | $336.30 |

No Load and load losses from CSA standard C802-94: Maximum losses for distribution, power and dry-type transformers commercial use.
Average load factor = 0.46 average loss factor = 0.2489

*For non-preferred KVA ratings no load and load losses are interpolated as per CSA standard

# REVENUE PER RATE CLASS UNDER CURRENT AND PROPOSED RATES

Please see Tables 1 through 5 for detailed calculations of revenue per rate class under current rates and a reconciliation of rate class revenue at current rates and other revenue to total revenue requirement.

Detailed calculations of revenue per rate class under proposed rates can be found in Appendix 2-V and as a PDF to this Exhibit. The difference in revenue deficiency is due to the different way in calculating average customers/connects. Hydro Ottawa Limited has used a monthly calculation whereas Appendix 2-V calculates the average by using the beginning and end of the year customer/connection numbers.

## Table 1 – Revenue per rate class and reconciliation to 2016 Revenue Requirement

| Rate Class | Average # Customers/ Connections | 2016 Consumption | | 2015 Rates | | Revenues at 2015 Rates (000) | Transformer Allowance Credit (000) | Difference |
|---|---|---|---|---|---|---|---|---|
| | | MWh | KW | Monthly Service Charge | Volumetric Rate (kWh/KW) | | | |
| Residential | 297,343 | 2,216,045 | | $ 9.67 | $ 0.0234 | $ 86,359 | | $ 86,359 |
| GS < 50 kW | 24,512 | 726,360 | | $ 16.72 | $ 0.0210 | $ 20,172 | | $ 20,172 |
| GS > 50 to 1,999 kW | 3,295 | 2,954,441 | 7,028 | $ 260.82 | $ 3.5691 | $ 35,398 | $ 791 | $ 34,607 |
| GS > 1,5000 to 4,999 kW | 76 | 863,309 | 1,847,365 | $ 4,193.93 | $ 3.4887 | $ 10,270 | $ 208 | $ 10,062 |
| Large Use | 11 | 620,218 | 1,121,449 | $ 15,231.32 | $ 3.3129 | $ 5,726 | $ 126 | $ 5,600 |
| Street Lighting | 55,516 | 43,552 | 123,144 | $ 0.57 | $ 3.9997 | $ 872 | | $ 872 |
| Sentinel Lighting | 55 | 48 | 216 | $ 2.62 | $ 10.0361 | $ 4 | | $ 4 |
| Unmetered Scattered Load | 3,477 | 16,651 | | $ 4.43 | $ 0.0219 | $ 549 | | $ 549 |
| Standby Power | 2 | | 4,800 | $ 122.41 | $ 1.4985 | $ 10 | | $ 10 |
| **Revenue** | | | | | | $ 159,360 | $ 1,125 | $ 158,235 |

| | |
|---|---|
| Other Revenue | $ 11,700 |
| Total Revenue | $ 169,935 |
| 2016 Revenue Requirement | $ 187,269 |
| 2016 Revenue Deficiency | $ 17,334 |

## Table 2 – Revenue per rate class and reconciliation to 2017 Revenue Requirement

| Rate Class | Average # Customers/ Connections | 2017 Consumption | | 2015 Rates | | Revenues at 2015 Rates (000) | Transformer Allowance Credit (000) | Difference |
|---|---|---|---|---|---|---|---|---|
| | | MWh | KW | Monthly Service Charge | Volumetric Rate (kWh/KW) | | | |
| Residential | 301,258 | 2,198,259 | | $ 9.67 | $ 0.0234 | $ 86,397 | | $ 86,397 |
| GS < 50 kW | 24,626 | 716,896 | | $ 16.72 | $ 0.0210 | $ 19,996 | | $ 19,996 |
| GS > 50 to 1,999 kW | 3,323 | 2,907,445 | 6,909 | $ 260.82 | $ 3.5691 | $ 35,059 | $ 777 | $ 34,281 |
| GS > 1,5000 to 4,999 kW | 76 | 877,400 | 1,877,691 | $ 4,193.93 | $ 3.4887 | $ 10,376 | $ 211 | $ 10,164 |
| Large Use | 11 | 619,253 | 1,119,726 | $ 15,231.32 | $ 3.3129 | $ 5,720 | $ 126 | $ 5,594 |
| Street Lighting | 55,516 | 43,653 | 123,144 | $ 0.57 | $ 3.9997 | $ 872 | | $ 872 |
| Sentinel Lighting | 51 | 48 | 216 | $ 2.62 | $ 10.0361 | $ 4 | | $ 4 |
| Unmetered Scattered Load | 3,525 | 16,690 | | $ 4.43 | $ 0.0219 | $ 553 | | $ 553 |
| Standby Power | 2 | | 4,800 | $ 122.41 | $ 1.4985 | $ 10 | | $ 10 |
| **Revenue** | | | | | | $ 158,986 | $ 1,114 | $ 157,872 |

| | |
|---|---|
| Other Revenue | $ 11,565 |
| Total Revenue | $ 169,437 |
| 2017 Revenue Requirement | $ 197,235 |
| 2017 Revenue Deficiency | $ 27,798 |

## Table 3 – Revenue per rate class and reconciliation to 2018 Revenue Requirement

| Rate Class | Average # Customers/ Connections | 2018 Consumption | | 2015 Rates | | Revenues at 2015 Rates (000) | Transformer Allowance Credit (000) | Difference |
|---|---|---|---|---|---|---|---|---|
| | | MWh | KW | Monthly Service Charge | Volumetric Rate (kWh/KW) | | | |
| Residential | 305,144 | 2,206,411 | | $ 9.67 | $ 0.0234 | $ 87,039 | | $ 87,039 |
| GS < 50 kW | 24,739 | 709,791 | | $ 16.72 | $ 0.0210 | $ 19,869 | | $ 19,869 |
| GS > 50 to 1,999 kW | 3,351 | 2,875,422 | 6,824 | $ 260.82 | $ 3.5691 | $ 34,846 | $ 768 | $ 34,078 |
| GS > 1,5000 to 4,999 kW | 76 | 895,369 | 1,916,044 | $ 4,193.93 | $ 3.4887 | $ 10,509 | $ 216 | $ 10,294 |
| Large Use | 11 | 618,467 | 1,118,300 | $ 15,231.32 | $ 3.3129 | $ 5,715 | $ 126 | $ 5,590 |
| Street Lighting | 55,516 | 43,765 | 123,144 | $ 0.57 | $ 3.9997 | $ 872 | | $ 872 |
| Sentinel Lighting | 47 | 48 | 216 | $ 2.62 | $ 10.0361 | $ 4 | | $ 4 |
| Unmetered Scattered Load | 3,573 | 16,731 | | $ 4.43 | $ 0.0219 | $ 556 | | $ 556 |
| Standby Power | 2 | | 4,800 | $ 122.41 | $ 1.4985 | $ 10 | | $ 10 |
| **Revenue** | | | | | | $ 159,421 | $ 1,109 | $ 158,312 |

| | |
|---|---|
| Other Revenue | $ 11,722 |
| Total Revenue | $ 170,034 |
| 2018 Revenue Requirement | $ 208,120 |
| 2018 Revenue Deficiency | $ 38,086 |

## Table 4 – Revenue Per Rate Class and Reconciliation to 2019 Revenue Requirement

| Rate Class | Average # Customers/ Connections | 2019 Consumption | | 2015 Rates | | Revenues at 2015 Rates (000) | Transformer Allowance Credit (000) | Difference |
|---|---|---|---|---|---|---|---|---|
| | | MWh | KW | Monthly Service Charge | Volumetric Rate (kWh/KW) | | | |
| Residential | 308,990 | 2,214,984 | | $ 9.67 | $ 0.0234 | $ 87,686 | | $ 87,686 |
| GS < 50 kW | 24,850 | 704,193 | | $ 16.72 | $ 0.0210 | $ 19,774 | | $ 19,774 |
| GS > 50 to 1,999 kW | 3,380 | 2,852,593 | 6,762 | $ 260.82 | $ 3.5691 | $ 34,712 | $ 761 | $ 33,952 |
| GS > 1,5000 to 4,999 kW | 76 | 914,569 | 1,957,009 | $ 4,193.93 | $ 3.4887 | $ 10,652 | $ 220 | $ 10,432 |
| Large Use | 11 | 617,036 | 1,115,702 | $ 15,231.32 | $ 3.3129 | $ 5,707 | $ 126 | $ 5,581 |
| Street Lighting | 55,516 | 43,876 | 123,144 | $ 0.57 | $ 3.9997 | $ 872 | | $ 872 |
| Sentinel Lighting | 43 | 48 | 216 | $ 2.62 | $ 10.0361 | $ 4 | | $ 4 |
| Unmetered Scattered Load | 3,621 | 16,772 | | $ 4.43 | $ 0.0219 | $ 560 | | $ 560 |
| Standby Power | 2 | | 4,800 | $ 122.41 | $ 1.4985 | $ 10 | | $ 10 |
| **Revenue** | | | | | | $ 159,977 | $ 1,106 | $ 158,870 |

| | |
|---|---|
| Other Revenue | $ 11,802 |
| Total Revenue | $ 170,672 |
| 2019 Revenue Requirement | $ 217,816 |
| 2019 Revenue Deficiency | $ 47,144 |

## Table 5 – Revenue Per Rate Class and Reconciliation to 2020 Revenue Requirement

| Rate Class | Average # Customers/ Connections | 2020 Consumption | | 2015 Rates | | Revenues at 2015 Rates (000) | Transformer Allowance Credit (000) | Difference |
|---|---|---|---|---|---|---|---|---|
| | | MWh | KW | Monthly Service Charge | Volumetric Rate (kWh/KW) | | | |
| Residential | 312,786 | 2,217,628 | | $ 9.67 | $ 0.0234 | $ 88,188 | | $ 88,188 |
| GS < 50 kW | 24,959 | 699,744 | | $ 16.72 | $ 0.0210 | $ 19,702 | | $ 19,702 |
| GS > 50 to 1,999 kW | 3,408 | 2,835,387 | 6,712 | $ 260.82 | $ 3.5691 | $ 34,620 | $ 755 | $ 33,865 |
| GS > 1,5000 to 4,999 kW | 76 | 935,554 | 2,001,525 | $ 4,193.93 | $ 3.4887 | $ 10,808 | $ 225 | $ 10,582 |
| Large Use | 11 | 615,195 | 1,112,342 | $ 15,231.32 | $ 3.3129 | $ 5,696 | $ 125 | $ 5,570 |
| Street Lighting | 55,516 | 44,015 | 123,144 | $ 0.57 | $ 3.9997 | $ 872 | | $ 872 |
| Sentinel Lighting | 39 | 48 | 216 | $ 2.62 | $ 10.0361 | $ 3 | | $ 3 |
| Unmetered Scattered Load | 3,669 | 16,827 | | $ 4.43 | $ 0.0219 | $ 564 | | $ 564 |
| Standby Power | 2 | | 4,800 | $ 122.41 | $ 1.4985 | $ 10 | | $ 10 |
| **Revenue** | | | | | | $ 160,464 | $ 1,105 | $ 159,358 |

| | |
|---|---|
| Other Revenue | $ 11,898 |
| Total Revenue | $ 171,256 |
| 2020 Revenue Requirement | $ 224,430 |
| 2020 Revenue Deficiency | $ 53,174 |

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# Appendix 2-V
## Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | | Revenues at Proposed Rates | Class Specific Revenue Requirement | Transformer Allowance Credit | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | | | | | | |
| | | | | | | | | kWh | kW | | | | | |
| Residential | Customers | 295,999 | 299,296 | 297,647.50 | 2,216,045,000 | | $ 12.25 | $ 0.0235 | | $ 95,853,400.45 | $ 95,819,638 | | $ 95,819,638 | -$ 33,762 |
| GS < 50 kW | Customers | 24,473 | 24,569 | 24,521.00 | 726,360,000 | | $ 22.75 | $ 0.0216 | | $ 22,383,609.00 | $ 22,381,467 | | $ 22,381,467 | -$ 2,142 |
| GS > 50 to 1,999 kW | Customers | 3,282 | 3,308 | 3,295.00 | 2,954,441,000 | 7,027,979 | $ 290.00 | | $ 3.9454 | $ 39,194,788.35 | $ 38,404,411 | $ 790,648 | $ 39,195,058 | $ 270 |
| GS > 1,5000 to 4,999 kW | Customers | 76 | 76 | 76.00 | 863,309,000 | 1,847,365 | $ 4,650.00 | | $ 3.8602 | $ 11,371,998.37 | $ 11,164,203 | $ 207,829 | $ 11,372,032 | $ 33 |
| Large Use | Connections | 11 | 11 | 11.00 | 620,218,000 | 1,121,449 | $ 16,900.00 | | $ 3.6644 | $ 6,340,237.72 | $ 6,214,047 | $ 126,163 | $ 6,340,210 | -$ 28 |
| Streetlighting | Connections | 55,516 | 55,516 | 55,516.00 | 43,552,000 | 123,144 | $ 0.65 | | $ 4.3442 | $ 967,986.96 | $ 967,982 | | $ 967,982 | -$ 5 |
| Sentinel Lighting | Connections | 57 | 53 | 55.00 | 48,000 | 216 | $ 3.25 | | $ 12.0650 | $ 4,751.04 | $ 4,751 | | $ 4,751 | $ 0 |
| Unmetered Scattered Load | Customers | 3,455 | 3,499 | 3,477.00 | 16,651,000 | | $ 4.75 | $ 0.0242 | | $ 601,143.20 | $ 601,871 | | $ 601,871 | $ 728 |
| Standby Power | Customers | 2 | 2 | 2.00 | | 4,800 | $ 135.00 | | $ 1.6668 | $ 11,240.64 | $ 11,240 | | $ 11,240 | -$ 0 |
| Embedded Distributor Class | | | | - | | | | | | $ - | | | $ - | $ - |
| etc. | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| **Total** | | | | | | | | | | $ 176,729,155.73 | $ 175,569,610 | $ 1,124,639 | $ 176,694,250 | -$ 34,906 |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
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# Appendix 2-V
## Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | | Revenues at Proposed Rates | Class Specific Revenue Requirement | Transformer Allowance Credit | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | | | | | | |
| | | | | | | | | kWh | kW | | | | | |
| Residential | Customers | 299,875 | 303,174 | 301,524.50 | 2,198,259,000 | | $ 14.25 | $ 0.0228 | | $ 101,697,333.58 | $ 101,651,762 | | $ 101,651,762 | -$ 45,572 |
| GS < 50 kW | Customers | 24,586 | 24,682 | 24,634.00 | 716,896,000 | | $ 27.75 | $ 0.0214 | | $ 23,523,935.53 | $ 23,521,272 | | $ 23,521,272 | -$ 2,664 |
| GS > 50 to 1,999 kW | Customers | 3,310 | 3,336 | 3,323.00 | 2,907,445,000 | 6,908,640 | $ 355.00 | | $ 3.8962 | $ 41,073,105.21 | $ 40,295,883 | $ 777,222 | $ 41,073,105 | $ - |
| GS > 1,5000 to 4,999 kW | Customers | 76 | 76 | 76.00 | 877,400,000 | 1,877,691 | $ 4,975.00 | | $ 4.0575 | $ 12,155,925.95 | $ 11,944,686 | $ 211,240 | $ 12,155,926 | $ - |
| Large Use | Connections | 11 | 11 | 11.00 | 619,253,000 | 1,119,726 | $ 17,900.00 | | $ 3.8746 | $ 6,701,275.50 | $ 6,575,306 | $ 125,969 | $ 6,701,275 | $ - |
| Streetlighting | Connections | 55,516 | 55,516 | 55,516.00 | 43,653,000 | 123,144 | $ 0.70 | | $ 4.5389 | $ 1,025,266.80 | $ 1,025,267 | | $ 1,025,267 | $ - |
| Sentinel Lighting | Connections | 53 | 49 | 51.00 | 48,000 | 216 | $ 3.25 | | $ 13.3241 | $ 4,867.00 | $ 4,867 | | $ 4,867 | $ - |
| Unmetered Scattered Load | Customers | 3,503 | 3,547 | 3,525.00 | 16,690,000 | | $ 5.75 | $ 0.0237 | | $ 638,998.49 | $ 638,998 | | $ 638,998 | $ - |
| Standby Power | Customers | 2 | 2 | 2.00 | | 4,800 | $ 143.00 | | $ 1.7652 | $ 11,905.05 | $ 11,905 | | $ 11,905 | $ - |
| Embedded Distributor Class | | | | - | | | | | | $ - | | | $ - | $ - |
| etc. | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| **Total** | | | | | | | | | | $ 186,832,613.11 | $ 185,669,946 | $ 1,114,431 | $ 186,784,378 | -$ 48,236 |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

| | |
|---|---|
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## Appendix 2-V
## Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | | Revenues at Proposed Rates | Class Specific Revenue Requirement | Transformer Allowance Credit | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | | | | | | |
| | | | | | | | | kWh | kW | | | | | |
| Residential | Customers | 303,718 | 307,033 | 305,375.50 | 2,206,411,000 | | $ 16.50 | $ 0.0216 | | $ 108,071,340.60 | $ 108,025,504 | | $ 108,025,504 | -$ 45,837 |
| GS < 50 kW | Customers | 24,697 | 24,793 | 24,745.00 | 709,791,000 | | $ 33.25 | $ 0.0208 | | $ 24,670,737.79 | $ 24,668,344 | | $ 24,668,344 | -$ 2,394 |
| GS > 50 to 1,999 kW | Customers | 3,338 | 3,365 | 3,351.50 | 2,875,422,000 | 6,824,350 | $ 420.00 | | $ 3.8299 | $ 43,028,395.56 | $ 42,258,136 | $ 767,739 | $ 43,025,876 | -$ 2,520 |
| GS > 1,5000 to 4,999 kW | Customers | 76 | 76 | 76.00 | 895,369,000 | 1,916,044 | $ 5,600.00 | | $ 4.1002 | $ 12,963,332.94 | $ 12,747,778 | $ 215,555 | $ 12,963,333 | $ - |
| Large Use | Connections | 11 | 11 | 11.00 | 618,467,000 | 1,118,300 | $ 21,000.00 | | $ 3.8254 | $ 7,049,984.77 | $ 6,924,176 | $ 125,809 | $ 7,049,985 | $ - |
| Streetlighting | Connections | 55,516 | 55,516 | 55,516.00 | 43,765,000 | 123,144 | $ 0.75 | | $ 4.7173 | $ 1,080,547.01 | $ 1,080,547 | | $ 1,080,547 | $ - |
| Sentinel Lighting | Connections | 49 | 45 | 47.00 | 48,000 | 216 | $ 4.00 | | $ 12.5418 | $ 4,965.02 | $ 4,965 | | $ 4,965 | $ - |
| Unmetered Scattered Load | Customers | 3,551 | 3,599 | 3,575.00 | 16,731,000 | | $ 7.00 | $ 0.0237 | $ 0.0225 | $ 697,045.73 | $ 676,378 | | $ 676,378 | -$ 20,668 |
| Standby Power | Customers | 2 | 2 | 2.00 | | 4,800 | $ 150.00 | | $ 1.8639 | $ 12,546.55 | $ 12,547 | | $ 12,547 | $ - |
| Embedded Distributor Class | | | | - | | | | | | $ - | | | $ - | $ - |
| etc. | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| **Total** | | | | | | | | | | $ 197,578,895.99 | $ 196,398,374 | $ 1,109,103 | $ 197,507,477 | -$ 71,419 |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

| | |
|---|---|
| **File Number:** | EB-2015-0004 |
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# Appendix 2-V
## Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | | Revenues at Proposed Rates | Class Specific Revenue Requirement | Transformer Allowance Credit | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | | | | | | |
| | | | | | | | | kWh | kW | | | | | |
| Residential | Customers | 307,543 | 310,839 | 309,191.00 | 2,214,984,000 | | $ 19.00 | $ 0.0196 | | $ 113,804,789.94 | $ 113,758,962 | | $ 113,758,962 | -$ 45,828 |
| GS < 50 kW | Customers | 24,808 | 24,903 | 24,855.50 | 704,193,000 | | $ 38.75 | $ 0.0201 | | $ 25,678,946.74 | $ 25,676,389 | | $ 25,676,389 | -$ 2,558 |
| GS > 50 to 1,999 kW | Customers | 3,367 | 3,393 | 3,380.00 | 2,852,593,000 | 6,761,930 | $ 490.00 | | $ 3.6842 | $ 44,786,740.12 | $ 44,026,023 | $ 760,717 | $ 44,786,740 | $ - |
| GS > 1,5000 to 4,999 kW | Customers | 76 | 76 | 76.00 | 914,569,000 | 1,957,009 | $ 6,650.00 | | $ 3.9007 | $ 13,698,463.42 | $ 13,478,300 | $ 220,164 | $ 13,698,463 | $ - |
| Large Use | Connections | 11 | 11 | 11.00 | 617,036,000 | 1,115,702 | $ 24,600.00 | | $ 3.6719 | $ 7,343,987.35 | $ 7,218,471 | $ 125,516 | $ 7,343,987 | $ - |
| Streetlighting | Connections | 55,516 | 55,516 | 55,516.00 | 43,876,000 | 123,144 | $ 0.80 | | $ 4.8325 | $ 1,128,044.86 | $ 1,128,045 | | $ 1,128,045 | $ - |
| Sentinel Lighting | Connections | 45 | 41 | 43.00 | 48,000 | 216 | $ 4.25 | | $ 12.9159 | $ 4,982.84 | $ 4,983 | | $ 4,983 | $ - |
| Unmetered Scattered Load | Customers | 3,599 | 3,643 | 3,621.00 | 16,772,000 | | $ 7.50 | $ 0.0237 | $ 0.0229 | $ 723,607.97 | $ 709,828 | | $ 709,828 | -$ 13,780 |
| Standby Power | Customers | 2 | 2 | 2.00 | | 4,800 | $ 159.00 | | $ 1.9337 | $ 13,097.70 | $ 13,098 | | $ 13,098 | $ - |
| Embedded Distributor Class | | | | - | | | | | | $ - | | | $ - | $ - |
| etc. | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| **Total** | | | | | | | | | | $ 207,182,660.95 | $ 206,014,098 | $ 1,106,397 | $ 207,120,495 | -$ 62,166 |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

| | |
|---|---|
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# Appendix 2-V
## Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | | Revenues at Proposed Rates | Class Specific Revenue Requirement | Transformer Allowance Credit | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | | | | | | |
| | | | | | | | | kWh | kW | | | | | |
| Residential | Customers | 311,321 | 314,604 | 312,962.50 | 2,217,628,000 | | $ 20.75 | $ 0.0180 | | $ 117,762,085.69 | $ 117,718,137 | | $ 117,718,137 | -$ 43,949 |
| GS < 50 kW | Customers | 24,917 | 25,012 | 24,964.50 | 699,744,000 | | $ 44.00 | $ 0.0188 | | $ 26,320,852.69 | $ 26,317,949 | | $ 26,317,949 | -$ 2,904 |
| GS > 50 to 1,999 kW | Customers | 3,395 | 3,421 | 3,408.00 | 2,835,387,000 | 6,711,579 | $ 550.00 | | $ 3.4930 | $ 45,936,323.44 | $ 45,181,271 | $ 755,053 | $ 45,936,323 | $ - |
| GS > 1,5000 to 4,999 kW | Customers | 76 | 76 | 76.00 | 935,554,000 | 2,001,525 | $ 7,700.00 | | $ 3.6031 | $ 14,234,115.33 | $ 14,008,944 | $ 225,172 | $ 14,234,115 | $ - |
| Large Use | Connections | 11 | 11 | 11.00 | 615,195,000 | 1,112,342 | $ 28,000.00 | | $ 3.4408 | $ 7,523,299.75 | $ 7,398,161 | $ 125,138 | $ 7,523,300 | $ - |
| Streetlighting | Connections | 55,516 | 55,516 | 55,516.00 | 44,015,000 | 123,144 | $ 0.80 | | $ 5.0761 | $ 1,158,045.08 | $ 1,158,045 | | $ 1,158,045 | $ - |
| Sentinel Lighting | Connections | 41 | 37 | 39.00 | 48,000 | 216 | $ 4.75 | | $ 12.4211 | $ 4,905.96 | $ 4,906 | | $ 4,906 | $ - |
| Unmetered Scattered Load | Customers | 3,647 | 3,691 | 3,669.00 | 16,827,000 | | $ 7.50 | $ 0.0237 | $ 0.0238 | $ 729,232.20 | $ 730,841 | | $ 730,841 | $ 1,609 |
| Standby Power | Customers | 2 | 2 | 2.00 | | 4,800 | $ 165.00 | | $ 1.9761 | $ 13,445.14 | $ 13,445 | | $ 13,445 | $ - |
| Embedded Distributor Class | | | | - | | | | | | $ - | | | $ - | $ - |
| etc. | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| | | | | - | | | | | | $ - | | | $ - | $ - |
| **Total** | | | | | | | | | | $ 213,682,305.27 | $ 212,531,699 | $ 1,105,363 | $ 213,637,062 | -$ 45,243 |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

# BILL IMPACT INFORMATION

This schedule describes bill impacts for typical customers in each rate class arising from Hydro Ottawa Limited's ("Hydro Ottawa") revenue requirement adjusted for cost allocation.

Details of the impacts of the proposed rates are provided in Appendix 2-W attached. The Appendix illustrates individual and the combined impacts of the distribution component of the rate transmission and network charges and the total bill impact, as based on the typical consumption level used for each rate class.

Table 1 provides a summary of bill impacts per rate class including the total change in monthly bill, including variance accounts, as expressed in both monetary and percentage terms. Please note additional bill impacts are provided in Appendix 2-W which are not shown on the summary table.

## Table 1 Summary of Rate Impacts

| *Rate Class* | | *2015 Approved* | *2016 Proposed* | *2017 Proposed* | *2018 Proposed* | *2019 Proposed* | *2020 Proposed* |
|---|---|---|---|---|---|---|---|
| ***Residential (800 kWh)*** | ***Distribution Charge*** | *$28.39* | *$31.05* | *$32.49* | *$33.78* | *$34.68* | *$35.15* |
| | ***Change in Distribution Charge*** | | *$2.66* | *$1.44* | *$1.29* | *$0.90* | *$0.47* |
| | ***% Distribution Increase*** | | *9.37%* | *4.64%* | *3.97%* | *2.66%* | *1.36%* |
| | ***% Increase of Total Bill*** | | *1.31%* | *1.59%* | *0.93%* | *0.65%* | *0.34%* |
| ***General Service <50kW (2000 kWh)*** | ***Distribution Charge*** | *$58.72* | *$65.95* | *$70.55* | *$74.85* | *$78.95* | *$81.60* |
| | ***Change in Distribution Charge*** | | *$7.23* | *$4.60* | *$4.30* | *$4.10* | *$2.65* |
| | ***% Distribution Increase*** | | *12.31%* | *6.97%* | *6.09%* | *5.48%* | *3.36%* |
| | ***% Increase of Total Bill*** | | *1.49%* | *2.03%* | *1.30%* | *1.22%* | *0.78%* |
| ***General Service 50-1,499 kWh (250KW)*** | ***Distribution Charge*** | *$1,153.10* | *$1,276.35* | *$1,329.05* | *$1,377.48* | *$1,411.05* | *$1,423.25* |
| | ***Change in Distribution Charge*** | | *$123.26* | *$52.70* | *$48.43* | *$33.58* | *$12.20* |
| | ***% Distribution Increase*** | | *10.69%* | *4.13%* | *3.64%* | *2.44%* | *0.86%* |
| | ***% Increase of Total Bill*** | | *-0.26%* | *1.12%* | *0.28%* | *0.19%* | *0.07%* |
| ***General Service 1,500-4,999 kWh (2500 KW)*** | ***Distribution Charge*** | *$12,915.68* | *$14,300.50* | *$15,118.75* | *$15,850.50* | *$16,401.75* | *$16,707.75* |
| | ***Change in Distribution Charge*** | | *$1,384.82* | *$818.25* | *$731.75* | *$551.25* | *$306.00* |
| | ***% Distribution Increase*** | | *10.72%* | *5.72%* | *4.84%* | *3.48%* | *1.87%* |
| | ***% Increase of Total Bill*** | | *-0.16%* | *1.12%* | *0.41%* | *0.31%* | *0.17%* |
| ***Large Use (7500 KW)*** | ***Distribution Charge*** | *$40,078.07* | *$44,383.00* | *$46,959.50* | *$49,690.50* | *$52,139.25* | *$53,806.00* |
| | ***Change in Distribution Charge*** | | *$4,304.93* | *$2,576.50* | *$2,731.00* | *$2,448.75* | *$1,666.75* |
| | ***% Distribution Increase*** | | *10.74%* | *5.81%* | *5.82%* | *4.93%* | *3.20%* |
| | ***% Increase of Total Bill*** | | *-0.23%* | *1.45%* | *0.50%* | *0.44%* | *0.30%* |
| ***Sentinel Lighting (0.4KW)*** | ***Distribution Charge*** | *$6.63* | *$8.08* | *$8.58* | *$9.02* | *$9.42* | *$9.72* |
| | ***Change in Distribution Charge*** | | *$1.44* | *$0.50* | *$0.44* | *$0.40* | *$0.30* |
| | ***% Distribution Increase*** | | *21.73%* | *6.24%* | *5.09%* | *4.43%* | *3.21%* |
| | ***% Increase of Total Bill*** | | *6.91%* | *2.82%* | *2.05%* | *1.84%* | *1.36%* |
| ***Street Lighting (1 KW)*** | ***Distribution Charge*** | *$4.57* | *$4.99* | *$5.24* | *$5.47* | *$5.63* | *$5.88* |
| | ***Change in Distribution Charge*** | | *$0.42* | *$0.24* | *$0.23* | *$0.17* | *$0.24* |
| | ***% Distribution Increase*** | | *9.29%* | *4.90%* | *4.36%* | *3.02%* | *4.32%* |
| | ***% Increase of Total Bill*** | | *0.00%* | *2.45%* | *0.86%* | *0.61%* | *0.90%* |
| ***Unmetered Scattered Load (470 kWh)*** | ***Distribution Charge*** | *$14.72* | *$16.12* | *$16.89* | *$17.58* | *$18.26* | *$18.69* |
| | ***Change in Distribution Charge*** | | *$1.40* | *$0.77* | *$0.69* | *$0.69* | *$0.42* |
| | ***% Distribution Increase*** | | *9.52%* | *4.74%* | *4.06%* | *3.91%* | *2.32%* |
| | ***% Increase of Total Bill*** | | *1.08%* | *1.61%* | *0.88%* | *0.87%* | *0.53%* |

1 1

## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 100 kWh (•) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 100 | $ 2.34 | $ 0.0235 | 100 | $ 2.35 | $ 0.01 | 0.43% |
| Smart Meter Disposition Rider | | | 100 | $ - | | 100 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 100 | $ - | -$ 0.0003 | 100 | -$ 0.03 | -$ 0.03 | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 12.01 | | | $ 14.57 | **$ 2.56** | **21.32%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 100 | $ - | -$ 0.0006 | 100 | -$ 0.06 | -$ 0.06 | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 104 | $ 0.01 | $ 0.00007 | 103 | $ 0.01 | $ 0.00 | 16.44% |
| Line Losses on Cost of Power | | $ 0.1021 | 4 | $ 0.37 | $ 0.1021 | 3 | $ 0.35 | -$ 0.02 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 13.17** | | | **$ 15.65** | **$ 2.48** | **18.83%** |
| RTSR - Network | per kWh | $ 0.0077 | 104 | $ 0.80 | $ 0.0077 | 103 | $ 0.80 | -$ 0.00 | -0.19% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 104 | $ 0.44 | $ 0.0042 | 103 | $ 0.43 | -$ 0.00 | -0.19% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 14.40** | | | **$ 16.88** | **$ 2.48** | **17.20%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 104 | $ 0.46 | $ 0.0044 | 103 | $ 0.45 | -$ 0.00 | -0.19% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 104 | $ 0.13 | $ 0.0013 | 103 | $ 0.13 | -$ 0.00 | -0.19% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 100 | $ 0.69 | $ 0.0069 | 100 | $ 0.69 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 64 | $ 5.12 | $ 0.0800 | 64 | $ 5.12 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 18 | $ 2.20 | $ 0.1220 | 18 | $ 2.20 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 18 | $ 2.90 | $ 0.1610 | 18 | $ 2.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 100 | $ 9.40 | $ 0.0940 | 100 | $ 9.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 26.15** | | | **$ 28.63** | **$ 2.48** | **9.47%** |
| HST | | 13% | | $ 3.40 | 13% | | $ 3.72 | $ 0.32 | 9.47% |
| **Total Bill** (including HST) | | | | $ 29.55 | | | $ 32.35 | $ 2.80 | 9.47% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 2.96 | | | -$ 3.24 | -$ 0.28 | 9.46% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 26.59** | | | **$ 29.11** | **$ 2.52** | **9.47%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 25.34** | | | **$ 27.82** | **$ 2.48** | **9.78%** |
| HST | | 13% | | $ 3.29 | 13% | | $ 3.62 | $ 0.32 | 9.78% |
| **Total Bill** (including HST) | | | | $ 28.63 | | | $ 31.43 | $ 2.80 | 9.78% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 2.86 | | | -$ 3.14 | -$ 0.28 | 9.79% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 25.77** | | | **$ 28.29** | **$ 2.52** | **9.77%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | $ 0.0228 | 100 | $ 2.28 | -$ 0.07 | -2.98% | $ 0.0216 | 100 | $ 2.16 | -$ 0.12 | -5.26% |
| Smart Meter Disposition Rider | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| LRAM & SSM Rate Rider | | 100 | $ - | $ 0.03 | -100.00% | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | $ 16.53 | **$ 1.96** | **13.45%** | | | $ 18.66 | **$ 2.13** | **12.89%** |
| Deferral/Variance Account Disposition Rate Rider | | 100 | $ - | $ 0.06 | -100.00% | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| Low Voltage Service Charge | $ 0.00007 | 103 | $ 0.01 | $ - | 0.00% | $ 0.00007 | 103 | $ 0.01 | $ - | 0.00% |
| Line Losses on Cost of Power | $ 0.1021 | 3 | $ 0.35 | $ - | 0.00% | $ 0.1021 | 3 | $ 0.35 | $ - | 0.00% |
| Smart Meter Entity Charge | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | **$ 17.67** | **$ 2.02** | **12.91%** | | | **$ 19.80** | **$ 2.13** | **12.05%** |
| RTSR - Network | $ 0.0077 | 103 | $ 0.80 | $ - | 0.00% | $ 0.0077 | 103 | $ 0.80 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | $ 0.0042 | 103 | $ 0.43 | $ - | 0.00% | $ 0.0042 | 103 | $ 0.43 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | **$ 18.90** | **$ 2.02** | **11.96%** | | | **$ 21.03** | **$ 2.13** | **11.27%** |
| Wholesale Market Service Charge (WMSC) | $ 0.0044 | 103 | $ 0.45 | $ - | 0.00% | $ 0.0044 | 103 | $ 0.45 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | $ 0.0013 | 103 | $ 0.13 | $ - | 0.00% | $ 0.0013 | 103 | $ 0.13 | $ - | 0.00% |
| Standard Supply Service Charge | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | $ 0.0069 | 100 | $ 0.69 | $ - | 0.00% | $ 0.0069 | 100 | $ 0.69 | $ - | 0.00% |
| TOU - Off Peak | $ 0.0800 | 64 | $ 5.12 | $ - | 0.00% | $ 0.0800 | 64 | $ 5.12 | $ - | 0.00% |
| TOU - Mid Peak | $ 0.1220 | 18 | $ 2.20 | $ - | 0.00% | $ 0.1220 | 18 | $ 2.20 | $ - | 0.00% |
| TOU - On Peak | $ 0.1610 | 18 | $ 2.90 | $ - | 0.00% | $ 0.1610 | 18 | $ 2.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | $ 0.0940 | 100 | $ 9.40 | $ - | 0.00% | $ 0.0940 | 100 | $ 9.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | **$ 30.65** | **$ 2.02** | **7.06%** | | | **$ 32.78** | **$ 2.13** | **6.95%** |
| HST | 13% | | $ 3.98 | $ 0.26 | 7.06% | 13% | | $ 4.26 | $ 0.28 | 6.95% |
| **Total Bill** (including HST) | | | $ 34.63 | $ 2.28 | 7.06% | | | $ 37.04 | $ 2.41 | 6.95% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 3.46 | -$ 0.22 | 6.79% | | | -$ 3.70 | -$ 0.24 | 6.94% |
| **Total Bill on TOU (including OCEB)** | | | **$ 31.17** | **$ 2.06** | **7.09%** | | | **$ 33.34** | **$ 2.17** | **6.95%** |
| **Total Bill on RPP (before Taxes)** | | | **$ 29.84** | **$ 2.02** | **7.26%** | | | **$ 31.97** | **$ 2.13** | **7.14%** |
| HST | 13% | | $ 3.88 | $ 0.26 | 7.26% | 13% | | $ 4.16 | $ 0.28 | 7.14% |
| **Total Bill** (including HST) | | | $ 33.71 | $ 2.28 | 7.26% | | | $ 36.12 | $ 2.41 | 7.14% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 3.37 | -$ 0.23 | 7.32% | | | -$ 3.61 | -$ 0.24 | 7.12% |
| **Total Bill on RPP (including OCEB)** | | | **$ 30.34** | **$ 2.05** | **7.26%** | | | **$ 32.51** | **$ 2.17** | **7.14%** |
| **Loss Factor (%)** | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 100 kWh ● May 1 - Oct

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 100 | $ 2.34 | $ 0.0196 | 100 | $ 1.96 | -$ 0.20 | -9.26% | $ 0.0180 | 100 | $ 1.80 | -$ 0.16 | -8.16% |
| Smart Meter Disposition Rider | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 12.01 | | | $ 20.96 | **$ 2.30** | **12.33%** | | | $ 22.55 | **$ 1.59** | **7.59%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| | | | 100 | $ - | | 100 | $ - | $ - | | | 100 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 104 | $ 0.01 | $ 0.00007 | 103 | $ 0.01 | $ - | 0.00% | $ 0.00007 | 103 | $ 0.01 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 4 | $ 0.37 | $ 0.1021 | 3 | $ 0.35 | $ - | 0.00% | $ 0.1021 | 3 | $ 0.35 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 13.17** | | | **$ 22.10** | **$ 2.30** | **11.61%** | | | **$ 23.69** | **$ 1.59** | **7.19%** |
| RTSR - Network | per kWh | $ 0.0077 | 104 | $ 0.80 | $ 0.0077 | 103 | $ 0.80 | $ - | 0.00% | $ 0.0077 | 103 | $ 0.80 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 104 | $ 0.44 | $ 0.0042 | 103 | $ 0.43 | $ - | 0.00% | $ 0.0042 | 103 | $ 0.43 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 14.40** | | | **$ 23.33** | **$ 2.30** | **10.94%** | | | **$ 24.92** | **$ 1.59** | **6.81%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 104 | $ 0.46 | $ 0.0044 | 103 | $ 0.45 | $ - | 0.00% | $ 0.0044 | 103 | $ 0.45 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 104 | $ 0.13 | $ 0.0013 | 103 | $ 0.13 | $ - | 0.00% | $ 0.0013 | 103 | $ 0.13 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 100 | $ 0.69 | $ 0.0069 | 100 | $ 0.69 | $ - | 0.00% | $ 0.0069 | 100 | $ 0.69 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 64 | $ 5.12 | $ 0.0800 | 64 | $ 5.12 | $ - | 0.00% | $ 0.0800 | 64 | $ 5.12 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 18 | $ 2.20 | $ 0.1220 | 18 | $ 2.20 | $ - | 0.00% | $ 0.1220 | 18 | $ 2.20 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 18 | $ 2.90 | $ 0.1610 | 18 | $ 2.90 | $ - | 0.00% | $ 0.1610 | 18 | $ 2.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 100 | $ 9.40 | $ 0.0940 | 100 | $ 9.40 | $ - | 0.00% | $ 0.0940 | 100 | $ 9.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 26.15** | | | **$ 35.08** | **$ 2.30** | **7.02%** | | | **$ 36.67** | **$ 1.59** | **4.53%** |
| HST | | 13% | | $ 3.40 | 13% | | $ 4.56 | $ 0.30 | 7.02% | 13% | | $ 4.77 | $ 0.21 | 4.53% |
| **Total Bill** (including HST) | | | | $ 29.55 | | | $ 39.64 | $ 2.60 | 7.02% | | | $ 41.44 | $ 1.80 | 4.53% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 2.96 | | | -$ 3.96 | -$ 0.26 | 7.03% | | | -$ 4.14 | -$ 0.18 | 4.55% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 26.59** | | | **$ 35.68** | **$ 2.34** | **7.02%** | | | **$ 37.30** | **$ 1.62** | **4.53%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 25.34** | | | **$ 34.27** | **$ 2.30** | **7.20%** | | | **$ 35.86** | **$ 1.59** | **4.64%** |
| HST | | 13% | | $ 3.29 | 13% | | $ 4.45 | $ 0.30 | 7.20% | 13% | | $ 4.66 | $ 0.21 | 4.64% |
| **Total Bill** (including HST) | | | | $ 28.63 | | | $ 38.72 | $ 2.60 | 7.20% | | | $ 40.52 | $ 1.80 | 4.64% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 2.86 | | | -$ 3.87 | -$ 0.26 | 7.20% | | | -$ 4.05 | -$ 0.18 | 4.65% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 25.77** | | | **$ 34.85** | **$ 2.34** | **7.19%** | | | **$ 36.47** | **$ 1.62** | **4.64%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 250 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2016 Proposed Rate ($) | Volume | Charge ($) | Impact 2016 vs 2015 $ Change | % Change | 2017 Proposed Rate ($) | Volume | Charge ($) | Impact 2017 vs 2016 $ Change | % Change | 2018 Proposed Rate ($) | Volume | Charge ($) | Impact 2018 vs 2017 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 250 | $ 5.85 | $ 0.0235 | 250 | $ 5.88 | $ 0.02 | 0.43% | $ 0.0228 | 250 | $ 5.70 | -$ 0.18 | -2.98% | $ 0.0216 | 250 | $ 5.40 | -$ 0.30 | -5.26% |
| Smart Meter Disposition Rider | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 250 | $ - | -$ 0.0003 | 250 | -$ 0.08 | -$ 0.08 | | | 250 | $ - | $ 0.08 | -100.00% | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 15.52 | | | $ 18.05 | **$ 2.53** | **16.30%** | | | $ 19.95 | **$ 1.90** | **10.53%** | | | $ 21.90 | **$ 1.95** | **9.77%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 250 | $ - | -$ 0.0006 | 250 | -$ 0.15 | -$ 0.15 | | | 250 | $ - | $ 0.15 | -100.00% | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 259 | $ 0.02 | $ 0.00007 | 258 | $ 0.02 | $ 0.00 | 16.44% | $ 0.00007 | 258 | $ 0.02 | $ - | 0.00% | $ 0.00007 | 258 | $ 0.02 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 9 | $ 0.91 | $ 0.1021 | 8 | $ 0.86 | -$ 0.05 | -5.59% | $ 0.1021 | 8 | $ 0.86 | $ - | 0.00% | $ 0.1021 | 8 | $ 0.86 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 17.24** | | | **$ 19.57** | **$ 2.33** | **13.52%** | | | **$ 21.62** | **$ 2.05** | **10.47%** | | | **$ 23.57** | **$ 1.95** | **9.02%** |
| RTSR - Network | per kWh | $ 0.0077 | 259 | $ 1.99 | $ 0.0077 | 258 | $ 1.99 | -$ 0.00 | -0.19% | $ 0.0077 | 258 | $ 1.99 | $ - | 0.00% | $ 0.0077 | 258 | $ 1.99 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 259 | $ 1.09 | $ 0.0042 | 258 | $ 1.09 | -$ 0.00 | -0.19% | $ 0.0042 | 258 | $ 1.09 | $ - | 0.00% | $ 0.0042 | 258 | $ 1.09 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 20.32** | | | **$ 22.65** | **$ 2.33** | **11.44%** | | | **$ 24.70** | **$ 2.05** | **9.05%** | | | **$ 26.65** | **$ 1.95** | **7.90%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 259 | $ 1.14 | $ 0.0044 | 258 | $ 1.14 | -$ 0.00 | -0.19% | $ 0.0044 | 258 | $ 1.14 | $ - | 0.00% | $ 0.0044 | 258 | $ 1.14 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 259 | $ 0.34 | $ 0.0013 | 258 | $ 0.34 | -$ 0.00 | -0.19% | $ 0.0013 | 258 | $ 0.34 | $ - | 0.00% | $ 0.0013 | 258 | $ 0.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 250 | $ 1.74 | $ 0.0069 | 250 | $ 1.74 | $ - | 0.00% | $ 0.0069 | 250 | $ 1.74 | $ - | 0.00% | $ 0.0069 | 250 | $ 1.74 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 160 | $ 12.80 | $ 0.0800 | 160 | $ 12.80 | $ - | 0.00% | $ 0.0800 | 160 | $ 12.80 | $ - | 0.00% | $ 0.0800 | 160 | $ 12.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45 | $ 5.49 | $ 0.1220 | 45 | $ 5.49 | $ - | 0.00% | $ 0.1220 | 45 | $ 5.49 | $ - | 0.00% | $ 0.1220 | 45 | $ 5.49 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45 | $ 7.25 | $ 0.1610 | 45 | $ 7.25 | $ - | 0.00% | $ 0.1610 | 45 | $ 7.25 | $ - | 0.00% | $ 0.1610 | 45 | $ 7.25 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 250 | $ 23.50 | $ 0.0940 | 250 | $ 23.50 | $ - | 0.00% | $ 0.0940 | 250 | $ 23.50 | $ - | 0.00% | $ 0.0940 | 250 | $ 23.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 49.32** | | | **$ 51.64** | **$ 2.32** | **4.71%** | | | **$ 53.69** | **$ 2.05** | **3.97%** | | | **$ 55.64** | **$ 1.95** | **3.63%** |
| HST | | 13% | | $ 6.41 | 13% | | $ 6.71 | $ 0.30 | 4.71% | 13% | | $ 6.98 | $ 0.27 | 3.97% | 13% | | $ 7.23 | $ 0.25 | 3.63% |
| **Total Bill** (including HST) | | | | $ 55.73 | | | $ 58.35 | $ 2.62 | 4.71% | | | $ 60.67 | $ 2.32 | 3.97% | | | $ 62.87 | $ 2.20 | 3.63% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 5.57 | | | -$ 5.84 | -$ 0.27 | 4.85% | | | -$ 6.07 | -$ 0.23 | 3.94% | | | -$ 6.29 | -$ 0.22 | 3.62% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 50.16** | | | **$ 52.51** | **$ 2.35** | **4.69%** | | | **$ 54.60** | **$ 2.09** | **3.97%** | | | **$ 56.58** | **$ 1.98** | **3.63%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 47.28** | | | **$ 49.60** | **$ 2.32** | **4.91%** | | | **$ 51.65** | **$ 2.05** | **4.13%** | | | **$ 53.60** | **$ 1.95** | **3.78%** |
| HST | | 13% | | $ 6.15 | 13% | | $ 6.45 | $ 0.30 | 4.91% | 13% | | $ 6.72 | $ 0.27 | 4.13% | 13% | | $ 6.97 | $ 0.25 | 3.78% |
| **Total Bill** (including HST) | | | | $ 53.43 | | | $ 56.05 | $ 2.62 | 4.91% | | | $ 58.37 | $ 2.32 | 4.13% | | | $ 60.57 | $ 2.20 | 3.78% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 5.34 | | | -$ 5.61 | -$ 0.27 | 5.06% | | | -$ 5.84 | -$ 0.23 | 4.10% | | | -$ 6.06 | -$ 0.22 | 3.77% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 48.09** | | | **$ 50.44** | **$ 2.35** | **4.90%** | | | **$ 52.53** | **$ 2.09** | **4.14%** | | | **$ 54.51** | **$ 1.98** | **3.78%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 250 kWh ◉ May 1 - Oct

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 250 | $ 5.85 | $ 0.0196 | 250 | $ 4.90 | -$ 0.50 | -9.26% | $ 0.0180 | 250 | $ 4.50 | -$ 0.40 | -8.16% |
| Smart Meter Disposition Rider | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 15.52 | | | $ 23.90 | **$ 2.00** | **9.13%** | | | $ 25.25 | **$ 1.35** | **5.65%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 259 | $ 0.02 | $ 0.00007 | 258 | $ 0.02 | $ - | 0.00% | $ 0.00007 | 258 | $ 0.02 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 9 | $ 0.91 | $ 0.1021 | 8 | $ 0.86 | $ - | 0.00% | $ 0.1021 | 8 | $ 0.86 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 17.24** | | | **$ 25.57** | **$ 2.00** | **8.48%** | | | **$ 26.92** | **$ 1.35** | **5.28%** |
| RTSR - Network | per kWh | $ 0.0077 | 259 | $ 1.99 | $ 0.0077 | 258 | $ 1.99 | $ - | 0.00% | $ 0.0077 | 258 | $ 1.99 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 259 | $ 1.09 | $ 0.0042 | 258 | $ 1.09 | $ - | 0.00% | $ 0.0042 | 258 | $ 1.09 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 20.32** | | | **$ 28.65** | **$ 2.00** | **7.51%** | | | **$ 30.00** | **$ 1.35** | **4.71%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 259 | $ 1.14 | $ 0.0044 | 258 | $ 1.14 | $ - | 0.00% | $ 0.0044 | 258 | $ 1.14 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 259 | $ 0.34 | $ 0.0013 | 258 | $ 0.34 | $ - | 0.00% | $ 0.0013 | 258 | $ 0.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 250 | $ 1.74 | $ 0.0069 | 250 | $ 1.74 | $ - | 0.00% | $ 0.0069 | 250 | $ 1.74 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 160 | $ 12.80 | $ 0.0800 | 160 | $ 12.80 | $ - | 0.00% | $ 0.0800 | 160 | $ 12.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45 | $ 5.49 | $ 0.1220 | 45 | $ 5.49 | $ - | 0.00% | $ 0.1220 | 45 | $ 5.49 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45 | $ 7.25 | $ 0.1610 | 45 | $ 7.25 | $ - | 0.00% | $ 0.1610 | 45 | $ 7.25 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 250 | $ 23.50 | $ 0.0940 | 250 | $ 23.50 | $ - | 0.00% | $ 0.0940 | 250 | $ 23.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 49.32** | | | **$ 57.64** | **$ 2.00** | **3.59%** | | | **$ 58.99** | **$ 1.35** | **2.34%** |
| HST | | 13% | | $ 6.41 | 13% | | $ 7.49 | $ 0.26 | 3.59% | 13% | | $ 7.67 | $ 0.18 | 2.34% |
| **Total Bill** (including HST) | | | | $ 55.73 | | | $ 65.13 | $ 2.26 | 3.59% | | | $ 66.66 | $ 1.53 | 2.34% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 5.57 | | | -$ 6.51 | -$ 0.22 | 3.50% | | | -$ 6.67 | -$ 0.16 | 2.46% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 50.16** | | | **$ 58.62** | **$ 2.04** | **3.61%** | | | **$ 59.99** | **$ 1.37** | **2.33%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 47.28** | | | **$ 55.60** | **$ 2.00** | **3.73%** | | | **$ 56.95** | **$ 1.35** | **2.43%** |
| HST | | 13% | | $ 6.15 | 13% | | $ 7.23 | $ 0.26 | 3.73% | 13% | | $ 7.40 | $ 0.18 | 2.43% |
| **Total Bill** (including HST) | | | | $ 53.43 | | | $ 62.83 | $ 2.26 | 3.73% | | | $ 64.36 | $ 1.53 | 2.43% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 5.34 | | | -$ 6.28 | -$ 0.22 | 3.63% | | | -$ 6.44 | -$ 0.16 | 2.55% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 48.09** | | | **$ 56.55** | **$ 2.04** | **3.74%** | | | **$ 57.92** | **$ 1.37** | **2.41%** |

| | | | |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 500 **kWh** (●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 500 | $ 11.70 | $ 0.0235 | 500 | $ 11.75 | $ 0.05 | 0.43% | $ 0.0228 | 500 | $ 11.40 | -$ 0.35 | -2.98% | $ 0.0216 | 500 | $ 10.80 | -$ 0.60 | -5.26% |
| Smart Meter Disposition Rider | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 500 | $ - | -$ 0.0003 | 500 | -$ 0.15 | -$ 0.15 | | | 500 | $ - | $ 0.15 | -100.00% | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 21.37 | | | $ 23.85 | **$ 2.48** | **11.61%** | | | $ 25.65 | **$ 1.80** | **7.55%** | | | $ 27.30 | **$ 1.65** | **6.43%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 500 | $ - | -$ 0.0006 | 500 | -$ 0.30 | -$ 0.30 | | | 500 | $ - | $ 0.30 | -100.00% | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 518 | $ 0.03 | $ 0.00007 | 517 | $ 0.04 | $ 0.01 | 16.44% | $ 0.00007 | 517 | $ 0.04 | $ - | 0.00% | $ 0.00007 | 517 | $ 0.04 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 18 | $ 1.83 | $ 0.1021 | 17 | $ 1.73 | -$ 0.10 | -5.59% | $ 0.1021 | 17 | $ 1.73 | $ - | 0.00% | $ 0.1021 | 17 | $ 1.73 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 24.02** | | | **$ 26.10** | **$ 2.08** | **8.67%** | | | **$ 28.20** | **$ 2.10** | **8.05%** | | | **$ 29.85** | **$ 1.65** | **5.85%** |
| RTSR - Network | per kWh | $ 0.0077 | 518 | $ 3.99 | $ 0.0077 | 517 | $ 3.98 | -$ 0.01 | -0.19% | $ 0.0077 | 517 | $ 3.98 | $ - | 0.00% | $ 0.0077 | 517 | $ 3.98 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 518 | $ 2.18 | $ 0.0042 | 517 | $ 2.17 | -$ 0.00 | -0.19% | $ 0.0042 | 517 | $ 2.17 | $ - | 0.00% | $ 0.0042 | 517 | $ 2.17 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 30.18** | | | **$ 32.25** | **$ 2.07** | **6.86%** | | | **$ 34.35** | **$ 2.10** | **6.51%** | | | **$ 36.00** | **$ 1.65** | **4.80%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 518 | $ 2.28 | $ 0.0044 | 517 | $ 2.27 | -$ 0.00 | -0.19% | $ 0.0044 | 517 | $ 2.27 | $ - | 0.00% | $ 0.0044 | 517 | $ 2.27 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 518 | $ 0.67 | $ 0.0013 | 517 | $ 0.67 | -$ 0.00 | -0.19% | $ 0.0013 | 517 | $ 0.67 | $ - | 0.00% | $ 0.0013 | 517 | $ 0.67 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 500 | $ 3.47 | $ 0.0069 | 500 | $ 3.47 | $ - | 0.00% | $ 0.0069 | 500 | $ 3.47 | $ - | 0.00% | $ 0.0069 | 500 | $ 3.47 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 320 | $ 25.60 | $ 0.0800 | 320 | $ 25.60 | $ - | 0.00% | $ 0.0800 | 320 | $ 25.60 | $ - | 0.00% | $ 0.0800 | 320 | $ 25.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 90 | $ 10.98 | $ 0.1220 | 90 | $ 10.98 | $ - | 0.00% | $ 0.1220 | 90 | $ 10.98 | $ - | 0.00% | $ 0.1220 | 90 | $ 10.98 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 90 | $ 14.49 | $ 0.1610 | 90 | $ 14.49 | $ - | 0.00% | $ 0.1610 | 90 | $ 14.49 | $ - | 0.00% | $ 0.1610 | 90 | $ 14.49 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 500 | $ 47.00 | $ 0.0940 | 500 | $ 47.00 | $ - | 0.00% | $ 0.0940 | 500 | $ 47.00 | $ - | 0.00% | $ 0.0940 | 500 | $ 47.00 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 87.92** | | | **$ 89.99** | **$ 2.07** | **2.35%** | | | **$ 92.09** | **$ 2.10** | **2.33%** | | | **$ 93.74** | **$ 1.65** | **1.79%** |
| HST | | 13% | | $ 11.43 | 13% | | $ 11.70 | $ 0.27 | 2.35% | 13% | | $ 11.97 | $ 0.27 | 2.33% | 13% | | $ 12.19 | $ 0.21 | 1.79% |
| **Total Bill** (including HST) | | | | $ 99.35 | | | $ 101.69 | $ 2.33 | 2.35% | | | $ 104.06 | $ 2.37 | 2.33% | | | $ 105.93 | $ 1.86 | 1.79% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 9.94 | | | -$ 10.17 | -$ 0.23 | 2.31% | | | -$ 10.41 | -$ 0.24 | 2.36% | | | -$ 10.59 | -$ 0.18 | 1.73% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 89.41** | | | **$ 91.52** | **$ 2.10** | **2.35%** | | | **$ 93.65** | **$ 2.13** | **2.33%** | | | **$ 95.34** | **$ 1.68** | **1.80%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 83.85** | | | **$ 85.92** | **$ 2.07** | **2.46%** | | | **$ 88.02** | **$ 2.10** | **2.44%** | | | **$ 89.67** | **$ 1.65** | **1.87%** |
| HST | | 13% | | $ 10.90 | 13% | | $ 11.17 | $ 0.27 | 2.46% | 13% | | $ 11.44 | $ 0.27 | 2.44% | 13% | | $ 11.66 | $ 0.21 | 1.87% |
| **Total Bill** (including HST) | | | | $ 94.76 | | | $ 97.09 | $ 2.33 | 2.46% | | | $ 99.46 | $ 2.37 | 2.44% | | | $ 101.33 | $ 1.86 | 1.87% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 9.48 | | | -$ 9.71 | -$ 0.23 | 2.43% | | | -$ 9.95 | -$ 0.24 | 2.47% | | | -$ 10.13 | -$ 0.18 | 1.81% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 85.28** | | | **$ 87.38** | **$ 2.10** | **2.47%** | | | **$ 89.51** | **$ 2.13** | **2.44%** | | | **$ 91.20** | **$ 1.68** | **1.88%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 500 **kWh** May 1 - Oct

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 500 | $ 11.70 | $ 0.0196 | 500 | $ 9.80 | -$ 1.00 | -9.26% | $ 0.0180 | 500 | $ 9.00 | -$ 0.80 | -8.16% |
| Smart Meter Disposition Rider | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 21.37 | | | $ 28.80 | **$ 1.50** | **5.49%** | | | $ 29.75 | **$ 0.95** | **3.30%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 518 | $ 0.03 | $ 0.00007 | 517 | $ 0.04 | $ - | 0.00% | $ 0.00007 | 517 | $ 0.04 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 18 | $ 1.83 | $ 0.1021 | 17 | $ 1.73 | $ - | 0.00% | $ 0.1021 | 17 | $ 1.73 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 24.02** | | | **$ 31.35** | **$ 1.50** | **5.02%** | | | **$ 32.30** | **$ 0.95** | **3.03%** |
| RTSR - Network | per kWh | $ 0.0077 | 518 | $ 3.99 | $ 0.0077 | 517 | $ 3.98 | $ - | 0.00% | $ 0.0077 | 517 | $ 3.98 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 518 | $ 2.18 | $ 0.0042 | 517 | $ 2.17 | $ - | 0.00% | $ 0.0042 | 517 | $ 2.17 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 30.18** | | | **$ 37.50** | **$ 1.50** | **4.17%** | | | **$ 38.45** | **$ 0.95** | **2.53%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 518 | $ 2.28 | $ 0.0044 | 517 | $ 2.27 | $ - | 0.00% | $ 0.0044 | 517 | $ 2.27 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 518 | $ 0.67 | $ 0.0013 | 517 | $ 0.67 | $ - | 0.00% | $ 0.0013 | 517 | $ 0.67 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 500 | $ 3.47 | $ 0.0069 | 500 | $ 3.47 | $ - | 0.00% | $ 0.0069 | 500 | $ 3.47 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 320 | $ 25.60 | $ 0.0800 | 320 | $ 25.60 | $ - | 0.00% | $ 0.0800 | 320 | $ 25.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 90 | $ 10.98 | $ 0.1220 | 90 | $ 10.98 | $ - | 0.00% | $ 0.1220 | 90 | $ 10.98 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 90 | $ 14.49 | $ 0.1610 | 90 | $ 14.49 | $ - | 0.00% | $ 0.1610 | 90 | $ 14.49 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 500 | $ 47.00 | $ 0.0940 | 500 | $ 47.00 | $ - | 0.00% | $ 0.0940 | 500 | $ 47.00 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 87.92** | | | **$ 95.24** | **$ 1.50** | **1.60%** | | | **$ 96.19** | **$ 0.95** | **1.00%** |
| HST | | 13% | | $ 11.43 | 13% | | $ 12.38 | $ 0.20 | 1.60% | 13% | | $ 12.50 | $ 0.12 | 1.00% |
| **Total Bill** (including HST) | | | | $ 99.35 | | | $ 107.62 | $ 1.70 | 1.60% | | | $ 108.69 | $ 1.07 | 1.00% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 9.94 | | | -$ 10.76 | -$ 0.17 | 1.61% | | | -$ 10.87 | -$ 0.11 | 1.02% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 89.41** | | | **$ 96.86** | **$ 1.53** | **1.60%** | | | **$ 97.82** | **$ 0.96** | **0.99%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 83.85** | | | **$ 91.17** | **$ 1.50** | **1.67%** | | | **$ 92.12** | **$ 0.95** | **1.04%** |
| HST | | 13% | | $ 10.90 | 13% | | $ 11.85 | $ 0.19 | 1.67% | 13% | | $ 11.98 | $ 0.12 | 1.04% |
| **Total Bill** (including HST) | | | | $ 94.76 | | | $ 103.02 | $ 1.70 | 1.67% | | | $ 104.10 | $ 1.07 | 1.04% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 9.48 | | | -$ 10.30 | -$ 0.17 | 1.68% | | | -$ 10.41 | -$ 0.11 | 1.07% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 85.28** | | | **$ 92.72** | **$ 1.53** | **1.67%** | | | **$ 93.69** | **$ 0.96** | **1.04%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 800 | $ 18.72 | $ 0.0235 | 800 | $ 18.80 | $ 0.08 | 0.43% | $ 0.0228 | 800 | $ 18.24 | -$ 0.56 | -2.98% | $ 0.0216 | 800 | $ 17.28 | -$ 0.96 | -5.26% |
| Smart Meter Disposition Rider | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 800 | $ - | -$ 0.0003 | 800 | -$ 0.24 | -$ 0.24 | | | 800 | $ - | $ 0.24 | -100.00% | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 28.39 | | | $ 30.81 | **$ 2.42** | **8.52%** | | | $ 32.49 | **$ 1.68** | **5.45%** | | | $ 33.78 | **$ 1.29** | **3.97%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 800 | $ - | -$ 0.0006 | 800 | -$ 0.48 | -$ 0.48 | | | 800 | $ - | $ 0.48 | -100.00% | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 829 | $ 0.05 | $ 0.00007 | 827 | $ 0.06 | $ 0.01 | 16.44% | $ 0.00007 | 827 | $ 0.06 | $ - | 0.00% | $ 0.00007 | 827 | $ 0.06 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 29 | $ 2.93 | $ 0.1021 | 27 | $ 2.76 | -$ 0.16 | -5.59% | $ 0.1021 | 27 | $ 2.76 | $ - | 0.00% | $ 0.1021 | 27 | $ 2.76 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 32.16** | | | **$ 33.94** | **$ 1.78** | **5.55%** | | | **$ 36.10** | **$ 2.16** | **6.36%** | | | **$ 37.39** | **$ 1.29** | **3.57%** |
| RTSR - Network | per kWh | $ 0.0077 | 829 | $ 6.38 | $ 0.0077 | 827 | $ 6.37 | -$ 0.01 | -0.19% | $ 0.0077 | 827 | $ 6.37 | $ - | 0.00% | $ 0.0077 | 827 | $ 6.37 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 829 | $ 3.48 | $ 0.0042 | 827 | $ 3.47 | -$ 0.01 | -0.19% | $ 0.0042 | 827 | $ 3.47 | $ - | 0.00% | $ 0.0042 | 827 | $ 3.47 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 42.02** | | | **$ 43.78** | **$ 1.77** | **4.20%** | | | **$ 45.94** | **$ 2.16** | **4.93%** | | | **$ 47.23** | **$ 1.29** | **2.81%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 829 | $ 3.65 | $ 0.0044 | 827 | $ 3.64 | -$ 0.01 | -0.19% | $ 0.0044 | 827 | $ 3.64 | $ - | 0.00% | $ 0.0044 | 827 | $ 3.64 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 829 | $ 1.08 | $ 0.0013 | 827 | $ 1.08 | -$ 0.00 | -0.19% | $ 0.0013 | 827 | $ 1.08 | $ - | 0.00% | $ 0.0013 | 827 | $ 1.08 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 800 | $ 5.55 | $ 0.0069 | 800 | $ 5.55 | $ - | 0.00% | $ 0.0069 | 800 | $ 5.55 | $ - | 0.00% | $ 0.0069 | 800 | $ 5.55 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 512 | $ 40.96 | $ 0.0800 | 512 | $ 40.96 | $ - | 0.00% | $ 0.0800 | 512 | $ 40.96 | $ - | 0.00% | $ 0.0800 | 512 | $ 40.96 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 144 | $ 17.57 | $ 0.1220 | 144 | $ 17.57 | $ - | 0.00% | $ 0.1220 | 144 | $ 17.57 | $ - | 0.00% | $ 0.1220 | 144 | $ 17.57 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 144 | $ 23.18 | $ 0.1610 | 144 | $ 23.18 | $ - | 0.00% | $ 0.1610 | 144 | $ 23.18 | $ - | 0.00% | $ 0.1610 | 144 | $ 23.18 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 200 | $ 22.00 | $ 0.1100 | 200 | $ 22.00 | $ - | 0.00% | $ 0.1100 | 200 | $ 22.00 | $ - | 0.00% | $ 0.1100 | 200 | $ 22.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 134.25** | | | **$ 136.01** | **$ 1.76** | **1.31%** | | | **$ 138.17** | **$ 2.16** | **1.59%** | | | **$ 139.46** | **$ 1.29** | **0.93%** |
| HST | | 13% | | $ 17.45 | 13% | | $ 17.68 | $ 0.23 | 1.31% | 13% | | $ 17.96 | $ 0.28 | 1.59% | 13% | | $ 18.13 | $ 0.17 | 0.93% |
| **Total Bill** (including HST) | | | | $ 151.71 | | | $ 153.69 | $ 1.98 | 1.31% | | | $ 156.13 | $ 2.44 | 1.59% | | | $ 157.59 | $ 1.46 | 0.93% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 15.17 | | | -$ 15.37 | -$ 0.20 | 1.32% | | | -$ 15.61 | -$ 0.24 | 1.56% | | | -$ 15.76 | -$ 0.15 | 0.96% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 136.54** | | | **$ 138.32** | **$ 1.78** | **1.31%** | | | **$ 140.52** | **$ 2.20** | **1.59%** | | | **$ 141.83** | **$ 1.31** | **0.93%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 130.94** | | | **$ 132.70** | **$ 1.76** | **1.34%** | | | **$ 134.86** | **$ 2.16** | **1.63%** | | | **$ 136.15** | **$ 1.29** | **0.96%** |
| HST | | 13% | | $ 17.02 | 13% | | $ 17.25 | $ 0.23 | 1.34% | 13% | | $ 17.53 | $ 0.28 | 1.63% | 13% | | $ 17.70 | $ 0.17 | 0.96% |
| **Total Bill** (including HST) | | | | $ 147.96 | | | $ 149.95 | $ 1.98 | 1.34% | | | $ 152.39 | $ 2.44 | 1.63% | | | $ 153.85 | $ 1.46 | 0.96% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 14.80 | | | -$ 14.99 | -$ 0.19 | 1.28% | | | -$ 15.24 | -$ 0.25 | 1.67% | | | -$ 15.38 | -$ 0.14 | 0.92% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 133.16** | | | **$ 134.96** | **$ 1.79** | **1.35%** | | | **$ 137.15** | **$ 2.19** | **1.62%** | | | **$ 138.47** | **$ 1.32** | **0.96%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 800 **kWh** May 1 - Oct

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 800 | $ 18.72 | $ 0.0196 | 800 | $ 15.68 | -$ 1.60 | -9.26% | $ 0.0180 | 800 | $ 14.40 | -$ 1.28 | -8.16% |
| Smart Meter Disposition Rider | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 28.39 | | | $ 34.68 | **$ 0.90** | **2.66%** | | | $ 35.15 | **$ 0.47** | **1.36%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | | | 800 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 829 | $ 0.05 | $ 0.00007 | 827 | $ 0.06 | $ - | 0.00% | $ 0.00007 | 827 | $ 0.06 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 29 | $ 2.93 | $ 0.1021 | 27 | $ 2.76 | $ - | 0.00% | $ 0.1021 | 27 | $ 2.76 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 32.16** | | | **$ 38.29** | **$ 0.90** | **2.41%** | | | **$ 38.76** | **$ 0.47** | **1.23%** |
| RTSR - Network | per kWh | $ 0.0077 | 829 | $ 6.38 | $ 0.0077 | 827 | $ 6.37 | $ - | 0.00% | $ 0.0077 | 827 | $ 6.37 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 829 | $ 3.48 | $ 0.0042 | 827 | $ 3.47 | $ - | 0.00% | $ 0.0042 | 827 | $ 3.47 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 42.02** | | | **$ 48.13** | **$ 0.90** | **1.91%** | | | **$ 48.60** | **$ 0.47** | **0.98%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 829 | $ 3.65 | $ 0.0044 | 827 | $ 3.64 | $ - | 0.00% | $ 0.0044 | 827 | $ 3.64 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 829 | $ 1.08 | $ 0.0013 | 827 | $ 1.08 | $ - | 0.00% | $ 0.0013 | 827 | $ 1.08 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 800 | $ 5.55 | $ 0.0069 | 800 | $ 5.55 | $ - | 0.00% | $ 0.0069 | 800 | $ 5.55 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 512 | $ 40.96 | $ 0.0800 | 512 | $ 40.96 | $ - | 0.00% | $ 0.0800 | 512 | $ 40.96 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 144 | $ 17.57 | $ 0.1220 | 144 | $ 17.57 | $ - | 0.00% | $ 0.1220 | 144 | $ 17.57 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 144 | $ 23.18 | $ 0.1610 | 144 | $ 23.18 | $ - | 0.00% | $ 0.1610 | 144 | $ 23.18 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 200 | $ 22.00 | $ 0.1100 | 200 | $ 22.00 | $ - | 0.00% | $ 0.1100 | 200 | $ 22.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 134.25** | | | **$ 140.36** | **$ 0.90** | **0.65%** | | | **$ 140.83** | **$ 0.47** | **0.33%** |
| HST | | 13% | | $ 17.45 | 13% | | $ 18.25 | $ 0.12 | 0.65% | 13% | | $ 18.31 | $ 0.06 | 0.33% |
| **Total Bill** (including HST) | | | | $ 151.71 | | | $ 158.61 | $ 1.02 | 0.65% | | | $ 159.14 | $ 0.53 | 0.33% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 15.17 | | | -$ 15.86 | -$ 0.10 | 0.63% | | | -$ 15.91 | -$ 0.05 | 0.32% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 136.54** | | | **$ 142.75** | **$ 0.92** | **0.65%** | | | **$ 143.23** | **$ 0.48** | **0.34%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 130.94** | | | **$ 137.05** | **$ 0.90** | **0.66%** | | | **$ 137.52** | **$ 0.47** | **0.34%** |
| HST | | 13% | | $ 17.02 | 13% | | $ 17.82 | $ 0.12 | 0.66% | 13% | | $ 17.88 | $ 0.06 | 0.34% |
| **Total Bill** (including HST) | | | | $ 147.96 | | | $ 154.86 | $ 1.02 | 0.66% | | | $ 155.39 | $ 0.53 | 0.34% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 14.80 | | | -$ 15.49 | -$ 0.11 | 0.72% | | | -$ 15.54 | -$ 0.05 | 0.32% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 133.16** | | | **$ 139.37** | **$ 0.91** | **0.66%** | | | **$ 139.85** | **$ 0.48** | **0.35%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 1,000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2016 Proposed Rate ($) | Volume | Charge ($) | Impact 2016 vs 2015 $ Change | % Change | 2017 Proposed Rate ($) | Volume | Charge ($) | Impact 2017 vs 2016 $ Change | % Change | 2018 Proposed Rate ($) | Volume | Charge ($) | Impact 2018 vs 2017 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 1000 | $ 23.40 | $ 0.0235 | 1000 | $ 23.50 | $ 0.10 | 0.43% | $ 0.0228 | 1000 | $ 22.80 | -$ 0.70 | -2.98% | $ 0.0216 | 1000 | $ 21.60 | -$ 1.20 | -5.26% |
| Smart Meter Disposition Rider | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1000 | $ - | -$ 0.0003 | 1000 | -$ 0.30 | -$ 0.30 | | | 1000 | $ - | $ 0.30 | -100.00% | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 33.07 | | | $ 35.45 | **$ 2.38** | **7.20%** | | | $ 37.05 | **$ 1.60** | **4.51%** | | | $ 38.10 | **$ 1.05** | **2.83%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1000 | $ - | -$ 0.0006 | 1000 | -$ 0.60 | -$ 0.60 | | | 1000 | $ - | $ 0.60 | -100.00% | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,036 | $ 0.06 | $ 0.00007 | 1,034 | $ 0.07 | $ 0.01 | 16.44% | $ 0.00007 | 1,034 | $ 0.07 | $ - | 0.00% | $ 0.00007 | 1,034 | $ 0.07 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 36 | $ 3.66 | $ 0.1021 | 34 | $ 3.45 | -$ 0.20 | -5.59% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 37.58** | | | **$ 39.16** | **$ 1.59** | **4.22%** | | | **$ 41.36** | **$ 2.20** | **5.62%** | | | **$ 42.41** | **$ 1.05** | **2.54%** |
| RTSR - Network | per kWh | $ 0.0077 | 1036 | $ 7.98 | $ 0.0077 | 1034 | $ 7.96 | -$ 0.02 | -0.19% | $ 0.0077 | 1034 | $ 7.96 | $ - | 0.00% | $ 0.0077 | 1034 | $ 7.96 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 1036 | $ 4.35 | $ 0.0042 | 1034 | $ 4.34 | -$ 0.01 | -0.19% | $ 0.0042 | 1034 | $ 4.34 | $ - | 0.00% | $ 0.0042 | 1034 | $ 4.34 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 49.90** | | | **$ 51.47** | **$ 1.56** | **3.13%** | | | **$ 53.67** | **$ 2.20** | **4.27%** | | | **$ 54.72** | **$ 1.05** | **1.96%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1036 | $ 4.56 | $ 0.0044 | 1034 | $ 4.55 | -$ 0.01 | -0.19% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1036 | $ 1.35 | $ 0.0013 | 1034 | $ 1.34 | -$ 0.00 | -0.19% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1000 | $ 6.94 | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 640 | $ 51.20 | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 180 | $ 21.96 | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 180 | $ 28.98 | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 400 | $ 44.00 | $ 0.1100 | 400 | $ 44.00 | $ - | 0.00% | $ 0.1100 | 400 | $ 44.00 | $ - | 0.00% | $ 0.1100 | 400 | $ 44.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 165.14** | | | **$ 166.69** | **$ 1.55** | **0.94%** | | | **$ 168.89** | **$ 2.20** | **1.32%** | | | **$ 169.94** | **$ 1.05** | **0.62%** |
| HST | | 13% | | $ 21.47 | 13% | | $ 21.67 | $ 0.20 | 0.94% | 13% | | $ 21.96 | $ 0.29 | 1.32% | 13% | | $ 22.09 | $ 0.14 | 0.62% |
| **Total Bill** (including HST) | | | | $ 186.61 | | | $ 188.36 | $ 1.75 | 0.94% | | | $ 190.85 | $ 2.49 | 1.32% | | | $ 192.03 | $ 1.19 | 0.62% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.66 | | | -$ 18.84 | -$ 0.18 | 0.96% | | | -$ 19.08 | -$ 0.24 | 1.27% | | | -$ 19.20 | -$ 0.12 | 0.63% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 167.95** | | | **$ 169.52** | **$ 1.57** | **0.94%** | | | **$ 171.77** | **$ 2.25** | **1.32%** | | | **$ 172.83** | **$ 1.07** | **0.62%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 163.40** | | | **$ 164.95** | **$ 1.55** | **0.95%** | | | **$ 167.15** | **$ 2.20** | **1.33%** | | | **$ 168.20** | **$ 1.05** | **0.63%** |
| HST | | 13% | | $ 21.24 | 13% | | $ 21.44 | $ 0.20 | 0.95% | 13% | | $ 21.73 | $ 0.29 | 1.33% | 13% | | $ 21.87 | $ 0.14 | 0.63% |
| **Total Bill** (including HST) | | | | $ 184.64 | | | $ 186.39 | $ 1.75 | 0.95% | | | $ 188.88 | $ 2.49 | 1.33% | | | $ 190.07 | $ 1.19 | 0.63% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.46 | | | -$ 18.64 | -$ 0.18 | 0.98% | | | -$ 18.89 | -$ 0.25 | 1.34% | | | -$ 19.01 | -$ 0.12 | 0.64% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 166.18** | | | **$ 167.75** | **$ 1.57** | **0.95%** | | | **$ 169.99** | **$ 2.24** | **1.33%** | | | **$ 171.06** | **$ 1.07** | **0.63%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **Residential**

**TOU / non-TOU:** TOU

**Consumption** 1,000 **kWh** May 1 - Oct

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 1000 | $ 23.40 | $ 0.0196 | 1000 | $ 19.60 | -$ 2.00 | -9.26% | $ 0.0180 | 1000 | $ 18.00 | -$ 1.60 | -8.16% |
| Smart Meter Disposition Rider | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 33.07 | | | $ 38.60 | **$ 0.50** | **1.31%** | | | $ 38.75 | **$ 0.15** | **0.39%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,036 | $ 0.06 | $ 0.00007 | 1,034 | $ 0.07 | $ - | 0.00% | $ 0.00007 | 1,034 | $ 0.07 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 36 | $ 3.66 | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 37.58** | | | **$ 42.91** | **$ 0.50** | **1.18%** | | | **$ 43.06** | **$ 0.15** | **0.35%** |
| RTSR - Network | per kWh | $ 0.0077 | 1036 | $ 7.98 | $ 0.0077 | 1034 | $ 7.96 | $ - | 0.00% | $ 0.0077 | 1034 | $ 7.96 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 1036 | $ 4.35 | $ 0.0042 | 1034 | $ 4.34 | $ - | 0.00% | $ 0.0042 | 1034 | $ 4.34 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 49.90** | | | **$ 55.22** | **$ 0.50** | **0.91%** | | | **$ 55.37** | **$ 0.15** | **0.27%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1036 | $ 4.56 | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1036 | $ 1.35 | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1000 | $ 6.94 | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 640 | $ 51.20 | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 180 | $ 21.96 | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 180 | $ 28.98 | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 400 | $ 44.00 | $ 0.1100 | 400 | $ 44.00 | $ - | 0.00% | $ 0.1100 | 400 | $ 44.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 165.14** | | | **$ 170.44** | **$ 0.50** | **0.29%** | | | **$ 170.59** | **$ 0.15** | **0.09%** |
| HST | | 13% | | $ 21.47 | 13% | | $ 22.16 | $ 0.06 | 0.29% | 13% | | $ 22.18 | $ 0.02 | 0.09% |
| **Total Bill** (including HST) | | | | $ 186.61 | | | $ 192.60 | $ 0.56 | 0.29% | | | $ 192.77 | $ 0.17 | 0.09% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.66 | | | -$ 19.26 | -$ 0.06 | 0.31% | | | -$ 19.28 | -$ 0.02 | 0.10% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 167.95** | | | **$ 173.34** | **$ 0.50** | **0.29%** | | | **$ 173.49** | **$ 0.15** | **0.09%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 163.40** | | | **$ 168.70** | **$ 0.50** | **0.30%** | | | **$ 168.85** | **$ 0.15** | **0.09%** |
| HST | | 13% | | $ 21.24 | 13% | | $ 21.93 | $ 0.07 | 0.30% | 13% | | $ 21.95 | $ 0.02 | 0.09% |
| **Total Bill** (including HST) | | | | $ 184.64 | | | $ 190.63 | $ 0.56 | 0.30% | | | $ 190.80 | $ 0.17 | 0.09% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.46 | | | -$ 19.06 | -$ 0.05 | 0.26% | | | -$ 19.08 | -$ 0.02 | 0.10% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 166.18** | | | **$ 171.57** | **$ 0.51** | **0.30%** | | | **$ 171.72** | **$ 0.15** | **0.09%** |

| | | | |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **Residential**

**TOU / non-TOU:** TOU

**Consumption** 1,500 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 1500 | $ 35.10 | $ 0.0235 | 1500 | $ 35.25 | $ 0.15 | 0.43% | $ 0.0228 | 1500 | $ 34.20 | -$ 1.05 | -2.98% | $ 0.0216 | 1500 | $ 32.40 | -$ 1.80 | -5.26% |
| Smart Meter Disposition Rider | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1500 | $ - | -$ 0.0003 | 1500 | -$ 0.45 | -$ 0.45 | | | 1500 | $ - | $ 0.45 | -100.00% | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 44.77 | | | $ 47.05 | **$ 2.28** | **5.09%** | | | $ 48.45 | **$ 1.40** | **2.98%** | | | $ 48.90 | **$ 0.45** | **0.93%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1500 | $ - | -$ 0.0006 | 1500 | -$ 0.90 | -$ 0.90 | | | 1500 | $ - | $ 0.90 | -100.00% | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,554 | $ 0.09 | $ 0.00007 | 1,551 | $ 0.11 | $ 0.02 | 16.44% | $ 0.00007 | 1,551 | $ 0.11 | $ - | 0.00% | $ 0.00007 | 1,551 | $ 0.11 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 54 | $ 5.48 | $ 0.1021 | 51 | $ 5.18 | -$ 0.31 | -5.59% | $ 0.1021 | 51 | $ 5.18 | $ - | 0.00% | $ 0.1021 | 51 | $ 5.18 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 51.14** | | | **$ 52.23** | **$ 1.09** | **2.13%** | | | **$ 54.53** | **$ 2.30** | **4.40%** | | | **$ 54.98** | **$ 0.45** | **0.83%** |
| RTSR - Network | per kWh | $ 0.0077 | 1554 | $ 11.96 | $ 0.0077 | 1551 | $ 11.94 | -$ 0.02 | -0.19% | $ 0.0077 | 1551 | $ 11.94 | $ - | 0.00% | $ 0.0077 | 1551 | $ 11.94 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 1554 | $ 6.53 | $ 0.0042 | 1551 | $ 6.51 | -$ 0.01 | -0.19% | $ 0.0042 | 1551 | $ 6.51 | $ - | 0.00% | $ 0.0042 | 1551 | $ 6.51 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 69.63** | | | **$ 70.68** | **$ 1.05** | **1.51%** | | | **$ 72.98** | **$ 2.30** | **3.25%** | | | **$ 73.43** | **$ 0.45** | **0.62%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1554 | $ 6.84 | $ 0.0044 | 1551 | $ 6.82 | -$ 0.01 | -0.19% | $ 0.0044 | 1551 | $ 6.82 | $ - | 0.00% | $ 0.0044 | 1551 | $ 6.82 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1554 | $ 2.02 | $ 0.0013 | 1551 | $ 2.02 | -$ 0.00 | -0.19% | $ 0.0013 | 1551 | $ 2.02 | $ - | 0.00% | $ 0.0013 | 1551 | $ 2.02 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1500 | $ 10.41 | $ 0.0069 | 1500 | $ 10.41 | $ - | 0.00% | $ 0.0069 | 1500 | $ 10.41 | $ - | 0.00% | $ 0.0069 | 1500 | $ 10.41 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 960 | $ 76.80 | $ 0.0800 | 960 | $ 76.80 | $ - | 0.00% | $ 0.0800 | 960 | $ 76.80 | $ - | 0.00% | $ 0.0800 | 960 | $ 76.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 270 | $ 32.94 | $ 0.1220 | 270 | $ 32.94 | $ - | 0.00% | $ 0.1220 | 270 | $ 32.94 | $ - | 0.00% | $ 0.1220 | 270 | $ 32.94 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 270 | $ 43.47 | $ 0.1610 | 270 | $ 43.47 | $ - | 0.00% | $ 0.1610 | 270 | $ 43.47 | $ - | 0.00% | $ 0.1610 | 270 | $ 43.47 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 900 | $ 99.00 | $ 0.1100 | 900 | $ 99.00 | $ - | 0.00% | $ 0.1100 | 900 | $ 99.00 | $ - | 0.00% | $ 0.1100 | 900 | $ 99.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 242.35** | | | **$ 243.39** | **$ 1.04** | **0.43%** | | | **$ 245.69** | **$ 2.30** | **0.94%** | | | **$ 246.14** | **$ 0.45** | **0.18%** |
| HST | | 13% | | $ 31.51 | 13% | | $ 31.64 | $ 0.13 | 0.43% | 13% | | $ 31.94 | $ 0.30 | 0.94% | 13% | | $ 32.00 | $ 0.06 | 0.18% |
| **Total Bill** (including HST) | | | | $ 273.86 | | | $ 275.03 | $ 1.17 | 0.43% | | | $ 277.63 | $ 2.60 | 0.94% | | | $ 278.14 | $ 0.51 | 0.18% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 27.39 | | | -$ 27.50 | -$ 0.11 | 0.40% | | | -$ 27.76 | -$ 0.26 | 0.95% | | | -$ 27.81 | -$ 0.05 | 0.18% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 246.47** | | | **$ 247.53** | **$ 1.06** | **0.43%** | | | **$ 249.87** | **$ 2.34** | **0.94%** | | | **$ 250.33** | **$ 0.46** | **0.18%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 244.54** | | | **$ 245.58** | **$ 1.04** | **0.42%** | | | **$ 247.88** | **$ 2.30** | **0.94%** | | | **$ 248.33** | **$ 0.45** | **0.18%** |
| HST | | 13% | | $ 31.79 | 13% | | $ 31.93 | $ 0.13 | 0.42% | 13% | | $ 32.22 | $ 0.30 | 0.94% | 13% | | $ 32.28 | $ 0.06 | 0.18% |
| **Total Bill** (including HST) | | | | $ 276.33 | | | $ 277.50 | $ 1.17 | 0.42% | | | $ 280.10 | $ 2.60 | 0.94% | | | $ 280.61 | $ 0.51 | 0.18% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 27.63 | | | -$ 27.75 | -$ 0.12 | 0.43% | | | -$ 28.01 | -$ 0.26 | 0.94% | | | -$ 28.06 | -$ 0.05 | 0.18% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 248.70** | | | **$ 249.75** | **$ 1.05** | **0.42%** | | | **$ 252.09** | **$ 2.34** | **0.94%** | | | **$ 252.55** | **$ 0.46** | **0.18%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **Residential**

**TOU / non-TOU:** TOU

**Consumption** 1,500 **kWh** May 1 - Oct

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 1500 | $ 35.10 | $ 0.0196 | 1500 | $ 29.40 | -$ 3.00 | -9.26% | $ 0.0180 | 1500 | $ 27.00 | -$ 2.40 | -8.16% |
| Smart Meter Disposition Rider | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 44.77 | | | $ 48.40 | **-$ 0.50** | **-1.02%** | | | $ 47.75 | **-$ 0.65** | **-1.34%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| | | | 1500 | $ - | | 1500 | $ - | $ - | | | 1500 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,554 | $ 0.09 | $ 0.00007 | 1,551 | $ 0.11 | $ - | 0.00% | $ 0.00007 | 1,551 | $ 0.11 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 54 | $ 5.48 | $ 0.1021 | 51 | $ 5.18 | $ - | 0.00% | $ 0.1021 | 51 | $ 5.18 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 51.14** | | | **$ 54.48** | **-$ 0.50** | **-0.91%** | | | **$ 53.83** | **-$ 0.65** | **-1.19%** |
| RTSR - Network | per kWh | $ 0.0077 | 1554 | $ 11.96 | $ 0.0077 | 1551 | $ 11.94 | $ - | 0.00% | $ 0.0077 | 1551 | $ 11.94 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 1554 | $ 6.53 | $ 0.0042 | 1551 | $ 6.51 | $ - | 0.00% | $ 0.0042 | 1551 | $ 6.51 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 69.63** | | | **$ 72.93** | **-$ 0.50** | **-0.68%** | | | **$ 72.28** | **-$ 0.65** | **-0.89%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1554 | $ 6.84 | $ 0.0044 | 1551 | $ 6.82 | $ - | 0.00% | $ 0.0044 | 1551 | $ 6.82 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1554 | $ 2.02 | $ 0.0013 | 1551 | $ 2.02 | $ - | 0.00% | $ 0.0013 | 1551 | $ 2.02 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1500 | $ 10.41 | $ 0.0069 | 1500 | $ 10.41 | $ - | 0.00% | $ 0.0069 | 1500 | $ 10.41 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 960 | $ 76.80 | $ 0.0800 | 960 | $ 76.80 | $ - | 0.00% | $ 0.0800 | 960 | $ 76.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 270 | $ 32.94 | $ 0.1220 | 270 | $ 32.94 | $ - | 0.00% | $ 0.1220 | 270 | $ 32.94 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 270 | $ 43.47 | $ 0.1610 | 270 | $ 43.47 | $ - | 0.00% | $ 0.1610 | 270 | $ 43.47 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 900 | $ 99.00 | $ 0.1100 | 900 | $ 99.00 | $ - | 0.00% | $ 0.1100 | 900 | $ 99.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 242.35** | | | **$ 245.64** | **-$ 0.50** | **-0.20%** | | | **$ 244.99** | **-$ 0.65** | **-0.26%** |
| HST | | 13% | | $ 31.51 | 13% | | $ 31.93 | -$ 0.06 | -0.20% | 13% | | $ 31.85 | -$ 0.08 | -0.26% |
| **Total Bill** (including HST) | | | | $ 273.86 | | | $ 277.57 | -$ 0.56 | -0.20% | | | $ 276.84 | -$ 0.73 | -0.26% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 27.39 | | | -$ 27.76 | $ 0.05 | -0.18% | | | -$ 27.68 | $ 0.08 | -0.29% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 246.47** | | | **$ 249.81** | **-$ 0.51** | **-0.21%** | | | **$ 249.16** | **-$ 0.65** | **-0.26%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 244.54** | | | **$ 247.83** | **-$ 0.50** | **-0.20%** | | | **$ 247.18** | **-$ 0.65** | **-0.26%** |
| HST | | 13% | | $ 31.79 | 13% | | $ 32.22 | -$ 0.07 | -0.20% | 13% | | $ 32.13 | -$ 0.08 | -0.26% |
| **Total Bill** (including HST) | | | | $ 276.33 | | | $ 280.05 | -$ 0.56 | -0.20% | | | $ 279.31 | -$ 0.73 | -0.26% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 27.63 | | | -$ 28.00 | $ 0.06 | -0.21% | | | -$ 27.93 | $ 0.07 | -0.25% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 248.70** | | | **$ 252.05** | **-$ 0.50** | **-0.20%** | | | **$ 251.38** | **-$ 0.66** | **-0.26%** |
| | | | | | | | | | | | | | | |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 2,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 12.2500 | 1 | $ 12.25 | $ 2.58 | 26.68% | $ 14.2500 | 1 | $ 14.25 | $ 2.00 | 16.33% | $ 16.5000 | 1 | $ 16.50 | $ 2.25 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 2000 | $ 46.80 | $ 0.0235 | 2000 | $ 47.00 | $ 0.20 | 0.43% | $ 0.0228 | 2000 | $ 45.60 | -$ 1.40 | -2.98% | $ 0.0216 | 2000 | $ 43.20 | -$ 2.40 | -5.26% |
| Smart Meter Disposition Rider | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 2000 | $ - | -$ 0.0003 | 2000 | -$ 0.60 | -$ 0.60 | | | 2000 | $ - | $ 0.60 | -100.00% | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 56.47 | | | $ 58.65 | **$ 2.18** | **3.86%** | | | $ 59.85 | **$ 1.20** | **2.05%** | | | $ 59.70 | **-$ 0.15** | **-0.25%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 2000 | $ - | -$ 0.0006 | 2000 | -$ 1.20 | -$ 1.20 | | | 2000 | $ - | $ 1.20 | -100.00% | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 2,072 | $ 0.12 | $ 0.00007 | 2,068 | $ 0.14 | $ 0.02 | 16.44% | $ 0.00007 | 2,068 | $ 0.14 | $ - | 0.00% | $ 0.00007 | 2,068 | $ 0.14 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 72 | $ 7.31 | $ 0.1021 | 68 | $ 6.90 | -$ 0.41 | -5.59% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 64.70** | | | **$ 65.29** | **$ 0.59** | **0.91%** | | | **$ 67.69** | **$ 2.40** | **3.68%** | | | **$ 67.54** | **-$ 0.15** | **-0.22%** |
| RTSR - Network | per kWh | $ 0.0077 | 2072 | $ 15.95 | $ 0.0077 | 2068 | $ 15.92 | -$ 0.03 | -0.19% | $ 0.0077 | 2068 | $ 15.92 | $ - | 0.00% | $ 0.0077 | 2068 | $ 15.92 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 2072 | $ 8.70 | $ 0.0042 | 2068 | $ 8.68 | -$ 0.02 | -0.19% | $ 0.0042 | 2068 | $ 8.68 | $ - | 0.00% | $ 0.0042 | 2068 | $ 8.68 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 89.35** | | | **$ 89.89** | **$ 0.54** | **0.61%** | | | **$ 92.29** | **$ 2.40** | **2.67%** | | | **$ 92.14** | **-$ 0.15** | **-0.16%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 2072 | $ 9.12 | $ 0.0044 | 2068 | $ 9.10 | -$ 0.02 | -0.19% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 2072 | $ 2.69 | $ 0.0013 | 2068 | $ 2.69 | -$ 0.01 | -0.19% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 2000 | $ 13.88 | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 1280 | $ 102.40 | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 360 | $ 43.92 | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 360 | $ 57.96 | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1400 | $ 154.00 | $ 0.1100 | 1400 | $ 154.00 | $ - | 0.00% | $ 0.1100 | 1400 | $ 154.00 | $ - | 0.00% | $ 0.1100 | 1400 | $ 154.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 319.57** | | | **$ 320.09** | **$ 0.52** | **0.16%** | | | **$ 322.49** | **$ 2.40** | **0.75%** | | | **$ 322.34** | **-$ 0.15** | **-0.05%** |
| HST | | 13% | | $ 41.54 | 13% | | $ 41.61 | $ 0.07 | 0.16% | 13% | | $ 41.92 | $ 0.31 | 0.75% | 13% | | $ 41.90 | -$ 0.02 | -0.05% |
| **Total Bill** (including HST) | | | | $ 361.11 | | | $ 361.70 | $ 0.59 | 0.16% | | | $ 364.41 | $ 2.71 | 0.75% | | | $ 364.24 | -$ 0.17 | -0.05% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.11 | | | -$ 36.17 | -$ 0.06 | 0.17% | | | -$ 36.44 | -$ 0.27 | 0.75% | | | -$ 36.42 | $ 0.02 | -0.05% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 325.00** | | | **$ 325.53** | **$ 0.53** | **0.16%** | | | **$ 327.97** | **$ 2.44** | **0.75%** | | | **$ 327.82** | **-$ 0.15** | **-0.05%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 325.69** | | | **$ 326.21** | **$ 0.52** | **0.16%** | | | **$ 328.61** | **$ 2.40** | **0.74%** | | | **$ 328.46** | **-$ 0.15** | **-0.05%** |
| HST | | 13% | | $ 42.34 | 13% | | $ 42.41 | $ 0.07 | 0.16% | 13% | | $ 42.72 | $ 0.31 | 0.74% | 13% | | $ 42.70 | -$ 0.02 | -0.05% |
| **Total Bill** (including HST) | | | | $ 368.03 | | | $ 368.62 | $ 0.59 | 0.16% | | | $ 371.33 | $ 2.71 | 0.74% | | | $ 371.16 | -$ 0.17 | -0.05% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.80 | | | -$ 36.86 | -$ 0.06 | 0.16% | | | -$ 37.13 | -$ 0.27 | 0.73% | | | -$ 37.12 | $ 0.01 | -0.03% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 331.23** | | | **$ 331.76** | **$ 0.53** | **0.16%** | | | **$ 334.20** | **$ 2.44** | **0.74%** | | | **$ 334.04** | **-$ 0.16** | **-0.05%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Residential

**TOU / non-TOU:** TOU

**Consumption** 2,000 **kWh** May 1 - Oct

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 9.6700 | 1 | $ 9.67 | $ 19.0000 | 1 | $ 19.00 | $ 2.50 | 15.15% | $ 20.7500 | 1 | $ 20.75 | $ 1.75 | 9.21% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0234 | 2000 | $ 46.80 | $ 0.0196 | 2000 | $ 39.20 | -$ 4.00 | -9.26% | $ 0.0180 | 2000 | $ 36.00 | -$ 3.20 | -8.16% |
| Smart Meter Disposition Rider | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 56.47 | | | $ 58.20 | **-$ 1.50** | **-2.51%** | | | $ 56.75 | **-$ 1.45** | **-2.49%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 2,072 | $ 0.12 | $ 0.00007 | 2,068 | $ 0.14 | $ - | 0.00% | $ 0.00007 | 2,068 | $ 0.14 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 72 | $ 7.31 | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 64.70** | | | **$ 66.04** | **-$ 1.50** | **-2.22%** | | | **$ 64.59** | **-$ 1.45** | **-2.20%** |
| RTSR - Network | per kWh | $ 0.0077 | 2072 | $ 15.95 | $ 0.0077 | 2068 | $ 15.92 | $ - | 0.00% | $ 0.0077 | 2068 | $ 15.92 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0042 | 2072 | $ 8.70 | $ 0.0042 | 2068 | $ 8.68 | $ - | 0.00% | $ 0.0042 | 2068 | $ 8.68 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 89.35** | | | **$ 90.64** | **-$ 1.50** | **-1.63%** | | | **$ 89.19** | **-$ 1.45** | **-1.60%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 2072 | $ 9.12 | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 2072 | $ 2.69 | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 2000 | $ 13.88 | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 1280 | $ 102.40 | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 360 | $ 43.92 | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 360 | $ 57.96 | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 600 | $ 56.40 | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% | $ 0.0940 | 600 | $ 56.40 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1400 | $ 154.00 | $ 0.1100 | 1400 | $ 154.00 | $ - | 0.00% | $ 0.1100 | 1400 | $ 154.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 319.57** | | | **$ 320.84** | **-$ 1.50** | **-0.47%** | | | **$ 319.39** | **-$ 1.45** | **-0.45%** |
| HST | | 13% | | $ 41.54 | 13% | | $ 41.71 | -$ 0.19 | -0.47% | 13% | | $ 41.52 | -$ 0.19 | -0.45% |
| **Total Bill** (including HST) | | | | $ 361.11 | | | $ 362.55 | -$ 1.69 | -0.47% | | | $ 360.91 | -$ 1.64 | -0.45% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.11 | | | -$ 36.25 | $ 0.17 | -0.47% | | | -$ 36.09 | $ 0.16 | -0.44% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 325.00** | | | **$ 326.30** | **-$ 1.52** | **-0.47%** | | | **$ 324.82** | **-$ 1.48** | **-0.45%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 325.69** | | | **$ 326.96** | **-$ 1.50** | **-0.46%** | | | **$ 325.51** | **-$ 1.45** | **-0.44%** |
| HST | | 13% | | $ 42.34 | 13% | | $ 42.50 | -$ 0.20 | -0.46% | 13% | | $ 42.32 | -$ 0.19 | -0.44% |
| **Total Bill** (including HST) | | | | $ 368.03 | | | $ 369.46 | -$ 1.70 | -0.46% | | | $ 367.83 | -$ 1.64 | -0.44% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.80 | | | -$ 36.95 | $ 0.17 | -0.46% | | | -$ 36.78 | $ 0.17 | -0.46% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 331.23** | | | **$ 332.51** | **-$ 1.53** | **-0.46%** | | | **$ 331.05** | **-$ 1.47** | **-0.44%** |

| | Current Board-Approved | 2019 Proposed | 2020 Proposed |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 1,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2016 Proposed Rate ($) | Volume | Charge ($) | Impact 2016 vs 2015 $ Change | % Change | 2017 Proposed Rate ($) | Volume | Charge ($) | Impact 2017 vs 2016 $ Change | % Change | 2018 Proposed Rate ($) | Volume | Charge ($) | Impact 2018 vs 2017 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 22.7500 | 1 | $ 22.75 | $ 6.03 | 36.06% | $ 27.7500 | 1 | $ 27.75 | $ 5.00 | 21.98% | $ 33.2500 | 1 | $ 33.25 | $ 5.50 | 19.82% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 1000 | $ 21.00 | $ 0.0216 | 1000 | $ 21.60 | $ 0.60 | 2.86% | $ 0.0214 | 1000 | $ 21.40 | -$ 0.20 | -0.93% | $ 0.0208 | 1000 | $ 20.80 | -$ 0.60 | -2.80% |
| Smart Meter Disposition Rider | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1000 | $ - | -$ 0.0001 | 1000 | -$ 0.10 | -$ 0.10 | | | 1000 | $ - | $ 0.10 | -100.00% | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 37.72 | | | $ 44.25 | **$ 6.53** | **17.31%** | | | $ 49.15 | **$ 4.90** | **11.07%** | | | $ 54.05 | **$ 4.90** | **9.97%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1000 | $ - | -$ 0.0009 | 1000 | -$ 0.90 | -$ 0.90 | | | 1000 | $ - | $ 0.90 | -100.00% | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,036 | $ 0.06 | $ 0.00006 | 1,034 | $ 0.06 | -$ 0.00 | -0.19% | $ 0.00006 | 1,034 | $ 0.06 | $ - | 0.00% | $ 0.00006 | 1,034 | $ 0.06 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 36 | $ 3.66 | $ 0.1021 | 34 | $ 3.45 | -$ 0.20 | -5.59% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 42.23** | | | **$ 47.65** | **$ 5.43** | **12.85%** | | | **$ 53.45** | **$ 5.80** | **12.17%** | | | **$ 58.35** | **$ 4.90** | **9.17%** |
| RTSR - Network | per kWh | $ 0.0070 | 1036 | $ 7.25 | $ 0.0070 | 1034 | $ 7.24 | -$ 0.01 | -0.19% | $ 0.0070 | 1034 | $ 7.24 | $ - | 0.00% | $ 0.0070 | 1034 | $ 7.24 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 1036 | $ 4.14 | $ 0.0040 | 1034 | $ 4.14 | -$ 0.01 | -0.19% | $ 0.0040 | 1034 | $ 4.14 | $ - | 0.00% | $ 0.0040 | 1034 | $ 4.14 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 53.62** | | | **$ 59.03** | **$ 5.40** | **10.08%** | | | **$ 64.83** | **$ 5.80** | **9.83%** | | | **$ 69.73** | **$ 4.90** | **7.56%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1036 | $ 4.56 | $ 0.0044 | 1034 | $ 4.55 | -$ 0.01 | -0.19% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1036 | $ 1.35 | $ 0.0013 | 1034 | $ 1.34 | -$ 0.00 | -0.19% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1000 | $ 6.94 | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 640 | $ 51.20 | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 180 | $ 21.96 | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 180 | $ 28.98 | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 250 | $ 27.50 | $ 0.1100 | 250 | $ 27.50 | $ - | 0.00% | $ 0.1100 | 250 | $ 27.50 | $ - | 0.00% | $ 0.1100 | 250 | $ 27.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 168.86** | | | **$ 174.25** | **$ 5.39** | **3.19%** | | | **$ 180.05** | **$ 5.80** | **3.33%** | | | **$ 184.95** | **$ 4.90** | **2.72%** |
| HST | | 13% | | $ 21.95 | 13% | | $ 22.65 | $ 0.70 | 3.19% | 13% | | $ 23.41 | $ 0.75 | 3.33% | 13% | | $ 24.04 | $ 0.64 | 2.72% |
| **Total Bill** (including HST) | | | | $ 190.81 | | | $ 196.90 | $ 6.09 | 3.19% | | | $ 203.46 | $ 6.55 | 3.33% | | | $ 208.99 | $ 5.54 | 2.72% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 19.08 | | | -$ 19.69 | -$ 0.61 | 3.20% | | | -$ 20.35 | -$ 0.66 | 3.35% | | | -$ 20.90 | -$ 0.55 | 2.70% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 171.73** | | | **$ 177.21** | **$ 5.48** | **3.19%** | | | **$ 183.11** | **$ 5.89** | **3.33%** | | | **$ 188.09** | **$ 4.99** | **2.72%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 164.72** | | | **$ 170.11** | **$ 5.39** | **3.27%** | | | **$ 175.91** | **$ 5.80** | **3.41%** | | | **$ 180.81** | **$ 4.90** | **2.79%** |
| HST | | 13% | | $ 21.41 | 13% | | $ 22.11 | $ 0.70 | 3.27% | 13% | | $ 22.87 | $ 0.75 | 3.41% | 13% | | $ 23.51 | $ 0.64 | 2.79% |
| **Total Bill** (including HST) | | | | $ 186.13 | | | $ 192.22 | $ 6.09 | 3.27% | | | $ 198.78 | $ 6.55 | 3.41% | | | $ 204.31 | $ 5.54 | 2.79% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.61 | | | -$ 19.22 | -$ 0.61 | 3.28% | | | -$ 19.88 | -$ 0.66 | 3.43% | | | -$ 20.43 | -$ 0.55 | 2.77% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 167.52** | | | **$ 173.00** | **$ 5.48** | **3.27%** | | | **$ 178.90** | **$ 5.89** | **3.41%** | | | **$ 183.88** | **$ 4.99** | **2.79%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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# Appendix 2-W
# Bill Impacts

**Customer Class:** **General Service < 50 kW**

**TOU / non-TOU:** TOU

**Consumption** 1,000 **kWh** May 1 - Oct

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 38.7500 | 1 | $ 38.75 | $ 5.50 | 16.54% | $ 44.0000 | 1 | $ 44.00 | $ 5.25 | 13.55% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 1000 | $ 21.00 | $ 0.0201 | 1000 | $ 20.10 | -$ 0.70 | -3.37% | $ 0.0188 | 1000 | $ 18.80 | -$ 1.30 | -6.47% |
| Smart Meter Disposition Rider | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 37.72 | | | $ 58.85 | **$ 4.80** | **8.88%** | | | $ 62.80 | **$ 3.95** | **6.71%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| | | | 1000 | $ - | | 1000 | $ - | $ - | | | 1000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 1,036 | $ 0.06 | $ 0.00006 | 1,034 | $ 0.06 | $ - | 0.00% | $ 0.00006 | 1,034 | $ 0.06 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 36 | $ 3.66 | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% | $ 0.1021 | 34 | $ 3.45 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 42.23** | | | **$ 63.15** | **$ 4.80** | **8.23%** | | | **$ 67.10** | **$ 3.95** | **6.25%** |
| RTSR - Network | per kWh | $ 0.0070 | 1036 | $ 7.25 | $ 0.0070 | 1034 | $ 7.24 | $ - | 0.00% | $ 0.0070 | 1034 | $ 7.24 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 1036 | $ 4.14 | $ 0.0040 | 1034 | $ 4.14 | $ - | 0.00% | $ 0.0040 | 1034 | $ 4.14 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 53.62** | | | **$ 74.53** | **$ 4.80** | **6.88%** | | | **$ 78.48** | **$ 3.95** | **5.30%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1036 | $ 4.56 | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% | $ 0.0044 | 1034 | $ 4.55 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1036 | $ 1.35 | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% | $ 0.0013 | 1034 | $ 1.34 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1000 | $ 6.94 | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% | $ 0.0069 | 1000 | $ 6.94 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 640 | $ 51.20 | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% | $ 0.0800 | 640 | $ 51.20 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 180 | $ 21.96 | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% | $ 0.1220 | 180 | $ 21.96 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 180 | $ 28.98 | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% | $ 0.1610 | 180 | $ 28.98 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 250 | $ 27.50 | $ 0.1100 | 250 | $ 27.50 | $ - | 0.00% | $ 0.1100 | 250 | $ 27.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 168.86** | | | **$ 189.75** | **$ 4.80** | **2.60%** | | | **$ 193.70** | **$ 3.95** | **2.08%** |
| HST | | 13% | | $ 21.95 | 13% | | $ 24.67 | $ 0.62 | 2.60% | 13% | | $ 25.18 | $ 0.51 | 2.08% |
| **Total Bill** (including HST) | | | | $ 190.81 | | | $ 214.42 | $ 5.42 | 2.60% | | | $ 218.88 | $ 4.46 | 2.08% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 19.08 | | | -$ 21.44 | -$ 0.54 | 2.58% | | | -$ 21.89 | -$ 0.45 | 2.10% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 171.73** | | | **$ 192.98** | **$ 4.88** | **2.60%** | | | **$ 196.99** | **$ 4.01** | **2.08%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 164.72** | | | **$ 185.61** | **$ 4.80** | **2.65%** | | | **$ 189.56** | **$ 3.95** | **2.13%** |
| HST | | 13% | | $ 21.41 | 13% | | $ 24.13 | $ 0.62 | 2.65% | 13% | | $ 24.64 | $ 0.51 | 2.13% |
| **Total Bill** (including HST) | | | | $ 186.13 | | | $ 209.74 | $ 5.42 | 2.65% | | | $ 214.20 | $ 4.46 | 2.13% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 18.61 | | | -$ 20.97 | -$ 0.54 | 2.64% | | | -$ 21.42 | -$ 0.45 | 2.15% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 167.52** | | | **$ 188.77** | **$ 4.88** | **2.66%** | | | **$ 192.78** | **$ 4.01** | **2.13%** |

| | | | |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 2,000 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 22.7500 | 1 | $ 22.75 | $ 6.03 | 36.06% | $ 27.7500 | 1 | $ 27.75 | $ 5.00 | 21.98% | $ 33.2500 | 1 | $ 33.25 | $ 5.50 | 19.82% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 2000 | $ 42.00 | $ 0.0216 | 2000 | $ 43.20 | $ 1.20 | 2.86% | $ 0.0214 | 2000 | $ 42.80 | -$ 0.40 | -0.93% | $ 0.0208 | 2000 | $ 41.60 | -$ 1.20 | -2.80% |
| Smart Meter Disposition Rider | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 2000 | $ - | -$ 0.0001 | 2000 | -$ 0.20 | -$ 0.20 | | | 2000 | $ - | $ 0.20 | -100.00% | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 58.72 | | | $ 65.75 | **$ 7.03** | **11.97%** | | | $ 70.55 | **$ 4.80** | **7.30%** | | | $ 74.85 | **$ 4.30** | **6.09%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 2000 | $ - | -$ 0.0009 | 2000 | -$ 1.80 | -$ 1.80 | | | 2000 | $ - | $ 1.80 | -100.00% | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 2,072 | $ 0.12 | $ 0.00006 | 2,068 | $ 0.12 | -$ 0.00 | -0.19% | $ 0.00006 | 2,068 | $ 0.12 | $ - | 0.00% | $ 0.00006 | 2,068 | $ 0.12 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 72 | $ 7.31 | $ 0.1021 | 68 | $ 6.90 | -$ 0.41 | -5.59% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 66.95** | | | **$ 71.77** | **$ 4.82** | **7.20%** | | | **$ 78.37** | **$ 6.60** | **9.20%** | | | **$ 82.67** | **$ 4.30** | **5.49%** |
| RTSR - Network | per kWh | $ 0.0070 | 2072 | $ 14.50 | $ 0.0070 | 2068 | $ 14.47 | -$ 0.03 | -0.19% | $ 0.0070 | 2068 | $ 14.47 | $ - | 0.00% | $ 0.0070 | 2068 | $ 14.47 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 2072 | $ 8.29 | $ 0.0040 | 2068 | $ 8.27 | -$ 0.02 | -0.19% | $ 0.0040 | 2068 | $ 8.27 | $ - | 0.00% | $ 0.0040 | 2068 | $ 8.27 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 89.74** | | | **$ 94.51** | **$ 4.78** | **5.32%** | | | **$ 101.11** | **$ 6.60** | **6.98%** | | | **$ 105.41** | **$ 4.30** | **4.25%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 2072 | $ 9.12 | $ 0.0044 | 2068 | $ 9.10 | -$ 0.02 | -0.19% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 2072 | $ 2.69 | $ 0.0013 | 2068 | $ 2.69 | -$ 0.01 | -0.19% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 2000 | $ 13.88 | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 1280 | $ 102.40 | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 360 | $ 43.92 | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 360 | $ 57.96 | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1250 | $ 137.50 | $ 0.1100 | 1250 | $ 137.50 | $ - | 0.00% | $ 0.1100 | 1250 | $ 137.50 | $ - | 0.00% | $ 0.1100 | 1250 | $ 137.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 319.95** | | | **$ 324.71** | **$ 4.75** | **1.49%** | | | **$ 331.31** | **$ 6.60** | **2.03%** | | | **$ 335.61** | **$ 4.30** | **1.30%** |
| HST | | 13% | | $ 41.59 | 13% | | $ 42.21 | $ 0.62 | 1.49% | 13% | | $ 43.07 | $ 0.86 | 2.03% | 13% | | $ 43.63 | $ 0.56 | 1.30% |
| **Total Bill** (including HST) | | | | $ 361.55 | | | $ 366.92 | $ 5.37 | 1.49% | | | $ 374.38 | $ 7.46 | 2.03% | | | $ 379.24 | $ 4.86 | 1.30% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.15 | | | -$ 36.69 | -$ 0.54 | 1.49% | | | -$ 37.44 | -$ 0.75 | 2.04% | | | -$ 37.92 | -$ 0.48 | 1.28% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 325.40** | | | **$ 330.23** | **$ 4.83** | **1.49%** | | | **$ 336.94** | **$ 6.71** | **2.03%** | | | **$ 341.32** | **$ 4.38** | **1.30%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 323.67** | | | **$ 328.43** | **$ 4.75** | **1.47%** | | | **$ 335.03** | **$ 6.60** | **2.01%** | | | **$ 339.33** | **$ 4.30** | **1.28%** |
| HST | | 13% | | $ 42.08 | 13% | | $ 42.70 | $ 0.62 | 1.47% | 13% | | $ 43.55 | $ 0.86 | 2.01% | 13% | | $ 44.11 | $ 0.56 | 1.28% |
| **Total Bill** (including HST) | | | | $ 365.75 | | | $ 371.12 | $ 5.37 | 1.47% | | | $ 378.58 | $ 7.46 | 2.01% | | | $ 383.44 | $ 4.86 | 1.28% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.58 | | | -$ 37.11 | -$ 0.53 | 1.45% | | | -$ 37.86 | -$ 0.75 | 2.02% | | | -$ 38.34 | -$ 0.48 | 1.27% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 329.17** | | | **$ 334.01** | **$ 4.84** | **1.47%** | | | **$ 340.72** | **$ 6.71** | **2.01%** | | | **$ 345.10** | **$ 4.38** | **1.29%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 2,000 kWh May 1 - Oct

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 38.7500 | 1 | $ 38.75 | $ 5.50 | 16.54% | $ 44.0000 | 1 | $ 44.00 | $ 5.25 | 13.55% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 2000 | $ 42.00 | $ 0.0201 | 2000 | $ 40.20 | -$ 1.40 | -3.37% | $ 0.0188 | 2000 | $ 37.60 | -$ 2.60 | -6.47% |
| Smart Meter Disposition Rider | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 58.72 | | | $ 78.95 | **$ 4.10** | **5.48%** | | | $ 81.60 | **$ 2.65** | **3.36%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | | | 2000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 2,072 | $ 0.12 | $ 0.00006 | 2,068 | $ 0.12 | $ - | 0.00% | $ 0.00006 | 2,068 | $ 0.12 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 72 | $ 7.31 | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% | $ 0.1021 | 68 | $ 6.90 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 66.95** | | | **$ 86.77** | **$ 4.10** | **4.96%** | | | **$ 89.42** | **$ 2.65** | **3.05%** |
| RTSR - Network | per kWh | $ 0.0070 | 2072 | $ 14.50 | $ 0.0070 | 2068 | $ 14.47 | $ - | 0.00% | $ 0.0070 | 2068 | $ 14.47 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 2072 | $ 8.29 | $ 0.0040 | 2068 | $ 8.27 | $ - | 0.00% | $ 0.0040 | 2068 | $ 8.27 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 89.74** | | | **$ 109.51** | **$ 4.10** | **3.89%** | | | **$ 112.16** | **$ 2.65** | **2.42%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 2072 | $ 9.12 | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% | $ 0.0044 | 2068 | $ 9.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 2072 | $ 2.69 | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% | $ 0.0013 | 2068 | $ 2.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 2000 | $ 13.88 | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% | $ 0.0069 | 2000 | $ 13.88 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 1280 | $ 102.40 | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% | $ 0.0800 | 1280 | $ 102.40 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 360 | $ 43.92 | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% | $ 0.1220 | 360 | $ 43.92 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 360 | $ 57.96 | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% | $ 0.1610 | 360 | $ 57.96 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1250 | $ 137.50 | $ 0.1100 | 1250 | $ 137.50 | $ - | 0.00% | $ 0.1100 | 1250 | $ 137.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 319.95** | | | **$ 339.71** | **$ 4.10** | **1.22%** | | | **$ 342.36** | **$ 2.65** | **0.78%** |
| HST | | 13% | | $ 41.59 | 13% | | $ 44.16 | $ 0.53 | 1.22% | 13% | | $ 44.51 | $ 0.34 | 0.78% |
| **Total Bill** (including HST) | | | | $ 361.55 | | | $ 383.87 | $ 4.63 | 1.22% | | | $ 386.86 | $ 2.99 | 0.78% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.15 | | | -$ 38.39 | -$ 0.47 | 1.24% | | | -$ 38.69 | -$ 0.30 | 0.78% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 325.40** | | | **$ 345.48** | **$ 4.16** | **1.22%** | | | **$ 348.17** | **$ 2.69** | **0.78%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 323.67** | | | **$ 343.43** | **$ 4.10** | **1.21%** | | | **$ 346.08** | **$ 2.65** | **0.77%** |
| HST | | 13% | | $ 42.08 | 13% | | $ 44.65 | $ 0.53 | 1.21% | 13% | | $ 44.99 | $ 0.34 | 0.77% |
| **Total Bill** (including HST) | | | | $ 365.75 | | | $ 388.07 | $ 4.63 | 1.21% | | | $ 391.07 | $ 2.99 | 0.77% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 36.58 | | | -$ 38.81 | -$ 0.47 | 1.23% | | | -$ 39.11 | -$ 0.30 | 0.77% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 329.17** | | | **$ 349.26** | **$ 4.16** | **1.21%** | | | **$ 351.96** | **$ 2.69** | **0.77%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 5,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 22.7500 | 1 | $ 22.75 | $ 6.03 | 36.06% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 5000 | $ 105.00 | $ 0.0216 | 5000 | $ 108.00 | $ 3.00 | 2.86% |
| Smart Meter Disposition Rider | | | 5000 | $ - | | 5000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 5000 | $ - | -$ 0.0001 | 5000 | -$ 0.50 | -$ 0.50 | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 121.72 | | | $ 130.25 | **$ 8.53** | **7.01%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 5000 | $ - | -$ 0.0009 | 5000 | -$ 4.50 | -$ 4.50 | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 5,179 | $ 0.31 | $ 0.00006 | 5,169 | $ 0.31 | -$ 0.00 | -0.19% |
| Line Losses on Cost of Power | | $ 0.1021 | 179 | $ 18.28 | $ 0.1021 | 169 | $ 17.26 | -$ 1.02 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 141.10** | | | **$ 144.11** | **$ 3.01** | **2.13%** |
| RTSR - Network | per kWh | $ 0.0070 | 5179 | $ 36.25 | $ 0.0070 | 5169 | $ 36.18 | -$ 0.07 | -0.19% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 5179 | $ 20.72 | $ 0.0040 | 5169 | $ 20.68 | -$ 0.04 | -0.19% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 198.07** | | | **$ 200.97** | **$ 2.90** | **1.46%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 5179 | $ 22.79 | $ 0.0044 | 5169 | $ 22.74 | -$ 0.04 | -0.19% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 5179 | $ 6.73 | $ 0.0013 | 5169 | $ 6.72 | -$ 0.01 | -0.19% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 5000 | $ 34.70 | $ 0.0069 | 5000 | $ 34.70 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 3200 | $ 256.00 | $ 0.0800 | 3200 | $ 256.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 900 | $ 109.80 | $ 0.1220 | 900 | $ 109.80 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 900 | $ 144.90 | $ 0.1610 | 900 | $ 144.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 4250 | $ 467.50 | $ 0.1100 | 4250 | $ 467.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 773.24** | | | **$ 776.08** | **$ 2.84** | **0.37%** |
| HST | | 13% | | $ 100.52 | 13% | | $ 100.89 | $ 0.37 | 0.37% |
| **Total Bill** (including HST) | | | | $ 873.76 | | | $ 876.98 | $ 3.21 | 0.37% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 87.38 | | | -$ 87.70 | -$ 0.32 | 0.37% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 786.38** | | | **$ 789.28** | **$ 2.89** | **0.37%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 800.54** | | | **$ 803.38** | **$ 2.84** | **0.35%** |
| HST | | 13% | | $ 104.07 | 13% | | $ 104.44 | $ 0.37 | 0.35% |
| **Total Bill** (including HST) | | | | $ 904.61 | | | $ 907.82 | $ 3.21 | 0.35% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 90.46 | | | -$ 90.78 | -$ 0.32 | 0.35% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 814.15** | | | **$ 817.04** | **$ 2.89** | **0.36%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | $ 27.7500 | 1 | $ 27.75 | $ 5.00 | 21.98% | $ 33.2500 | 1 | $ 33.25 | $ 5.50 | 19.82% |
| Smart Meter Rate Adder | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | $ 0.0214 | 5000 | $ 107.00 | -$ 1.00 | -0.93% | $ 0.0208 | 5000 | $ 104.00 | -$ 3.00 | -2.80% |
| Smart Meter Disposition Rider | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| LRAM & SSM Rate Rider | | 5000 | $ - | $ 0.50 | -100.00% | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | $ 134.75 | **$ 4.50** | **3.45%** | | | $ 137.25 | **$ 2.50** | **1.86%** |
| Deferral/Variance Account Disposition Rate Rider | | 5000 | $ - | $ 4.50 | -100.00% | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| Low Voltage Service Charge | $ 0.00006 | 5,169 | $ 0.31 | $ - | 0.00% | $ 0.00006 | 5,169 | $ 0.31 | $ - | 0.00% |
| Line Losses on Cost of Power | $ 0.1021 | 169 | $ 17.26 | $ - | 0.00% | $ 0.1021 | 169 | $ 17.26 | $ - | 0.00% |
| Smart Meter Entity Charge | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | **$ 153.11** | **$ 9.00** | **6.25%** | | | **$ 155.61** | **$ 2.50** | **1.63%** |
| RTSR - Network | $ 0.0070 | 5169 | $ 36.18 | $ - | 0.00% | $ 0.0070 | 5169 | $ 36.18 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | $ 0.0040 | 5169 | $ 20.68 | $ - | 0.00% | $ 0.0040 | 5169 | $ 20.68 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | **$ 209.97** | **$ 9.00** | **4.48%** | | | **$ 212.47** | **$ 2.50** | **1.19%** |
| Wholesale Market Service Charge (WMSC) | $ 0.0044 | 5169 | $ 22.74 | $ - | 0.00% | $ 0.0044 | 5169 | $ 22.74 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | $ 0.0013 | 5169 | $ 6.72 | $ - | 0.00% | $ 0.0013 | 5169 | $ 6.72 | $ - | 0.00% |
| Standard Supply Service Charge | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | $ 0.0069 | 5000 | $ 34.70 | $ - | 0.00% | $ 0.0069 | 5000 | $ 34.70 | $ - | 0.00% |
| TOU - Off Peak | $ 0.0800 | 3200 | $ 256.00 | $ - | 0.00% | $ 0.0800 | 3200 | $ 256.00 | $ - | 0.00% |
| TOU - Mid Peak | $ 0.1220 | 900 | $ 109.80 | $ - | 0.00% | $ 0.1220 | 900 | $ 109.80 | $ - | 0.00% |
| TOU - On Peak | $ 0.1610 | 900 | $ 144.90 | $ - | 0.00% | $ 0.1610 | 900 | $ 144.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | $ 0.1100 | 4250 | $ 467.50 | $ - | 0.00% | $ 0.1100 | 4250 | $ 467.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | **$ 785.08** | **$ 9.00** | **1.16%** | | | **$ 787.58** | **$ 2.50** | **0.32%** |
| HST | 13% | | $ 102.06 | $ 1.17 | 1.16% | 13% | | $ 102.39 | $ 0.33 | 0.32% |
| **Total Bill** (including HST) | | | $ 887.15 | $ 10.17 | 1.16% | | | $ 889.97 | $ 2.83 | 0.32% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 88.71 | -$ 1.01 | 1.15% | | | -$ 89.00 | -$ 0.29 | 0.33% |
| **Total Bill on TOU (including OCEB)** | | | **$ 798.44** | **$ 9.16** | **1.16%** | | | **$ 800.97** | **$ 2.54** | **0.32%** |
| **Total Bill on RPP (before Taxes)** | | | **$ 812.38** | **$ 9.00** | **1.12%** | | | **$ 814.88** | **$ 2.50** | **0.31%** |
| HST | 13% | | $ 105.61 | $ 1.17 | 1.12% | 13% | | $ 105.93 | $ 0.33 | 0.31% |
| **Total Bill** (including HST) | | | $ 917.99 | $ 10.17 | 1.12% | | | $ 920.82 | $ 2.82 | 0.31% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 91.80 | -$ 1.02 | 1.12% | | | -$ 92.08 | -$ 0.28 | 0.31% |
| **Total Bill on RPP (including OCEB)** | | | **$ 826.19** | **$ 9.15** | **1.12%** | | | **$ 828.74** | **$ 2.54** | **0.31%** |
| **Loss Factor (%)** | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 5,000 kWh May 1 - Oct

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 38.7500 | 1 | $ 38.75 | $ 5.50 | 16.54% | $ 44.0000 | 1 | $ 44.00 | $ 5.25 | 13.55% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 5000 | $ 105.00 | $ 0.0201 | 5000 | $ 100.50 | -$ 3.50 | -3.37% | $ 0.0188 | 5000 | $ 94.00 | -$ 6.50 | -6.47% |
| Smart Meter Disposition Rider | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 121.72 | | | $ 139.25 | **$ 2.00** | **1.46%** | | | $ 138.00 | **-$ 1.25** | **-0.90%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| | | | 5000 | $ - | | 5000 | $ - | $ - | | | 5000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 5,179 | $ 0.31 | $ 0.00006 | 5,169 | $ 0.31 | $ - | 0.00% | $ 0.00006 | 5,169 | $ 0.31 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 179 | $ 18.28 | $ 0.1021 | 169 | $ 17.26 | $ - | 0.00% | $ 0.1021 | 169 | $ 17.26 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 141.10** | | | **$ 157.61** | **$ 2.00** | **1.29%** | | | **$ 156.36** | **-$ 1.25** | **-0.79%** |
| RTSR - Network | per kWh | $ 0.0070 | 5179 | $ 36.25 | $ 0.0070 | 5169 | $ 36.18 | $ - | 0.00% | $ 0.0070 | 5169 | $ 36.18 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 5179 | $ 20.72 | $ 0.0040 | 5169 | $ 20.68 | $ - | 0.00% | $ 0.0040 | 5169 | $ 20.68 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 198.07** | | | **$ 214.47** | **$ 2.00** | **0.94%** | | | **$ 213.22** | **-$ 1.25** | **-0.58%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 5179 | $ 22.79 | $ 0.0044 | 5169 | $ 22.74 | $ - | 0.00% | $ 0.0044 | 5169 | $ 22.74 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 5179 | $ 6.73 | $ 0.0013 | 5169 | $ 6.72 | $ - | 0.00% | $ 0.0013 | 5169 | $ 6.72 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 5000 | $ 34.70 | $ 0.0069 | 5000 | $ 34.70 | $ - | 0.00% | $ 0.0069 | 5000 | $ 34.70 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 3200 | $ 256.00 | $ 0.0800 | 3200 | $ 256.00 | $ - | 0.00% | $ 0.0800 | 3200 | $ 256.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 900 | $ 109.80 | $ 0.1220 | 900 | $ 109.80 | $ - | 0.00% | $ 0.1220 | 900 | $ 109.80 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 900 | $ 144.90 | $ 0.1610 | 900 | $ 144.90 | $ - | 0.00% | $ 0.1610 | 900 | $ 144.90 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 4250 | $ 467.50 | $ 0.1100 | 4250 | $ 467.50 | $ - | 0.00% | $ 0.1100 | 4250 | $ 467.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 773.24** | | | **$ 789.58** | **$ 2.00** | **0.25%** | | | **$ 788.33** | **-$ 1.25** | **-0.16%** |
| HST | | 13% | | $ 100.52 | 13% | | $ 102.65 | $ 0.26 | 0.25% | 13% | | $ 102.48 | -$ 0.16 | -0.16% |
| **Total Bill** (including HST) | | | | $ 873.76 | | | $ 892.23 | $ 2.26 | 0.25% | | | $ 890.82 | -$ 1.41 | -0.16% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 87.38 | | | -$ 89.22 | -$ 0.22 | 0.25% | | | -$ 89.08 | $ 0.14 | -0.16% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 786.38** | | | **$ 803.01** | **$ 2.04** | **0.25%** | | | **$ 801.74** | **-$ 1.27** | **-0.16%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 800.54** | | | **$ 816.88** | **$ 2.00** | **0.25%** | | | **$ 815.63** | **-$ 1.25** | **-0.15%** |
| HST | | 13% | | $ 104.07 | 13% | | $ 106.19 | $ 0.26 | 0.25% | 13% | | $ 106.03 | -$ 0.16 | -0.15% |
| **Total Bill** (including HST) | | | | $ 904.61 | | | $ 923.08 | $ 2.26 | 0.25% | | | $ 921.67 | -$ 1.41 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 90.46 | | | -$ 92.31 | -$ 0.23 | 0.25% | | | -$ 92.17 | $ 0.14 | -0.15% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 814.15** | | | **$ 830.77** | **$ 2.03** | **0.24%** | | | **$ 829.50** | **-$ 1.27** | **-0.15%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 10,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2016 Proposed Rate ($) | Volume | Charge ($) | Impact 2016 vs 2015 $ Change | % Change | 2017 Proposed Rate ($) | Volume | Charge ($) | Impact 2017 vs 2016 $ Change | % Change | 2018 Proposed Rate ($) | Volume | Charge ($) | Impact 2018 vs 2017 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 22.7500 | 1 | $ 22.75 | $ 6.03 | 36.06% | $ 27.7500 | 1 | $ 27.75 | $ 5.00 | 21.98% | $ 33.2500 | 1 | $ 33.25 | $ 5.50 | 19.82% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 10000 | $ 210.00 | $ 0.0216 | 10000 | $ 216.00 | $ 6.00 | 2.86% | $ 0.0214 | 10000 | $ 214.00 | -$ 2.00 | -0.93% | $ 0.0208 | 10000 | $ 208.00 | -$ 6.00 | -2.80% |
| Smart Meter Disposition Rider | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 10000 | $ - | -$ 0.0001 | 10000 | -$ 1.00 | -$ 1.00 | | | 10000 | $ - | $ 1.00 | -100.00% | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 226.72 | | | $ 237.75 | **$ 11.03** | **4.87%** | | | $ 241.75 | **$ 4.00** | **1.68%** | | | $ 241.25 | **-$ 0.50** | **-0.21%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 10000 | $ - | -$ 0.0009 | 10000 | -$ 9.00 | -$ 9.00 | | | 10000 | $ - | $ 9.00 | -100.00% | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 10,358 | $ 0.62 | $ 0.00006 | 10,338 | $ 0.62 | -$ 0.00 | -0.19% | $ 0.00006 | 10,338 | $ 0.62 | $ - | 0.00% | $ 0.00006 | 10,338 | $ 0.62 | $ - | 0.00% |
| Line Losses on Cost of Power | per kWh | $ 0.1021 | 358 | $ 36.57 | $ 0.1021 | 338 | $ 34.52 | -$ 2.04 | -5.59% | $ 0.1021 | 338 | $ 34.52 | $ - | 0.00% | $ 0.1021 | 338 | $ 34.52 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 264.70** | | | **$ 264.68** | **-$ 0.01** | **-0.01%** | | | **$ 277.68** | **$ 13.00** | **4.91%** | | | **$ 277.18** | **-$ 0.50** | **-0.18%** |
| RTSR - Network | per kWh | $ 0.0070 | 10358 | $ 72.51 | $ 0.0070 | 10338 | $ 72.37 | -$ 0.14 | -0.19% | $ 0.0070 | 10338 | $ 72.37 | $ - | 0.00% | $ 0.0070 | 10338 | $ 72.37 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 10358 | $ 41.43 | $ 0.0040 | 10338 | $ 41.35 | -$ 0.08 | -0.19% | $ 0.0040 | 10338 | $ 41.35 | $ - | 0.00% | $ 0.0040 | 10338 | $ 41.35 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 378.64** | | | **$ 378.40** | **-$ 0.23** | **-0.06%** | | | **$ 391.40** | **$ 13.00** | **3.44%** | | | **$ 390.90** | **-$ 0.50** | **-0.13%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 10358 | $ 45.58 | $ 0.0044 | 10338 | $ 45.49 | -$ 0.09 | -0.19% | $ 0.0044 | 10338 | $ 45.49 | $ - | 0.00% | $ 0.0044 | 10338 | $ 45.49 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 10358 | $ 13.47 | $ 0.0013 | 10338 | $ 13.44 | -$ 0.03 | -0.19% | $ 0.0013 | 10338 | $ 13.44 | $ - | 0.00% | $ 0.0013 | 10338 | $ 13.44 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 10000 | $ 69.40 | $ 0.0069 | 10000 | $ 69.40 | $ - | 0.00% | $ 0.0069 | 10000 | $ 69.40 | $ - | 0.00% | $ 0.0069 | 10000 | $ 69.40 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 6400 | $ 512.00 | $ 0.0800 | 6400 | $ 512.00 | $ - | 0.00% | $ 0.0800 | 6400 | $ 512.00 | $ - | 0.00% | $ 0.0800 | 6400 | $ 512.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 1800 | $ 219.60 | $ 0.1220 | 1800 | $ 219.60 | $ - | 0.00% | $ 0.1220 | 1800 | $ 219.60 | $ - | 0.00% | $ 0.1220 | 1800 | $ 219.60 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 1800 | $ 289.80 | $ 0.1610 | 1800 | $ 289.80 | $ - | 0.00% | $ 0.1610 | 1800 | $ 289.80 | $ - | 0.00% | $ 0.1610 | 1800 | $ 289.80 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 9250 | $ 1,017.50 | $ 0.1100 | 9250 | $ 1,017.50 | $ - | 0.00% | $ 0.1100 | 9250 | $ 1,017.50 | $ - | 0.00% | $ 0.1100 | 9250 | $ 1,017.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 1,528.73** | | | **$ 1,528.38** | **-$ 0.35** | **-0.02%** | | | **$ 1,541.38** | **$ 13.00** | **0.85%** | | | **$ 1,540.88** | **-$ 0.50** | **-0.03%** |
| HST | | 13% | | $ 198.73 | 13% | | $ 198.69 | -$ 0.05 | -0.02% | 13% | | $ 200.38 | $ 1.69 | 0.85% | 13% | | $ 200.31 | -$ 0.06 | -0.03% |
| **Total Bill** (including HST) | | | | $ 1,727.46 | | | $ 1,727.07 | -$ 0.39 | -0.02% | | | $ 1,741.76 | $ 14.69 | 0.85% | | | $ 1,741.19 | -$ 0.56 | -0.03% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 172.75 | | | -$ 172.71 | $ 0.04 | -0.02% | | | -$ 174.18 | -$ 1.47 | 0.85% | | | -$ 174.12 | $ 0.06 | -0.03% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 1,554.71** | | | **$ 1,554.36** | **-$ 0.35** | **-0.02%** | | | **$ 1,567.58** | **$ 13.22** | **0.85%** | | | **$ 1,567.07** | **-$ 0.50** | **-0.03%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 1,595.33** | | | **$ 1,594.98** | **-$ 0.35** | **-0.02%** | | | **$ 1,607.98** | **$ 13.00** | **0.82%** | | | **$ 1,607.48** | **-$ 0.50** | **-0.03%** |
| HST | | 13% | | $ 207.39 | 13% | | $ 207.35 | -$ 0.05 | -0.02% | 13% | | $ 209.04 | $ 1.69 | 0.82% | 13% | | $ 208.97 | -$ 0.06 | -0.03% |
| **Total Bill** (including HST) | | | | $ 1,802.72 | | | $ 1,802.33 | -$ 0.39 | -0.02% | | | $ 1,817.02 | $ 14.69 | 0.82% | | | $ 1,816.45 | -$ 0.57 | -0.03% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 180.27 | | | -$ 180.23 | $ 0.04 | -0.02% | | | -$ 181.70 | -$ 1.47 | 0.82% | | | -$ 181.65 | $ 0.05 | -0.03% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 1,622.45** | | | **$ 1,622.10** | **-$ 0.35** | **-0.02%** | | | **$ 1,635.32** | **$ 13.22** | **0.81%** | | | **$ 1,634.80** | **-$ 0.52** | **-0.03%** |

| | | | | |
|---|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 10,000 kWh May 1 - Octo

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 38.7500 | 1 | $ 38.75 | $ 5.50 | 16.54% | $ 44.0000 | 1 | $ 44.00 | $ 5.25 | 13.55% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 10000 | $ 210.00 | $ 0.0201 | 10000 | $ 201.00 | -$ 7.00 | -3.37% | $ 0.0188 | 10000 | $ 188.00 | -$ 13.00 | -6.47% |
| Smart Meter Disposition Rider | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 226.72 | | | $ 239.75 | **-$ 1.50** | **-0.62%** | | | $ 232.00 | **-$ 7.75** | **-3.23%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| | | | 10000 | $ - | | 10000 | $ - | $ - | | | 10000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 10,358 | $ 0.62 | $ 0.00006 | 10,338 | $ 0.62 | $ - | 0.00% | $ 0.00006 | 10,338 | $ 0.62 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 358 | $ 36.57 | $ 0.1021 | 338 | $ 34.52 | $ - | 0.00% | $ 0.1021 | 338 | $ 34.52 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 264.70** | | | **$ 275.68** | **-$ 1.50** | **-0.54%** | | | **$ 267.93** | **-$ 7.75** | **-2.81%** |
| RTSR - Network | per kWh | $ 0.0070 | 10358 | $ 72.51 | $ 0.0070 | 10338 | $ 72.37 | $ - | 0.00% | $ 0.0070 | 10338 | $ 72.37 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 10358 | $ 41.43 | $ 0.0040 | 10338 | $ 41.35 | $ - | 0.00% | $ 0.0040 | 10338 | $ 41.35 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 378.64** | | | **$ 389.40** | **-$ 1.50** | **-0.38%** | | | **$ 381.65** | **-$ 7.75** | **-1.99%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 10358 | $ 45.58 | $ 0.0044 | 10338 | $ 45.49 | $ - | 0.00% | $ 0.0044 | 10338 | $ 45.49 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 10358 | $ 13.47 | $ 0.0013 | 10338 | $ 13.44 | $ - | 0.00% | $ 0.0013 | 10338 | $ 13.44 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 10000 | $ 69.40 | $ 0.0069 | 10000 | $ 69.40 | $ - | 0.00% | $ 0.0069 | 10000 | $ 69.40 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 6400 | $ 512.00 | $ 0.0800 | 6400 | $ 512.00 | $ - | 0.00% | $ 0.0800 | 6400 | $ 512.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 1800 | $ 219.60 | $ 0.1220 | 1800 | $ 219.60 | $ - | 0.00% | $ 0.1220 | 1800 | $ 219.60 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 1800 | $ 289.80 | $ 0.1610 | 1800 | $ 289.80 | $ - | 0.00% | $ 0.1610 | 1800 | $ 289.80 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 9250 | $ 1,017.50 | $ 0.1100 | 9250 | $ 1,017.50 | $ - | 0.00% | $ 0.1100 | 9250 | $ 1,017.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 1,528.73** | | | **$ 1,539.38** | **-$ 1.50** | **-0.10%** | | | **$ 1,531.63** | **-$ 7.75** | **-0.50%** |
| HST | | 13% | | $ 198.73 | 13% | | $ 200.12 | -$ 0.20 | -0.10% | 13% | | $ 199.11 | -$ 1.01 | -0.50% |
| **Total Bill** (including HST) | | | | $ 1,727.46 | | | $ 1,739.50 | -$ 1.70 | -0.10% | | | $ 1,730.74 | -$ 8.76 | -0.50% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 172.75 | | | -$ 173.95 | $ 0.17 | -0.10% | | | -$ 173.07 | $ 0.88 | -0.51% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 1,554.71** | | | **$ 1,565.55** | **-$ 1.53** | **-0.10%** | | | **$ 1,557.67** | **-$ 7.88** | **-0.50%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 1,595.33** | | | **$ 1,605.98** | **-$ 1.50** | **-0.09%** | | | **$ 1,598.23** | **-$ 7.75** | **-0.48%** |
| HST | | 13% | | $ 207.39 | 13% | | $ 208.78 | -$ 0.19 | -0.09% | 13% | | $ 207.77 | -$ 1.01 | -0.48% |
| **Total Bill** (including HST) | | | | $ 1,802.72 | | | $ 1,814.76 | -$ 1.69 | -0.09% | | | $ 1,806.00 | -$ 8.76 | -0.48% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 180.27 | | | -$ 181.48 | $ 0.17 | -0.09% | | | -$ 180.60 | $ 0.88 | -0.48% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 1,622.45** | | | **$ 1,633.28** | **-$ 1.52** | **-0.09%** | | | **$ 1,625.40** | **-$ 7.88** | **-0.48%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 15,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 22.7500 | 1 | $ 22.75 | $ 6.03 | 36.06% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 15000 | $ 315.00 | $ 0.0216 | 15000 | $ 324.00 | $ 9.00 | 2.86% |
| Smart Meter Disposition Rider | | | 15000 | $ - | | 15000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 15000 | $ - | -$ 0.0001 | 15000 | -$ 1.50 | -$ 1.50 | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 331.72 | | | $ 345.25 | **$ 13.53** | **4.08%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 15000 | $ - | -$ 0.0009 | 15000 | -$ 13.50 | -$ 13.50 | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 15,537 | $ 0.93 | $ 0.00006 | 15,507 | $ 0.93 | -$ 0.00 | -0.19% |
| Line Losses on Cost of Power | | $ 0.1021 | 537 | $ 54.85 | $ 0.1021 | 507 | $ 51.78 | -$ 3.06 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 388.29** | | | **$ 385.26** | **-$ 3.04** | **-0.78%** |
| RTSR - Network | per kWh | $ 0.0070 | 15537 | $ 108.76 | $ 0.0070 | 15507 | $ 108.55 | -$ 0.21 | -0.19% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 15537 | $ 62.15 | $ 0.0040 | 15507 | $ 62.03 | -$ 0.12 | -0.19% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 559.20** | | | **$ 555.83** | **-$ 3.37** | **-0.60%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 15537 | $ 68.36 | $ 0.0044 | 15507 | $ 68.23 | -$ 0.13 | -0.19% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 15537 | $ 20.20 | $ 0.0013 | 15507 | $ 20.16 | -$ 0.04 | -0.19% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 15000 | $ 104.10 | $ 0.0069 | 15000 | $ 104.10 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 9600 | $ 768.00 | $ 0.0800 | 9600 | $ 768.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 2700 | $ 329.40 | $ 0.1220 | 2700 | $ 329.40 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 2700 | $ 434.70 | $ 0.1610 | 2700 | $ 434.70 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 14250 | $1,567.50 | $ 0.1100 | 14250 | $1,567.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$2,284.21** | | | **$2,280.67** | **-$ 3.54** | **-0.15%** |
| HST | | 13% | | $ 296.95 | 13% | | $ 296.49 | -$ 0.46 | -0.15% |
| **Total Bill** (including HST) | | | | $2,581.16 | | | $2,577.16 | -$ 4.00 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 258.12 | | | -$ 257.72 | $ 0.40 | -0.15% |
| **Total Bill on TOU (including OCEB)** | | | | **$2,323.04** | | | **$2,319.44** | **-$ 3.60** | **-0.15%** |
| **Total Bill on RPP (before Taxes)** | | | | **$2,390.11** | | | **$2,386.57** | **-$ 3.54** | **-0.15%** |
| HST | | 13% | | $ 310.71 | 13% | | $ 310.25 | -$ 0.46 | -0.15% |
| **Total Bill** (including HST) | | | | $2,700.82 | | | $2,696.83 | -$ 4.00 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 270.08 | | | -$ 269.68 | $ 0.40 | -0.15% |
| **Total Bill on RPP (including OCEB)** | | | | **$2,430.74** | | | **$2,427.15** | **-$ 3.60** | **-0.15%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | $ 27.7500 | 1 | $ 27.75 | $ 5.00 | 21.98% | $ 33.2500 | 1 | $ 33.25 | $ 5.50 | 19.82% |
| Smart Meter Rate Adder | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | $ 0.0214 | 15000 | $ 321.00 | -$ 3.00 | -0.93% | $ 0.0208 | 15000 | $ 312.00 | -$ 9.00 | -2.80% |
| Smart Meter Disposition Rider | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| LRAM & SSM Rate Rider | | 15000 | $ - | $ 1.50 | -100.00% | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | $ 348.75 | **$ 3.50** | **1.01%** | | | $ 345.25 | **-$ 3.50** | **-1.00%** |
| Deferral/Variance Account Disposition Rate Rider | | 15000 | $ - | $ 13.50 | -100.00% | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| Low Voltage Service Charge | $ 0.00006 | 15,507 | $ 0.93 | $ - | 0.00% | $ 0.00006 | 15,507 | $ 0.93 | $ - | 0.00% |
| Line Losses on Cost of Power | $ 0.1021 | 507 | $ 51.78 | $ - | 0.00% | $ 0.1021 | 507 | $ 51.78 | $ - | 0.00% |
| Smart Meter Entity Charge | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | **$ 402.26** | **$ 17.00** | **4.41%** | | | **$ 398.76** | **-$ 3.50** | **-0.87%** |
| RTSR - Network | $ 0.0070 | 15507 | $ 108.55 | $ - | 0.00% | $ 0.0070 | 15507 | $ 108.55 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | $ 0.0040 | 15507 | $ 62.03 | $ - | 0.00% | $ 0.0040 | 15507 | $ 62.03 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | **$ 572.83** | **$ 17.00** | **3.06%** | | | **$ 569.33** | **-$ 3.50** | **-0.61%** |
| Wholesale Market Service Charge (WMSC) | $ 0.0044 | 15507 | $ 68.23 | $ - | 0.00% | $ 0.0044 | 15507 | $ 68.23 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | $ 0.0013 | 15507 | $ 20.16 | $ - | 0.00% | $ 0.0013 | 15507 | $ 20.16 | $ - | 0.00% |
| Standard Supply Service Charge | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | $ 0.0069 | 15000 | $ 104.10 | $ - | 0.00% | $ 0.0069 | 15000 | $ 104.10 | $ - | 0.00% |
| TOU - Off Peak | $ 0.0800 | 9600 | $ 768.00 | $ - | 0.00% | $ 0.0800 | 9600 | $ 768.00 | $ - | 0.00% |
| TOU - Mid Peak | $ 0.1220 | 2700 | $ 329.40 | $ - | 0.00% | $ 0.1220 | 2700 | $ 329.40 | $ - | 0.00% |
| TOU - On Peak | $ 0.1610 | 2700 | $ 434.70 | $ - | 0.00% | $ 0.1610 | 2700 | $ 434.70 | $ - | 0.00% |
| Energy - RPP - Tier 1 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | $ 0.1100 | 14250 | $1,567.50 | $ - | 0.00% | $ 0.1100 | 14250 | $1,567.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | **$2,297.67** | **$ 17.00** | **0.75%** | | | **$2,294.17** | **-$ 3.50** | **-0.15%** |
| HST | 13% | | $ 298.70 | $ 2.21 | 0.75% | 13% | | $ 298.24 | -$ 0.45 | -0.15% |
| **Total Bill** (including HST) | | | $2,596.37 | $ 19.21 | 0.75% | | | $2,592.41 | -$ 3.95 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 259.64 | -$ 1.92 | 0.74% | | | -$ 259.24 | $ 0.40 | -0.15% |
| **Total Bill on TOU (including OCEB)** | | | **$2,336.73** | **$ 17.29** | **0.75%** | | | **$2,333.17** | **-$ 3.56** | **-0.15%** |
| **Total Bill on RPP (before Taxes)** | | | **$2,403.57** | **$ 17.00** | **0.71%** | | | **$2,400.07** | **-$ 3.50** | **-0.15%** |
| HST | 13% | | $ 312.46 | $ 2.21 | 0.71% | 13% | | $ 312.01 | -$ 0.46 | -0.15% |
| **Total Bill** (including HST) | | | $2,716.04 | $ 19.21 | 0.71% | | | $2,712.08 | -$ 3.95 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | -$ 271.60 | -$ 1.92 | 0.71% | | | -$ 271.21 | $ 0.39 | -0.14% |
| **Total Bill on RPP (including OCEB)** | | | **$2,444.44** | **$ 17.29** | **0.71%** | | | **$2,440.87** | **-$ 3.57** | **-0.15%** |
| **Loss Factor (%)** | 3.3800% | | | | | 3.3800% | | | | |

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# Appendix 2-W
# Bill Impacts

**Customer Class:** General Service < 50 kW

**TOU / non-TOU:** TOU

**Consumption** 15,000 **kWh** May 1 - Octo

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 16.7200 | 1 | $ 16.72 | $ 38.7500 | 1 | $ 38.75 | $ 5.50 | 16.54% | $ 44.0000 | 1 | $ 44.00 | $ 5.25 | 13.55% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0210 | 15000 | $ 315.00 | $ 0.0201 | 15000 | $ 301.50 | -$ 10.50 | -3.37% | $ 0.0188 | 15000 | $ 282.00 | -$ 19.50 | -6.47% |
| Smart Meter Disposition Rider | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 331.72 | | | $ 340.25 | **-$ 5.00** | **-1.45%** | | | $ 326.00 | **-$ 14.25** | **-4.19%** |
| Deferral/Variance Account Disposition Rate Rider | | $ - | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| | | | 15000 | $ - | | 15000 | $ - | $ - | | | 15000 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 15,537 | $ 0.93 | $ 0.00006 | 15,507 | $ 0.93 | $ - | 0.00% | $ 0.00006 | 15,507 | $ 0.93 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 537 | $ 54.85 | $ 0.1021 | 507 | $ 51.78 | $ - | 0.00% | $ 0.1021 | 507 | $ 51.78 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 388.29** | | | **$ 393.76** | **-$ 5.00** | **-1.25%** | | | **$ 379.51** | **-$ 14.25** | **-3.62%** |
| RTSR - Network | per kWh | $ 0.0070 | 15537 | $ 108.76 | $ 0.0070 | 15507 | $ 108.55 | $ - | 0.00% | $ 0.0070 | 15507 | $ 108.55 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 15537 | $ 62.15 | $ 0.0040 | 15507 | $ 62.03 | $ - | 0.00% | $ 0.0040 | 15507 | $ 62.03 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 559.20** | | | **$ 564.33** | **-$ 5.00** | **-0.88%** | | | **$ 550.08** | **-$ 14.25** | **-2.53%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 15537 | $ 68.36 | $ 0.0044 | 15507 | $ 68.23 | $ - | 0.00% | $ 0.0044 | 15507 | $ 68.23 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 15537 | $ 20.20 | $ 0.0013 | 15507 | $ 20.16 | $ - | 0.00% | $ 0.0013 | 15507 | $ 20.16 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 15000 | $ 104.10 | $ 0.0069 | 15000 | $ 104.10 | $ - | 0.00% | $ 0.0069 | 15000 | $ 104.10 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 9600 | $ 768.00 | $ 0.0800 | 9600 | $ 768.00 | $ - | 0.00% | $ 0.0800 | 9600 | $ 768.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 2700 | $ 329.40 | $ 0.1220 | 2700 | $ 329.40 | $ - | 0.00% | $ 0.1220 | 2700 | $ 329.40 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 2700 | $ 434.70 | $ 0.1610 | 2700 | $ 434.70 | $ - | 0.00% | $ 0.1610 | 2700 | $ 434.70 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 14250 | $1,567.50 | $ 0.1100 | 14250 | $ 1,567.50 | $ - | 0.00% | $ 0.1100 | 14250 | $1,567.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$2,284.21** | | | **$ 2,289.17** | **-$ 5.00** | **-0.22%** | | | **$2,274.92** | **-$ 14.25** | **-0.62%** |
| HST | | 13% | | $ 296.95 | 13% | | $ 297.59 | -$ 0.65 | -0.22% | 13% | | $ 295.74 | -$ 1.85 | -0.62% |
| **Total Bill** (including HST) | | | | $2,581.16 | | | $ 2,586.76 | -$ 5.65 | -0.22% | | | $2,570.66 | -$ 16.10 | -0.62% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 258.12 | | | -$ 258.68 | $ 0.56 | -0.22% | | | -$ 257.07 | $ 1.61 | -0.62% |
| **Total Bill on TOU (including OCEB)** | | | | **$2,323.04** | | | **$ 2,328.08** | **-$ 5.09** | **-0.22%** | | | **$2,313.59** | **-$ 14.49** | **-0.62%** |
| **Total Bill on RPP (before Taxes)** | | | | **$2,390.11** | | | **$ 2,395.07** | **-$ 5.00** | **-0.21%** | | | **$2,380.82** | **-$ 14.25** | **-0.59%** |
| HST | | 13% | | $ 310.71 | 13% | | $ 311.36 | -$ 0.65 | -0.21% | 13% | | $ 309.51 | -$ 1.85 | -0.59% |
| **Total Bill** (including HST) | | | | $2,700.82 | | | $ 2,706.43 | -$ 5.65 | -0.21% | | | $2,690.33 | -$ 16.10 | -0.59% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 270.08 | | | -$ 270.64 | $ 0.57 | -0.21% | | | -$ 269.03 | $ 1.61 | -0.59% |
| **Total Bill on RPP (including OCEB)** | | | | **$2,430.74** | | | **$ 2,435.79** | **-$ 5.08** | **-0.21%** | | | **$2,421.30** | **-$ 14.49** | **-0.59%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 51,100 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
50 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 290.0000 | 1 | $ 290.00 | $ 29.18 | 11.19% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 50 | $ 178.46 | $ 3.9454 | 50 | $ 197.27 | $ 18.82 | 10.54% |
| Smart Meter Disposition Rider | | | 51100 | $ - | | 51100 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 50 | $ - | -$ 0.0010 | 50 | -$ 0.05 | -$ 0.05 | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 439.28 | | | $ 487.22 | **$ 47.95** | **10.91%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 50 | $ - | -$ 0.41220 | 50 | -$ 20.61 | -$ 20.61 | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 51100 | $ - | -$ 0.0003 | 51100 | -$ 15.33 | -$ 15.33 | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 50 | $ 1.18 | $ 0.02526 | 50 | $ 1.26 | $ 0.09 | 7.31% |
| Line Losses on Cost of Power | | $ 0.1021 | 1,829 | $ 186.85 | $ 0.1021 | 1,727 | $ 176.41 | -$ 10.44 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 627.30** | | | **$ 628.96** | **$ 1.65** | **0.26%** |
| RTSR - Network | per kW | $ 2.9072 | 50 | $ 145.36 | $ 2.9072 | 50 | $ 145.36 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 50 | $ 81.16 | $ 1.6232 | 50 | $ 81.16 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 853.82** | | | **$ 855.48** | **$ 1.65** | **0.19%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 52929 | $ 232.89 | $ 0.0044 | 52827 | $ 232.44 | -$ 0.45 | -0.19% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 52929 | $ 68.81 | $ 0.0013 | 52827 | $ 68.68 | -$ 0.13 | -0.19% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 51100 | $ 354.63 | $ 0.0069 | 51100 | $ 354.63 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 32704 | $ 2,616.32 | $ 0.0800 | 32704 | $ 2,616.32 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 9198 | $ 1,122.16 | $ 0.1220 | 9198 | $ 1,122.16 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 9198 | $ 1,480.88 | $ 0.1610 | 9198 | $ 1,480.88 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 50350 | $ 5,538.50 | $ 0.1100 | 50350 | $ 5,538.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 6,729.76** | | | **$ 6,730.83** | **$ 1.07** | **0.02%** |
| HST | | 13% | | $ 874.87 | 13% | | $ 875.01 | $ 0.14 | 0.02% |
| **Total Bill** (including HST) | | | | $ 7,604.63 | | | $ 7,605.84 | $ 1.21 | 0.02% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 7,604.63** | | | **$ 7,605.84** | **$ 1.21** | **0.02%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 7,119.41** | | | **$ 7,120.48** | **$ 1.07** | **0.02%** |
| HST | | 13% | | $ 925.52 | 13% | | $ 925.66 | $ 0.14 | 0.02% |
| **Total Bill** (including HST) | | | | $ 8,044.93 | | | $ 8,046.14 | $ 1.21 | 0.02% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 8,044.93** | | | **$ 8,046.14** | **$ 1.21** | **0.02%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | $ 355.0000 | 1 | $ 355.00 | $ 65.00 | 22.41% | $ 420.0000 | 1 | $ 420.00 | $ 65.00 | 18.31% |
| Smart Meter Rate Adder | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | $ 3.8962 | 50 | $ 194.81 | -$ 2.46 | -1.25% | $ 3.8299 | 50 | $ 191.50 | -$ 3.32 | -1.70% |
| Smart Meter Disposition Rider | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| LRAM & SSM Rate Rider | | 50 | $ - | $ 0.05 | -100.00% | | 50 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | $ 549.81 | **$ 62.59** | **12.85%** | | | $ 611.50 | **$ 61.69** | **11.22%** |
| Deferral/Variance Account Disposition Rate Rider | | 50 | $ - | $ 20.61 | -100.00% | | 50 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | | 51100 | $ - | $ 15.33 | -100.00% | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| Low Voltage Service Charge | $ 0.02549 | 50 | $ 1.27 | $ 0.01 | 0.91% | $ 0.02555 | 50 | $ 1.28 | $ 0.00 | 0.24% |
| Line Losses on Cost of Power | $ 0.1021 | 1,727 | $ 176.41 | $ - | 0.00% | $ 0.1021 | 1,727 | $ 176.41 | $ - | 0.00% |
| Smart Meter Entity Charge | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | **$ 727.50** | **$ 98.54** | **15.67%** | | | **$ 789.19** | **$ 61.69** | **8.48%** |
| RTSR - Network | $ 2.9072 | 50 | $ 145.36 | $ - | 0.00% | $ 2.9072 | 50 | $ 145.36 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | $ 1.6232 | 50 | $ 81.16 | $ - | 0.00% | $ 1.6232 | 50 | $ 81.16 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | **$ 954.02** | **$ 98.54** | **11.52%** | | | **$ 1,015.71** | **$ 61.69** | **6.47%** |
| Wholesale Market Service Charge (WMSC) | $ 0.0044 | 52827 | $ 232.44 | $ - | 0.00% | $ 0.0044 | 52827 | $ 232.44 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | $ 0.0013 | 52827 | $ 68.68 | $ - | 0.00% | $ 0.0013 | 52827 | $ 68.68 | $ - | 0.00% |
| Standard Supply Service Charge | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | $ 0.0069 | 51100 | $ 354.63 | $ - | 0.00% | $ 0.0069 | 51100 | $ 354.63 | $ - | 0.00% |
| TOU - Off Peak | $ 0.0800 | 32704 | $ 2,616.32 | $ - | 0.00% | $ 0.0800 | 32704 | $ 2,616.32 | $ - | 0.00% |
| TOU - Mid Peak | $ 0.1220 | 9198 | $ 1,122.16 | $ - | 0.00% | $ 0.1220 | 9198 | $ 1,122.16 | $ - | 0.00% |
| TOU - On Peak | $ 0.1610 | 9198 | $ 1,480.88 | $ - | 0.00% | $ 0.1610 | 9198 | $ 1,480.88 | $ - | 0.00% |
| Energy - RPP - Tier 1 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | $ 0.1100 | 50350 | $ 5,538.50 | $ - | 0.00% | $ 0.1100 | 50350 | $ 5,538.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | **$ 6,829.37** | **$ 98.54** | **1.46%** | | | **$ 6,891.06** | **$ 61.69** | **0.90%** |
| HST | 13% | | $ 887.82 | $ 12.81 | 1.46% | 13% | | $ 895.84 | $ 8.02 | 0.90% |
| **Total Bill** (including HST) | | | $ 7,717.19 | $ 111.35 | 1.46% | | | $ 7,786.90 | $ 69.71 | 0.90% |
| ***Ontario Clean Energy Benefit*** [1] | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | **$ 7,717.19** | **$ 111.35** | **1.46%** | | | **$ 7,786.90** | **$ 69.71** | **0.90%** |
| **Total Bill on RPP (before Taxes)** | | | **$ 7,219.02** | **$ 98.54** | **1.38%** | | | **$ 7,280.71** | **$ 61.69** | **0.85%** |
| HST | 13% | | $ 938.47 | $ 12.81 | 1.38% | 13% | | $ 946.49 | $ 8.02 | 0.85% |
| **Total Bill** (including HST) | | | $ 8,157.49 | $ 111.35 | 1.38% | | | $ 8,227.20 | $ 69.71 | 0.85% |
| ***Ontario Clean Energy Benefit*** [1] | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | **$ 8,157.49** | **$ 111.35** | **1.38%** | | | **$ 8,227.20** | **$ 69.71** | **0.85%** |
| **Loss Factor (%)** | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 51,100 kWh ● May 1 - October
50 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 490.0000 | 1 | $ 490.00 | $ 70.00 | 16.67% | $ 550.0000 | 1 | $ 550.00 | $ 60.00 | 12.24% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 50 | $ 178.46 | $ 3.6842 | 50 | $ 184.21 | -$ 7.29 | -3.80% | $ 3.4930 | 50 | $ 174.65 | -$ 9.56 | -5.19% |
| Smart Meter Disposition Rider | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 50 | $ - | | 50 | $ - | $ - | | | 50 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 439.28 | | | $ 674.21 | **$ 62.72** | **10.26%** | | | $ 724.65 | **$ 50.44** | **7.48%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 50 | $ - | | 50 | $ - | $ - | | | 50 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| | | | 51100 | $ - | | 51100 | $ - | $ - | | | 51100 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 50 | $ 1.18 | $ 0.02557 | 50 | $ 1.28 | $ 0.00 | 0.08% | $ 0.02558 | 50 | $ 1.28 | $ 0.00 | 0.04% |
| Line Losses on Cost of Power | | $ 0.1021 | 1,829 | $ 186.85 | $ 0.1021 | 1,727 | $ 176.41 | $ - | 0.00% | $ 0.1021 | 1,727 | $ 176.41 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 627.30** | | | **$ 851.90** | **$ 62.72** | **7.95%** | | | **$ 902.34** | **$ 50.44** | **5.92%** |
| RTSR - Network | per kW | $ 2.9072 | 50 | $ 145.36 | $ 2.9072 | 50 | $ 145.36 | $ - | 0.00% | $ 2.9072 | 50 | $ 145.36 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 50 | $ 81.16 | $ 1.6232 | 50 | $ 81.16 | $ - | 0.00% | $ 1.6232 | 50 | $ 81.16 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 853.82** | | | **$ 1,078.42** | **$ 62.72** | **6.17%** | | | **$ 1,128.86** | **$ 50.44** | **4.68%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 52929 | $ 232.89 | $ 0.0044 | 52827 | $ 232.44 | $ - | 0.00% | $ 0.0044 | 52827 | $ 232.44 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 52929 | $ 68.81 | $ 0.0013 | 52827 | $ 68.68 | $ - | 0.00% | $ 0.0013 | 52827 | $ 68.68 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 51100 | $ 354.63 | $ 0.0069 | 51100 | $ 354.63 | $ - | 0.00% | $ 0.0069 | 51100 | $ 354.63 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 32704 | $ 2,616.32 | $ 0.0800 | 32704 | $ 2,616.32 | $ - | 0.00% | $ 0.0800 | 32704 | $ 2,616.32 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 9198 | $ 1,122.16 | $ 0.1220 | 9198 | $ 1,122.16 | $ - | 0.00% | $ 0.1220 | 9198 | $ 1,122.16 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 9198 | $ 1,480.88 | $ 0.1610 | 9198 | $ 1,480.88 | $ - | 0.00% | $ 0.1610 | 9198 | $ 1,480.88 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 50350 | $ 5,538.50 | $ 0.1100 | 50350 | $ 5,538.50 | $ - | 0.00% | $ 0.1100 | 50350 | $ 5,538.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 6,729.76** | | | **$ 6,953.78** | **$ 62.72** | **0.91%** | | | **$ 7,004.22** | **$ 50.44** | **0.73%** |
| HST | | 13% | | $ 874.87 | 13% | | $ 903.99 | $ 8.15 | 0.91% | 13% | | $ 910.55 | $ 6.56 | 0.73% |
| **Total Bill** (including HST) | | | | $ 7,604.63 | | | $ 7,857.77 | $ 70.87 | 0.91% | | | $ 7,914.76 | $ 57.00 | 0.73% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 7,604.63** | | | **$ 7,857.77** | **$ 70.87** | **0.91%** | | | **$ 7,914.76** | **$ 57.00** | **0.73%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 7,119.41** | | | **$ 7,343.42** | **$ 62.72** | **0.86%** | | | **$ 7,393.86** | **$ 50.44** | **0.69%** |
| HST | | 13% | | $ 925.52 | 13% | | $ 954.64 | $ 8.15 | 0.86% | 13% | | $ 961.20 | $ 6.56 | 0.69% |
| **Total Bill** (including HST) | | | | $ 8,044.93 | | | $ 8,298.07 | $ 70.87 | 0.86% | | | $ 8,355.06 | $ 57.00 | 0.69% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 8,044.93** | | | **$ 8,298.07** | **$ 70.87** | **0.86%** | | | **$ 8,355.06** | **$ 57.00** | **0.69%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **General Service 50 to 1,499 KW**

**TOU / non-TOU:** TOU

**Consumption** 127,750 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

250 KW

| | | Current Board-Approved | | | 2016 Proposed | | | Impact 2016 vs 2015 | | 2017 Proposed | | | Impact 2017 vs 2016 | | 2018 Proposed | | | Impact 2018 vs 2017 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 290.0000 | 1 | $ 290.00 | $ 29.18 | 11.19% | $ 355.0000 | 1 | $ 355.00 | $ 65.00 | 22.41% | $ 420.0000 | 1 | $ 420.00 | $ 65.00 | 18.31% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 250 | $ 892.28 | $ 3.9454 | 250 | $ 986.35 | $ 94.07 | 10.54% | $ 3.8962 | 250 | $ 974.05 | -$ 12.30 | -1.25% | $ 3.8299 | 250 | $ 957.48 | -$ 16.58 | -1.70% |
| Smart Meter Disposition Rider | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 250 | $ - | -$ 0.0010 | 250 | -$ 0.25 | -$ 0.25 | | | 250 | $ - | $ 0.25 | -100.00% | | 250 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 1,153.10 | | | $ 1,276.10 | **$ 123.01** | **10.67%** | | | $ 1,329.05 | **$ 52.95** | **4.15%** | | | $ 1,377.48 | **$ 48.43** | **3.64%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 250 | $ - | -$ 0.41220 | 250 | -$ 103.05 | -$ 103.05 | | | 250 | $ - | $ 103.05 | -100.00% | | 250 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 127750 | $ - | -$ 0.0003 | 127750 | -$ 38.33 | -$ 38.33 | | | 127750 | $ - | $ 38.33 | -100.00% | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 250 | $ 5.89 | $ 0.02526 | 250 | $ 6.32 | $ 0.43 | 7.31% | $ 0.02549 | 250 | $ 6.37 | $ 0.06 | 0.91% | $ 0.02555 | 250 | $ 6.39 | $ 0.02 | 0.24% |
| Line Losses on Cost of Power | | $ 0.1021 | 4,573 | $ 467.13 | $ 0.1021 | 4,318 | $ 441.04 | -$ 26.10 | -5.59% | $ 0.1021 | 4,318 | $ 441.04 | $ - | 0.00% | $ 0.1021 | 4,318 | $ 441.04 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 1,626.11** | | | **$ 1,582.08** | **-$ 44.04** | **-2.71%** | | | **$ 1,776.46** | **$ 194.38** | **12.29%** | | | **$ 1,824.90** | **$ 48.44** | **2.73%** |
| RTSR - Network | per kW | $ 2.9072 | 250 | $ 726.80 | $ 2.9072 | 250 | $ 726.80 | $ - | 0.00% | $ 2.9072 | 250 | $ 726.80 | $ - | 0.00% | $ 2.9072 | 250 | $ 726.80 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 250 | $ 405.80 | $ 1.6232 | 250 | $ 405.80 | $ - | 0.00% | $ 1.6232 | 250 | $ 405.80 | $ - | 0.00% | $ 1.6232 | 250 | $ 405.80 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 2,758.71** | | | **$ 2,714.68** | **-$ 44.04** | **-1.60%** | | | **$ 2,909.06** | **$ 194.38** | **7.16%** | | | **$ 2,957.50** | **$ 48.44** | **1.67%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 132323 | $ 582.22 | $ 0.0044 | 132068 | $ 581.10 | -$ 1.12 | -0.19% | $ 0.0044 | 132068 | $ 581.10 | $ - | 0.00% | $ 0.0044 | 132068 | $ 581.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 132323 | $ 172.02 | $ 0.0013 | 132068 | $ 171.69 | -$ 0.33 | -0.19% | $ 0.0013 | 132068 | $ 171.69 | $ - | 0.00% | $ 0.0013 | 132068 | $ 171.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 127750 | $ 886.59 | $ 0.0069 | 127750 | $ 886.59 | $ - | 0.00% | $ 0.0069 | 127750 | $ 886.59 | $ - | 0.00% | $ 0.0069 | 127750 | $ 886.59 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 81760 | $ 6,540.80 | $ 0.0800 | 81760 | $ 6,540.80 | $ - | 0.00% | $ 0.0800 | 81760 | $ 6,540.80 | $ - | 0.00% | $ 0.0800 | 81760 | $ 6,540.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 22995 | $ 2,805.39 | $ 0.1220 | 22995 | $ 2,805.39 | $ - | 0.00% | $ 0.1220 | 22995 | $ 2,805.39 | $ - | 0.00% | $ 0.1220 | 22995 | $ 2,805.39 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 22995 | $ 3,702.20 | $ 0.1610 | 22995 | $ 3,702.20 | $ - | 0.00% | $ 0.1610 | 22995 | $ 3,702.20 | $ - | 0.00% | $ 0.1610 | 22995 | $ 3,702.20 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 127000 | $ 13,970.00 | $ 0.1100 | 127000 | $ 13,970.00 | $ - | 0.00% | $ 0.1100 | 127000 | $13,970.00 | $ - | 0.00% | $ 0.1100 | 127000 | $13,970.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 17,448.18** | | | **$ 17,402.68** | **-$ 45.49** | **-0.26%** | | | **$17,597.07** | **$ 194.38** | **1.12%** | | | **$17,645.51** | **$ 48.44** | **0.28%** |
| HST | | 13% | | $ 2,268.26 | 13% | | $ 2,262.35 | -$ 5.91 | -0.26% | 13% | | $ 2,287.62 | $ 25.27 | 1.12% | 13% | | $ 2,293.92 | $ 6.30 | 0.28% |
| **Total Bill** (including HST) | | | | $ 19,716.44 | | | $ 19,665.03 | -$ 51.41 | -0.26% | | | $19,884.68 | $ 219.65 | 1.12% | | | $19,939.42 | $ 54.74 | 0.28% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 19,716.44** | | | **$ 19,665.03** | **-$ 51.41** | **-0.26%** | | | **$19,884.68** | **$ 219.65** | **1.12%** | | | **$19,939.42** | **$ 54.74** | **0.28%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 18,440.29** | | | **$ 18,394.80** | **-$ 45.49** | **-0.25%** | | | **$18,589.18** | **$ 194.38** | **1.06%** | | | **$18,637.62** | **$ 48.44** | **0.26%** |
| HST | | 13% | | $ 2,397.24 | 13% | | $ 2,391.32 | -$ 5.91 | -0.25% | 13% | | $ 2,416.59 | $ 25.27 | 1.06% | 13% | | $ 2,422.89 | $ 6.30 | 0.26% |
| **Total Bill** (including HST) | | | | $ 20,837.53 | | | $ 20,786.12 | -$ 51.41 | -0.25% | | | $21,005.77 | $ 219.65 | 1.06% | | | $21,060.51 | $ 54.74 | 0.26% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 20,837.53** | | | **$ 20,786.12** | **-$ 51.41** | **-0.25%** | | | **$21,005.77** | **$ 219.65** | **1.06%** | | | **$21,060.51** | **$ 54.74** | **0.26%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 127,750 kWh (May 1 - October)
250 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 490.0000 | 1 | $ 490.00 | $ 70.00 | 16.67% | $ 550.0000 | 1 | $ 550.00 | $ 60.00 | 12.24% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 250 | $ 892.28 | $ 3.6842 | 250 | $ 921.05 | -$ 36.42 | -3.80% | $ 3.4930 | 250 | $ 873.25 | -$ 47.80 | -5.19% |
| Smart Meter Disposition Rider | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 1,153.10 | | | $ 1,411.05 | **$ 33.58** | **2.44%** | | | $ 1,423.25 | **$ 12.20** | **0.86%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 250 | $ - | | 250 | $ - | $ - | | | 250 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| | | | 127750 | $ - | | 127750 | $ - | $ - | | | 127750 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 250 | $ 5.89 | $ 0.02557 | 250 | $ 6.39 | $ 0.00 | 0.08% | $ 0.02558 | 250 | $ 6.40 | $ 0.00 | 0.04% |
| Line Losses on Cost of Power | | $ 0.1021 | 4,573 | $ 467.13 | $ 0.1021 | 4,318 | $ 441.04 | $ - | 0.00% | $ 0.1021 | 4,318 | $ 441.04 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 1,626.11** | | | **$ 1,858.48** | **$ 33.58** | **1.84%** | | | **$ 1,870.68** | **$ 12.20** | **0.66%** |
| RTSR - Network | per kW | $ 2.9072 | 250 | $ 726.80 | $ 2.9072 | 250 | $ 726.80 | $ - | 0.00% | $ 2.9072 | 250 | $ 726.80 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 250 | $ 405.80 | $ 1.6232 | 250 | $ 405.80 | $ - | 0.00% | $ 1.6232 | 250 | $ 405.80 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 2,758.71** | | | **$ 2,991.08** | **$ 33.58** | **1.14%** | | | **$ 3,003.28** | **$ 12.20** | **0.41%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 132323 | $ 582.22 | $ 0.0044 | 132068 | $ 581.10 | $ - | 0.00% | $ 0.0044 | 132068 | $ 581.10 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 132323 | $ 172.02 | $ 0.0013 | 132068 | $ 171.69 | $ - | 0.00% | $ 0.0013 | 132068 | $ 171.69 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 127750 | $ 886.59 | $ 0.0069 | 127750 | $ 886.59 | $ - | 0.00% | $ 0.0069 | 127750 | $ 886.59 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 81760 | $ 6,540.80 | $ 0.0800 | 81760 | $ 6,540.80 | $ - | 0.00% | $ 0.0800 | 81760 | $ 6,540.80 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 22995 | $ 2,805.39 | $ 0.1220 | 22995 | $ 2,805.39 | $ - | 0.00% | $ 0.1220 | 22995 | $ 2,805.39 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 22995 | $ 3,702.20 | $ 0.1610 | 22995 | $ 3,702.20 | $ - | 0.00% | $ 0.1610 | 22995 | $ 3,702.20 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 127000 | $ 13,970.00 | $ 0.1100 | 127000 | $13,970.00 | $ - | 0.00% | $ 0.1100 | 127000 | $13,970.00 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 17,448.18** | | | **$17,679.09** | **$ 33.58** | **0.19%** | | | **$17,691.29** | **$ 12.20** | **0.07%** |
| HST | | 13% | | $ 2,268.26 | 13% | | $ 2,298.28 | $ 4.37 | 0.19% | 13% | | $ 2,299.87 | $ 1.59 | 0.07% |
| **Total Bill** (including HST) | | | | $ 19,716.44 | | | $19,977.37 | $ 37.95 | 0.19% | | | $19,991.16 | $ 13.79 | 0.07% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 19,716.44** | | | **$19,977.37** | **$ 37.95** | **0.19%** | | | **$19,991.16** | **$ 13.79** | **0.07%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 18,440.29** | | | **$18,671.20** | **$ 33.58** | **0.18%** | | | **$18,683.40** | **$ 12.20** | **0.07%** |
| HST | | 13% | | $ 2,397.24 | 13% | | $ 2,427.26 | $ 4.37 | 0.18% | 13% | | $ 2,428.84 | $ 1.59 | 0.07% |
| **Total Bill** (including HST) | | | | $ 20,837.53 | | | $21,098.46 | $ 37.95 | 0.18% | | | $21,112.25 | $ 13.79 | 0.07% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 20,837.53** | | | **$21,098.46** | **$ 37.95** | **0.18%** | | | **$21,112.25** | **$ 13.79** | **0.07%** |

| | Current Board-Approved | 2019 Proposed | 2020 Proposed |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 255,500 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

500 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 290.0000 | 1 | $ 290.00 | $ 29.18 | 11.19% | $ 355.0000 | 1 | $ 355.00 | $ 65.00 | 22.41% | $ 420.0000 | 1 | $ 420.00 | $ 65.00 | 18.31% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 500 | $ 1,784.55 | $ 3.9454 | 500 | $ 1,972.70 | $ 188.15 | 10.54% | $ 3.8962 | 500 | $ 1,948.10 | -$ 24.60 | -1.25% | $ 3.8299 | 500 | $ 1,914.95 | -$ 33.15 | -1.70% |
| Smart Meter Disposition Rider | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 500 | $ - | -$ 0.0010 | 500 | -$ 0.50 | -$ 0.50 | | | 500 | $ - | $ 0.50 | -100.00% | | 500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 2,045.37 | | | $ 2,262.20 | **$ 216.83** | **10.60%** | | | $ 2,303.10 | **$ 40.90** | **1.81%** | | | $ 2,334.95 | **$ 31.85** | **1.38%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 500 | $ - | -$ 0.4122 | 500 | -$ 206.10 | -$ 206.10 | | | 500 | $ - | $ 206.10 | -100.00% | | 500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 255500 | $ - | -$ 0.0003 | 255500 | -$ 76.65 | -$ 76.65 | | | 255500 | $ - | $ 76.65 | -100.00% | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 500 | $ 11.77 | $ 0.02526 | 500 | $ 12.63 | $ 0.86 | 7.31% | $ 0.02549 | 500 | $ 12.75 | $ 0.11 | 0.91% | $ 0.02555 | 500 | $ 12.78 | $ 0.03 | 0.24% |
| Line Losses on Cost of Power | | $ 0.1021 | 9,147 | $ 934.26 | $ 0.1021 | 8,636 | $ 882.07 | -$ 52.19 | -5.59% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 2,991.40** | | | **$ 2,874.15** | **-$ 117.25** | **-3.92%** | | | **$ 3,197.92** | **$ 323.77** | **11.26%** | | | **$ 3,229.80** | **$ 31.88** | **1.00%** |
| RTSR - Network | per kW | $ 2.9072 | 500 | $ 1,453.60 | $ 2.9072 | 500 | $ 1,453.60 | $ - | 0.00% | $ 2.9072 | 500 | $ 1,453.60 | $ - | 0.00% | $ 2.9072 | 500 | $ 1,453.60 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 500 | $ 811.60 | $ 1.6232 | 500 | $ 811.60 | $ - | 0.00% | $ 1.6232 | 500 | $ 811.60 | $ - | 0.00% | $ 1.6232 | 500 | $ 811.60 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 5,256.60** | | | **$ 5,139.35** | **-$ 117.25** | **-2.23%** | | | **$ 5,463.12** | **$ 323.77** | **6.30%** | | | **$ 5,495.00** | **$ 31.88** | **0.58%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 264647 | $ 1,164.45 | $ 0.0044 | 264136 | $ 1,162.20 | -$ 2.25 | -0.19% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 264647 | $ 344.04 | $ 0.0013 | 264136 | $ 343.38 | -$ 0.66 | -0.19% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 255500 | $ 1,773.17 | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 163520 | $ 13,081.60 | $ 0.0800 | 163520 | $ 13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45990 | $ 5,610.78 | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45990 | $ 7,404.39 | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 254750 | $ 28,022.50 | $ 0.1100 | 254750 | $ 28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 34,635.28** | | | **$ 34,515.12** | **-$ 120.17** | **-0.35%** | | | **$34,838.88** | **$ 323.76** | **0.94%** | | | **$34,870.76** | **$ 31.88** | **0.09%** |
| HST | | 13% | | $ 4,502.59 | 13% | | $ 4,486.97 | -$ 15.62 | -0.35% | 13% | | $ 4,529.05 | $ 42.09 | 0.94% | 13% | | $ 4,533.20 | $ 4.14 | 0.09% |
| **Total Bill** (including HST) | | | | $ 39,137.87 | | | $ 39,002.08 | -$ 135.79 | -0.35% | | | $39,367.93 | $ 365.85 | 0.94% | | | $39,403.96 | $ 36.02 | 0.09% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 39,137.87** | | | **$ 39,002.08** | **-$ 135.79** | **-0.35%** | | | **$39,367.93** | **$ 365.85** | **0.94%** | | | **$39,403.96** | **$ 36.02** | **0.09%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 36,631.51** | | | **$ 36,511.35** | **-$ 120.17** | **-0.33%** | | | **$36,835.11** | **$ 323.76** | **0.89%** | | | **$36,866.99** | **$ 31.88** | **0.09%** |
| HST | | 13% | | $ 4,762.10 | 13% | | $ 4,746.47 | -$ 15.62 | -0.33% | 13% | | $ 4,788.56 | $ 42.09 | 0.89% | 13% | | $ 4,792.71 | $ 4.14 | 0.09% |
| **Total Bill** (including HST) | | | | $ 41,393.61 | | | $ 41,257.82 | -$ 135.79 | -0.33% | | | $41,623.67 | $ 365.85 | 0.89% | | | $41,659.70 | $ 36.02 | 0.09% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 41,393.61** | | | **$ 41,257.82** | **-$ 135.79** | **-0.33%** | | | **$41,623.67** | **$ 365.85** | **0.89%** | | | **$41,659.70** | **$ 36.02** | **0.09%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 255,500 kWh ◉ May 1 - October
500 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 490.0000 | 1 | $ 490.00 | $ 70.00 | 16.67% | $ 550.0000 | 1 | $ 550.00 | $ 60.00 | 12.24% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 500 | $ 1,784.55 | $ 3.6842 | 500 | $ 1,842.10 | -$ 72.85 | -3.80% | $ 3.4930 | 500 | $ 1,746.50 | -$ 95.60 | -5.19% |
| Smart Meter Disposition Rider | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 2,045.37 | | | $ 2,332.10 | **-$ 2.85** | **-0.12%** | | | $ 2,296.50 | **-$ 35.60** | **-1.53%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 500 | $ - | | 500 | $ - | $ - | | | 500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 255500 | $ - | | 500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 500 | $ 11.77 | $ 0.02557 | 500 | $ 12.79 | $ 0.01 | 0.08% | $ 0.02558 | 500 | $ 12.79 | $ 0.00 | 0.04% |
| Line Losses on Cost of Power | | $ 0.1021 | 9,147 | $ 934.26 | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 2,991.40** | | | **$ 3,226.96** | **-$ 2.84** | **-0.09%** | | | **$ 3,191.36** | **-$ 35.60** | **-1.10%** |
| RTSR - Network | per kW | $ 2.9072 | 500 | $ 1,453.60 | $ 2.9072 | 500 | $ 1,453.60 | $ - | 0.00% | $ 2.9072 | 500 | $ 1,453.60 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 500 | $ 811.60 | $ 1.6232 | 500 | $ 811.60 | $ - | 0.00% | $ 1.6232 | 500 | $ 811.60 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 5,256.60** | | | **$ 5,492.16** | **-$ 2.84** | **-0.05%** | | | **$ 5,456.56** | **-$ 35.60** | **-0.65%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 264647 | $ 1,164.45 | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 264647 | $ 344.04 | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 255500 | $ 1,773.17 | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 163520 | $ 13,081.60 | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45990 | $ 5,610.78 | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45990 | $ 7,404.39 | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 254750 | $ 28,022.50 | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 34,635.28** | | | **$34,867.92** | **-$ 2.84** | **-0.01%** | | | **$34,832.33** | **-$ 35.60** | **-0.10%** |
| HST | | 13% | | $ 4,502.59 | 13% | | $ 4,532.83 | -$ 0.37 | -0.01% | 13% | | $ 4,528.20 | -$ 4.63 | -0.10% |
| **Total Bill** (including HST) | | | | $ 39,137.87 | | | $39,400.75 | -$ 3.21 | -0.01% | | | $39,360.53 | -$ 40.22 | -0.10% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 39,137.87** | | | **$39,400.75** | **-$ 3.21** | **-0.01%** | | | **$39,360.53** | **-$ 40.22** | **-0.10%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 36,631.51** | | | **$36,864.15** | **-$ 2.84** | **-0.01%** | | | **$36,828.56** | **-$ 35.60** | **-0.10%** |
| HST | | 13% | | $ 4,762.10 | 13% | | $ 4,792.34 | -$ 0.37 | -0.01% | 13% | | $ 4,787.71 | -$ 4.63 | -0.10% |
| **Total Bill** (including HST) | | | | $ 41,393.61 | | | $41,656.49 | -$ 3.21 | -0.01% | | | $41,616.27 | -$ 40.22 | -0.10% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 41,393.61** | | | **$41,656.49** | **-$ 3.21** | **-0.01%** | | | **$41,616.27** | **-$ 40.22** | **-0.10%** |

**Loss Factor (%)** 3.5800% 3.3800% 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 255,500 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
1,000 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 290.0000 | 1 | $ 290.00 | $ 29.18 | 11.19% | $ 355.0000 | 1 | $ 355.00 | $ 65.00 | 22.41% | $ 420.0000 | 1 | $ 420.00 | $ 65.00 | 18.31% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 1,000 | $ 3,569.10 | $ 3.9454 | 1,000 | $ 3,945.40 | $ 376.30 | 10.54% | $ 3.8962 | 1,000 | $ 3,896.20 | -$ 49.20 | -1.25% | $ 3.8299 | 1,000 | $ 3,829.90 | -$ 66.30 | -1.70% |
| Smart Meter Disposition Rider | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 1,000 | $ - | -$ 0.0010 | 1,000 | -$ 1.00 | -$ 1.00 | | | 1,000 | $ - | $ 1.00 | -100.00% | | 1,000 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 3,829.92 | | | $ 4,234.40 | **$ 404.48** | **10.56%** | | | $ 4,251.20 | **$ 16.80** | **0.40%** | | | $ 4,249.90 | **-$ 1.30** | **-0.03%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 1,000 | $ - | -$ 0.4122 | 1,000 | -$ 412.20 | -$ 412.20 | | | 1,000 | $ - | $ 412.20 | -100.00% | | 1,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 255500 | $ - | -$ 0.0003 | 255500 | -$ 76.65 | -$ 76.65 | | | 255500 | $ - | $ 76.65 | -100.00% | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 1,000 | $ 23.54 | $ 0.02526 | 1,000 | $ 25.26 | $ 1.72 | 7.31% | $ 0.02549 | 1,000 | $ 25.49 | $ 0.23 | 0.91% | $ 0.02555 | 1,000 | $ 25.55 | $ 0.06 | 0.24% |
| Line Losses on Cost of Power | | $ 0.1021 | 9,147 | $ 934.26 | $ 0.1021 | 8,636 | $ 882.07 | -$ 52.19 | -5.59% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 4,787.72** | | | **$ 4,652.88** | **-$ 134.84** | **-2.82%** | | | **$ 5,158.76** | **$ 505.88** | **10.87%** | | | **$ 5,157.52** | **-$ 1.24** | **-0.02%** |
| RTSR - Network | per kW | $ 2.9072 | 1000 | $ 2,907.20 | $ 2.9072 | 1000 | $ 2,907.20 | $ - | 0.00% | $ 2.9072 | 1000 | $ 2,907.20 | $ - | 0.00% | $ 2.9072 | 1000 | $ 2,907.20 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 1000 | $ 1,623.20 | $ 1.6232 | 1000 | $ 1,623.20 | $ - | 0.00% | $ 1.6232 | 1000 | $ 1,623.20 | $ - | 0.00% | $ 1.6232 | 1000 | $ 1,623.20 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 9,318.12** | | | **$ 9,183.28** | **-$ 134.84** | **-1.45%** | | | **$ 9,689.16** | **$ 505.88** | **5.51%** | | | **$ 9,687.92** | **-$ 1.24** | **-0.01%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 264647 | $ 1,164.45 | $ 0.0044 | 264136 | $ 1,162.20 | -$ 2.25 | -0.19% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 264647 | $ 344.04 | $ 0.0013 | 264136 | $ 343.38 | -$ 0.66 | -0.19% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 255500 | $ 1,773.17 | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 163520 | $ 13,081.60 | $ 0.0800 | 163520 | $ 13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45990 | $ 5,610.78 | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45990 | $ 7,404.39 | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 254750 | $ 28,022.50 | $ 0.1100 | 254750 | $ 28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 38,696.80** | | | **$ 38,559.05** | **-$ 137.76** | **-0.36%** | | | **$39,064.93** | **$ 505.88** | **1.31%** | | | **$39,063.69** | **-$ 1.24** | **0.00%** |
| HST | | 13% | | $ 5,030.58 | 13% | | $ 5,012.68 | -$ 17.91 | -0.36% | 13% | | $ 5,078.44 | $ 65.76 | 1.31% | 13% | | $ 5,078.28 | -$ 0.16 | 0.00% |
| **Total Bill** (including HST) | | | | $ 43,727.39 | | | $ 43,571.72 | -$ 155.66 | -0.36% | | | $44,143.37 | $ 571.64 | 1.31% | | | $44,141.96 | -$ 1.40 | 0.00% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 43,727.39** | | | **$ 43,571.72** | **-$ 155.66** | **-0.36%** | | | **$44,143.37** | **$ 571.64** | **1.31%** | | | **$44,141.96** | **-$ 1.40** | **0.00%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 40,693.03** | | | **$ 40,555.28** | **-$ 137.76** | **-0.34%** | | | **$41,061.16** | **$ 505.88** | **1.25%** | | | **$41,059.92** | **-$ 1.24** | **0.00%** |
| HST | | 13% | | $ 5,290.09 | 13% | | $ 5,272.19 | -$ 17.91 | -0.34% | 13% | | $ 5,337.95 | $ 65.76 | 1.25% | 13% | | $ 5,337.79 | -$ 0.16 | 0.00% |
| **Total Bill** (including HST) | | | | $ 45,983.13 | | | $ 45,827.46 | -$ 155.66 | -0.34% | | | $46,399.11 | $ 571.64 | 1.25% | | | $46,397.70 | -$ 1.40 | 0.00% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 45,983.13** | | | **$ 45,827.46** | **-$ 155.66** | **-0.34%** | | | **$46,399.11** | **$ 571.64** | **1.25%** | | | **$46,397.70** | **-$ 1.40** | **0.00%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 50 to 1,499 KW

**TOU / non-TOU:** TOU

**Consumption** 255,500 kWh — May 1 - October
1,000 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 260.8200 | 1 | $ 260.82 | $ 490.0000 | 1 | $ 490.00 | $ 70.00 | 16.67% | $ 550.0000 | 1 | $ 550.00 | $ 60.00 | 12.24% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.5691 | 1,000 | $ 3,569.10 | $ 3.6842 | 1,000 | $ 3,684.20 | -$ 145.70 | -3.80% | $ 3.4930 | 1,000 | $ 3,493.00 | -$ 191.20 | -5.19% |
| Smart Meter Disposition Rider | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 1,000 | $ - | | 1,000 | $ - | $ - | | | 1,000 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 3,829.92 | | | $ 4,174.20 | **-$ 75.70** | **-1.78%** | | | $ 4,043.00 | **-$ 131.20** | **-3.14%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 1,000 | $ - | | 1,000 | $ - | $ - | | | 1,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 255500 | $ - | | 1,000 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| | | | 255500 | $ - | | 255500 | $ - | $ - | | | 255500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02354 | 1,000 | $ 23.54 | $ 0.02557 | 1,000 | $ 25.57 | $ 0.02 | 0.08% | $ 0.02558 | 1,000 | $ 25.58 | $ 0.01 | 0.04% |
| Line Losses on Cost of Power | | $ 0.1021 | 9,147 | $ 934.26 | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% | $ 0.1021 | 8,636 | $ 882.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 4,787.72** | | | **$ 5,081.84** | **-$ 75.68** | **-1.47%** | | | **$ 4,950.65** | **-$ 131.19** | **-2.58%** |
| RTSR - Network | per kW | $ 2.9072 | 1000 | $ 2,907.20 | $ 2.9072 | 1000 | $ 2,907.20 | $ - | 0.00% | $ 2.9072 | 1000 | $ 2,907.20 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6232 | 1000 | $ 1,623.20 | $ 1.6232 | 1000 | $ 1,623.20 | $ - | 0.00% | $ 1.6232 | 1000 | $ 1,623.20 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 9,318.12** | | | **$ 9,612.24** | **-$ 75.68** | **-0.78%** | | | **$ 9,481.05** | **-$ 131.19** | **-1.36%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 264647 | $ 1,164.45 | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% | $ 0.0044 | 264136 | $ 1,162.20 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 264647 | $ 344.04 | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% | $ 0.0013 | 264136 | $ 343.38 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 255500 | $ 1,773.17 | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% | $ 0.0069 | 255500 | $ 1,773.17 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 163520 | $ 13,081.60 | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% | $ 0.0800 | 163520 | $13,081.60 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 45990 | $ 5,610.78 | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% | $ 0.1220 | 45990 | $ 5,610.78 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 45990 | $ 7,404.39 | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% | $ 0.1610 | 45990 | $ 7,404.39 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 254750 | $ 28,022.50 | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% | $ 0.1100 | 254750 | $28,022.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 38,696.80** | | | **$38,988.01** | **-$ 75.68** | **-0.19%** | | | **$38,856.82** | **-$ 131.19** | **-0.34%** |
| HST | | 13% | | $ 5,030.58 | 13% | | $ 5,068.44 | -$ 9.84 | -0.19% | 13% | | $ 5,051.39 | -$ 17.05 | -0.34% |
| **Total Bill** (including HST) | | | | $ 43,727.39 | | | $44,056.45 | -$ 85.52 | -0.19% | | | $43,908.20 | -$ 148.24 | -0.34% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 43,727.39** | | | **$44,056.45** | **-$ 85.52** | **-0.19%** | | | **$43,908.20** | **-$ 148.24** | **-0.34%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 40,693.03** | | | **$40,984.24** | **-$ 75.68** | **-0.18%** | | | **$40,853.05** | **-$ 131.19** | **-0.32%** |
| HST | | 13% | | $ 5,290.09 | 13% | | $ 5,327.95 | -$ 9.84 | -0.18% | 13% | | $ 5,310.90 | -$ 17.05 | -0.32% |
| **Total Bill** (including HST) | | | | $ 45,983.13 | | | $46,312.19 | -$ 85.52 | -0.18% | | | $46,163.94 | -$ 148.24 | -0.32% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 45,983.13** | | | **$46,312.19** | **-$ 85.52** | **-0.18%** | | | **$46,163.94** | **-$ 148.24** | **-0.32%** |

**Loss Factor (%)** — Current Board-Approved: 3.5800% — 2019 Proposed: 3.3800% — 2020 Proposed: 3.3800%

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **General Service 1,500 to 4,999 KW**

**TOU / non-TOU:** TOU

**Consumption** 1,277,500 kWh ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
2,500 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 4,193.93 | 1 | $ 4,193.93 | 4,650.00 | 1 | $ 4,650.00 | $ 456.07 | 10.87% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.4887 | 2,500 | $ 8,721.75 | $ 3.8602 | 2,500 | $ 9,650.50 | $ 928.75 | 10.65% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 2,500 | $ - | -$ 0.0001 | 2,500 | -$ 0.25 | -$ 0.25 | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 12,915.68 | | | $ 14,300.25 | **$ 1,384.57** | **10.72%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 2,500 | $ - | -$ 0.4598 | 2,500 | -$ 1,149.50 | -$ 1,149.50 | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 1,277,500 | $ - | -$ 0.0003 | 2,500 | -$ 0.75 | -$ 0.75 | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02516 | 2,500 | $ 62.90 | $ 0.02700 | 2,500 | $ 67.50 | $ 4.60 | 7.31% |
| Line Losses on Cost of Power | | $ 0.1021 | 45,735 | $ 4,671.32 | $ 0.1021 | 43,180 | $ 4,410.35 | -$ 260.97 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 17,649.90** | | | **$ 17,627.85** | **-$ 22.05** | **-0.12%** |
| RTSR - Network | per kW | $ 3.0186 | 2500 | $ 7,546.50 | $ 3.0186 | 2500 | $ 7,546.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 2500 | $ 4,336.75 | $ 1.7347 | 2500 | $ 4,336.75 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 29,533.15** | | | **$ 29,511.10** | **-$ 22.05** | **-0.07%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1323235 | $ 5,822.23 | $ 0.0044 | 1277500 | $ 5,621.00 | -$ 201.23 | -3.46% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1323235 | $ 1,720.20 | $ 0.0013 | 1277500 | $ 1,660.75 | -$ 59.45 | -3.46% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $ 140,442.50 | $ 0.1100 | 1276750 | $ 140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 176,425.54** | | | **$ 176,142.80** | **-$ 282.73** | **-0.16%** |
| HST | | 13% | | $ 22,935.32 | 13% | | $ 22,898.56 | -$ 36.76 | -0.16% |
| **Total Bill** (including HST) | | | | $ 199,360.86 | | | $ 199,041.37 | -$ 319.49 | -0.16% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 199,360.86** | | | **$ 199,041.37** | **-$ 319.49** | **-0.16%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 186,454.69** | | | **$ 186,171.95** | **-$ 282.73** | **-0.15%** |
| HST | | 13% | | $ 24,239.11 | 13% | | $ 24,202.35 | -$ 36.76 | -0.15% |
| **Total Bill** (including HST) | | | | $ 210,693.80 | | | $ 210,374.31 | -$ 319.49 | -0.15% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 210,693.80** | | | **$ 210,374.31** | **-$ 319.49** | **-0.15%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | Charge Unit | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change |
|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 4,975.000 | 1 | $ 4,975.00 | $ 325.00 | 6.99% |
| Smart Meter Rate Adder | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 4.0575 | 2,500 | $ 10,143.75 | $ 493.25 | 5.11% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | | 2,500 | $ - | $ 0.25 | -100.00% |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 15,118.75 | **$ 818.50** | **5.72%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | | 2,500 | $ - | $ 1,149.50 | -100.00% |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 2,500 | $ - | $ 0.75 | -100.00% |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02724 | 2,500 | $ 68.10 | $ 0.60 | 0.89% |
| Line Losses on Cost of Power | | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 19,597.20** | **$ 1,969.35** | **11.17%** |
| RTSR - Network | per kW | $ 3.0186 | 2500 | $ 7,546.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 2500 | $ 4,336.75 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 31,480.45** | **$ 1,969.35** | **6.67%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $ 140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 178,112.15** | **$ 1,969.35** | **1.12%** |
| HST | | 13% | | $ 23,154.58 | $ 256.02 | 1.12% |
| **Total Bill** (including HST) | | | | $ 201,266.73 | $ 2,225.37 | 1.12% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 201,266.73** | **$ 2,225.37** | **1.12%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 188,141.30** | **$ 1,969.35** | **1.06%** |
| HST | | 13% | | $ 24,458.37 | $ 256.02 | 1.06% |
| **Total Bill** (including HST) | | | | $ 212,599.67 | $ 2,225.37 | 1.06% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 212,599.67** | **$ 2,225.37** | **1.06%** |
| **Loss Factor (%)** | | 3.3800% | | | | |

| | Charge Unit | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 5,600.000 | 1 | $ 5,600.00 | $ 625.00 | 12.56% |
| Smart Meter Rate Adder | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 4.1002 | 2,500 | $ 10,250.50 | $ 106.75 | 1.05% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | | 2,500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 15,850.50 | **$ 731.75** | **4.84%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | | 2,500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 2,500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02730 | 2,500 | $ 68.25 | $ 0.15 | 0.22% |
| Line Losses on Cost of Power | | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 20,329.10** | **$ 731.90** | **3.73%** |
| RTSR - Network | per kW | $ 3.0186 | 2500 | $ 7,546.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 2500 | $ 4,336.75 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 32,212.35** | **$ 731.90** | **2.32%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $ 140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 178,844.05** | **$ 731.90** | **0.41%** |
| HST | | 13% | | $ 23,249.73 | $ 95.15 | 0.41% |
| **Total Bill** (including HST) | | | | $ 202,093.78 | $ 827.05 | 0.41% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 202,093.78** | **$ 827.05** | **0.41%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 188,873.20** | **$ 731.90** | **0.39%** |
| HST | | 13% | | $ 24,553.52 | $ 95.15 | 0.39% |
| **Total Bill** (including HST) | | | | $ 213,426.72 | $ 827.05 | 0.39% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 213,426.72** | **$ 827.05** | **0.39%** |
| **Loss Factor (%)** | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 1,500 to 4,999 KW

**TOU / non-TOU:** TOU

**Consumption** 1,277,500 kWh ● May 1 - October 31
2,500 KW

| | | Current Board-Approved | | | 2019 Proposed | | | Impact 2019 vs 2018 | | 2020 Proposed | | | Impact 2020 vs 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 4,193.93 | 1 | $ 4,193.93 | $ 6,650.000 | 1 | $ 6,650.00 | $ 1,050.00 | 18.75% | $ 7,700.000 | 1 | $ 7,700.00 | $ 1,050.00 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.4887 | 2,500 | $ 8,721.75 | $ 3.9007 | 2,500 | $ 9,751.75 | -$ 498.75 | -4.87% | $ 3.6031 | 2,500 | $ 9,007.75 | -$ 744.00 | -7.63% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 2,500 | $ - | | 2,500 | $ - | $ - | | | 2,500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 12,915.68 | | | $ 16,401.75 | **$ 551.25** | **3.48%** | | | $ 16,707.75 | **$ 306.00** | **1.87%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 2,500 | $ - | | 2,500 | $ - | $ - | | | 2,500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 1,277,500 | $ - | | 2,500 | $ - | $ - | | | 2,500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02516 | 2,500 | $ 62.90 | $ 0.02732 | 2,500 | $ 68.30 | $ 0.05 | 0.07% | $ 0.02734 | 2,500 | $ 68.35 | $ 0.05 | 0.07% |
| Line Losses on Cost of Power | | $ 0.1021 | 45,735 | $ 4,671.32 | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 17,649.90** | | | **$ 20,880.40** | **$ 551.30** | **2.71%** | | | **$ 21,186.45** | **$ 306.05** | **1.47%** |
| RTSR - Network | per kW | $ 3.0186 | 2500 | $ 7,546.50 | $ 3.0186 | 2500 | $ 7,546.50 | $ - | 0.00% | $ 3.0186 | 2500 | $ 7,546.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 2500 | $ 4,336.75 | $ 1.7347 | 2500 | $ 4,336.75 | $ - | 0.00% | $ 1.7347 | 2500 | $ 4,336.75 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 29,533.15** | | | **$ 32,763.65** | **$ 551.30** | **1.71%** | | | **$ 33,069.70** | **$ 306.05** | **0.93%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1323235 | $ 5,822.23 | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1323235 | $ 1,720.20 | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $ 140,442.50 | $ 0.1100 | 1276750 | $ 140,442.50 | $ - | 0.00% | $ 0.1100 | 1276750 | $ 140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 176,425.54** | | | **$ 179,395.35** | **$ 551.30** | **0.31%** | | | **$ 179,701.40** | **$ 306.05** | **0.17%** |
| HST | | 13% | | $ 22,935.32 | 13% | | $ 23,321.40 | $ 71.67 | 0.31% | 13% | | $ 23,361.18 | $ 39.79 | 0.17% |
| **Total Bill** (including HST) | | | | $ 199,360.86 | | | $ 202,716.75 | $ 622.97 | 0.31% | | | $ 203,062.59 | $ 345.84 | 0.17% |
| ***Ontario Clean Energy Benefit* [1]** | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 199,360.86** | | | **$ 202,716.75** | **$ 622.97** | **0.31%** | | | **$ 203,062.59** | **$ 345.84** | **0.17%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 186,454.69** | | | **$ 189,424.50** | **$ 551.30** | **0.29%** | | | **$ 189,730.55** | **$ 306.05** | **0.16%** |
| HST | | 13% | | $ 24,239.11 | 13% | | $ 24,625.19 | $ 71.67 | 0.29% | 13% | | $ 24,664.97 | $ 39.79 | 0.16% |
| **Total Bill** (including HST) | | | | $ 210,693.80 | | | $ 214,049.69 | $ 622.97 | 0.29% | | | $ 214,395.53 | $ 345.84 | 0.16% |
| ***Ontario Clean Energy Benefit* [1]** | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 210,693.80** | | | **$ 214,049.69** | **$ 622.97** | **0.29%** | | | **$ 214,395.53** | **$ 345.84** | **0.16%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 1,500 to 4,999 KW

**TOU / non-TOU:** TOU

**Consumption** 1,277,500 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
4,000 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 4,193.93 | 1 | $ 4,193.93 | 4,650.00 | 1 | $ 4,650.00 | $ 456.07 | 10.87% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.4887 | 4,000 | $ 13,954.80 | $ 3.8602 | 4,000 | $ 15,440.80 | $ 1,486.00 | 10.65% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 4,000 | $ - | -$ 0.0001 | 4,000 | -$ 0.40 | -$ 0.40 | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 18,148.73 | | | $ 20,090.40 | **$ 1,941.67** | **10.70%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 4,000 | $ - | -$ 0.4598 | 4,000 | -$ 1,839.20 | -$ 1,839.20 | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 1,277,500 | $ - | -$ 0.0003 | 4,000 | -$ 1.20 | -$ 1.20 | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02516 | 4,000 | $ 100.64 | $ 0.02700 | 4,000 | $ 108.00 | $ 7.36 | 7.31% |
| Line Losses on Cost of Power | | $ 0.1021 | 45,735 | $ 4,671.32 | $ 0.1021 | 43,180 | $ 4,410.35 | -$ 260.97 | -5.59% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 22,920.69** | | | **$ 22,768.35** | **-$ 152.34** | **-0.66%** |
| RTSR - Network | per kW | $ 3.0186 | 4000 | $ 12,074.40 | $ 3.0186 | 4000 | $ 12,074.40 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 4000 | $ 6,938.80 | $ 1.7347 | 4000 | $ 6,938.80 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 41,933.89** | | | **$ 41,781.55** | **-$ 152.34** | **-0.36%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1323235 | $ 5,822.23 | $ 0.0044 | 1277500 | $ 5,621.00 | -$ 201.23 | -3.46% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1323235 | $ 1,720.20 | $ 0.0013 | 1277500 | $ 1,660.75 | -$ 59.45 | -3.46% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $140,442.50 | $ 0.1100 | 1276750 | $140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$188,826.28** | | | **$188,413.25** | **-$ 413.02** | **-0.22%** |
| HST | | 13% | | $ 24,547.42 | 13% | | $ 24,493.72 | -$ 53.69 | -0.22% |
| **Total Bill** (including HST) | | | | $213,373.69 | | | $212,906.98 | -$ 466.72 | -0.22% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$213,373.69** | | | **$212,906.98** | **-$ 466.72** | **-0.22%** |
| **Total Bill on RPP (before Taxes)** | | | | **$198,855.43** | | | **$198,442.40** | **-$ 413.02** | **-0.21%** |
| HST | | 13% | | $ 25,851.21 | 13% | | $ 25,797.51 | -$ 53.69 | -0.21% |
| **Total Bill** (including HST) | | | | $224,706.63 | | | $224,239.92 | -$ 466.72 | -0.21% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$224,706.63** | | | **$224,239.92** | **-$ 466.72** | **-0.21%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | |

| | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | $ 4,975.000 | 1 | $ 4,975.00 | $ 325.00 | 6.99% | $ 5,600.000 | 1 | $ 5,600.00 | $ 625.00 | 12.56% |
| Smart Meter Rate Adder | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | $ 4.0575 | 4,000 | $ 16,230.00 | $ 789.20 | 5.11% | $ 4.1002 | 4,000 | $ 16,400.80 | $ 170.80 | 1.05% |
| Smart Meter Disposition Rider | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | | 4,000 | $ - | $ 0.40 | -100.00% | | 4,000 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | $ 21,205.00 | **$ 1,114.60** | **5.55%** | | | $ 22,000.80 | **$ 795.80** | **3.75%** |
| Deferral/Variance Account Disposition Rate Rider | | 4,000 | $ - | $ 1,839.20 | -100.00% | | 4,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | | 4,000 | $ - | $ 1.20 | -100.00% | | 4,000 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | $ 0.02724 | 4,000 | $ 108.96 | $ 0.96 | 0.89% | $ 0.02730 | 4,000 | $ 109.20 | $ 0.24 | 0.22% |
| Line Losses on Cost of Power | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% |
| Smart Meter Entity Charge | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | **$ 25,724.31** | **$ 2,955.96** | **12.98%** | | | **$ 26,520.35** | **$ 796.04** | **3.09%** |
| RTSR - Network | $ 3.0186 | 4000 | $ 12,074.40 | $ - | 0.00% | $ 3.0186 | 4000 | $ 12,074.40 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | $ 1.7347 | 4000 | $ 6,938.80 | $ - | 0.00% | $ 1.7347 | 4000 | $ 6,938.80 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | **$ 44,737.51** | **$ 2,955.96** | **7.07%** | | | **$ 45,533.55** | **$ 796.04** | **1.78%** |
| Wholesale Market Service Charge (WMSC) | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% |
| Standard Supply Service Charge | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | $ 0.1100 | 1276750 | $140,442.50 | $ - | 0.00% | $ 0.1100 | 1276750 | $140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | **$191,369.21** | **$ 2,955.96** | **1.57%** | | | **$192,165.25** | **$ 796.04** | **0.42%** |
| HST | 13% | | $ 24,878.00 | $ 384.27 | 1.57% | 13% | | $ 24,981.48 | $ 103.49 | 0.42% |
| **Total Bill** (including HST) | | | $216,247.21 | $ 3,340.23 | 1.57% | | | $217,146.74 | $ 899.53 | 0.42% |
| ***Ontario Clean Energy Benefit*** [1] | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | **$216,247.21** | **$ 3,340.23** | **1.57%** | | | **$217,146.74** | **$ 899.53** | **0.42%** |
| **Total Bill on RPP (before Taxes)** | | | **$201,398.36** | **$ 2,955.96** | **1.49%** | | | **$202,194.40** | **$ 796.04** | **0.40%** |
| HST | 13% | | $ 26,181.79 | $ 384.27 | 1.49% | 13% | | $ 26,285.27 | $ 103.49 | 0.40% |
| **Total Bill** (including HST) | | | $227,580.15 | $ 3,340.23 | 1.49% | | | $228,479.68 | $ 899.53 | 0.40% |
| ***Ontario Clean Energy Benefit*** [1] | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | **$227,580.15** | **$ 3,340.23** | **1.49%** | | | **$228,479.68** | **$ 899.53** | **0.40%** |
| **Loss Factor (%)** | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** General Service 1,500 to 4,999 KW

**TOU / non-TOU:** TOU

**Consumption** 1,277,500 kWh — May 1 - October 31
4,000 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 4,193.93 | 1 | $ 4,193.93 | $ 6,650.000 | 1 | $ 6,650.00 | $ 1,050.00 | 18.75% | $ 7,700.000 | 1 | $ 7,700.00 | $ 1,050.00 | 15.79% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.4887 | 4,000 | $ 13,954.80 | $ 3.9007 | 4,000 | $ 15,602.80 | -$ 798.00 | -4.87% | $ 3.6031 | 4,000 | $ 14,412.40 | -$ 1,190.40 | -7.63% |
| Smart Meter Disposition Rider | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 4,000 | $ - | | 4,000 | $ - | $ - | | | 4,000 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 18,148.73 | | | $ 22,252.80 | **$ 252.00** | **1.15%** | | | $ 22,112.40 | **-$ 140.40** | **-0.63%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 4,000 | $ - | | 4,000 | $ - | $ - | | | 4,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kW | | 1,277,500 | $ - | | 4,000 | $ - | $ - | | | 4,000 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| | | | 1277500 | $ - | | 1277500 | $ - | $ - | | | 1277500 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02516 | 4,000 | $ 100.64 | $ 0.02732 | 4,000 | $ 109.28 | $ 0.08 | 0.07% | $ 0.02734 | 4,000 | $ 109.36 | $ 0.08 | 0.07% |
| Line Losses on Cost of Power | | $ 0.1021 | 45,735 | $ 4,671.32 | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% | $ 0.1021 | 43,180 | $ 4,410.35 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 22,920.69** | | | **$ 26,772.43** | **$ 252.08** | **0.95%** | | | **$ 26,632.11** | **-$ 140.32** | **-0.52%** |
| RTSR - Network | per kW | $ 3.0186 | 4000 | $ 12,074.40 | $ 3.0186 | 4000 | $ 12,074.40 | $ - | 0.00% | $ 3.0186 | 4000 | $ 12,074.40 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.7347 | 4000 | $ 6,938.80 | $ 1.7347 | 4000 | $ 6,938.80 | $ - | 0.00% | $ 1.7347 | 4000 | $ 6,938.80 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 41,933.89** | | | **$ 45,785.63** | **$ 252.08** | **0.55%** | | | **$ 45,645.31** | **-$ 140.32** | **-0.31%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 1323235 | $ 5,822.23 | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% | $ 0.0044 | 1277500 | $ 5,621.00 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 1323235 | $ 1,720.20 | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% | $ 0.0013 | 1277500 | $ 1,660.75 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 1277500 | $ 8,865.85 | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% | $ 0.0069 | 1277500 | $ 8,865.85 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 817600 | $ 65,408.00 | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% | $ 0.0800 | 817600 | $ 65,408.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 229950 | $ 28,053.90 | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% | $ 0.1220 | 229950 | $ 28,053.90 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 229950 | $ 37,021.95 | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% | $ 0.1610 | 229950 | $ 37,021.95 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 1276750 | $140,442.50 | $ 0.1100 | 1276750 | $140,442.50 | $ - | 0.00% | $ 0.1100 | 1276750 | $140,442.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$188,826.28** | | | **$192,417.33** | **$ 252.08** | **0.13%** | | | **$192,277.01** | **-$ 140.32** | **-0.07%** |
| HST | | 13% | | $ 24,547.42 | 13% | | $ 25,014.25 | $ 32.77 | 0.13% | 13% | | $ 24,996.01 | -$ 18.24 | -0.07% |
| **Total Bill** (including HST) | | | | $213,373.69 | | | $217,431.59 | $ 284.85 | 0.13% | | | $217,273.03 | -$ 158.56 | -0.07% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$213,373.69** | | | **$217,431.59** | **$ 284.85** | **0.13%** | | | **$217,273.03** | **-$ 158.56** | **-0.07%** |
| **Total Bill on RPP (before Taxes)** | | | | **$198,855.43** | | | **$202,446.48** | **$ 252.08** | **0.12%** | | | **$202,306.16** | **-$ 140.32** | **-0.07%** |
| HST | | 13% | | $ 25,851.21 | 13% | | $ 26,318.04 | $ 32.77 | 0.12% | 13% | | $ 26,299.80 | -$ 18.24 | -0.07% |
| **Total Bill** (including HST) | | | | $224,706.63 | | | $228,764.53 | $ 284.85 | 0.12% | | | $228,605.97 | -$ 158.56 | -0.07% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$224,706.63** | | | **$228,764.53** | **$ 284.85** | **0.12%** | | | **$228,605.97** | **-$ 158.56** | **-0.07%** |

| | Current Board-Approved | 2019 Proposed | 2020 Proposed |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Large User

**TOU / non-TOU:** TOU

**Consumption** 4,000,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
7,500 KW

| | | Current Board-Approved | | | 2016 Proposed | | | Impact 2016 vs 2015 | | 2017 Proposed | | | Impact 2017 vs 2016 | | 2018 Proposed | | | Impact 2018 vs 2017 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 15,231.32 | 1 | $ 15,231.32 | 16,900.00 | 1 | $ 16,900.00 | $ 1,668.68 | 10.96% | $ 17,900.00 | 1 | $ 17,900.00 | $ 1,000.00 | 5.92% | $ 21,000.00 | 1 | $ 21,000.00 | $ 3,100.00 | 17.32% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.3129 | 7,500 | $ 24,846.75 | $ 3.6644 | 7,500 | $ 27,483.00 | $ 2,636.25 | 10.61% | $ 3.8746 | 7,500 | $ 29,059.50 | $ 1,576.50 | 5.74% | $ 3.8254 | 7,500 | $ 28,690.50 | -$ 369.00 | -1.27% |
| Smart Meter Disposition Rider | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 7,500 | $ - | - 0.00002 | 7,500 | -$ 0.15 | -$ 0.15 | | | 7,500 | $ - | $ 0.15 | -100.00% | | 7,500 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 40,078.07 | | | $ 44,382.85 | **$ 4,304.78** | **10.74%** | | | $ 46,959.50 | **$ 2,576.65** | **5.81%** | | | $ 49,690.50 | **$ 2,731.00** | **5.82%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 7,500 | $ - | -$ 0.5443 | 7,500 | -$ 4,082.25 | -$ 4,082.25 | | | 7,500 | $ - | $ 4,082.25 | -100.00% | | 7,500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 4,000,000 | $ - | -$ 0.0003 | 4,000,000 | -$ 1,200.00 | -$ 1,200.00 | | | 4,000,000 | $ - | $ 1,200.00 | -100.00% | | 4,000,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02833 | 7,500 | $ 212.48 | $ 0.03040 | 7,500 | $ 228.00 | $ 15.53 | 7.31% | $ 0.03067 | 7,500 | $ 230.03 | $ 2.03 | 0.89% | $ 0.03074 | 7,500 | $ 230.55 | $ 0.53 | 0.23% |
| Line Losses on Cost of Power | | $ 0.1021 | 27,600 | $ 2,819.06 | $ 0.1021 | 24,800 | $ 2,533.07 | -$ 285.99 | -10.14% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 43,109.61** | | | **$ 41,861.67** | **-$ 1,247.94** | **-2.89%** | | | **$ 49,722.60** | **$ 7,860.93** | **18.78%** | | | **$ 52,454.12** | **$ 2,731.53** | **5.49%** |
| RTSR - Network | per kW | $ 3.3462 | 7500 | $ 25,096.50 | $ 3.3462 | 7500 | $ 25,096.50 | $ - | 0.00% | $ 3.3462 | 7500 | $ 25,096.50 | $ - | 0.00% | $ 3.3462 | 7500 | $ 25,096.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.9535 | 7500 | $ 14,651.25 | $ 1.9535 | 7500 | $ 14,651.25 | $ - | 0.00% | $ 1.9535 | 7500 | $ 14,651.25 | $ - | 0.00% | $ 1.9535 | 7500 | $ 14,651.25 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 82,857.36** | | | **$ 81,609.42** | **-$ 1,247.94** | **-1.51%** | | | **$ 89,470.35** | **$ 7,860.93** | **9.63%** | | | **$ 92,201.87** | **$ 2,731.52** | **3.05%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 4027600 | $ 17,721.44 | $ 0.0044 | 4024800 | $ 17,709.12 | -$ 12.32 | -0.07% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 4027600 | $ 5,235.88 | $ 0.0013 | 4024800 | $ 5,232.24 | -$ 3.64 | -0.07% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 4000000 | $ 27,760.00 | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 2560000 | $ 204,800.00 | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 720000 | $ 87,840.00 | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 720000 | $ 115,920.00 | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 3999250 | $ 439,917.50 | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 542,134.93** | | | **$ 540,871.03** | **-$ 1,263.90** | **-0.23%** | | | **$ 548,731.96** | **$ 7,860.92** | **1.45%** | | | **$ 551,463.48** | **$ 2,731.53** | **0.50%** |
| HST | | 13% | | $ 70,477.54 | 13% | | $ 70,313.23 | -$ 164.31 | -0.23% | 13% | | $ 71,335.15 | $ 1,021.92 | 1.45% | 13% | | $ 71,690.25 | $ 355.10 | 0.50% |
| **Total Bill** (including HST) | | | | $ 612,612.47 | | | $ 611,184.27 | -$ 1,428.20 | -0.23% | | | $ 620,067.11 | $ 8,882.85 | 1.45% | | | $ 623,153.73 | $ 3,086.62 | 0.50% |
| ***Ontario Clean Energy Benefit* [1]** | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 612,612.47** | | | **$ 611,184.27** | **-$ 1,428.20** | **-0.23%** | | | **$ 620,067.11** | **$ 8,882.85** | **1.45%** | | | **$ 623,153.73** | **$ 3,086.62** | **0.50%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 573,562.93** | | | **$ 572,299.03** | **-$ 1,263.90** | **-0.22%** | | | **$ 580,159.96** | **$ 7,860.93** | **1.37%** | | | **$ 582,891.48** | **$ 2,731.52** | **0.47%** |
| HST | | 13% | | $ 74,563.18 | 13% | | $ 74,398.87 | -$ 164.31 | -0.22% | 13% | | $ 75,420.79 | $ 1,021.92 | 1.37% | 13% | | $ 75,775.89 | $ 355.10 | 0.47% |
| **Total Bill** (including HST) | | | | $ 648,126.11 | | | $ 646,697.91 | -$ 1,428.20 | -0.22% | | | $ 655,580.75 | $ 8,882.85 | 1.37% | | | $ 658,667.37 | $ 3,086.62 | 0.47% |
| ***Ontario Clean Energy Benefit* [1]** | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 648,126.11** | | | **$ 646,697.91** | **-$ 1,428.20** | **-0.22%** | | | **$ 655,580.75** | **$ 8,882.85** | **1.37%** | | | **$ 658,667.37** | **$ 3,086.62** | **0.47%** |
| **Loss Factor (%)** | | 0.6900% | | | 0.6200% | | | | | 0.6200% | | | | | 0.6200% | | | | |

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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## Appendix 2-W
## Bill Impacts

**Customer Class:** **Large User**

**TOU / non-TOU:** TOU

**Consumption** **4,000,000** **kWh** ◉ May 1 - October 31
**7,500** KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 15,231.32 | 1 | $ 15,231.32 | $ 24,600.00 | 1 | $ 24,600.00 | $ 3,600.00 | 17.14% | $ 28,000.00 | 1 | $ 28,000.00 | $ 3,400.00 | 13.82% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.3129 | 7,500 | $ 24,846.75 | $ 3.6719 | 7,500 | $ 27,539.25 | -$ 1,151.25 | -4.01% | $ 3.4408 | 7,500 | $ 25,806.00 | -$ 1,733.25 | -6.29% |
| Smart Meter Disposition Rider | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 7,500 | $ - | | 7,500 | $ - | $ - | | | 7,500 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 40,078.07 | | | $ 52,139.25 | **$ 2,448.75** | **4.93%** | | | $ 53,806.00 | **$ 1,666.75** | **3.20%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 7,500 | $ - | | 7,500 | $ - | $ - | | | 7,500 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 4,000,000 | $ - | | 4,000,000 | $ - | $ - | | | 4,000,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02833 | 7,500 | $ 212.48 | $ 0.03077 | 7,500 | $ 230.78 | $ 0.22 | 0.10% | $ 0.03079 | 7,500 | $ 230.93 | $ 0.15 | 0.06% |
| Line Losses on Cost of Power | | $ 0.1021 | 27,600 | $ 2,819.06 | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 43,109.61** | | | **$ 54,903.10** | **$ 2,448.98** | **4.67%** | | | **$ 56,570.00** | **$ 1,666.90** | **3.04%** |
| RTSR - Network | per kW | $ 3.3462 | 7500 | $ 25,096.50 | $ 3.3462 | 7500 | $ 25,096.50 | $ - | 0.00% | $ 3.3462 | 7500 | $ 25,096.50 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.9535 | 7500 | $ 14,651.25 | $ 1.9535 | 7500 | $ 14,651.25 | $ - | 0.00% | $ 1.9535 | 7500 | $ 14,651.25 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 82,857.36** | | | **$ 94,650.85** | **$ 2,448.98** | **2.66%** | | | **$ 96,317.75** | **$ 1,666.90** | **1.76%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 4027600 | $ 17,721.44 | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 4027600 | $ 5,235.88 | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 4000000 | $ 27,760.00 | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 2560000 | $ 204,800.00 | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 720000 | $ 87,840.00 | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 720000 | $ 115,920.00 | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 3999250 | $ 439,917.50 | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 542,134.93** | | | **$ 553,912.46** | **$ 2,448.97** | **0.44%** | | | **$ 555,579.36** | **$ 1,666.90** | **0.30%** |
| HST | | 13% | | $ 70,477.54 | 13% | | $ 72,008.62 | $ 318.37 | 0.44% | 13% | | $ 72,225.32 | $ 216.70 | 0.30% |
| **Total Bill** (including HST) | | | | $ 612,612.47 | | | $ 625,921.08 | $ 2,767.34 | 0.44% | | | $ 627,804.67 | $ 1,883.60 | 0.30% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 612,612.47** | | | **$ 625,921.08** | **$ 2,767.34** | **0.44%** | | | **$ 627,804.67** | **$ 1,883.60** | **0.30%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 573,562.93** | | | **$ 585,340.46** | **$ 2,448.98** | **0.42%** | | | **$ 587,007.36** | **$ 1,666.90** | **0.28%** |
| HST | | 13% | | $ 74,563.18 | 13% | | $ 76,094.26 | $ 318.37 | 0.42% | 13% | | $ 76,310.96 | $ 216.70 | 0.28% |
| **Total Bill** (including HST) | | | | $ 648,126.11 | | | $ 661,434.72 | $ 2,767.34 | 0.42% | | | $ 663,318.31 | $ 1,883.60 | 0.28% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 648,126.11** | | | **$ 661,434.72** | **$ 2,767.34** | **0.42%** | | | **$ 663,318.31** | **$ 1,883.60** | **0.28%** |
| **Loss Factor (%)** | | 0.6900% | | | 0.6200% | | | | | 0.6200% | | | | |

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010*.

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Large User

**TOU / non-TOU:** TOU

**Consumption** 4,000,000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

10,000 KW

| | | Current Board-Approved | | | 2016 Proposed | | | Impact 2016 vs 2015 | | 2017 Proposed | | | Impact 2017 vs 2016 | | 2018 Proposed | | | Impact 2018 vs 2017 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 15,231.32 | 1 | $ 15,231.32 | 16,900.00 | 1 | $ 16,900.00 | $ 1,668.68 | 10.96% | $ 17,900.00 | 1 | $ 17,900.00 | $ 1,000.00 | 5.92% | $ 21,000.00 | 1 | $ 21,000.00 | $ 3,100.00 | 17.32% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.3129 | 10,000 | $ 33,129.00 | $ 3.6644 | 10,000 | $ 36,644.00 | $ 3,515.00 | 10.61% | $ 3.8746 | 10,000 | $ 38,746.00 | $ 2,102.00 | 5.74% | $ 3.8254 | 10,000 | $ 38,254.00 | -$ 492.00 | -1.27% |
| Smart Meter Disposition Rider | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 10,000 | $ - | - 0.00002 | 10,000 | -$ 0.20 | -$ 0.20 | | | 10,000 | $ - | $ 0.20 | -100.00% | | 10,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 48,360.32 | | | $ 53,543.80 | **$ 5,183.48** | **10.72%** | | | $ 56,646.00 | **$ 3,102.20** | **5.79%** | | | $ 59,254.00 | **$ 2,608.00** | **4.60%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 10,000 | $ - | -$ 0.5443 | 10,000 | -$ 5,443.00 | -$ 5,443.00 | | | 10,000 | $ - | $ 5,443.00 | -100.00% | | 10,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 4,000,000 | $ - | -$ 0.0003 | 4,000,000 | -$ 1,200.00 | -$ 1,200.00 | | | 4,000,000 | $ - | $ 1,200.00 | -100.00% | | 4,000,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02833 | 10,000 | $ 283.30 | $ 0.03040 | 10,000 | $ 304.00 | $ 20.70 | 7.31% | $ 0.03067 | 10,000 | $ 306.70 | $ 2.70 | 0.89% | $ 0.03074 | 10,000 | $ 307.40 | $ 0.70 | 0.23% |
| Line Losses on Cost of Power | | $ 0.1021 | 27,600 | $ 2,819.06 | $ 0.1021 | 24,800 | $ 2,533.07 | -$ 285.99 | -10.14% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 51,462.68** | | | **$ 49,737.87** | **-$ 1,724.81** | **-3.35%** | | | **$ 59,485.77** | **$ 9,747.90** | **19.60%** | | | **$ 62,094.47** | **$ 2,608.70** | **4.39%** |
| RTSR - Network | per kW | $ 3.3462 | 10000 | $ 33,462.00 | $ 3.3462 | 10000 | $ 33,462.00 | $ - | 0.00% | $ 3.3462 | 10000 | $ 33,462.00 | $ - | 0.00% | $ 3.3462 | 10000 | $ 33,462.00 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.9535 | 10000 | $ 19,535.00 | $ 1.9535 | 10000 | $ 19,535.00 | $ - | 0.00% | $ 1.9535 | 10000 | $ 19,535.00 | $ - | 0.00% | $ 1.9535 | 10000 | $ 19,535.00 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 104,459.68** | | | **$ 102,734.87** | **-$ 1,724.81** | **-1.65%** | | | **$ 112,482.77** | **$ 9,747.90** | **9.49%** | | | **$ 115,091.47** | **$ 2,608.70** | **2.32%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 4027600 | $ 17,721.44 | $ 0.0044 | 4024800 | $ 17,709.12 | -$ 12.32 | -0.07% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 4027600 | $ 5,235.88 | $ 0.0013 | 4024800 | $ 5,232.24 | -$ 3.64 | -0.07% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 4000000 | $ 27,760.00 | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 2560000 | $ 204,800.00 | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 720000 | $ 87,840.00 | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 720000 | $ 115,920.00 | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 3999250 | $ 439,917.50 | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 563,737.25** | | | **$ 561,996.48** | **-$ 1,740.77** | **-0.31%** | | | **$ 571,744.38** | **$ 9,747.90** | **1.73%** | | | **$ 574,353.08** | **$ 2,608.70** | **0.46%** |
| HST | | 13% | | $ 73,285.84 | 13% | | $ 73,059.54 | -$ 226.30 | -0.31% | 13% | | $ 74,326.77 | $ 1,267.23 | 1.73% | 13% | | $ 74,665.90 | $ 339.13 | 0.46% |
| **Total Bill** (including HST) | | | | $ 637,023.10 | | | $ 635,056.02 | -$ 1,967.07 | -0.31% | | | $ 646,071.15 | $ 11,015.13 | 1.73% | | | $ 649,018.98 | $ 2,947.83 | 0.46% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 637,023.10** | | | **$ 635,056.02** | **-$ 1,967.07** | **-0.31%** | | | **$ 646,071.15** | **$ 11,015.13** | **1.73%** | | | **$ 649,018.98** | **$ 2,947.83** | **0.46%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 595,165.25** | | | **$ 593,424.48** | **-$ 1,740.77** | **-0.29%** | | | **$ 603,172.38** | **$ 9,747.90** | **1.64%** | | | **$ 605,781.08** | **$ 2,608.70** | **0.43%** |
| HST | | 13% | | $ 77,371.48 | 13% | | $ 77,145.18 | -$ 226.30 | -0.29% | 13% | | $ 78,412.41 | $ 1,267.23 | 1.64% | 13% | | $ 78,751.54 | $ 339.13 | 0.43% |
| **Total Bill** (including HST) | | | | $ 672,536.74 | | | $ 670,569.66 | -$ 1,967.07 | -0.29% | | | $ 681,584.79 | $ 11,015.13 | 1.64% | | | $ 684,532.62 | $ 2,947.83 | 0.43% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 672,536.74** | | | **$ 670,569.66** | **-$ 1,967.07** | **-0.29%** | | | **$ 681,584.79** | **$ 11,015.13** | **1.64%** | | | **$ 684,532.62** | **$ 2,947.83** | **0.43%** |
| **Loss Factor (%)** | | 0.6900% | | | 0.6200% | | | | | 0.6200% | | | | | 0.6200% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Large User

**TOU / non-TOU:** TOU

**Consumption** 4,000,000 kWh ◉ May 1 - October 31
10,000 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 15,231.32 | 1 | $ 15,231.32 | $ 24,600.00 | 1 | $ 24,600.00 | $ 3,600.00 | 17.14% | $ 28,000.00 | 1 | $ 28,000.00 | $ 3,400.00 | 13.82% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.3129 | 10,000 | $ 33,129.00 | $ 3.6719 | 10,000 | $ 36,719.00 | -$ 1,535.00 | -4.01% | $ 3.4408 | 10,000 | $ 34,408.00 | -$ 2,311.00 | -6.29% |
| Smart Meter Disposition Rider | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 10,000 | $ - | | 10,000 | $ - | $ - | | | 10,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 48,360.32 | | | $ 61,319.00 | **$ 2,065.00** | **3.48%** | | | $ 62,408.00 | **$ 1,089.00** | **1.78%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 10,000 | $ - | | 10,000 | $ - | $ - | | | 10,000 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 4,000,000 | $ - | | 4,000,000 | $ - | $ - | | | 4,000,000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| | | | 4000000 | $ - | | 4000000 | $ - | $ - | | | 4000000 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.02833 | 10,000 | $ 283.30 | $ 0.03077 | 10,000 | $ 307.70 | $ 0.30 | 0.10% | $ 0.03079 | 10,000 | $ 307.90 | $ 0.20 | 0.06% |
| Line Losses on Cost of Power | | $ 0.1021 | 27,600 | $ 2,819.06 | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% | $ 0.1021 | 24,800 | $ 2,533.07 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 51,462.68** | | | **$ 64,159.77** | **$ 2,065.30** | **3.33%** | | | **$ 65,248.97** | **$ 1,089.20** | **1.70%** |
| RTSR - Network | per kW | $ 3.3462 | 10000 | $ 33,462.00 | $ 3.3462 | 10000 | $ 33,462.00 | $ - | 0.00% | $ 3.3462 | 10000 | $ 33,462.00 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.9535 | 10000 | $ 19,535.00 | $ 1.9535 | 10000 | $ 19,535.00 | $ - | 0.00% | $ 1.9535 | 10000 | $ 19,535.00 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 104,459.68** | | | **$ 117,156.77** | **$ 2,065.30** | **1.79%** | | | **$ 118,245.97** | **$ 1,089.20** | **0.93%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 4027600 | $ 17,721.44 | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% | $ 0.0044 | 4024800 | $ 17,709.12 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 4027600 | $ 5,235.88 | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% | $ 0.0013 | 4024800 | $ 5,232.24 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 4000000 | $ 27,760.00 | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% | $ 0.0069 | 4000000 | $ 27,760.00 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 2560000 | $ 204,800.00 | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% | $ 0.0800 | 2560000 | $ 204,800.00 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 720000 | $ 87,840.00 | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% | $ 0.1220 | 720000 | $ 87,840.00 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 720000 | $ 115,920.00 | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% | $ 0.1610 | 720000 | $ 115,920.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 750 | $ 70.50 | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% | $ 0.0940 | 750 | $ 70.50 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 3999250 | $ 439,917.50 | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% | $ 0.1100 | 3999250 | $ 439,917.50 | $ - | 0.00% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 563,737.25** | | | **$ 576,418.38** | **$ 2,065.30** | **0.36%** | | | **$ 577,507.58** | **$ 1,089.20** | **0.19%** |
| HST | | 13% | | $ 73,285.84 | 13% | | $ 74,934.39 | $ 268.49 | 0.36% | 13% | | $ 75,075.99 | $ 141.60 | 0.19% |
| **Total Bill** (including HST) | | | | $ 637,023.10 | | | $ 651,352.77 | $ 2,333.79 | 0.36% | | | $ 652,583.57 | $ 1,230.80 | 0.19% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 637,023.10** | | | **$ 651,352.77** | **$ 2,333.79** | **0.36%** | | | **$ 652,583.57** | **$ 1,230.80** | **0.19%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 595,165.25** | | | **$ 607,846.38** | **$ 2,065.30** | **0.34%** | | | **$ 608,935.58** | **$ 1,089.20** | **0.18%** |
| HST | | 13% | | $ 77,371.48 | 13% | | $ 79,020.03 | $ 268.49 | 0.34% | 13% | | $ 79,161.63 | $ 141.60 | 0.18% |
| **Total Bill** (including HST) | | | | $ 672,536.74 | | | $ 686,866.41 | $ 2,333.79 | 0.34% | | | $ 688,097.21 | $ 1,230.80 | 0.18% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 672,536.74** | | | **$ 686,866.41** | **$ 2,333.79** | **0.34%** | | | **$ 688,097.21** | **$ 1,230.80** | **0.18%** |
| **Loss Factor (%)** | | 0.6900% | | | 0.6200% | | | | | 0.6200% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Unmetered Scattered Load

**TOU / non-TOU:** TOU

**Consumption** 470 kWh / KW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | | Current Board-Approved | | | 2016 Proposed | | | Impact 2016 vs 2015 | | 2017 Proposed | | | Impact 2017 vs 2016 | | 2018 Proposed | | | Impact 2018 vs 2017 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Charge Unit | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | Monthly | $ 4.43 | 1 | $ 4.43 | 4.75 | 1 | $ 4.75 | $ 0.32 | 7.22% | $ 5.750 | 1 | $ 5.75 | $ 1.00 | 21.05% | $ 7.000 | 1 | $ 7.00 | $ 1.25 | 21.74% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0219 | 470 | $ 10.29 | $ 0.0242 | 470 | $ 11.37 | $ 1.08 | 10.50% | $ 0.0237 | 470 | $ 11.14 | -$ 0.23 | -2.07% | $ 0.0225 | 470 | $ 10.58 | -$ 0.56 | -5.06% |
| Smart Meter Disposition Rider | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 470 | $ - | $ - | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 14.72 | | | $ 16.12 | **$ 1.40** | **9.52%** | | | $ 16.89 | **$ 0.77** | **4.74%** | | | $ 17.58 | **$ 0.69** | **4.06%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | $ - | 470 | $ - | -$ 0.0010 | 470 | -$ 0.47 | -$ 0.47 | | | 470 | $ - | $ 0.47 | -100.00% | | 470 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 487 | $ 0.03 | $ 0.00006 | 487 | $ 0.03 | $ - | 0.00% | $ 0.00006 | 487 | $ 0.03 | $ - | 0.00% | $ 0.00006 | 487 | $ 0.03 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 17 | $ 1.72 | $ 0.1021 | 16 | $ 1.62 | -$ 0.10 | -5.59% | $ 0.1021 | 16 | $ 1.62 | $ - | 0.00% | $ 0.1021 | 16 | $ 1.62 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 16.47** | | | **$ 17.31** | **$ 0.83** | **5.07%** | | | **$ 18.54** | **$ 1.24** | **7.14%** | | | **$ 19.23** | **$ 0.69** | **3.70%** |
| RTSR - Network | per kWh | $ 0.0070 | 487 | $ 3.41 | $ 0.0070 | 486 | $ 3.40 | -$ 0.01 | -0.19% | $ 0.0070 | 486 | $ 3.40 | $ - | 0.00% | $ 0.0070 | 486 | $ 3.40 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 487 | $ 1.95 | $ 0.0040 | 486 | $ 1.94 | -$ 0.00 | -0.19% | $ 0.0040 | 486 | $ 1.94 | $ - | 0.00% | $ 0.0040 | 486 | $ 1.94 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 21.83** | | | **$ 22.65** | **$ 0.82** | **3.78%** | | | **$ 23.89** | **$ 1.24** | **5.45%** | | | **$ 24.57** | **$ 0.69** | **2.87%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 487 | $ 2.14 | $ 0.0044 | 486 | $ 2.14 | -$ 0.00 | -0.19% | $ 0.0044 | 486 | $ 2.14 | $ - | 0.00% | $ 0.0044 | 486 | $ 2.14 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 487 | $ 0.63 | $ 0.0013 | 486 | $ 0.63 | -$ 0.00 | -0.19% | $ 0.0013 | 486 | $ 0.63 | $ - | 0.00% | $ 0.0013 | 486 | $ 0.63 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 470 | $ 3.26 | $ 0.0069 | 470 | $ 3.26 | $ - | 0.00% | $ 0.0069 | 470 | $ 3.26 | $ - | 0.00% | $ 0.0069 | 470 | $ 3.26 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 301 | $ 24.06 | $ 0.0800 | 301 | $ 24.06 | $ - | 0.00% | $ 0.0800 | 301 | $ 24.06 | $ - | 0.00% | $ 0.0800 | 301 | $ 24.06 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 85 | $ 10.32 | $ 0.1220 | 85 | $ 10.32 | $ - | 0.00% | $ 0.1220 | 85 | $ 10.32 | $ - | 0.00% | $ 0.1220 | 85 | $ 10.32 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 85 | $ 13.62 | $ 0.1610 | 85 | $ 13.62 | $ - | 0.00% | $ 0.1610 | 85 | $ 13.62 | $ - | 0.00% | $ 0.1610 | 85 | $ 13.62 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 470 | $ 44.18 | $ 0.0940 | 470 | $ 44.18 | $ - | 0.00% | $ 0.0940 | 470 | $ 44.18 | $ - | 0.00% | $ 0.0940 | 470 | $ 44.18 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 76.12** | | | **$ 76.94** | **$ 0.82** | **1.08%** | | | **$ 78.17** | **$ 1.24** | **1.61%** | | | **$ 78.86** | **$ 0.69** | **0.88%** |
| HST | | 13% | | $ 9.90 | 13% | | $ 10.00 | $ 0.11 | 1.08% | 13% | | $ 10.16 | $ 0.16 | 1.61% | 13% | | $ 10.25 | $ 0.09 | 0.88% |
| **Total Bill** (including HST) | | | | $ 86.01 | | | $ 86.94 | $ 0.93 | 1.08% | | | $ 88.34 | $ 1.40 | 1.61% | | | $ 89.11 | $ 0.78 | 0.88% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 86.01** | | | **$ 86.94** | **$ 0.93** | **1.08%** | | | **$ 88.34** | **$ 1.40** | **1.61%** | | | **$ 89.11** | **$ 0.78** | **0.88%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 72.29** | | | **$ 73.11** | **$ 0.82** | **1.13%** | | | **$ 74.35** | **$ 1.24** | **1.69%** | | | **$ 75.03** | **$ 0.69** | **0.92%** |
| HST | | 13% | | $ 9.40 | 13% | | $ 9.50 | $ 0.11 | 1.13% | 13% | | $ 9.67 | $ 0.16 | 1.69% | 13% | | $ 9.75 | $ 0.09 | 0.92% |
| **Total Bill** (including HST) | | | | $ 81.69 | | | $ 82.62 | $ 0.93 | 1.13% | | | $ 84.01 | $ 1.40 | 1.69% | | | $ 84.79 | $ 0.78 | 0.92% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 81.69** | | | **$ 82.62** | **$ 0.93** | **1.13%** | | | **$ 84.01** | **$ 1.40** | **1.69%** | | | **$ 84.79** | **$ 0.78** | **0.92%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Unmetered Scattered Load

**TOU / non-TOU:** TOU

**Consumption** 470 **kWh** KW ● May 1 - October

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 4.43 | 1 | $ 4.43 | $ 7.500 | 1 | $ 7.50 | $ 0.50 | 7.14% | $ 7.500 | 1 | $ 7.50 | $ - | 0.00% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0219 | 470 | $ 10.29 | $ 0.0229 | 470 | $ 10.76 | $ 0.19 | 1.78% | $ 0.0238 | 470 | $ 11.19 | $ 0.42 | 3.93% |
| Smart Meter Disposition Rider | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ - | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 14.72 | | | $ 18.26 | **$ 0.69** | **3.91%** | | | $ 18.69 | **$ 0.42** | **2.32%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | $ - | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| | | | 470 | $ - | | 470 | $ - | $ - | | | 470 | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.00006 | 487 | $ 0.03 | $ 0.00006 | 487 | $ 0.03 | $ - | 0.00% | $ 0.00006 | 487 | $ 0.03 | $ - | 0.00% |
| Line Losses on Cost of Power | | $ 0.1021 | 17 | $ 1.72 | $ 0.1021 | 16 | $ 1.62 | $ - | 0.00% | $ 0.1021 | 16 | $ 1.62 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 16.47** | | | **$ 19.91** | **$ 0.69** | **3.58%** | | | **$ 20.34** | **$ 0.42** | **2.12%** |
| RTSR - Network | per kWh | $ 0.0070 | 487 | $ 3.41 | $ 0.0070 | 486 | $ 3.40 | $ - | 0.00% | $ 0.0070 | 486 | $ 3.40 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0040 | 487 | $ 1.95 | $ 0.0040 | 486 | $ 1.94 | $ - | 0.00% | $ 0.0040 | 486 | $ 1.94 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 21.83** | | | **$ 25.26** | **$ 0.69** | **2.80%** | | | **$ 25.68** | **$ 0.42** | **1.67%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 487 | $ 2.14 | $ 0.0044 | 486 | $ 2.14 | $ - | 0.00% | $ 0.0044 | 486 | $ 2.14 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 487 | $ 0.63 | $ 0.0013 | 486 | $ 0.63 | $ - | 0.00% | $ 0.0013 | 486 | $ 0.63 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 470 | $ 3.26 | $ 0.0069 | 470 | $ 3.26 | $ - | 0.00% | $ 0.0069 | 470 | $ 3.26 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 301 | $ 24.06 | $ 0.0800 | 301 | $ 24.06 | $ - | 0.00% | $ 0.0800 | 301 | $ 24.06 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 85 | $ 10.32 | $ 0.1220 | 85 | $ 10.32 | $ - | 0.00% | $ 0.1220 | 85 | $ 10.32 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 85 | $ 13.62 | $ 0.1610 | 85 | $ 13.62 | $ - | 0.00% | $ 0.1610 | 85 | $ 13.62 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 470 | $ 44.18 | $ 0.0940 | 470 | $ 44.18 | $ - | 0.00% | $ 0.0940 | 470 | $ 44.18 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 76.12** | | | **$ 79.55** | **$ 0.69** | **0.87%** | | | **$ 79.97** | **$ 0.42** | **0.53%** |
| HST | | 13% | | $ 9.90 | 13% | | $ 10.34 | $ 0.09 | 0.87% | 13% | | $ 10.40 | $ 0.05 | 0.53% |
| **Total Bill** (including HST) | | | | $ 86.01 | | | $ 89.89 | $ 0.78 | 0.87% | | | $ 90.37 | $ 0.48 | 0.53% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 86.01** | | | **$ 89.89** | **$ 0.78** | **0.87%** | | | **$ 90.37** | **$ 0.48** | **0.53%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 72.29** | | | **$ 75.72** | **$ 0.69** | **0.92%** | | | **$ 76.14** | **$ 0.42** | **0.56%** |
| HST | | 13% | | $ 9.40 | 13% | | $ 9.84 | $ 0.09 | 0.92% | 13% | | $ 9.90 | $ 0.05 | 0.56% |
| **Total Bill** (including HST) | | | | $ 81.69 | | | $ 85.56 | $ 0.78 | 0.92% | | | $ 86.04 | $ 0.48 | 0.56% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 81.69** | | | **$ 85.56** | **$ 0.78** | **0.92%** | | | **$ 86.04** | **$ 0.48** | **0.56%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Sentinel Lights

**TOU / non-TOU:** TOU

**Consumption** 94 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
0.40 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2016 Proposed Rate ($) | 2016 Proposed Volume | 2016 Proposed Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Proposed Volume | 2017 Proposed Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Proposed Volume | 2018 Proposed Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 2.62 | 1 | $ 2.62 | 3.25 | 1 | $ 3.25 | $ 0.63 | 24.05% | $ 3.250 | 1 | $ 3.25 | $ - | 0.00% | $ 4.000 | 1 | $ 4.00 | $ 0.75 | 23.08% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 10.0361 | 0 | $ 4.01 | $ 12.0650 | 0 | $ 4.83 | $ 0.81 | 20.22% | $ 13.3241 | 0 | $ 5.33 | $ 0.50 | 10.44% | $ 12.5418 | 0 | $ 5.02 | -$ 0.31 | -5.87% |
| Smart Meter Disposition Rider | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 0 | $ - | $ - | 0 | $ - | $ - | | | 0 | $ - | $ - | | | 0 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 6.63 | | | $ 8.08 | **$ 1.44** | **21.73%** | | | $ 8.58 | **$ 0.50** | **6.24%** | | | $ 9.02 | **$ 0.44** | **5.09%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 0 | $ - | -$ 0.2038 | 0 | -$ 0.08 | -$ 0.08 | | | 0 | $ - | $ 0.08 | -100.00% | | 0 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 94 | $ - | $ - | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.01785 | 0 | $ 0.01 | $ 0.01877 | 0 | $ 0.01 | $ 0.00 | 5.15% | $ 0.01893 | 0 | $ 0.01 | $ 0.00 | 0.85% | $ 0.01898 | 0 | $ 0.01 | $ 0.00 | 0.26% |
| Line Losses on Cost of Power | | $ 0.1021 | 3 | $ 0.34 | $ 0.1021 | 3 | $ 0.32 | -$ 0.02 | -5.59% | $ 0.1021 | 3 | $ 0.32 | $ - | 0.00% | $ 0.1021 | 3 | $ 0.32 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 6.99** | | | **$ 8.33** | **$ 1.34** | **19.20%** | | | **$ 8.91** | **$ 0.59** | **7.03%** | | | **$ 9.35** | **$ 0.44** | **4.90%** |
| RTSR - Network | per kW | $ 2.1461 | 0.4 | $ 0.86 | $ 2.1461 | 0.4 | $ 0.86 | $ - | 0.00% | $ 2.1461 | 0.4 | $ 0.86 | $ - | 0.00% | $ 2.1461 | 0.4 | $ 0.86 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.2058 | 0.4 | $ 0.48 | $ 1.2058 | 0.4 | $ 0.48 | $ - | 0.00% | $ 1.2058 | 0.4 | $ 0.48 | $ - | 0.00% | $ 1.2058 | 0.4 | $ 0.48 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 8.33** | | | **$ 9.67** | **$ 1.34** | **16.11%** | | | **$ 10.25** | **$ 0.59** | **6.05%** | | | **$ 10.69** | **$ 0.44** | **4.26%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 97 | $ 0.43 | $ 0.0044 | 97 | $ 0.43 | -$ 0.00 | -0.19% | $ 0.0044 | 97 | $ 0.43 | $ - | 0.00% | $ 0.0044 | 97 | $ 0.43 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 97 | $ 0.13 | $ 0.0013 | 97 | $ 0.13 | -$ 0.00 | -0.19% | $ 0.0013 | 97 | $ 0.13 | $ - | 0.00% | $ 0.0013 | 97 | $ 0.13 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 94 | $ 0.65 | $ 0.0069 | 94 | $ 0.65 | $ - | 0.00% | $ 0.0069 | 94 | $ 0.65 | $ - | 0.00% | $ 0.0069 | 94 | $ 0.65 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 60 | $ 4.81 | $ 0.0800 | 60 | $ 4.81 | $ - | 0.00% | $ 0.0800 | 60 | $ 4.81 | $ - | 0.00% | $ 0.0800 | 60 | $ 4.81 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 17 | $ 2.06 | $ 0.1220 | 17 | $ 2.06 | $ - | 0.00% | $ 0.1220 | 17 | $ 2.06 | $ - | 0.00% | $ 0.1220 | 17 | $ 2.06 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 17 | $ 2.72 | $ 0.1610 | 17 | $ 2.72 | $ - | 0.00% | $ 0.1610 | 17 | $ 2.72 | $ - | 0.00% | $ 0.1610 | 17 | $ 2.72 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 94 | $ 8.84 | $ 0.0940 | 94 | $ 8.84 | $ - | 0.00% | $ 0.0940 | 94 | $ 8.84 | $ - | 0.00% | $ 0.0940 | 94 | $ 8.84 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 19.38** | | | **$ 20.72** | **$ 1.34** | **6.91%** | | | **$ 21.31** | **$ 0.59** | **2.82%** | | | **$ 21.75** | **$ 0.44** | **2.05%** |
| HST | | 13% | | $ 2.52 | 13% | | $ 2.69 | $ 0.17 | 6.91% | 13% | | $ 2.77 | $ 0.08 | 2.82% | 13% | | $ 2.83 | $ 0.06 | 2.05% |
| **Total Bill** (including HST) | | | | $ 21.90 | | | $ 23.42 | $ 1.51 | 6.91% | | | $ 24.08 | $ 0.66 | 2.82% | | | $ 24.57 | $ 0.49 | 2.05% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 21.90** | | | **$ 23.42** | **$ 1.51** | **6.91%** | | | **$ 24.08** | **$ 0.66** | **2.82%** | | | **$ 24.57** | **$ 0.49** | **2.05%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 18.62** | | | **$ 19.96** | **$ 1.34** | **7.20%** | | | **$ 20.54** | **$ 0.59** | **2.93%** | | | **$ 20.98** | **$ 0.44** | **2.13%** |
| HST | | 13% | | $ 2.42 | 13% | | $ 2.59 | $ 0.17 | 7.20% | 13% | | $ 2.67 | $ 0.08 | 2.93% | 13% | | $ 2.73 | $ 0.06 | 2.13% |
| **Total Bill** (including HST) | | | | $ 21.04 | | | $ 22.55 | $ 1.51 | 7.20% | | | $ 23.22 | $ 0.66 | 2.93% | | | $ 23.71 | $ 0.49 | 2.13% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 21.04** | | | **$ 22.55** | **$ 1.51** | **7.20%** | | | **$ 23.22** | **$ 0.66** | **2.93%** | | | **$ 23.71** | **$ 0.49** | **2.13%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Sentinel Lights

**TOU / non-TOU:** TOU

**Consumption** 94 kWh ● May 1 - October
0.40 KW

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | 2019 Proposed Rate ($) | Volume | Charge ($) | Impact 2019 vs 2018 $ Change | % Change | 2020 Proposed Rate ($) | Volume | Charge ($) | Impact 2020 vs 2019 $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 2.62 | 1 | $ 2.62 | $ 4.250 | 1 | $ 4.25 | $ 0.25 | 6.25% | $ 4.750 | 1 | $ 4.75 | $ 0.50 | 11.76% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 10.0361 | 0 | $ 4.01 | $ 12.9159 | 0 | $ 5.17 | $ 0.15 | 2.98% | $ 12.4211 | 0 | $ 4.97 | -$ 0.20 | -3.83% |
| Smart Meter Disposition Rider | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 0 | $ - | | 0 | $ - | $ - | | | 0 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 6.63 | | | $ 9.42 | **$ 0.40** | **4.43%** | | | $ 9.72 | **$ 0.30** | **3.21%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 0 | $ - | | 0 | $ - | $ - | | | 0 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| | | | 94 | $ - | | 94 | $ - | $ - | | | 94 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.01785 | 0 | $ 0.01 | $ 0.01899 | 0 | $ 0.01 | $ 0.00 | 0.05% | $ 0.01900 | 0 | $ 0.01 | $ 0.00 | 0.05% |
| Line Losses on Cost of Power | | $ 0.1021 | 3 | $ 0.34 | $ 0.1021 | 3 | $ 0.32 | $ - | 0.00% | $ 0.1021 | 3 | $ 0.32 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 6.99** | | | **$ 9.75** | **$ 0.40** | **4.27%** | | | **$ 10.05** | **$ 0.30** | **3.10%** |
| RTSR - Network | per kW | $ 2.1461 | 0.4 | $ 0.86 | $ 2.1461 | 0.4 | $ 0.86 | $ - | 0.00% | $ 2.1461 | 0.4 | $ 0.86 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.2058 | 0.4 | $ 0.48 | $ 1.2058 | 0.4 | $ 0.48 | $ - | 0.00% | $ 1.2058 | 0.4 | $ 0.48 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 8.33** | | | **$ 11.09** | **$ 0.40** | **3.74%** | | | **$ 11.39** | **$ 0.30** | **2.72%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 97 | $ 0.43 | $ 0.0044 | 97 | $ 0.43 | $ - | 0.00% | $ 0.0044 | 97 | $ 0.43 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 97 | $ 0.13 | $ 0.0013 | 97 | $ 0.13 | $ - | 0.00% | $ 0.0013 | 97 | $ 0.13 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 94 | $ 0.65 | $ 0.0069 | 94 | $ 0.65 | $ - | 0.00% | $ 0.0069 | 94 | $ 0.65 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 60 | $ 4.81 | $ 0.0800 | 60 | $ 4.81 | $ - | 0.00% | $ 0.0800 | 60 | $ 4.81 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 17 | $ 2.06 | $ 0.1220 | 17 | $ 2.06 | $ - | 0.00% | $ 0.1220 | 17 | $ 2.06 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 17 | $ 2.72 | $ 0.1610 | 17 | $ 2.72 | $ - | 0.00% | $ 0.1610 | 17 | $ 2.72 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 94 | $ 8.84 | $ 0.0940 | 94 | $ 8.84 | $ - | 0.00% | $ 0.0940 | 94 | $ 8.84 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 19.38** | | | **$ 22.15** | **$ 0.40** | **1.84%** | | | **$ 22.45** | **$ 0.30** | **1.36%** |
| HST | | 13% | | $ 2.52 | 13% | | $ 2.88 | $ 0.05 | 1.84% | 13% | | $ 2.92 | $ 0.04 | 1.36% |
| **Total Bill** (including HST) | | | | $ 21.90 | | | $ 25.03 | $ 0.45 | 1.84% | | | $ 25.37 | $ 0.34 | 1.36% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 21.90** | | | **$ 25.03** | **$ 0.45** | **1.84%** | | | **$ 25.37** | **$ 0.34** | **1.36%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 18.62** | | | **$ 21.38** | **$ 0.40** | **1.90%** | | | **$ 21.68** | **$ 0.30** | **1.41%** |
| HST | | 13% | | $ 2.42 | 13% | | $ 2.78 | $ 0.05 | 1.90% | 13% | | $ 2.82 | $ 0.04 | 1.41% |
| **Total Bill** (including HST) | | | | $ 21.04 | | | $ 24.16 | $ 0.45 | 1.90% | | | $ 24.50 | $ 0.34 | 1.41% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 21.04** | | | **$ 24.16** | **$ 0.45** | **1.90%** | | | **$ 24.50** | **$ 0.34** | **1.41%** |

| | Current | 2019 | 2020 |
|---|---|---|---|
| **Loss Factor (%)** | 3.5800% | 3.3800% | 3.3800% |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Street Light

**TOU / non-TOU:** TOU

**Consumption** 150 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

1.00 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Volume | Current Charge ($) | 2016 Proposed Rate ($) | 2016 Volume | 2016 Charge ($) | Impact 2016 vs 2015 $ Change | Impact 2016 vs 2015 % Change | 2017 Proposed Rate ($) | 2017 Volume | 2017 Charge ($) | Impact 2017 vs 2016 $ Change | Impact 2017 vs 2016 % Change | 2018 Proposed Rate ($) | 2018 Volume | 2018 Charge ($) | Impact 2018 vs 2017 $ Change | Impact 2018 vs 2017 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 0.57 | 1 | $ 0.57 | 0.65 | 1 | $ 0.65 | $ 0.08 | 14.04% | $ 0.70 | 1 | $ 0.70 | $ 0.05 | 7.69% | $ 0.75 | 1 | $ 0.75 | $ 0.05 | 7.14% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.9997 | 1 | $ 4.00 | $ 4.3442 | 1 | $ 4.34 | $ 0.34 | 8.61% | $ 4.5389 | 1 | $ 4.54 | $ 0.19 | 4.48% | $ 4.7173 | 1 | $ 4.72 | $ 0.18 | 3.93% |
| Smart Meter Disposition Rider | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 1 | $ - | - 0.0001 | 1 | -$ 0.00 | -$ 0.00 | | | 1 | $ - | $ 0.00 | -100.00% | | 1 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 4.57 | | | $ 4.99 | **$ 0.42** | **9.29%** | | | $ 5.24 | **$ 0.24** | **4.90%** | | | $ 5.47 | **$ 0.23** | **4.36%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 1 | $ - | - 0.34790 | 1 | -$ 0.35 | -$ 0.35 | | | 1 | $ - | $ 0.35 | -100.00% | | 1 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 150 | $ - | -$ 0.0003 | 150 | -$ 0.05 | -$ 0.05 | | | 150 | $ - | $ 0.05 | -100.00% | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.01749 | 1 | $ 0.02 | $ 0.01916 | 1 | $ 0.02 | $ 0.00 | 9.55% | $ 0.01933 | 1 | $ 0.02 | $ 0.00 | 0.89% | $ 0.01937 | 1 | $ 0.02 | $ 0.00 | 0.21% |
| Line Losses on Cost of Power | | $ 0.1021 | 5 | $ 0.55 | $ 0.1021 | 5 | $ 0.52 | -$ 0.03 | -5.59% | $ 0.1021 | 5 | $ 0.52 | $ - | 0.00% | $ 0.1021 | 5 | $ 0.52 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 5.14** | | | **$ 5.14** | **$ 0.00** | **0.05%** | | | **$ 5.78** | **$ 0.64** | **12.41%** | | | **$ 6.00** | **$ 0.23** | **3.95%** |
| RTSR - Network | per kW | $ 2.1570 | 1 | $ 2.16 | $ 2.1570 | 1 | $ 2.16 | $ - | 0.00% | $ 2.1570 | 1 | $ 2.16 | $ - | 0.00% | $ 2.1570 | 1 | $ 2.16 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.2310 | 1 | $ 1.23 | $ 1.2310 | 1 | $ 1.23 | $ - | 0.00% | $ 1.2310 | 1 | $ 1.23 | $ - | 0.00% | $ 1.2310 | 1 | $ 1.23 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 8.52** | | | **$ 8.53** | **$ 0.00** | **0.03%** | | | **$ 9.16** | **$ 0.64** | **7.48%** | | | **$ 9.39** | **$ 0.23** | **2.49%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 155 | $ 0.68 | $ 0.0044 | 155 | $ 0.68 | -$ 0.00 | -0.19% | $ 0.0044 | 155 | $ 0.68 | $ - | 0.00% | $ 0.0044 | 155 | $ 0.68 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 155 | $ 0.20 | $ 0.0013 | 155 | $ 0.20 | -$ 0.00 | -0.19% | $ 0.0013 | 155 | $ 0.20 | $ - | 0.00% | $ 0.0013 | 155 | $ 0.20 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 150 | $ 1.04 | $ 0.0069 | 150 | $ 1.04 | $ - | 0.00% | $ 0.0069 | 150 | $ 1.04 | $ - | 0.00% | $ 0.0069 | 150 | $ 1.04 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 96 | $ 7.68 | $ 0.0800 | 96 | $ 7.68 | $ - | 0.00% | $ 0.0800 | 96 | $ 7.68 | $ - | 0.00% | $ 0.0800 | 96 | $ 7.68 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 27 | $ 3.29 | $ 0.1220 | 27 | $ 3.29 | $ - | 0.00% | $ 0.1220 | 27 | $ 3.29 | $ - | 0.00% | $ 0.1220 | 27 | $ 3.29 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 27 | $ 4.35 | $ 0.1610 | 27 | $ 4.35 | $ - | 0.00% | $ 0.1610 | 27 | $ 4.35 | $ - | 0.00% | $ 0.1610 | 27 | $ 4.35 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 150 | $ 14.10 | $ 0.0940 | 150 | $ 14.10 | $ - | 0.00% | $ 0.0940 | 150 | $ 14.10 | $ - | 0.00% | $ 0.0940 | 150 | $ 14.10 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 26.02** | | | **$ 26.02** | **$ 0.00** | **0.00%** | | | **$ 26.66** | **$ 0.64** | **2.45%** | | | **$ 26.89** | **$ 0.23** | **0.86%** |
| HST | | 13% | | $ 3.38 | 13% | | $ 3.38 | $ 0.00 | 0.00% | 13% | | $ 3.47 | $ 0.08 | 2.45% | 13% | | $ 3.50 | $ 0.03 | 0.86% |
| **Total Bill** (including HST) | | | | $ 29.40 | | | $ 29.40 | $ 0.00 | 0.00% | | | $ 30.13 | $ 0.72 | 2.45% | | | $ 30.38 | $ 0.26 | 0.86% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 29.40** | | | **$ 29.40** | **$ 0.00** | **0.00%** | | | **$ 30.13** | **$ 0.72** | **2.45%** | | | **$ 30.38** | **$ 0.26** | **0.86%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 24.80** | | | **$ 24.80** | **$ 0.00** | **0.00%** | | | **$ 25.44** | **$ 0.64** | **2.57%** | | | **$ 25.67** | **$ 0.23** | **0.90%** |
| HST | | 13% | | $ 3.22 | 13% | | $ 3.22 | $ 0.00 | 0.00% | 13% | | $ 3.31 | $ 0.08 | 2.57% | 13% | | $ 3.34 | $ 0.03 | 0.90% |
| **Total Bill** (including HST) | | | | $ 28.02 | | | $ 28.03 | $ 0.00 | 0.00% | | | $ 28.75 | $ 0.72 | 2.57% | | | $ 29.00 | $ 0.26 | 0.90% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 28.02** | | | **$ 28.03** | **$ 0.00** | **0.00%** | | | **$ 28.75** | **$ 0.72** | **2.57%** | | | **$ 29.00** | **$ 0.26** | **0.90%** |
| **Loss Factor (%)** | | 3.5800% | | | 3.3800% | | | | | 3.3800% | | | | | 3.3800% | | | | |

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## Appendix 2-W
## Bill Impacts

**Customer Class:** Street Light

**TOU / non-TOU:** TOU

**Consumption** 150 kWh ● May 1 - October
1.00 KW

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | 2019 Proposed Rate ($) | 2019 Proposed Volume | 2019 Proposed Charge ($) | Impact 2019 vs 2018 $ Change | Impact 2019 vs 2018 % Change | 2020 Proposed Rate ($) | 2020 Proposed Volume | 2020 Proposed Charge ($) | Impact 2020 vs 2019 $ Change | Impact 2020 vs 2019 % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 0.57 | 1 | $ 0.57 | $ 0.80 | 1 | $ 0.80 | $ 0.05 | 6.67% | $ 0.80 | 1 | $ 0.80 | $ - | 0.00% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 3.9997 | 1 | $ 4.00 | $ 4.8325 | 1 | $ 4.83 | $ 0.12 | 2.44% | $ 5.0761 | 1 | $ 5.08 | $ 0.24 | 5.04% |
| Smart Meter Disposition Rider | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| **Sub-Total A (excluding pass through)** | | | | $ 4.57 | | | $ 5.63 | **$ 0.17** | **3.02%** | | | $ 5.88 | **$ 0.24** | **4.32%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 1 | $ - | | 1 | $ - | $ - | | | 1 | $ - | $ - | |
| Deferral/Variance Account Disposition Rate Rider - Global Adjustment | per kWh | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| | | | 150 | $ - | | 150 | $ - | $ - | | | 150 | $ - | $ - | |
| Low Voltage Service Charge | per kW | $ 0.01749 | 1 | $ 0.02 | $ 0.01939 | 1 | $ 0.02 | $ 0.00 | 0.10% | $ 0.01940 | 1 | $ 0.02 | $ 0.00 | 0.05% |
| Line Losses on Cost of Power | | $ 0.1021 | 5 | $ 0.55 | $ 0.1021 | 5 | $ 0.52 | $ - | 0.00% | $ 0.1021 | 5 | $ 0.52 | $ - | 0.00% |
| Smart Meter Entity Charge | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | | $ - | 1 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 5.14** | | | **$ 6.17** | **$ 0.17** | **2.75%** | | | **$ 6.41** | **$ 0.24** | **3.95%** |
| RTSR - Network | per kW | $ 2.1570 | 1 | $ 2.16 | $ 2.1570 | 1 | $ 2.16 | $ - | 0.00% | $ 2.1570 | 1 | $ 2.16 | $ - | 0.00% |
| RTSR - Line and Transformation Connection | per kW | $ 1.2310 | 1 | $ 1.23 | $ 1.2310 | 1 | $ 1.23 | $ - | 0.00% | $ 1.2310 | 1 | $ 1.23 | $ - | 0.00% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 8.52** | | | **$ 9.56** | **$ 0.17** | **1.76%** | | | **$ 9.80** | **$ 0.24** | **2.55%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 155 | $ 0.68 | $ 0.0044 | 155 | $ 0.68 | $ - | 0.00% | $ 0.0044 | 155 | $ 0.68 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0013 | 155 | $ 0.20 | $ 0.0013 | 155 | $ 0.20 | $ - | 0.00% | $ 0.0013 | 155 | $ 0.20 | $ - | 0.00% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0069 | 150 | $ 1.04 | $ 0.0069 | 150 | $ 1.04 | $ - | 0.00% | $ 0.0069 | 150 | $ 1.04 | $ - | 0.00% |
| TOU - Off Peak | | $ 0.0800 | 96 | $ 7.68 | $ 0.0800 | 96 | $ 7.68 | $ - | 0.00% | $ 0.0800 | 96 | $ 7.68 | $ - | 0.00% |
| TOU - Mid Peak | | $ 0.1220 | 27 | $ 3.29 | $ 0.1220 | 27 | $ 3.29 | $ - | 0.00% | $ 0.1220 | 27 | $ 3.29 | $ - | 0.00% |
| TOU - On Peak | | $ 0.1610 | 27 | $ 4.35 | $ 0.1610 | 27 | $ 4.35 | $ - | 0.00% | $ 0.1610 | 27 | $ 4.35 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0940 | 150 | $ 14.10 | $ 0.0940 | 150 | $ 14.10 | $ - | 0.00% | $ 0.0940 | 150 | $ 14.10 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.1100 | 0 | $ - | $ 0.1100 | 0 | $ - | $ - | | $ 0.1100 | 0 | $ - | $ - | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 26.02** | | | **$ 27.05** | **$ 0.17** | **0.61%** | | | **$ 27.30** | **$ 0.24** | **0.90%** |
| HST | | 13% | | $ 3.38 | 13% | | $ 3.52 | $ 0.02 | 0.61% | 13% | | $ 3.55 | $ 0.03 | 0.90% |
| **Total Bill** (including HST) | | | | $ 29.40 | | | $ 30.57 | $ 0.19 | 0.61% | | | $ 30.85 | $ 0.28 | 0.90% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on TOU (including OCEB)** | | | | **$ 29.40** | | | **$ 30.57** | **$ 0.19** | **0.61%** | | | **$ 30.85** | **$ 0.28** | **0.90%** |
| **Total Bill on RPP (before Taxes)** | | | | **$ 24.80** | | | **$ 25.83** | **$ 0.17** | **0.64%** | | | **$ 26.08** | **$ 0.24** | **0.94%** |
| HST | | 13% | | $ 3.22 | 13% | | $ 3.36 | $ 0.02 | 0.64% | 13% | | $ 3.39 | $ 0.03 | 0.94% |
| **Total Bill** (including HST) | | | | $ 28.02 | | | $ 29.19 | $ 0.19 | 0.64% | | | $ 29.47 | $ 0.28 | 0.94% |
| ***Ontario Clean Energy Benefit*** [1] | | | | $ - | | | $ - | $ - | | | | $ - | $ - | |
| **Total Bill on RPP (including OCEB)** | | | | **$ 28.02** | | | **$ 29.19** | **$ 0.19** | **0.64%** | | | **$ 29.47** | **$ 0.28** | **0.94%** |

**Loss Factor (%)** — Current Board-Approved: 3.5800% — 2019 Proposed: 3.3800% — 2020 Proposed: 3.3800%

# CURRENT DEFERRAL AND VARIANCE ACCOUNTS

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") has included a request for approval of the disposition for the Group 1 and Group 2 Deferral and Variance Accounts ("DVAs") based on the balances at December 31, 2013 and the forecasted interest through December 31, 2014 in this Custom Incentive Rate Application. Hydro Ottawa intends to file an updated request based on December 31, 2014 balances and forecasted interest for 2015 as part of the rate application process.

## 2.0 DETAILS OF DEFERRAL AND VARIANCE ACCOUNTS

Included in the following Tables 1 and 2 is a complete list of Hydro Ottawa's active DVAs categorized based on the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report"), which categorizes the DVA accounts into Group 1 and Group 2 accounts.

**Table 1 – Group 1 Deferral and Variance Accounts**

| Group 1 Account – Description | Account |
|---|---|
| Low Voltage ("LV") Account | 1550 |
| Smart Meter Entity Charge Variance Account | 1551 |
| Retail Settlement Variance Account ("RSVA")- Wholesale Market Service Charge | 1580 |
| RSVA - Retail Transmission Network Charge | 1584 |
| RSVA - Retail Transmission Connection Charge | 1586 |
| RSVA - Power (Excluding Global Adjustment) | 1588 |
| RSVA - Global Adjustment | 1589 |
| Disposition and Recovery/Refund of Regulatory Balances Account | 1595 |

**Table 2 – Group 2 Deferral and Variance Accounts**

| Group 2 Account – Description | Account |
|---|---|
| Other Regulatory Assets | 1508 |
| Retail Cost Variance Account – Retail | 1518 |
| Renewable Connection OM&A Deferral Account | 1532 |
| Smart Grid OM&A Deferral Account | 1535 |
| Retail Cost Variance Account – STR | 1548 |
| Smart Meter Capital Account | 1555 |
| Smart Meter OM&A Account | 1556 |
| LRAM Variance Account ("LRAMVA") | 1568 |
| IFRS-CGAAP Transitional PP&E Amounts | 1575 |
| RSVA - One-time Wholesale Market Service | 1582 |
| PILs and Tax Variance | 1592 |

Hydro Ottawa confirms that no deferral and variance accounts are being used differently than as prescribed in the Accounting Procedures Handbook ("APH").

## 3.0 CONTINUITY SCHEDULE

Attachment I-8(A) to this Exhibit is a complete continuity schedule for all Deferral and Variance accounts based on the Deferral and Variance Account (Continuity Schedule) Work Form – version 2.4 Excel spreadsheet as posted by the Board on its website June 26, 2014.

Hydro Ottawa is proposing to dispose of Group 1 and Group 2 accounts, except for those listed in section 3 of Exhibit I-8-1, the total DVA disposal of $8.2 million is to be returned to customers over a period of one year. This will be divided into three rate riders, the total proposed disposition for Group 1 and Group 2, excluding Global Adjustment and LRAMVA is a credit of $6.3 million to be returned to all customer classes. The global adjustment rate rider proposed would return $1.3 million to non-Regulated Price Plan ("non-RPP") customers. The LRAM rate rider proposed would return $679k to all customer classes. Please refer to Exhibit I-8-1 for further details on the disposition plan.

## 4.0 CARRYING CHARGES

The interest rate used for the calculation of all carrying charges was as prescribed by the Board and published quarterly on its website. Please refer to Table 3 for a listing of these interest rates up to 2015 Q2. Hydro Ottawa confirms it uses these interest rates as provided by the Board.

**Table 3 – Interest Rates for Carrying Charges on Deferral and Variance Accounts**

| Approved Deferral and Variance Accounts | |
|---|---|
| **Quarter by Year** | **Prescribed Interest Rate** |
| Q2 2015 | 1.10% |
| Q1 2015 | 1.47% |
| Q4 2014 | 1.47% |
| Q3 2014 | 1.47% |
| Q2 2014 | 1.47% |
| Q1 2014 | 1.47% |
| Q4 2013 | 1.47% |
| Q3 2013 | 1.47% |
| Q2 2013 | 1.47% |
| Q1 2013 | 1.47% |
| Q4 2012 | 1.47% |
| Q3 2012 | 1.47% |
| Q2 2012 | 1.47% |
| Q1 2012 | 1.47% |
| Q4 2011 | 1.47% |
| Q3 2011 | 1.47% |
| Q2 2011 | 1.47% |
| Q1 2011 | 1.47% |
| Q4 2010 | 1.20% |
| Q3 2010 | 0.89% |
| Q2 2010 | 0.55% |
| Q1 2010 | 0.55% |

Carrying charges were calculated on all deferral and variance accounts with the exception of:

- USofA's 1575 – IFRS –CGAAP Transitional PP&E Amounts
- USofA 1508, Other Regulatory Assets, Sub-Account P&OPEB Deferral Account and,
- 1592 - PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT.

## 5.0 RECONCILIATION OF CONTINUITY SCHEDULE VS. RRR's

As per the Continuity Schedule in Appendix I-8(A), there are two differences in the account balances as of December 31, 2013 between the continuity schedule and 2.1.7 Electricity Reporting and Record-keeping Requirements ("RRR's") reported to the Board.

The Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") – USofA 1568 has a difference of $104k when compared to the December 31, 2013 2.1.7 RRR as reported to the OEB. The Continuity Schedule includes balances to the end of 2014 so they can be disposed of as part of this rate application, resulting in a timing difference.

There is also a difference in USofA 1592 - PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs). Question 1 from the Board's APH FAQ's dated December 23, 2010, stated that for regulatory reporting purposes the sub-account and contra account for HST/OVAT will have a reporting amount for RRR's that nets to zero. This is consistent with Hydro Ottawa's RRR 2.1.7 filing. The same document from the Board states that the balance in this sub-account should be reported for disposition; therefore, the credit balance of $545k will be returned to customers.

The result is a variance between the RRR filing and the balance to be disposed of $441k.

## 6.0 STATUS OF GROUP 2 ACCOUNTS

Hydro Ottawa identified active Group 2 accounts in Table 2 of this Exhibit. Please refer to Table 4 for an outline of Group 2 accounts that Hydro Ottawa is proposing to continue or discontinue.

**Table 4 - Status of Group 2 Accounts**

| Group 2 Account - Description | Account | Continue/Discontinue |
|---|---|---|
| Other Regulatory Assets | 1508 | Continue |
| Retail Cost Variance Account – Retail | 1518 | Continue[1] |
| Renewable Connection OM&A Deferral Account | 1532 | Continue |
| Smart Grid OM&A Deferral Account | 1535 | Continue |
| Retail Cost Variance Account – STR | 1548 | Continue[1] |
| Smart Meter Capital Account | 1555 | Discontinue[2] |
| Smart Meter OM&A Account | 1556 | Discontinue |
| LRAM Variance Account ("LRAMVA") | 1568 | Continue |
| IFRS-CGAAP Transitional PP&E Amounts | 1575 | Discontinue |
| RSVA - One-time Wholesale Market Service | 1582 | Continue |
| PILs and Tax Variance | 1592 | Discontinue |

1. Proposal to Continue tracking until end of 2015, Dispose of remaining balance in 2018 for 2019 rates, see Exhibits I-7-1 and I-8-1

2. 1555 upon approval of disposition through 1595 rate rider

## 7.0 NEW DEFERRAL AND VARIANCE ACCOUNTS AND SUB-ACCOUNTS

Please refer to Exhibit I-1-2 for details regarding new DVAs that Hydro Ottawa is requesting.

## 8.0 ADJUSTMENTS TO DEFERAL AND VARIANCE ACCOUNTS

Hydro Ottawa confirms it has not made any adjustments to DVA balances that were previously approved by the board on a final basis, in either a Cost of Service or Incentive Regulation Mechanism ("IRM") proceedings.

## 9.0 ENERGY SALES AND COST OF POWER EXPENSE BALANCES

The sale of energy and cost of power are flow through items. The components of energy sales and the cost of power are broken down by USofA in Table 5. Hydro Ottawa does not report any difference for financial purposes between the energy sales and the cost of power. As a result, Hydro Ottawa does not derive any economic gain or loss in the flow through of these accounts.

**Table 5 – Cost of Power and Energy Sales**

| ENERGY SALES | | |
|---|---|---|
| **Account and Description** | **2012** | **2013** |
| 4006 Residential Energy Sales | ($178,314,106) | ($192,253,659) |
| 4020 Energy Sales to Large Users | (38,006,458) | (47,291,162) |
| 4025 Street Lighting Energy Sales | (934,382) | (2,907,587) |
| 4030 Sentinel Lighting Energy Sales | (8,926) | (8,727) |
| 4035 General Energy Sales | (370,884,811) | (401,258,444) |
| 4050 Revenue Adjustment | 1,123,181 | - |
| 4062 Billed WMS | (40,131,924) | (39,786,424) |
| 4066 Billed NW | (49,877,881) | (51,001,142) |
| 4068 Billed CN | (32,396,995) | (31,148,466) |
| 4075 Billed – LV | (502,730) | (438,498) |
| 4076 Billed Smart Metering Entity Charge | | (1,984,655) |
| **Sum of Energy Sales** | **($709,935,032)** | **($768,078,763)** |
| **COST OF POWER** | | |
| **Account and Description** | **2012** | **2013** |
| 4705 Power Purchased | $ 622,335,248 | $ 643,719,579 |
| 4708 Charges-WMS | 37,219,173 | 39,786,424 |
| 4714 Charges-NW | 49,877,881 | 51,001,142 |
| 4716 Charges-CN | | 31,148,466 |
| 4750 Charges – LV | 502,730 | 438,498 |
| 4751 Charges - Smart Metering Charge | | 1,984,655 |
| **Sum of Cost of Power** | **$ 709,935,032** | **$ 768,078,763** |
| **Sum of Energy Sales and Cost of Power** | **-** | **-** |

The totals of energy sales and cost of power are reconciled to the audited financial statements, please refer to Table 6.

**Table 6 – Reconciliation to Audited Financial Statements**

| **Reconciliation to Audited Financial Statements - $000's** | | |
|---|---|---|
| **Energy Sales** | 2012 | 2013 |
| Total Energy Sales as per Audited Financial Statements | ($709,935) | ($768,079) |
| **Cost of Power** | | |
| Total Cost of Power as per Audited Financial Statements | $ 709,935 | $ 768,079 |
| **Net Energy Sales and Cost of Power** | **0** | **0** |

## 10.0 IESO GLOBAL ADJUSTMENT CHARGE (RPP AND NON-RPP)

Hydro Ottawa confirms that the Independent Electricity System Operator ("IESO") Global Adjustment Charge is pro-rated between Regulated Price Plan ("RPP") and non-RPP portions.

# NEW DEFERRAL AND VARIANCE ACCOUNTS

## 1.0 INTRODUCTION

This Schedule describes Hydro Ottawa Limited ("Hydro Ottawa") proposal for six new deferral and variance accounts ("DVAs"). Below Hydro Ottawa describes the eligibility criteria regarding causation, materiality and prudence for each of the new accounts proposed. In addition, a draft accounting order including mechanics of the account and illustrations of general ledger entries using the Uniform System of Accounts ("USofA") for new DVAs is included as applicable.

## 2.0 PROPOSED TREATMENT OF GROUP 1 AND GROUP 2 ACCOUNTS

Hydro Ottawa proposes to dispose of Group 1 and Group 2 DVAs by way of this application. Pursuant to Hydro Ottawa's Custom Incentive Regulation (Custom IR) rate setting model, as set out in Exhibit A-2-1, Hydro Ottawa proposes to lock-in final distribution rates for 2016, 2017 and 2018. As a consequence, Hydro Ottawa will not file an annual Incentive Regulation Mechanism ("IRM") to change distribution rates, however it will file an annual update to Hydro One Transmission and Connection Rates, as per Exhibit H-3-1. To be clear, Hydro Ottawa proposes to update the retail transmission service rates ("RTSRs") on an annual basis, 2017 through 2020, based on Board Approved adjustments to the Hydro One Uniform Transmission Rates ("UTRs") using the RTSR model, which is part of the IRM model. Given Hydro One UTRs are not typically approved in time for adjusting Hydro Ottawa's rates on January 1, Hydro Ottawa proposes to set each year's RTSRs using the previous year's UTRs. Hydro Ottawa proposes that the differences from the new yearly rates be captured in Uniform System of Accounts 1584 – RSVA Network and 1586 – RSVA Connection for future disposition. With respect to the Group 1 accounts, Hydro Ottawa proposes to reserve the ability to dispose of these balances on an annual basis, as contemplated in Boards *Filling Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications,* Section 3.2.3, page 10 there is a pre-set disposition threshold of $0.001

per kWh and consistent with a letter from the Board dated July 25, 2014, distributors may now elect to dispose of Group 1 account balances below the threshold. For Group 2 accounts Hydro Ottawa proposes to dispose of these balances when applying for 2019 & 2020 rates, with the exception of Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"), which may be disposed of on an annual basis using a separate rate rider. This is consistent with the Boards *Filling Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications* Section 3.2.4.1 on page 9, that allows distributors to apply for disposition of the LRAMVA balance on an annual basis, if said balance is deemed significant by the applicant. Hydro Ottawa proposes these methods for disposing of DVAs to avoid or reduce the impact of intergenerational rate inequities.

## 3.0 NEW DEFERRAL AND VARIANCE ACCOUNTS BEING REQUESTED

### 3.1 Facilities Implementation Plan – Y Factor

Hydro Ottawa proposes to recover the costs associated with the construction of a new South Operations and Warehouse facility and an Eastern Operations and Administrative Campus facility through use of a Y factor. The Y factor recovers routine or expected cost changes outside the scope of the annual adjustment mechanism; these are considered to be a cost pass-through. Hydro Ottawa proposes to use a Y factor to pass along to ratepayers the costs associated with the construction of the administrative and operational buildings as outlined in section 3.4.5.3 of Hydro Ottawa Distribution System Plan found in Exhibit B-1-2. Hydro Ottawa proposes to use the Y factor as opposed to embedding the full cost into revenue requirement as the precise costs and the timing in which they will be incurred remain unknown at this time. Hydro Ottawa proposes to record the expenses incurred due to the construction of new head office and operations facilities by using a Y factor Variance or Deferral Account.

The associated project costs will be allocated in accordance pursuant to the Board-approved cost allocation methodologies and the rate setting principles approved as a result of Hydro Ottawa's 2016 custom rate application. The incremental revenue impact associated with the Y factors will be passed through to rates and allocated to rate classes and collected via rate riders.

Hydro Ottawa shall maintain the deferral and variance accounts related to the Y factor for the term of the custom IR.

Hydro Ottawa proposes to recover the rate rider amounts on a fixed per customer basis using the same customer class allocation methodology as distribution revenue for the year the Y factor is introduced.

Please find below Hydro Ottawa's proposed accounting entries for tracking this Y Factor by USofA.

Accounting Entries (Proposed)

**A) Asset Capitalization**

| | Debit | Credit |
|---|---|---|
| Regulatory Asset – Expense | | |
| Sub-Account – Depreciation | x,xxx.xx | |
| Sub-Account – Interest | x,xxx.xx | |
| Sub-Account – Return | x,xxx.xx | |
| Sub-Account – PILs | x,xxx.xx | |
| Distribution Revenue | | x,xxx.xx |

To record expenses once asset has been capitalized

**B) Revenue Collection**

| | Debit | Credit |
|---|---|---|
| Distribution Revenue | x,xxx.xx | |
| Regulatory Asset – Sub Account Revenue | | x,xxx.xx |

To collect Revenue after Rate Rider is in place.

These journal entries would continue until Hydro Ottawa's next Custom IR application or rebasing, at which point the residual balances will be requested to be cleared.

### 3.2 Proceeds of Sale of Existing Facilities

Following the move to its new office facilities, Hydro Ottawa's existing Albion Road, Merivale Road and Bank Street facilities ("Existing Facilities") will be marketed for sale. Presently Hydro Ottawa does not know the market value or sale price for the Existing Facilities nor the year in which the sale will occur.

Hydro Ottawa proposes to set up a deferral account to record the after tax gain/loss from the sale of the Existing Facilities. Hydro Ottawa proposes to credit/debit ratepayers with the entire value of the after-tax net gain/loss on the sale for the buildings and for 50% of the after-tax net gain for the sale of the lands. The 50% share of the after tax net gain for the sale of the land recognizes that land is an undepreciated asset. This deferral account will be forwarded for clearance in a future proceeding(s) once the after tax net gain/loss on the buildings and plots of land have been assessed by Canada Revenue Agency. Hydro Ottawa proposes using a sub-account of USofA 1508 – Other Regulatory Assets, or a new deferral account as ordered by the Board. Simple interest is to be calculated on the monthly opening balance of this account using approved EB-2006-0117 interest rate methodology. Please find below proposed accounting entries for tracking these deferral accounts by USofA.

Accounting Entries (Proposed)

**A) Sale of Land**

| | Debit | Credit |
|---|---|---|
| Dr. Account 1005 - Cash | x,xxx.xx | |
| Cr. Account 1905 - Land | | x,xxx.xx |
| Cr. Account 1508 - Other Regulatory Assets, Sub-account Deferred Gain on Sale of Land | | x,xxx.xx |
| Cr. Account 2294 - Accrual for Taxes, "Payments in Lieu" of Taxes, Etc. | | x,xxx.xx |
| Cr.Account 4355 - Gain on Disposition of Utility and Other Property | | x,xxx.xx |

To record the sale of land and the shareholders' 50% share of the after-tax net gain on the sale of the land. This example is for a gain on the sale of land, should the sale result in a loss the accounting entry would be adjusted accordingly.

| | Debit | Credit |
|---|---|---|
| Dr. Account 6035 – Other Interest Expense | x,xxx.xx | |
| Cr. Account 1508 - Other Regulatory Assets, Sub-account Deferred Gain on Sale of Land | | x,xxx.xx |

To record simple interest on the monthly opening balance of the Other Regulatory Assets, Sub-account Deferred Gain on Sale of Land using the Board approved EB-2006-0117 interest rate methodology. This example is for a net gain on the sale of land, should the sale result in a net loss the accounting entry would be adjusted accordingly.

**B) Sale of Building**

| | Debit | Credit |
|---|---|---|
| Dr. Account 1005 - Cash | x,xxx.xx | |
| Dr. Account 2105 - Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment | x,xxx.xx | |
| Dr. Account 1508 - Other Regulatory Assets, Sub-account Deferred Loss on Sale of Building | x,xxx.xx | |
| Dr. Account 2294 - Accrual for Taxes, "Payments in Lieu" of Taxes, Etc. | x,xxx.xx | |
| Cr. Account 1908 - Buildings and Fixtures | | x,xxx.xx |

To record the sale of the building and the ratepayers' 100% share of the after tax net loss on the sale of the building. This example is for a net loss on the sale of the building, should the sale result in a gain the accounting entry would be adjusted accordingly.

| | Debit | Credit |
|---|---|---|
| Dr. Account 1508 – Other Regulatory Assets, Sub-account Deferred Loss on Sale of Building | x,xxx.xx | |
| Cr. Account 6105 – Other Interest Expense | | x,xxx.xx |

To record simple interest on the monthly opening balance of the Other Regulatory Assets, Sub-account Deferred Loss on Sale of Building using the Board approved EB-2006-0117 interest rate methodology. This example is for a net loss on the sale of the building, should the sale result in a net gain the accounting entry would be adjusted accordingly.

### 3.3 Energy East – Trans Canada Pipeline

In its letter dated April 15, 2014, the Board advised that a portion of the costs associated with consultations regarding the TransCanada PipeLines Limited's Proposed Energy East Pipeline Project would be recovered from all entities which are subject to the Board's cost assessment under section 26 of the *Ontario Energy Board Act*. In its letter the Board noted that it is prepared to make deferral accounts available to affected rate-regulated entities in relation to those costs. Hydro Ottawa hereby requests the Board to allow all costs apportioned with respect to the Energy East Canada Project to be recorded in deferral account USofA 1508 Other Regulatory Assets, Sub-account Energy East Consultation Costs, as per the Board's letter of June 13, 2014 for Board File Number: EB-2013-0398. Carrying charges shall apply to this account.

### 3.4 DVA for Transition to Monthly Billing

Pursuant to the Board's letter of April 15, 2015, regarding Amendments to the Distribution Code, board file number EB-2014-0198, Hydro Ottawa hereby applies for the deferral account to record costs associated with the transition to monthly billing. Hydro Ottawa will analyze these costs at a later date.

### 3.5 Loss on Disposal of Fixed Assets

Hydro Ottawa requests a deferral or variance account for the net loss on disposal of fixed assets. This proposed new DVA would account for the difference between the forecast and actual loss on disposal of fixed assets, related to retirement of assets or damage to plant. Please refer to the Other Revenue section of this rate application – Exhibit C-2-1 for details on the forecasted amount. The forecasted amounts are in USofA 4362 – Loss from Retirement of Utility and Other Property.

### 3.6 Earnings Sharing Mechanism

Hydro Ottawa proposes to include an Earnings Sharing Mechanism ("ESM") as a component of its Custom Incentive rate-setting framework. Consequently, Hydro Ottawa requests a new deferral or variance account for its ESM. If Hydro Ottawa's actual utility annual Return on Equity ("ROE"), calculated on a normalized basis, differs from the approved ROE, Hydro Ottawa proposes the following:

- Under Earning – borne entirely by the shareholder
- 0 – 150 basis points – fully retained by shareholder
- 151-250 basis points – 50:50 sharing of ratepayer/shareholder
- 251 basis points and above – 90:10 sharing of ratepayer/shareholder

The regulatory net income will be calculated, for the purpose of earnings sharing, in the same manner as net income for regulatory purposes under the Reporting and Record Keeping Requirements ("RRR") filings. This will exclude revenue and expenses that are not otherwise included for regulatory purposes, such as:

- Settlement of any regulatory assets or regulatory liabilities including the lost revenue adjustment mechanism ("LRAM");
- Changes in taxes/PILS to which the USofA 1592 – PILs and Tax Variance for 2006 and Subsequent Years applies, which will be shared through that account rather than through earning sharing mechanism;

The ratepayer share of earnings will be credited to the newly proposed deferral or variance account for ESM to be cleared at the next applicable annual rate filing. For example if Hydro Ottawa over-earned in 2016, it would report the balance in the deferral or variance account in 2017, and apply for disposal of this account as part of the custom IRM in order to return to ratepayers over the twelve months commencing January 1, 2018. Please see below for the proposed accounting entries for tracking these deferral accounts by USofA.

Accounting Entries (Proposed)

**A) Ratepayers' share of earnings**

| | Debit | Credit |
|---|---|---|
| Dr. Account e.g. 4390 – Operating revenue | x,xxx.xx | |
| Cr. Account TBD – ESM – Deferral or Variance Account | | x,xxx.xx |

To record the ratepayers' share of earnings as a result of the earnings sharing mechanism

**B) Interest on ESM account**

| | | |
|---|---|---|
| Dr. Account 6035 – Other Interest Expense | x,xxx.xx | |
| Cr. Account – TBD Interest on 'yyyy' ESM – Deferral or Variance Account | | x,xxx.xx |

To record interest accrual

### 3.7 Z Factor

Within Hydro Ottawa's Custom IR Application, it would like to keep open the possibility of using a Z Factor cost recovery mechanism in the future. Hydro Ottawa will only resort to using the Z factor mechanism if costs incurred arise from unforeseen events, decisions or activities, the results of which cannot be reasonably anticipated or quantified at this juncture and where the costs exceed Hydro Ottawa's materiality threshold. Examples include unforeseen weather events or changes to laws or regulations requiring significant implementation investment. Hydro Ottawa would apply to the Board for a Z factor within 6 months of the Z factor event. Should this occur and be approved by the Board, any related costs would be recorded in USofA 1572, Extraordinary Event Costs and Hydro Ottawa would follow the guidelines discussed in section 2.6 of the Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors – July 14, 2008.

# ACCOUNT 1592 - PILS AND TAX VARIANCE

## 1.0 INTRODUCTION

Hydro Ottawa Limited has filed for and been approved for disposition of Uniform System of Account ("USofA") 1592 – PILS and Tax Variance in a previous rate application. Hydro Ottawa completed the disposition as ordered by the OEB and seeks no further requests regarding USofA 1592 for this rate application. In addition, Appendix 2-TA has not been completed by Hydro Ottawa as per the reasons above.

# HARMONIZED SALES TAX DEFERRAL ACCOUNT

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") is proposing to dispose of the balances in the Uniform System of Accounts ("USofA") 1592 – PILS and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs) in this Custom Incentive Rate Application. The amount proposed for disposal in this account is a $545k credit, payment to customers as part of the Group 2 disposal. Please refer to Exhibit I-8-1 for further details regarding the disposal of Group 2 deferral and variance accounts.

The proposed disposal is made up of $122k from 2010 (July 1 – December 31) and $423k from 2011 for provincial sales tax ("PST") savings. As Hydro Ottawa rebased in 2012, no further amounts were added to this account in 2012 and onwards.

Hydro Ottawa followed the Ontario Energy Board's frequently asked questions (No. 1 – 5) issued December 23, 2010 to determine the PST savings to include in USofA 1592.

| | |
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# Appendix 2-TB
## Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries.

100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs), should be recorded in this table.

**Summary of PST Savings from 2009 Historic Year Analysis**

| | Principal 2010 | Principal 2011 | Principal 2012 | Principal 2013 | Principal 2014 | Principal Jan-April 2015 [1] | Carrying Charges to April 30, 2015 |
|---|---|---|---|---|---|---|---|
| OM&A Expenses PST Savings | | | | | | | |
| Capital Items PST Savings | | | | | | | |
| Total Annual PST Savings [2] | $ 121,512 | $ 423,171 | $ - | $ - | | $ - | $ - |

[1] Include January to April 30, 2015 PST savings if the rate year begins May 1, 2015. If the rate year begins Jan 1, 2015, include PST savings to December 31, 2014.
[2] Derived PST savings proxy for each year per 2009 historic year analysis

**Note:** Assumes level OM&A and Capital Spending year over year. An alternative detailed transactional analysis may also be performed using actual expenditures from 2010 to the start

# ONE-TIME INCREMENTAL IFRS COSTS

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") adopted International Financial Reporting Standards ("IFRS") effective January 1, 2015 for financial reporting purposes. The first day of the comparative year is referred to as the "transition date" and the first day of the year in which the utility has chosen to adopt IFRS for financial reporting purposes is referred to as the "changeover date". For Hydro Ottawa, the transition date was January 1, 2014, and the changeover date was January 1, 2015.

## 2.0 BACKGROUND

On February 13, 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises ("PAEs") would be required to transition to IFRS effective January 1, 2011. While Hydro Ottawa is not a PAE, it is a Government Business Enterprise, given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date IFRS did not contain a standard governing rate-regulated activities ("RRA"). Due to the significance of this issue in Canada, the Canadian AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA, pending the completion of an interim standard by the International Accounting Standards Board ("IASB"). Until January 1, 2015, qualifying entities were permitted to continue reporting under Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ("CGAAP").

While early adoption was permitted by the Canadian AcSB, Hydro Ottawa elected to defer the adoption of IFRS for financial reporting purposes due to the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS, and its potential material impact on Hydro Ottawa's financial statements.

In a letter issued March 15, 2011, the Ontario Energy Board (the "Board") directed electricity distributors filing cost of service applications for rates for 2012 to make all reasonable efforts to provide the forecasts for the 2012 test year in modified IFRS ("MIFRS") accounting format.

In compliance with the Board's direction, Hydro Ottawa filed its 2012 Cost of Service Application on June 17, 2011 using MIFRS as the accounting basis.

Hydro Ottawa adopted MIFRS for regulatory accounting and reporting purposes effective January 1, 2012 with a transition date of January 1, 2011.

## 3.0 ADOPTION OF IFRS FOR FINANCIAL REPORTING

On January 30, 2014, the IASB issued interim standard *IFRS 14 - Regulatory Deferred Accounts* ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted. Hydro Ottawa adopted IFRS and early adopted IFRS 14 on January 1, 2015 with a transition date of January 1, 2014 for financial reporting purposes.

Hydro Ottawa continues to report under MIFRS to the Board while providing reconciliation to its audited financial statements, prepared in accordance with Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ("CGAAP"). To limit the differences caused by the different accounting basis, Hydro Ottawa has sought to align its CGAAP accounting policies with IFRS requirements wherever possible as of January 1, 2012. Nonetheless, a difference in the effective implementation dates gave rise to a $ 502k difference in the carrying values of certain Property, Plant and Equipment for CGAAP and MIFRS reporting purposes.

Consequently, Hydro Ottawa recorded a one-time adjustment to align MIFRS and CGAAP. Please see Exhibit A-4-7 Accounting Standards for further details.

## 4.0 ALIGNING REGULATORY REPORTING AND FINANCIAL REPORTING

Hydro Ottawa maintains two sets of records: i) a set of records using MIFRS as the accounting basis to satisfy regulatory reporting or rate-making requirements, and ii) a set of records using the applicable Canadian accounting principles (CGAAP/IFRS) to satisfy financial or statutory reporting requirements. The aligning of the regulatory and financial reporting set of records will allow Hydro Ottawa to maintain one set of records which will satisfy both reporting requirements. The consolidation of the records will serve to enhance operational efficiency and reduce the burden on Hydro Ottawa's IT systems.

With the adoption of IFRS and early adoption of IFRS 14 as the accounting basis for financial reporting purposes on January 1, 2015, Hydro Ottawa's regulatory and financial reporting records are now aligned from an accounting standards basis.

## 5.0 IFRS - INCREMENTAL TRANSITION COSTS ACCOUNT

The variance account is a continuation of the account established in 2009, as per the Board's guidance in the Accounting Procedures Handbook ("APH") Frequently Asked Questions ("FAQs") #3, October 2009. Hydro Ottawa confirms that no capital costs, on-going IFRS compliance costs or impacts arising from adopting accounting policy changes are recorded in the Uniform System of Account ("USofA") 1508 – Other Regulatory Assets sub-account Deferred IFRS Transition Costs Variance Account.

Hydro Ottawa confirms that all costs included meet the criteria in the APH FAQs #3, October 2009, as they are all related to professional accounting and legal fees, salaries, wages and benefits of staff as a result of one-time administrative costs caused by the transition of accounting policies, procedures and processes to IFRS. Descriptions of these costs can be found in Appendix 2-U under the column, 'Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs.' Refer to Appendix 2-U for details on the costs up to December 31, 2015.

## 6.0 DISPOSITION REQUEST – UsofA 1508 – OTHER REGULATORY ASSETS SUB-ACCOUNT DEFERRED IFRS TRANSITION COSTS

Hydro Ottawa requests as part of this rate application, the OEB review USofA 1508– Other Regulatory Assets sub-account Deferred IFRS Transition Costs for disposition. As per Appendix 2-U Hydro Ottawa is requesting disposition of costs and carrying charges in the amount of $1,432k. This includes audited incremental transition costs to 2013, unaudited actuals for 2014 and a forecast for remaining costs to be included in the bridge year, 2015. Hydro Ottawa is not forecasting any one-time administrative incremental IFRS transition costs for the test years, 2016 to 2020. Please refer to Exhibit I-8-1 for a comprehensive outline of all Hydro Ottawa's accounts proposed for disposition.

| | |
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## Appendix 2-U
## One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

| Nature of One-Time Incremental IFRS Transition Costs [1] | Audited Actual Costs Incurred 2009 | Audited Actual Costs Incurred 2010 | Audited Actual Costs Incurred 2011 | Audited Actual Costs Incurred 2012 | Audited Actual Costs Incurred 2013 | Audited Carrying Charges to Dec 31, 2013 | Unaudited Actual Costs 2014 | Forecasted Costs 2015 | Total Costs Excluding Carrying Charges | Carrying Charges January 1, 2014 to December 31, 2015 | Total Costs and Carrying Charges | Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| professional accounting fees | $ 487,258 | $ 166,626 | $ 395,863 | $ 84,485 | $ 13,037 | | | $ 81,000 | $ 1,228,269 | | $ 1,228,269 | IFRS consulting, advisory and comparative audit works |
| professional legal fees | | | $ 90,000 | | | | | | $ 90,000 | | $ 90,000 | IFRS legal opinion |
| salaries, wages and benefits of staff added to support the transition to IFRS | $ 23,992 | $ 261,457 | $ 218,943 | $ 189,811 | $ 118,018 | | $ 110,160 | $ 59,945 | $ 982,326 | | $ 982,326 | Internal project lead and temporary staff |
| associated staff training and development costs | | $ 3,198 | $ 477 | $ 53 | $ 2,142 | | | | $ 5,869 | | $ 5,869 | Internal project lead and temporary staff |
| costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion | | | | | | | | | $ - | | $ - | |
| | | | | | | | | | $ - | | $ - | |
| Carrying Charges | | | | | | $ 50,886 | | | $ - | $ 37,132 | $ 88,018 | |
| | | | | | | | | | $ - | | $ - | |
| | | | | | | | | | $ - | | $ - | |
| Amounts, if any, included in previous Board approved rates (amounts should be negative) [3] | | | -$ 942,530 | | | -$ 20,145 | | | -$ 942,530 | | -$ 962,675 | |
| | | | | | | | | | $ - | | $ - | |
| Insert description of additional item(s) and new rows if needed. | | | | | | | | | $ - | | $ - | |
| **Total** | $ 511,250 | $ 431,280 | -$ 237,248 | $ 274,349 | $ 133,197 | $ 30,741 | $ 110,160 | $ 140,945 | $ 1,363,934 | $ 37,132 | $ 1,431,808 | |

**Note:**

1. The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.
2. If there were any amounts approved in previous Board approved rates, please state the EB #: EB-2011-0054

# BREAKDOWN OF BALANCE RELATED TO IFRS-CGAAP TRANSITIONAL PP&E

## 1.0 INTRODUCTION

Hydro Ottawa Limited's ("Hydro Ottawa") 2012 rate application was submitted under Modified International Financial Reporting Standards ("MIFRS") with a transition date of January 1, 2011 as directed by Ontario Energy Board (the "Board"). International Financial Reporting Standards ("IFRS") at that time did not contain standard governing rate-regulated activities. In May 2012 the International Accounting Standards Board ("IASB") decided to develop a project on Rate-regulated Activities. With this pending the Canadian Accounting Standards Board allowed qualifying Rate Regulated entities to defer the adoption of IFRS to January 1, 2015. Hydro Ottawa Limited elected to take this deferral for financial reporting purposes while continuing to maintain MIFRS for regulatory purposes. The IASB has since issued interim standard IFRS 14 - Regulatory Deferred Accounts ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing rate-regulated accounting.

As per Hydro Ottawa's 2012 decision and rate order Addendum, January 16, 2012, Hydro Ottawa was instructed to establish a deferral account to recover $123k over a four year period, 2012 to 2015. Uniform System of Accounts ("USofA") account 1575 IFRS-CGAAP Transitional Property, Plant and Equipment ("PP&E") Amounts was established. Amortization of approximately $31k per year is being recorded, as of December 31, 2015 no balance will exist. As Hydro Ottawa elected to defer transitioning to IFRS for financial reporting purposes, no further amounts will be added to USofA deferral account 1575. Hydro Ottawa confirms that no carrying charges have been applied to the balances in USofA 1575 IFRS-CGAAP Transitional PP&E Amounts.

## 2.0 BREAKDOWN OF BALANCE RELATED TO IFRS-CGAAP

Given Hydro Ottawa's 2012 rate application dealt with the transitional amount of PP&E, there is no need to provide it in Hydro Ottawa's 2016 rate application. Hence Appendix

2-EA – Account 1575 – IFRS-CGAAP Transitional PP&E Amounts is not necessary as part of this application.

## 3.0 LISTING AND QUANTIFICATION OF DRIVERS

USofA 1575 was established upon Hydro Ottawa's 2012 decision and rate order Addendum. Hydro Ottawa does not propose any further additions to USofA deferral account 1575 IFRS-CGAAP Transitional PP&E Amounts.

## 4.0 RATE RIDER – NOT REQUESTED

Hydro Ottawa is not requesting a separate volumetric rate rider for Account 1575 – IFRS-CGAAP Transitional PP&E Amounts.

## 5.0 BALANCE IN 1575 AS PER THE DVA CONTINUITY SCHEDULE

As per Attachment I-8(A) EDDVAR Continuity Schedule, the balance in USofA 1575 – IFRS-CGAAP Transitional PP&E Amounts, as of December 31, 2013 was $62k. Hydro Ottawa has continued with scheduled amortization of $31k in year 2014 and will continue in year 2015, to achieve a zero balance in this account by December 31, 2015.

# ACCOUNT 1576 – ACCOUNTING CHANGES UNDER CGAAP

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") confirms that Uniform System of Accounts ("USofA") 1576 – Accounting Changes under CGAAP was not used by Hydro Ottawa as it adopted International Financial Reporting Standards ("IFRS") on January 1, 2012 for rate settling purposes. Please refer to Exhibit B-2-1 for further details regarding Hydro Ottawa's conversion to IFRS.

Hydro Ottawa did not record financial differences arising as a result of changes to accounting depreciation or capitalization policies as permitted by the Ontario Energy Board ("the Board") into USofA 1576 – Accounting Changes under CGAAP.

As per Attachment I-8(A) EDDVAR Continuity Schedule, the balance in USofA 1576 – Accounting Changes under CGAAP, as of December 31, 2013 is zero dollars. Consequently Hydro Ottawa has omitted Chapter 2 Appendices 2-EB and 2-EC from this filing as they are not relevant.

Hydro Ottawa's confirms that Appendix 2-BA Fixed Asset Continuity Schedule for years 2012 to 2020 has not been adjusted for balances related to USofA 1576.

# RETAIL SERVICE CHARGES

## 1.0 INTRODUCTION

Table 1 below shows the balance of Uniform System of Accounts ("USofA") 1518 RCVA Retail ("1518") and 1548 RCVA STR ("1548") for 2013.

**Table 1 – Account Balances - Uniform System of Accounts 1518 and 1548**

| Uniform System of Account Number | Uniform System of Account Description | Principal at December 31, 2013 | Interest at December 31, 2013 | Total at December 31, 2013 | 2.1.7 RRR Balances as of December 31, 2013 | Variance to 2.1.7 RRR |
|---|---|---|---|---|---|---|
| 1518 | RCVA-Retail | (286,798) | (36,736) | (323,534) | (323,534) | 0 |
| 1548 | RCVA-STR | 1,288,821 | 68,243 | 1,357,064 | 1,357,065 | 1 |
| | **Total-RVCA** | **$ 1,002,023** | **$ 31,507** | **$ 1,033,530** | **$ 1,033,531** | |

Hydro Ottawa Limited ("Hydro Ottawa") confirms that all costs incorporated into the variances for 1518 RCVA Retail and 1548 RCVA STR are incremental costs associated with providing a retail service for Hydro Ottawa customers. Hydro Ottawa has complied with Article 490, Retail Services and Settlement Variances of the Ontario Energy Board's ("Board") Accounting Procedures Handbook ("APH"), with respect to the costs and balances in these accounts.

The main cost drivers for USofA 1518 are:

- Wages and Benefits - employees working directly with retailer activities (5615 - General Administrative Salaries and Expenses; 5315 - Customer Billing and 5610 - Management Salaries and Expenses)
- Call center retailer inquiry costs (5410 - Community Relations - Sundry)

The main cost drivers for the USofA 1548 are:

- Wages and Benefits - employees working directly with retailer activities (5315 - Customer Billing)
- Annual maintenance costs of Hydro Ottawa's Customer Information System ("CIS") – percentage of retailer customers (5315 - Customer Billing)

Hydro Ottawa will be seeking clearance of both the USofA 1518 and 1548 as part of this rate application, please refer to Exhibit I-8-1, for the full explanation of the Group 2 regulatory accounts to be cleared.

Starting in 2016 Hydro Ottawa is requesting to cease tracking and recording costs and revenues for both USofA 1518 and 1548 into variance accounts. Hydro Ottawa feels that it can reasonably estimate both revenues and costs associated with retailer transactions and no longer requires variance accounts. Both revenues and costs related to retailer transactions are included in Hydro Ottawa's requested Revenue Requirement. Additionally, since Hydro Ottawa presently expends a significant amount of effort to track and record the costs and revenues in USofA 1518 and 1548, the proposal to cease tracking these activities into the variance accounts would be more administratively efficient.

# DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

## 1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") is requesting the disposition of the Deferral and Variance Accounts ("DVAs") identified in Table 1 in compliance with the Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report").

**Table 1 – Hydro Ottawa's Proposed DVA Dispositions**

| Group | USofA Number | Deferral/Variance Account Description | Amount | Principal | Interest |
|---|---|---|---|---|---|
| 1 | 1550 | LV Variance Account | $15,559 | $15,980 | $(421) |
| 1 | 1551 | Smart Metering Entity Charge Variance Account | $163,191 | $159,042 | $4,149 |
| 1 | 1580 | RSVA - Wholesale Market Service Charge | $(5,350,768) | $(5,223,230) | $(127,538) |
| 1 | 1584 | RSVA - Retail Transmission Network Charge | $581,580 | $563,007 | $18,573 |
| 1 | 1586 | RSVA - Retail Transmission Connection Charge | $(1,736,487) | $(1,703,997) | $(32,490) |
| 1 | 1588 | RSVA - Power (excluding Global Adjustment) | $5,024,770 | $4,969,223 | $55,547 |
| 1 | 1595 | Disposition and Recovery/Refund of Regulatory Balances (2010) | $(736,696) | $(1,287,221) | $550,525 |
| 1 | 1595 | Disposition and Recovery/Refund of Regulatory Balances (2011) | $(677,884) | $(1,281,760) | $603,876 |
| 1 | 1595 | Disposition and Recovery/Refund of Regulatory Balances (2012) | $(150,510) | $(11,831) | $(138,679) |
| 2 | 1508 | Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | $1,431,808 | $1,363,935 | $67,873 |
| 2 | 1518 | Retail Cost Variance Account - Retail | $(327,751) | $(286,799) | $(40,952) |
| 2 | 1532 | Renewable Generation Connection OM&A Deferral Account | $431,555 | $408,537 | $23,018 |
| 2 | 1535 | Smart Grid OM&A Deferral Account | $199,090 | $188,477 | $10,613 |
| 2 | 1548 | Retail Cost Variance Account - STR | $1,376,010 | $1,288,821 | $87,189 |
| 2 | 1582 | RSVA - One-time | $(6) | $(123) | $117 |
| 2 | 1592 | PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | $(544,683) | $(544,683) | $0 |
| 2 | 1555 | Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs10 | $(5,973,776) | $(5,973,776) | $0 |
| | | **TOTAL - DVA Excluding Global Adjustment and LRAM)** | **$(6,274,998)** | **$(7,356,398)** | **$1,081,400** |
| 1 | 1589 | RSVA - Global Adjustment | $(1,250,514) | $(1,288,246) | $37,732 |
| 2 | 1568 | LRAM Variance Account | $(679,243) | $(678,660) | $(583) |
| | | **TOTAL DVA's** | **$(8,204,755)** | **$(9,323,304)** | **$1,118,549** |

Hydro Ottawa has complied with the EDDVAR Report guidelines and is requesting a disposition period of one year. Please refer to Attachment I-8(A) after Exhibit I-8-1 for the complete Deferral and Variance Account (Continuity Schedule). Differences between Table 1 and the EDDVAR report are primarily due to timing differences, please see section 4.2 of this exhibit for a discussion of these variances. When available, Hydro Ottawa intends to use an updated 2016 EDDVAR model that will provide principle balances to December 31, 2014 and forecasted interest to December 31, 2015.

The principle and interest for each DVA are identified in Table 1. Per the Deferral and Variance Account (Continuity Schedule) Work Form – version 2.4 Excel spreadsheet posted by the Board on June 26, 2014, principle balances are up to December 31, 2013 and interest is forecasted to December 31, 2014. Currently Hydro Ottawa is proposing to dispose of $8.2 million to be returned to customers. This amount for disposal includes Group 1 accounts, Group 2 accounts, the Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”) – Uniform System of Accounts (“USofA”) 1568 and Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs – USofA 1555. USofA 1575 - IFRS-CGAAP Transition PP&E Amounts Balance and Return Component is not included for disposition as this account will have a zero balance at the end of December 31, 2015 and therefore does not require disposition.

## 2.0 ACCOUNTS FOR WHICH HYDRO OTTAWA IS SEEKING DISPOSITION

Please refer to Table 1 above for a list of the DVA’s for which Hydro Ottawa is seeking disposition.

## 3.0 ACCOUNTS FOR WHICH HYDRO OTTAWA IS NOT SEEKING DISPOSITION

The following are accounts for which Hydro Ottawa is not seeking disposition for.

USofA 1575 - IFRS-CGAAP Transition PP&E Amounts Balance and Return Component is not included for disposition as this account will have a zero balance at the end of December 31, 2015. The balance at December 31, 2013 is $62k. As per Hydro Ottawa’s Draft Rate Order filed: January 16, 2012 for EB-2011-0054, Hydro Ottawa was to recover $123k over the four year period (2012 – 2015) in the amount of $31k per year, leaving a closing balance of $0 in USofA 1575. As Hydro Ottawa is on track to recover the amount, no further disposition is requested, Hydro Ottawa is requesting to discontinue using this account after December 31, 2015, please refer to section 6 of Exhibit I-1-1 for more details.

USofA 1508 Other Regulatory Assets, Sub-Account P&OPEB Deferral Account, Hydro Ottawa does not propose to dispose of this account and will continue to use seeks a continuance of this account. This account was originally approved in Hydro Ottawa's 2012 Rate Application (EB-2011-0054) of which the Draft Rate Order filed: January 16, 2012, states the purpose of the account is to record the retirement liability as a result of an election under IFSR 1 that would otherwise result in a change to Hydro Ottawa's retained earnings. Hydro Ottawa proposes disposal of this DVA will occur sometime in the future in accordance with Board guidelines in effect at the appropriate time. As of December 31, 2013 the balance in this account is $3.1M.

USofA 1555 – Smart Meter Capital and Recovery Offset Variance – Sub-Account – Recoveries and USofA 1556 – Smart Meter OM&A Variance, at the end of 2014 these two accounts have zero balances, hence Hydro Ottawa is not seeking to dispose of these accounts, and is proposing to discontinue use of these accounts.

## 4.0 VARIANCE ANALYSIS

### 4.1 Balances proposed for disposition consistent with Audited Financial Statements

Hydro Ottawa intends to use 2016 updated Deferral and Variance Account model that will provide principle balances to December 31, 2014 and forecasted interest to December 31, 2015. At the time the updated model is filed with the Ontario Energy Board ("the Board"), Hydro Ottawa will confirm the amounts proposed for disposition align with Hydro Ottawa's Financial Statements and/or provide explanations for any variances at the time of this update.

### 4.2 Explanation of Variances

Please see below for explanations for variances greater than the 5% threshold between the amounts proposed for disposition (Table 1 – above) and the amount reported on the December 31, 2013 2.1.7 RRR as per the EDDVAR report in Attachment I-8(A). Hydro Ottawa does not have any variances below the 5% threshold that relate to matters of principle and/or the cumulative effect of immaterial differences over several accounts that total to a material difference between what is proposed for disposition in total before forecasted interest and what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings.

The Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") – USofA 1568 has a difference of $104k when compared to the December 31, 2013 2.1.7 RRR as reported to the OEB. For this account the Continuity Schedule includes balances to the end of 2014 so they can be disposed of in this rate application, the result shows as a difference when compared to the December 31, 2013 2.1.7 RRR as reported to the OEB. Hydro Ottawa proposes to dispose of $584k the balance at the end of 2014.

There is also a difference in USofA 1592 - PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs). Question 1 from the Board's APH FAQ's dated December 23, 2010 stated that for regulatory reporting purposes the sub-account and contra account for HST/OVAT will have a reporting amount for RRR's that nets to zero. This is consistent with Hydro Ottawa's RRR 2.1.7 filing. The same document from the Board states that the balance in this sub-account should be reported for disposition; therefore, the credit balance of $545k will be returned to customers. The result is a variance between the RRR filing and the balance to be disposed of $545k.

The amount Hydro Ottawa proposed to dispose of in USofA 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs is $1.4 million. This includes audited incremental transition costs to 2013, unaudited actuals for 2014 and a forecast for remaining costs to be included in the bridge year, 2015. The EDDVAR report balance to the end of 2013 is $1.1 million, causing a variance of $288k, due to the allowance of forecasted amounts. Please refer to Exhibit I-4-1 and Appendix 2-U for further details.

## 5.0 ALLOCATION OF DVA's AND LENGTH OF DISPOSITION PERIOD

Hydro Ottawa is requesting a one year rate rider for the recovery or refund of balances proposed for disposition. This adheres to the default disposition period in EDDVAR.

## 6.0 PROPOSED RATE RIDERS

Tables 2 to 4 identify the proposed rate riders to clear the DVA balances in Group 1 and Group 2 accounts Hydro Ottawa is seeking disposition for. These all have a rate rider recovery period of 1 year. Hydro Ottawa is proposing allocators that it feels best suit the type of group or individual variance account.

### Table 2 – Rate Riders for DVAs (excluding Global Adjustment)

| Rate Class (Enter Rate Classes in cells below) | Units | kW / kWh / # of Customers | Allocated Balance (excluding 1589) | Rate Rider for Deferral/Variance Accounts | |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 2,216,045,000 | $(1,223,158) | (0.0006) | $/kWh |
| GENREAL SERVICE LESS THAN 50KW | kWh | 726,360,000 | $(635,933) | (0.0009) | $/kWh |
| GENERAL SERVICE 50 TO 1,499 KW | kW | 7,027,979 | $(2,897,218) | (0.4122) | $/kW |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | 1,847,365 | $(849,446) | (0.4598) | $/kW |
| LARGE USE | kW | 1,121,449 | $(610,399) | (0.5443) | $/kW |
| UNMETERED SCATTERED LOAD | kWh | 16,651,000 | $(15,957) | (0.0010) | $/kWh |
| STANDBY POWER GENERAL SERVICE 50 TO 1,499 KW | kW | - | - | 0.0000 | $/kW |
| STANDBY POWER GENERAL SERVICE 1,500 TO 4,999 KW | kW | - | - | 0.0000 | $/kW |
| STANDBY POWER GENERAL SERVICE LARGE USE | kW | - | - | 0.0000 | $/kW |
| SENITEL LIGHTING | kW | 216 | $(44) | (0.2037) | $/kW |
| STREET LIGHTING | kW | 123,144 | $(42,839) | (0.3479) | $/kW |
| microFIT | | - | - | - | |
| **Total** | | | **$(6,274,994)** | | |

**Table 3 – Rate Riders for DVAs - Global Adjustment**

| **Rate Class** (Enter Rate Classes in cells below) | **Units** | **Non-RPP kW / kWh / # of Customers** | **Balance of RSVA - Power - Global Adjustment** | **Rate Rider for RSVA - Power - Global Adjustment** | |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 100,015,579 | $(28,542) | (0.0003) | $/kWh |
| GENREAL SERVICE LESS THAN 50KW | kWh | 67,683,742 | $(19,316) | (0.0003) | $/kWh |
| GENERAL SERVICE 50 TO 1,499 KW | kWh | 2,676,165,018 | $(763,731) | (0.0003) | $/kWh |
| GENERAL SERVICE 1,500 TO 4,999 KW | kWh | 876,597,685 | $(250,166) | (0.0003) | $/kWh |
| LARGE USE | kWh | 615,205,612 | $(175,569) | (0.0003) | $/kWh |
| UNMETERED SCATTERED LOAD | kWh | - | - | 0.0000 | $/kWh |
| STANDBY POWER GENERAL SERVICE 50 TO 1,499 KW | kWh | - | - | 0.0000 | $/kWh |
| STANDBY POWER GENERAL SERVICE 1,500 TO 4,999 KW | kWh | - | - | 0.0000 | $/kWh |
| STANDBY POWER GENERAL SERVICE LARGE USE | kWh | - | - | 0.0000 | $/kWh |
| SENITEL LIGHTING | kWh | - | - | 0.0000 | $/kWh |
| STREET LIGHTING | kWh | 46,220,021 | $(13,190) | (0.0003) | $/kWh |
| microFIT | | - | - | - | |
| **Total** | | | **$(1,250,514)** | | |

**Table 4 – Rate Riders for DVAs – Lost Revenue Adjustment Mechanism**

| Rate Class (Enter Rate Classes in cells below) | Units | kW / kWh / # of Customers | Balance of Account 1568 | Rate Rider for Account 1568 | |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 2,216,045,000 | $(620,714) | (0.0003) | $/kWh |
| GENREAL SERVICE LESS THAN 50KW | kWh | 726,360,000 | $(51,170) | (0.0001) | $/kWh |
| GENERAL SERVICE 50 TO 1,499 KW | kW | 7,027,979 | $(6,881) | (0.0010) | $/kW |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | 1,847,365 | $(159) | (0.0001) | $/kW |
| LARGE USE | kW | 1,121,449 | $(23) | (0.0000) | $/kW |
| UNMETERED SCATTERED LOAD | kWh | 16,651,000 | $(280) | (0.0000) | $/kWh |
| STANDBY POWER GENERAL SERVICE 50 TO 1,499 KW | kW | - | - | 0.0000 | $/kW |
| STANDBY POWER GENERAL SERVICE 1,500 TO 4,999 KW | kW | - | - | 0.0000 | $/kW |
| STANDBY POWER GENERAL SERVICE LARGE USE | kW | - | - | 0.0000 | $/kW |
| SENITEL LIGHTING | kW | 216 | - | 0.0000 | $/kW |
| STREET LIGHTING | kW | 123,144 | $(17) | (0.0001) | $/kW |
| microFIT | | - | - | - | |
| **Total** | | | **$(679,243)** | | |

## 7.0 RATE RIDERS FOR MARKET PARTICIPANTS ("MPs")

Hydro Ottawa currently has one market participant ("MP") that settles directly with the Independent Electricity System Operator ("IESO"). When updating the EDDVAR model for 2014 year end balances, Hydro Ottawa will create a separate rate riders for this customer, and will file the related evidence at a later date.

## 8.0 RATE RIDER FOR GLOBAL ADJUSTMENT

Hydro Ottawa has both Class A and Class B Global Adjustment ("GA") customers. Currently the disposition of USofA 1589 – RCVA – Global Adjustment is allocated to all non-Rate Regulated Plan ("non-RPP") customers on a kWh basis; this method has been used consistently for several years and was maintained upon the introduction of Class A GA customers. This method is consistent with the Incentive Regulation Mechanism ("IRM") and EDDVAR models used to determine these rate riders. Hydro Ottawa recognizes that the Board would like to establish separate rate riders for the Class A GA customers and upon updating data for 2014 year end balances Hydro Ottawa will work with the Board to modify the EDDVAR model or develop custom models to supplement this model so these newly required separate rate riders can be established.

## 9.0 PROPOSED ESTABLISHMENT OF NEW DVA's

Please refer to Exhibit I-1-2 for new deferral and variance accounts being proposed by Hydro Ottawa.

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

Version 2.4

| | |
|---|---|
| **Utility Name** | Hydro Ottawa Limited |
| **Service Territory** | *(if applicable)* |
| **Assigned EB Number** | EB-2015-0004 |
| **Name of Contact and Title** | April Barrie; Manager, Rates and Revenue |
| **Phone Number** | 613-738-5499, ext 106 |
| **Email Address** | AprilBarrie@HydroOttawa.com |

**General Notes**

**Notes**

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| Account Descriptions | Account Number | 2009 Opening Principal Amounts as of Jan-1-09 | Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3] | Board-Approved Disposition during 2009 | Adjustments during 2009 - other [2] | Closing Principal Balance as of Dec-31-09 | Opening Interest Amounts as of Jan-1-09 | Interest Jan-1 to Dec-31-09 | Board-Approved Disposition during 2009 | Adjustments during 2009 - other [2] | Closing Interest Amounts as of Dec-31-09 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | $341,423 | -$806,430 | | | -$465,007 | $8,610 | $1,244 | | | $9,854 |
| Smart Metering Entity Charge Variance Account | 1551 | | | | | $0 | | | | | $0 |
| RSVA - Wholesale Market Service Charge | 1580 | -$5,535,584 | -$2,615,936 | | | -$8,151,520 | -$107,697 | -$62,363 | | | -$170,060 |
| RSVA - Retail Transmission Network Charge | 1584 | -$4,828,149 | -$799,298 | | | -$5,627,447 | -$123,118 | -$52,334 | | | -$175,452 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$3,039,509 | -$3,257,761 | | | -$6,297,270 | -$45,873 | -$40,319 | | | -$86,192 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $8,628,731 | -$835,728 | | | $7,793,003 | $106,179 | $57,079 | | | $163,258 |
| RSVA - Global Adjustment | 1589 | $8,336,384 | $8,318,310 | | | $16,654,694 | $189,331 | $110,317 | | | $299,648 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | -$3,531,907 | $2,451,634 | | | -$1,080,273 | $1,673,047 | -$23,663 | | | $1,649,384 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | | | | | $0 | | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | | | | | $0 | | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | | | | | $0 | | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | | | | | $0 | | | | | $0 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | $371,389 | $2,454,791 | $0 | $0 | $2,826,180 | $1,700,479 | -$10,039 | $0 | $0 | $1,690,440 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$7,964,995 | -$5,863,519 | $0 | $0 | -$13,828,514 | $1,511,148 | -$120,356 | $0 | $0 | $1,390,792 |
| **RSVA - Global Adjustment** | **1589** | $8,336,384 | $8,318,310 | $0 | $0 | $16,654,694 | $189,331 | $110,317 | $0 | $0 | $299,648 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | | $511,250 | | | $511,250 | | $220 | | | $220 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | | | $0 | | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act [8] | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | | | | | $0 | -$2,124 | | | | -$2,124 |
| Retail Cost Variance Account - Retail | 1518 | -$336,240 | -$269,521 | | | -$605,761 | -$7,266 | -$4,695 | | | -$11,961 |
| Misc. Deferred Debits | 1525 | | | | | $0 | -$82 | | | | -$82 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | | | $0 | | | | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | | | $0 | | | | | $0 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | | | $0 | | | | | $0 |
| Smart Grid Capital Deferral Account | 1534 | | | | | $0 | | | | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | | | | | $0 | | | | | $0 |
| Smart Grid Funding Adder Deferral Account | 1536 | | | | | $0 | | | | | $0 |
| Retail Cost Variance Account - STR | 1548 | $378,403 | $402,518 | | | $780,921 | $5,277 | $5,605 | | | $10,882 |
| Board-Approved CDM Variance Account | 1567 | | | | | | | | | | $0 |
| Extra-Ordinary Event Costs | 1572 | | | | | $0 | | | | | $0 |
| Deferred Rate Impact Amounts | 1574 | | | | | $0 | | | | | $0 |
| RSVA - One-time | 1582 | $248,449 | -$243,785 | | | $4,664 | $3,989 | -$3,972 | | | $17 |
| Other Deferred Credits | 2425 | | | | | $0 | | | | | $0 |
| **Group 2 Sub-Total** | | $290,612 | $400,461 | $0 | $0 | $691,073 | -$206 | -$2,843 | $0 | $0 | -$3,049 |
| Deferred Payments in Lieu of Taxes | 1562 | | | | | $0 | $131 | -$131 | | | -$0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | -$200,861 | | | | -$200,861 | -$6,025 | -$2,271 | | | -$8,296 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | | | | | $0 | | | | | $0 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | $461,140 | $2,855,253 | $0 | $0 | $3,316,393 | $1,694,379 | -$15,284 | $0 | $0 | $1,679,095 |
| **LRAM Variance Account** | **1568** | | | | | | | | | | |
| **Total including Account 1568** | | $461,140 | $2,855,253 | $0 | $0 | $3,316,393 | $1,694,379 | -$15,284 | $0 | $0 | $1,679,095 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital [10] | 1555 | | | | | $0 | | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries [10] | 1555 | -$7,167,747 | -$3,495,193 | | | -$10,662,940 | | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs [10] | 1555 | $12,950,636 | -$1,192,601 | | | $11,758,035 | | | | | $0 |
| Smart Meter OM&A Variance [10] | 1556 | $5,241,463 | $3,633,261 | | | $8,874,724 | -$82,232 | -$20,723 | | | -$102,955 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component [9] | 1575 | | | | | | | | | | |
| Accounting Changes Under CGAAP Balance + Return Component [9] | 1576 | | | | | | | | | | |

ntario Energy Board

# 2015 Deferral/Variance Account Workform

| | | 2010 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Account Descriptions** | Account Number | Opening Principal Amounts as of Jan-1-10 | Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3] | Board-Approved Disposition during 2010 | Adjustments during 2010 - other [2] | Closing Principal Balance as of Dec-31-10 | Opening Interest Amounts as of Jan-1-10 | Interest Jan-1 to Dec-31-10 | Board-Approved Disposition during 2010 | Adjustments during 2010 - other [2] | Closing Interest Amounts as of Dec-31-10 |
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$465,007 | -$1,144,417 | | | -$1,609,423 | $9,854 | -$8,572 | | | $1,282 |
| Smart Metering Entity Charge Variance Account | 1551 | $0 | | | | $0 | $0 | | | | $0 |
| RSVA - Wholesale Market Service Charge | 1580 | -$8,151,520 | -$8,098,525 | | | -$16,250,046 | -$170,060 | -$104,549 | | | -$274,609 |
| RSVA - Retail Transmission Network Charge | 1584 | -$5,627,447 | $392,976 | | | -$5,234,471 | -$175,452 | -$38,900 | | | -$214,352 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$6,297,270 | -$2,755,674 | | | -$9,052,944 | -$86,192 | -$60,931 | | | -$147,123 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $7,793,003 | $3,479,179 | | | $11,272,182 | $163,258 | $49,751 | | | $213,009 |
| RSVA - Global Adjustment | 1589 | $16,654,694 | -$6,031,437 | | | $10,623,257 | $299,648 | $96,331 | | | $395,979 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | -$1,080,273 | -$533,002 | | | -$1,613,275 | $1,649,384 | -$10,515 | | | $1,638,869 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | $2,826,180 | -$14,690,899 | $0 | $0 | -$11,864,719 | $1,690,440 | -$77,386 | $0 | $0 | $1,613,055 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$13,828,514 | -$8,659,462 | $0 | $0 | -$22,487,976 | $1,390,792 | -$173,716 | $0 | $0 | $1,217,076 |
| **RSVA - Global Adjustment** | **1589** | $16,654,694 | -$6,031,437 | $0 | $0 | $10,623,257 | $299,648 | $96,331 | $0 | $0 | $395,979 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $511,250 | $431,280 | | | $942,530 | $220 | $6,061 | | | $6,281 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $0 | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $0 | $92,803 | | | $92,803 | -$2,124 | $2,124 | | | $0 |
| Retail Cost Variance Account - Retail | 1518 | -$605,761 | -$188,350 | | | -$794,111 | -$11,961 | -$5,884 | | | -$17,845 |
| Misc. Deferred Debits | 1525 | $0 | | | | $0 | -$82 | $82 | | | $0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $0 | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $0 | $197,472 | | | $197,472 | $0 | $767 | | | $767 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Grid Capital Deferral Account | 1534 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | $0 | $92,621 | | | $92,621 | $0 | $555 | | | $555 |
| Smart Grid Funding Adder Deferral Account | 1536 | $0 | | | | $0 | $0 | | | | $0 |
| Retail Cost Variance Account - STR | 1548 | $780,921 | $551,064 | | | $1,331,984 | $10,882 | $8,070 | | | $18,952 |
| Board-Approved CDM Variance Account | 1567 | | | | | $0 | $0 | | | | $0 |
| Extra-Ordinary Event Costs | 1572 | $0 | | | | $0 | $0 | | | | $0 |
| Deferred Rate Impact Amounts | 1574 | $0 | | | | $0 | $0 | | | | $0 |
| RSVA - One-time | 1582 | $4,664 | | | | $4,664 | $17 | $37 | | | $54 |
| Other Deferred Credits | 2425 | $0 | | | | $0 | $0 | | | | $0 |
| **Group 2 Sub-Total** | | $691,073 | $1,176,890 | $0 | $0 | $1,867,964 | -$3,049 | $11,813 | $0 | $0 | $8,764 |
| Deferred Payments in Lieu of Taxes | 1562 | $0 | | | | $0 | -$0 | | | | -$0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | -$200,861 | | | | -$200,861 | -$8,296 | -$1,606 | | | -$9,902 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $0 | -$121,512 | | | -$121,512 | $0 | | | | $0 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | $3,316,393 | -$13,635,521 | $0 | $0 | -$10,319,128 | $1,679,095 | -$67,179 | $0 | $0 | $1,611,916 |
| **LRAM Variance Account** | **1568** | | | | | $0 | | | | | $0 |
| **Total including Account 1568** | | $3,316,393 | -$13,635,521 | $0 | $0 | -$10,319,128 | $1,679,095 | -$67,179 | $0 | $0 | $1,611,916 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10] | 1555 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10] | 1555 | -$10,662,940 | -$3,949,848 | | | -$14,612,788 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10] | 1555 | $11,758,035 | -$2,905,311 | | | $8,852,725 | $0 | | | | $0 |
| Smart Meter OM&A Variance[10] | 1556 | $8,874,724 | $4,752,896 | | | $13,627,620 | -$102,955 | -$11,852 | | | -$114,807 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9] | 1575 | | | | | | | | | | |
| Accounting Changes Under CGAAP Balance + Return Component[9] | 1576 | | | | | | | | | | |

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# 2015 Deferral/Variance Account Workform

| Account Descriptions | Account Number | 2011 Opening Principal Amounts as of Jan-1-11 | Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3] | Board-Approved Disposition during 2011 | Adjustments during 2010 - other [2] | Closing Principal Balance as of Dec-31-11 | Opening Interest Amounts as of Jan-1-11 | Interest Jan-1 to Dec-31-11 | Board-Approved Disposition during 2011 | Adjustments during 2011 - other [2] | Closing Interest Amounts as of Dec-31-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$1,609,423 | -$1,024,964 | -$1,609,423 | | -$1,024,964 | $1,282 | -$30,468 | -$22,377 | | -$6,809 |
| Smart Metering Entity Charge Variance Account | 1551 | $0 | | | | $0 | $0 | | | | $0 |
| RSVA - Wholesale Market Service Charge | 1580 | -$16,250,046 | -$7,769,682 | -$16,250,046 | | -$7,769,682 | -$274,609 | -$301,929 | -$513,484 | | -$63,054 |
| RSVA - Retail Transmission Network Charge | 1584 | -$5,234,471 | $776,427 | -$5,234,471 | | $776,427 | -$214,352 | -$70,687 | -$291,299 | | $6,260 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$9,052,944 | -$1,220,099 | -$9,052,943 | | -$1,220,100 | -$147,123 | -$144,981 | -$280,201 | | -$11,903 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $11,272,182 | -$7,111,287 | $11,650,893 | | -$7,489,998 | $213,009 | $30,356 | | | $243,365 |
| RSVA - Global Adjustment | 1589 | $10,623,257 | -$5,192,002 | $10,623,257 | | -$5,192,002 | $395,979 | $133,356 | $552,141 | | -$22,806 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | -$1,613,275 | -$405,063 | -$1,613,274 | $405,064 | $0 | $1,638,869 | -$27,337 | $1,615,153 | $3,621 | -$0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | $0 | | -$10,623,257 | | $10,623,257 | $0 | | -$552,141 | | $552,141 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | $0 | | | | $0 | $0 | | | | $0 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | -$11,864,719 | -$21,946,670 | -$22,109,264 | $405,064 | -$11,297,061 | $1,613,055 | -$411,690 | $507,792 | $3,621 | $697,193 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$22,487,976 | -$16,754,668 | -$32,732,521 | $405,064 | -$6,105,059 | $1,217,076 | -$545,046 | -$44,349 | $3,621 | $720,000 |
| **RSVA - Global Adjustment** | **1589** | $10,623,257 | -$5,192,002 | $10,623,257 | $0 | -$5,192,002 | $395,979 | $133,356 | $552,141 | $0 | -$22,806 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $942,530 | $705,283 | $962,675 | | $685,138 | $6,281 | $17,946 | | | $24,227 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $0 | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | $0 | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | $0 | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $92,803 | $1,270 | $94,159 | | -$86 | $0 | $1,388 | | | $1,388 |
| Retail Cost Variance Account - Retail | 1518 | -$794,111 | -$148,075 | -$823,629 | | -$118,557 | -$17,845 | -$12,732 | | | -$30,576 |
| Misc. Deferred Debits | 1525 | $0 | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $0 | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $197,472 | $211,064 | | | $408,537 | $767 | $4,219 | | | $4,985 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Grid Capital Deferral Account | 1534 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | $92,621 | $95,856 | | | $188,477 | $555 | $1,739 | | | $2,294 |
| Smart Grid Funding Adder Deferral Account | 1536 | $0 | | | | $0 | $0 | | | | $0 |
| Retail Cost Variance Account - STR | 1548 | $1,331,984 | -$893,533 | | | $438,451 | $18,952 | $23,399 | | | $42,350 |
| Board-Approved CDM Variance Account | 1567 | $0 | | | | $0 | $0 | | | | $0 |
| Extra-Ordinary Event Costs | 1572 | $0 | | | | $0 | $0 | | | | $0 |
| Deferred Rate Impact Amounts | 1574 | $0 | | | | $0 | $0 | | | | $0 |
| RSVA - One-time | 1582 | $4,664 | | $4,786 | | -$123 | $54 | $69 | | | $123 |
| Other Deferred Credits | 2425 | $0 | | | | $0 | $0 | | | | $0 |
| **Group 2 Sub-Total** | | $1,867,964 | -$28,135 | $237,991 | $0 | $1,601,838 | $8,764 | $36,027 | $0 | $0 | $44,791 |
| Deferred Payments in Lieu of Taxes | 1562 | $0 | | | | $0 | -$0 | $0 | | | -$0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | -$200,861 | $0 | -$200,861 | | $0 | -$9,902 | -$2,953 | -$12,855 | | $0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | -$121,512 | -$423,171 | | | -$544,683 | $0 | | | | $0 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$10,319,128 | -$22,397,976 | -$22,072,134 | $405,064 | -$10,239,906 | $1,611,916 | -$378,615 | $494,937 | $3,621 | $741,984 |
| **LRAM Variance Account** | **1568** | $0 | | | | $0 | $0 | | | | $0 |
| **Total including Account 1568** | | -$10,319,128 | -$22,397,976 | -$22,072,134 | $405,064 | -$10,239,906 | $1,611,916 | -$378,615 | $494,937 | $3,621 | $741,984 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10] | 1555 | $0 | | | | $0 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10] | 1555 | -$14,612,788 | -$3,343,772 | | | -$17,956,560 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10] | 1555 | $8,852,725 | -$2,882,519 | | | $5,970,205 | $0 | | | | $0 |
| Smart Meter OM&A Variance[10] | 1556 | $13,627,620 | $5,268,480 | | | $18,896,100 | -$114,807 | -$394,587 | | | -$509,395 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9] | 1575 | | | | | | | | | | |
| Accounting Changes Under CGAAP Balance + Return Component[9] | 1576 | | | | | | | | | | |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| Account Descriptions | Account Number | 2012 Opening Principal Amounts as of Jan-1-12 | Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3] | Board-Approved Disposition during 2012 | Other [2] Adjustments during Q1 2012 | Other [2] Adjustments during Q2 2012 | Other [2] Adjustments during Q3 2012 | Other [2] Adjustments during Q4 2012 | Closing Principal Balance as of Dec-31-12 | Opening Interest Amounts as of Jan-1-12 | Interest Jan-1 to Dec-31-12 | Board-Approved Disposition during 2012 | Adjustments during 2012 - other [2] | Closing Interest Amounts as of Dec-31-12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | | | | |
| LV Variance Account | 1550 | -$1,024,964 | -$30,829 | | | | | | -$1,055,793 | -$6,809 | -$15,282 | | | -$22,092 |
| Smart Metering Entity Charge Variance Account | 1551 | $0 | | | | | | | $0 | $0 | | | | $0 |
| RSVA - Wholesale Market Service Charge | 1580 | -$7,769,682 | -$9,808,445 | | | | | | -$17,578,127 | -$63,054 | -$178,134 | | | -$241,188 |
| RSVA - Retail Transmission Network Charge | 1584 | $776,427 | -$1,681,231 | | | | | | -$904,804 | $6,260 | $3,977 | | | $10,237 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$1,220,100 | -$1,683,899 | | | | | | -$2,903,999 | -$11,903 | -$24,873 | | | -$36,775 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$7,489,998 | -$288,893 | | | | | | -$7,778,891 | $243,365 | -$131,402 | | | $111,964 |
| RSVA - Global Adjustment | 1589 | -$5,192,002 | -$5,253,421 | | | | | | -$10,445,423 | -$22,806 | -$127,080 | | | -$149,886 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | $0 | | | | | | | $0 | -$0 | | | | -$0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | $0 | $20,740,824 | $21,566,079 | | | | | -$825,255 | $0 | -$188,428 | -$782,598 | | $594,170 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | $10,623,257 | -$11,455,366 | | | | | | -$832,109 | $552,141 | $85,259 | | | $637,400 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | $0 | | | | | | | $0 | $0 | | | | $0 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | -$11,297,061 | -$9,461,260 | $21,566,079 | $0 | $0 | $0 | $0 | -$42,324,400 | $697,193 | -$575,964 | -$782,598 | $0 | $903,828 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$6,105,059 | -$4,207,839 | $21,566,079 | $0 | $0 | $0 | $0 | -$31,878,977 | $720,000 | -$448,884 | -$782,598 | $0 | $1,053,714 |
| **RSVA - Global Adjustment** | **1589** | -$5,192,002 | -$5,253,421 | $0 | $0 | $0 | $0 | $0 | -$10,445,423 | -$22,806 | -$127,080 | $0 | $0 | -$149,886 |
| **Group 2 Accounts** | | | | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $685,138 | $274,349 | | | | | | $959,487 | $24,227 | $11,689 | | | $35,916 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | -$86 | $4,976,895 | | | | | | $4,976,809 | $1,388 | -$1 | | | $1,386 |
| Retail Cost Variance Account - Retail | 1518 | -$118,557 | -$102,703 | | | | | | -$221,259 | -$30,576 | -$2,445 | | | -$33,021 |
| Misc. Deferred Debits | 1525 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $408,537 | | | | | | | $408,537 | $4,985 | $6,022 | | | $11,007 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Grid Capital Deferral Account | 1534 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | $188,477 | | | | | | | $188,477 | $2,294 | $2,778 | | | $5,072 |
| Smart Grid Funding Adder Deferral Account | 1536 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Retail Cost Variance Account - STR | 1548 | $438,451 | $442,637 | | | | | | $881,088 | $42,350 | $10,058 | | | $52,408 |
| Board-Approved CDM Variance Account | 1567 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Extra-Ordinary Event Costs | 1572 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Deferred Rate Impact Amounts | 1574 | $0 | | | | | | | $0 | $0 | | | | $0 |
| RSVA - One-time | 1582 | -$123 | | | | | | | -$123 | $123 | -$2 | | | $121 |
| Other Deferred Credits | 2425 | $0 | | | | | | | $0 | $0 | | | | $0 |
| **Group 2 Sub-Total** | | $1,601,838 | $5,591,178 | $0 | $0 | $0 | $0 | $0 | $7,193,015 | $44,791 | $28,100 | $0 | $0 | $72,891 |
| Deferred Payments in Lieu of Taxes | 1562 | $0 | | | | | | | $0 | -$0 | | | | -$0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $0 | | | | | | | $0 | $0 | | | | $0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | -$544,683 | | | | | | | -$544,683 | $0 | | | | $0 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$10,239,906 | -$3,870,082 | $21,566,079 | $0 | $0 | $0 | $0 | -$35,676,068 | $741,984 | -$547,864 | -$782,598 | $0 | $976,718 |
| **LRAM Variance Account** | **1568** | $0 | | | | | | | $0 | $0 | | | | $0 |
| **Total including Account 1568** | | -$10,239,906 | -$3,870,082 | $21,566,079 | $0 | $0 | $0 | $0 | -$35,676,068 | $741,984 | -$547,864 | -$782,598 | $0 | $976,718 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10] | 1555 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10] | 1555 | -$17,956,560 | -$1,474,685 | | | | | | -$19,431,245 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10] | 1555 | $5,970,205 | -$2,986,888 | | | | | | $2,983,317 | $0 | | | | $0 |
| Smart Meter OM&A Variance[10] | 1556 | $18,896,100 | | | | | | | $18,896,100 | -$509,395 | | | | -$509,395 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9] | 1575 | | | | | | | $92,250 | $92,250 | $0 | | | | $0 |
| Accounting Changes Under CGAAP Balance + Return Component[9] | 1576 | | | | | | | | $0 | $0 | | | | $0 |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| | | 2013 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Account Descriptions** | Account Number | Opening Principal Amounts as of Jan-1-13 | Transactions Debit / (Credit) during 2013 excluding interest and adjustments 3 | Board-Approved Disposition during 2013 | Other 2 Adjustments during Q1 2013 | Other 2 Adjustments during Q2 2013 | Other 2 Adjustments during Q3 2013 | Other 2 Adjustments during Q4 2013 | Closing Principal Balance as of Dec-31-13 | Opening Interest Amounts as of Jan-1-13 | Interest Jan-1 to Dec-31-13 | Board-Approved Disposition during 2013 | Adjustments during 2013 - other 2 | Closing Interest Amounts as of Dec-31-13 |
| **Group 1 Accounts** | | | | | | | | | | | | | | |
| LV Variance Account | 1550 | -$1,055,793 | $15,980 | -$1,024,964 | | | | | -$14,849 | -$22,092 | -$1,109 | -$21,877 | | -$1,324 |
| Smart Metering Entity Charge Variance Account | 1551 | $0 | $159,042 | $0 | | | | | $159,042 | $0 | $1,811 | $0 | | $1,811 |
| RSVA - Wholesale Market Service Charge | 1580 | -$17,578,127 | -$5,223,229 | -$7,769,681 | | | | | -$15,031,675 | -$241,188 | -$194,941 | -$177,269 | | -$258,861 |
| RSVA - Retail Transmission Network Charge | 1584 | -$904,804 | $563,006 | $776,426 | | | | | -$1,118,224 | $10,237 | -$14,417 | $17,673 | | -$21,853 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$2,903,999 | -$1,703,996 | -$1,220,099 | | | | | -$3,387,896 | -$36,775 | -$32,194 | -$29,838 | | -$39,131 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$7,778,891 | $9,979,249 | -$7,489,997 | | | | -$5,010,026 | $4,680,329 | $111,964 | -$21,749 | $133,261 | | -$43,047 |
| RSVA - Global Adjustment | 1589 | -$10,445,423 | -$1,288,246 | -$5,192,002 | | | | | -$6,541,667 | -$149,886 | -$20,555 | -$99,128 | | -$71,314 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | $0 | | | | | | | $0 | -$0 | | | | -$0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | -$825,255 | -$461,966 | | | | | | -$1,287,221 | $594,170 | -$24,722 | | | $569,447 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | -$832,109 | -$449,650 | | | | | | -$1,281,759 | $637,400 | -$14,681 | | | $622,718 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | $0 | -$11,831 | | | | | | -$11,831 | $0 | -$138,505 | | | -$138,505 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | -$42,324,400 | $1,578,359 | -$21,920,317 | $0 | $0 | $0 | -$5,010,026 | -$23,835,750 | $903,828 | -$461,062 | -$177,178 | $0 | $619,943 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$31,878,977 | $2,866,605 | -$16,728,315 | $0 | $0 | $0 | -$5,010,026 | -$17,294,083 | $1,053,714 | -$440,507 | -$78,050 | $0 | $691,257 |
| **RSVA - Global Adjustment** | **1589** | -$10,445,423 | -$1,288,246 | -$5,192,002 | $0 | $0 | $0 | $0 | -$6,541,667 | -$149,886 | -$20,555 | -$99,128 | $0 | -$71,314 |
| **Group 2 Accounts** | | | | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $959,487 | $133,197 | | | | | | $1,092,685 | $35,916 | $14,969 | | | $50,886 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $4,976,809 | -$1,867,100 | | | | | | $3,109,709 | $1,386 | -$1 | | | $1,385 |
| Retail Cost Variance Account - Retail | 1518 | -$221,259 | -$65,539 | | | | | | -$286,799 | -$33,021 | -$3,715 | | | -$36,736 |
| Misc. Deferred Debits | 1525 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $408,537 | | | | | | | $408,537 | $11,007 | $6,006 | | | $17,013 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Grid Capital Deferral Account | 1534 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | $188,477 | | | | | | | $188,477 | $5,072 | $2,771 | | | $7,842 |
| Smart Grid Funding Adder Deferral Account | 1536 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Retail Cost Variance Account - STR | 1548 | $881,088 | $407,733 | | | | | | $1,288,821 | $52,408 | $15,835 | | | $68,243 |
| Board-Approved CDM Variance Account | 1567 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Extra-Ordinary Event Costs | 1572 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Deferred Rate Impact Amounts | 1574 | $0 | | | | | | | $0 | $0 | | | | $0 |
| RSVA - One-time | 1582 | -$123 | | | | | | | -$123 | $121 | -$2 | | | $119 |
| Other Deferred Credits | 2425 | $0 | | | | | | | $0 | $0 | | | | $0 |
| **Group 2 Sub-Total** | | $7,193,015 | -$1,391,709 | $0 | $0 | $0 | $0 | $0 | $5,801,306 | $72,891 | $35,863 | $0 | $0 | $108,753 |
| Deferred Payments in Lieu of Taxes | 1562 | $0 | | | | | | | $0 | -$0 | | | | -$0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $0 | | | | | | | $0 | $0 | | | | $0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | -$544,683 | | | | | | | -$544,683 | $0 | | | | $0 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$35,676,068 | $186,649 | -$21,920,317 | $0 | $0 | $0 | -$5,010,026 | -$18,579,127 | $976,718 | -$425,200 | -$177,178 | $0 | $728,696 |
| **LRAM Variance Account** | **1568** | $0 | -$779,519 | | | | | $100,859 | -$678,660 | $0 | -$3,316 | | $2,733 | -$583 |
| **Total including Account 1568** | | -$35,676,068 | -$592,870 | -$21,920,317 | $0 | $0 | $0 | -$4,909,167 | -$19,257,787 | $976,718 | -$428,516 | -$177,178 | $2,733 | $728,113 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10] | 1555 | $0 | | | | | | | $0 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10] | 1555 | -$19,431,245 | | | | | | | -$19,431,245 | $0 | | | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10] | 1555 | $2,983,317 | -$2,983,317 | | | | | | -$0 | $0 | | | | $0 |
| Smart Meter OM&A Variance[10] | 1556 | $18,896,100 | | | | | | | $18,896,100 | -$509,395 | | | | -$509,395 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9] | 1575 | | | | | | | $61,500 | $61,500 | $0 | | | | $0 |
| Accounting Changes Under CGAAP Balance + Return Component[9] | 1576 | | | | | | | | $0 | $0 | | | | $0 |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| | | 2014 | | | | Projected Interest on Dec-31-13 Balances | | | 2.1.7 RRR | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Account Descriptions** | Account Number | Principal Disposition during 2014 - instructed by Board | Interest Disposition during 2014 - instructed by Board | Closing Principal Balances as of Dec 31-13 Adjusted for Dispositions during 2014 | Closing Interest Balances as of Dec 31-13 Adjusted for Dispositions during 2014 | Projected Interest from Jan 1, 2014 to December 31, 2014 on Dec 31 -13 balance adjusted for disposition during 2014 [6] | Projected Interest from January 1, 2015 to April 30, 2015 on Dec 31 -13 balance adjusted for disposition during 2014 [6] | Total Claim | As of Dec 31-13 | Variance RRR vs. 2013 Balance *(Principal + Interest)* |
| **Group 1 Accounts** | | | | | | | | | | |
| LV Variance Account | 1550 | -$30,829 | -$668 | $15,980 | -$656 | $235 | | $15,559 | -$16,174 | -$0 |
| Smart Metering Entity Charge Variance Account | 1551 | $0 | $0 | $159,042 | $1,811 | $2,338 | | $163,191 | $160,853 | $0 |
| RSVA - Wholesale Market Service Charge | 1580 | -$9,808,445 | -$208,104 | -$5,223,230 | -$50,757 | -$76,781 | | -$5,350,768 | -$15,290,536 | -$1 |
| RSVA - Retail Transmission Network Charge | 1584 | -$1,681,231 | -$32,150 | $563,007 | $10,297 | $8,276 | | $581,580 | -$1,140,077 | -$0 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$1,683,899 | -$31,690 | -$1,703,997 | -$7,441 | -$25,049 | | -$1,736,487 | -$3,427,027 | $0 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$288,894 | -$25,546 | $4,969,223 | -$17,501 | $73,048 | | $5,024,770 | $4,637,283 | $0 |
| RSVA - Global Adjustment | 1589 | -$5,253,421 | -$127,983 | -$1,288,246 | $56,669 | -$18,937 | | -$1,250,514 | -$6,612,981 | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | | | $0 | -$0 | | | $0 | | -$0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | | | $0 | $0 | | | $0 | | $0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | | | -$1,287,221 | $569,447 | -$18,922 | | -$736,696 | -$717,774 | -$1 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | | | -$1,281,759 | $622,718 | -$18,842 | | -$677,883 | -$659,041 | -$0 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | | | -$11,831 | -$138,505 | -$174 | | -$150,510 | -$150,336 | -$0 |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | -$18,746,719 | -$426,141 | -$5,089,031 | $1,046,084 | -$74,809 | $0 | -$4,117,756 | -$23,215,809 | -$2 |
| **Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)** | | -$13,493,298 | -$298,158 | -$3,800,785 | $989,415 | -$55,872 | $0 | -$2,867,242 | -$16,602,829 | -$2 |
| **RSVA - Global Adjustment** | **1589** | -$5,253,421 | -$127,983 | -$1,288,246 | $56,669 | -$18,937 | $0 | -$1,250,514 | -$6,612,981 | $0 |
| **Group 2 Accounts** | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | | | $1,092,685 | $50,886 | $37,132 | $251,105 | $1,431,808 | $1,143,570 | $0 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | $0 | $0 | -$5,973,776 | | -$5,973,776 | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | $0 | $0 | | | $0 | | $0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | $0 | $0 | | | $0 | | $0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | | | $3,109,709 | $1,385 | $45,713 | -$3,156,807 | -$0 | $3,111,094 | $0 |
| Retail Cost Variance Account - Retail | 1518 | | | -$286,799 | -$36,736 | -$4,216 | | -$327,750 | -$323,534 | $0 |
| Misc. Deferred Debits | 1525 | | | $0 | $0 | | | $0 | | -$0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | $0 | $0 | | | $0 | | $0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | $408,537 | $17,013 | $6,005 | | $431,555 | $425,549 | -$0 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | $0 | $0 | | | $0 | | $0 |
| Smart Grid Capital Deferral Account | 1534 | | | $0 | $0 | | | $0 | | $0 |
| Smart Grid OM&A Deferral Account | 1535 | | | $188,477 | $7,842 | $2,771 | | $199,090 | $196,319 | $0 |
| Smart Grid Funding Adder Deferral Account | 1536 | | | $0 | $0 | | | $0 | | $0 |
| Retail Cost Variance Account - STR | 1548 | | | $1,288,821 | $68,243 | $18,946 | | $1,376,010 | $1,357,065 | $1 |
| Board-Approved CDM Variance Account | 1567 | | | $0 | $0 | | | $0 | | $0 |
| Extra-Ordinary Event Costs | 1572 | | | $0 | $0 | | | $0 | | $0 |
| Deferred Rate Impact Amounts | 1574 | | | $0 | $0 | | | $0 | | $0 |
| RSVA - One-time | 1582 | | | -$123 | $119 | -$2 | | -$5 | | $3 |
| Other Deferred Credits | 2425 | | | $0 | $0 | | | $0 | | $0 |
| **Group 2 Sub-Total** | | $0 | $0 | $5,801,306 | $108,753 | -$5,867,427 | -$2,905,702 | -$2,863,069 | $5,910,064 | $4 |
| Deferred Payments in Lieu of Taxes | 1562 | | | $0 | -$0 | | | -$0 | | $0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | | | $0 | $0 | | | $1 | | -$1 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | | | -$544,683 | $0 | | | -$544,683 | $0 | $544,683 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$18,746,719 | -$426,141 | $167,592 | $1,154,837 | -$5,942,236 | -$2,905,702 | -$7,525,508 | -$17,305,745 | $544,685 |
| **LRAM Variance Account** | **1568** | | | -$678,660 | -$583 | | | -$679,243 | -$782,835 | -$103,592 |
| **Total including Account 1568** | | -$18,746,719 | -$426,141 | -$511,068 | $1,154,254 | -$5,942,236 | -$2,905,702 | -$8,204,751 | -$18,088,580 | $441,094 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10] | 1555 | | | $0 | $0 | | | $0 | | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10] | 1555 | | | -$19,431,245 | $0 | | | -$19,431,245 | -$19,431,245 | $0 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10] | 1555 | | | -$0 | $0 | -$5,973,776 | | -$5,973,776 | $0 | $0 |
| Smart Meter OM&A Variance[10] | 1556 | | | $18,896,100 | -$509,395 | $1,044,540 | Exhibit I-8-1 (2014 Princ) | $19,431,245 | $18,386,705 | $0 |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9] | 1575 | | | $61,500 | $0 | | | $61,500 | $61,500 | $0 |
| Accounting Changes Under CGAAP Balance + Return Component[9] | 1576 | | | $0 | $0 | | | $0 | | $0 |


**Accounts that produced a variance on the 2014 continuity schedule are listed below.**
**Please provide a detailed explanation for each variance below.**

| Account Descriptions | Account Number | Variance RRR vs. 2013 Balance *(Principal + Interest)* | Explanation |
|---|---|---|---|
| **Group 1 Accounts** | | | |
| LV Variance Account | 1550 | $ (0.27) | |
| RSVA - Wholesale Market Service Charge | 1580 | $ (0.77) | |
| RSVA - Retail Transmission Network Charge | 1584 | $ (0.46) | |
| RSVA - Retail Transmission Connection Charge | 1586 | $ 0.17 | |
| RSVA - Power (excluding Global Adjustment) | 1588 | $ 0.45 | |
| RSVA - Global Adjustment | 1589 | $ 0.26 | |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | $ (0.01) | |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | $ (0.54) | |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | $ (0.15) | |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | $ (0.35) | |
| **Group 2 Accounts** | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ 0.17 | |
| Other Regulatory Assets - Sub-Account - Other | 1508 | $ 0.10 | |
| Retail Cost Variance Account - Retail | 1518 | $ 0.37 | |
| Misc. Deferred Debits | 1525 | $ (0.40) | |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $ (0.01) | |
| Retail Cost Variance Account - STR | 1548 | $ 0.81 | |
| RSVA - One-time | 1582 | $ 3.46 | |
| Deferred Payments in Lieu of Taxes | 1562 | $ 0.01 | |
| PILs and Tax Variance for 2006 and Subsequent Years | 1592 | $ (0.52) | |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT | 1592 | $ 544,683.06 | |
| LRAM Variance Account | 1568 | $ (103,591.88) | |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries | 1555 | $ 0.14 | |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs | 1555 | $ 0.06 | |
| Smart Meter OM&A Variance | 1556 | $ 0.32 | |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

| Rate Class (Enter Rate Classes in cells below) | Units | # of Customers | Metered kWh | Metered kW | Billed kWh for Non-RPP Customers | Estimated kW for Non-RPP Customers | Distribution Revenue [1] | 1590 Recovery Share Proportion | 1595 Recovery Share Proportion (2008) [2] | 1595 Recovery Share Proportion (2009) [2] |
|---|---|---|---|---|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 297,343 | 2,216,045,000 | | 100,015,579 | - | 95,819,638 | | | |
| GENREAL SERVICE LESS THAN 50KW | kWh | 24,512 | 726,360,000 | | 67,683,742 | - | 22,381,467 | | | |
| GENERAL SERVICE 50 TO 1,499 KW | kW | 3,296 | 2,954,441,000 | 7,027,979 | 2,676,165,018 | 6,366,020 | 39,195,058 | | | |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | 76 | 863,309,000 | 1,847,365 | 876,597,685 | 1,875,801 | 11,372,032 | | | |
| LARGE USE | kW | 11 | 620,218,000 | 1,121,449 | 615,205,612 | 1,112,386 | 6,340,210 | | | |
| UNMETERED SCATTERED LOAD | kWh | 134 | 16,651,000 | | | - | 601,871 | | | |
| STANDBY POWER GENERAL SERVICE 50 TO 1 | kW | | | | | - | - | | | |
| STANDBY POWER GENERAL SERVICE 1,500 T | kW | - | | - | | - | 11,240 | | | |
| STANDBY POWER GENERAL SERVICE LARGE | kW | | | | | - | - | | | |
| SENITEL LIGHTING | kW | 1 | 48,000 | 216 | | - | 4,751 | | | |
| STREET LIGHTING | kW | 8 | 43,552,000 | 123,144 | 46,220,021 | 130,688 | 967,982 | | | |
| microFIT | | | | | | - | | | | |
| | | | | | | - | | | | |
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| | | | | | | - | | | | |
| | | | | | | - | | | | |
| **Total** | | **325,382** | **7,440,624,000** | **10,120,153** | **4,381,887,658** | **9,484,895** | **$ 176,694,250** | **0%** | **0%** | **0%** |

Ontario Energy Board

# 2015 Deferral/Var

In the green shaded cells, enter the most recent Board App
the most recent 12-month actual volumetric data, use the m

| Rate Class (Enter Rate Classes in cells below) | Units | 1595 Recovery Share Proportion (2010) [2] | 1595 Recovery Share Proportion (2011) [2] | 1595 Recovery Share Proportion (2012) [2] | 1568 LRAM Variance Account Class Allocation ($ amounts) |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | | | | -620,714 |
| GENREAL SERVICE LESS THAN 50KW | kWh | | | | -51,170 |
| GENERAL SERVICE 50 TO 1,499 KW | kW | | | | -6,881 |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | | | | -159 |
| LARGE USE | kW | | | | -23 |
| UNMETERED SCATTERED LOAD | kWh | | | | -280 |
| STANDBY POWER GENERAL SERVICE 50 TO 1 | kW | | | | - |
| STANDBY POWER GENERAL SERVICE 1,500 T | kW | | | | - |
| STANDBY POWER GENERAL SERVICE LARGE | kW | | | | - |
| SENITEL LIGHTING | kW | | | | |
| STREET LIGHTING | kW | | | | -17 |
| microFIT | | | | | |
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| | | | | | |
| | | | | | |
| | | | | | |
| **Total** | | **0%** | **0%** | **0%** | **-$ 679,243** |
| | | | | Balance as per Sheet 2 | -$ 679,243 |
| | | | | Variance | $ - |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| | | Amounts from Sheet 2 | Allocator | RESIDENTIAL | GENREAL SERVICE LESS THAN 50KW | GENERAL SERVICE 50 TO 1,499 KW | GENERAL SERVICE 1,500 TO 4,999 KW | LARGE USE | UNMETERED SCATTERED LOAD |
|---|---|---|---|---|---|---|---|---|---|
| LV Variance Account | 1550 | 15,559 | kWh | 4,634 | 1,519 | 6,178 | 1,805 | 1,297 | 35 |
| Smart Metering Entity Charge Variance Account | 1551 | 163,191 | kWh | 48,603 | 15,931 | 64,798 | 18,934 | 13,603 | 365 |
| RSVA - Wholesale Market Service Charge | 1580 | (5,350,768) | kWh | (1,593,622) | (522,346) | (2,124,624) | (620,830) | (446,017) | (11,974) |
| RSVA - Retail Transmission Network Charge | 1584 | 581,580 | kWh | 173,212 | 56,774 | 230,928 | 67,479 | 48,478 | 1,301 |
| RSVA - Retail Transmission Connection Charge | 1586 | (1,736,487) | kWh | (517,179) | (169,517) | (689,505) | (201,478) | (144,746) | (3,886) |
| RSVA - Power (excluding Global Adjustment) | 1588 | 5,024,770 | kWh | 1,496,530 | 490,522 | 1,995,180 | 583,006 | 418,843 | 11,245 |
| RSVA - Global Adjustment | 1589 | (1,250,514) | Non-RPP kWh | (28,543) | (19,316) | (763,731) | (250,166) | (175,569) | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | (736,696) | kWh | (219,410) | (71,917) | (292,519) | (85,476) | (61,408) | (1,649) |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | (677,883) | kWh | (201,894) | (66,175) | (269,166) | (78,652) | (56,505) | (1,517) |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | (150,510) | kWh | (44,826) | (14,693) | (59,763) | (17,463) | (12,546) | (337) |
| **Total of Group 1 Accounts (excluding 1589)** | | **(2,867,242)** | | **(853,952)** | **(279,903)** | **(1,138,493)** | **(332,676)** | **(239,001)** | **(6,416)** |
| | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | 1,431,808 | kWh | 426,436 | 139,774 | 568,526 | 166,128 | 119,349 | 3,204 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | (5,973,776) | kWh | (1,779,173) | (583,165) | (2,372,001) | (693,116) | (497,948) | (13,368) |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | (0) | kWh | (0) | (0) | (0) | (0) | (0) | (0) |
| Retail Cost Variance Account - Retail | 1518 | (327,750) | # of Customers | (299,508) | (24,691) | (3,320) | (77) | (11) | (135) |
| Misc. Deferred Debits | 1525 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | 431,555 | kWh | 128,530 | 42,129 | 171,357 | 50,072 | 35,973 | 966 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Smart Grid Capital Deferral Account | 1534 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Smart Grid OM&A Deferral Account | 1535 | 199,090 | kWh | 59,295 | 19,435 | 79,052 | 23,100 | 16,595 | 446 |
| Smart Grid Funding Adder Deferral Account | 1536 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Retail Cost Variance Account - STR | 1548 | 1,376,010 | # of Customers | 1,257,439 | 103,660 | 13,938 | 321 | 47 | 567 |
| Board-Approved CDM Variance Account | 1567 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Extra-Ordinary Event Costs | 1572 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Deferred Rate Impact Amounts | 1574 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| RSVA - One-time | 1582 | (5) | kWh | (2) | (1) | (2) | (1) | (0) | (0) |
| Other Deferred Credits | 2425 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total of Group 2 Accounts** | | **(2,863,069)** | | **(206,982)** | **(302,858)** | **(1,542,449)** | **(453,573)** | **(325,996)** | **(8,321)** |
| | | | | | | | | | |
| Deferred Payments in Lieu of Taxes | 1562 | (0) | | (0) | (0) | (0) | (0) | (0) | (0) |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account) | 1592 | 1 | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | (544,683) | kWh | (162,223) | (53,172) | (216,277) | (63,198) | (45,402) | (1,219) |
| **Total of Account 1562 and Account 1592** | | **(544,683)** | | **(162,223)** | **(53,172)** | **(216,277)** | **(63,198)** | **(45,402)** | **(1,219)** |
| | | | | | | | | | |
| LRAM Variance Account **(Enter dollar amount for each class)** | 1568 | (679,243) | | (620,714) | (51,170) | (6,881) | (159) | (23) | (280) |
| (Account 1568 - total amount allocated to classes) | | (679,243) | | | | | | | |
| Variance | | 0 | | | | | | | |
| | | | | | | | | | |
| **Total Balance Allocated to each class (excluding 1589 and 1586)** | | **(6,274,994)** | | **(1,223,158)** | **(635,933)** | **(2,897,218)** | **(849,446)** | **(610,399)** | **(15,957)** |
| **Total Balance Allocated to each class from Account 1589** | | **(1,250,514)** | | **(28,543)** | **(19,316)** | **(763,731)** | **(250,166)** | **(175,569)** | **0** |
| **Total Balance Allocated to each class (including 1589 and excluding 1586)** | | **(7,525,508)** | | **(1,251,700)** | **(655,248)** | **(3,660,949)** | **(1,099,612)** | **(785,968)** | **(15,957)** |
| | | | | | | | | | |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component | 1575 | 61,500 | | 56,201 | 4,633 | 623 | 14 | 2 | 25 |
| Accounting Changes Under CGAAP Balance + Return Component | 1576 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Balance Allocated to each class for Accounts 1575 and 1576** | | **61,500** | | **56,201** | **4,633** | **623** | **14** | **2** | **25** |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| | | Amounts from Sheet 2 | Allocator | RESIDENTIAL | STANDBY POWER GENERAL SERVICE 50 TO 1,499 KW | STANDBY POWER GENERAL SERVICE 1,500 TO 4,999 KW | STANDBY POWER GENERAL SERVICE LARGE USE | SENITEL LIGHTING | STREET LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| LV Variance Account | 1550 | 15,559 | kWh | 4,634 | 0 | 0 | 0 | 0 | 91 |
| Smart Metering Entity Charge Variance Account | 1551 | 163,191 | kWh | 48,603 | 0 | 0 | 0 | 1 | 955 |
| RSVA - Wholesale Market Service Charge | 1580 | (5,350,768) | kWh | (1,593,622) | 0 | 0 | 0 | (35) | (31,320) |
| RSVA - Retail Transmission Network Charge | 1584 | 581,580 | kWh | 173,212 | 0 | 0 | 0 | 4 | 3,404 |
| RSVA - Retail Transmission Connection Charge | 1586 | (1,736,487) | kWh | (517,179) | 0 | 0 | 0 | (11) | (10,164) |
| RSVA - Power (excluding Global Adjustment) | 1588 | 5,024,770 | kWh | 1,496,530 | 0 | 0 | 0 | 32 | 29,411 |
| RSVA - Global Adjustment | 1589 | (1,250,514) | Non-RPP kWh | (28,543) | 0 | 0 | 0 | 0 | (13,190) |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | (736,696) | kWh | (219,410) | 0 | 0 | 0 | (5) | (4,312) |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | (677,883) | kWh | (201,894) | 0 | 0 | 0 | (4) | (3,968) |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | (150,510) | kWh | (44,826) | 0 | 0 | 0 | (1) | (881) |
| **Total of Group 1 Accounts (excluding 1589)** | | **(2,867,242)** | | **(853,952)** | **0** | **0** | **0** | **(18)** | **(16,783)** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | 1,431,808 | kWh | 426,436 | 0 | 0 | 0 | 9 | 8,381 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | (5,973,776) | kWh | (1,779,173) | 0 | 0 | 0 | (39) | (34,966) |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | (0) | kWh | (0) | 0 | 0 | 0 | (0) | (0) |
| Retail Cost Variance Account - Retail | 1518 | (327,750) | # of Customers | (299,508) | 0 | 0 | 0 | (1) | (8) |
| Misc. Deferred Debits | 1525 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | 431,555 | kWh | 128,530 | 0 | 0 | 0 | 3 | 2,526 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Smart Grid Capital Deferral Account | 1534 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Smart Grid OM&A Deferral Account | 1535 | 199,090 | kWh | 59,295 | 0 | 0 | 0 | 1 | 1,165 |
| Smart Grid Funding Adder Deferral Account | 1536 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Retail Cost Variance Account - STR | 1548 | 1,376,010 | # of Customers | 1,257,439 | 0 | 0 | 0 | 4 | 34 |
| Board-Approved CDM Variance Account | 1567 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Extra-Ordinary Event Costs | 1572 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| Deferred Rate Impact Amounts | 1574 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| RSVA - One-time | 1582 | (5) | kWh | (2) | 0 | 0 | 0 | (0) | (0) |
| Other Deferred Credits | 2425 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total of Group 2 Accounts** | | **(2,863,069)** | | **(206,982)** | **0** | **0** | **0** | **(22)** | **(22,868)** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Deferred Payments in Lieu of Taxes | 1562 | (0) | | (0) | 0 | 0 | 0 | (0) | (0) |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account) | 1592 | 1 | kWh | 0 | 0 | 0 | 0 | 0 | 0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | (544,683) | kWh | (162,223) | 0 | 0 | 0 | (4) | (3,188) |
| **Total of Account 1562 and Account 1592** | | **(544,683)** | | **(162,223)** | **0** | **0** | **0** | **(4)** | **(3,188)** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| LRAM Variance Account **(Enter dollar amount for each class)** | 1568 | (679,243) | | (620,714) | 0 | 0 | 0 | 0 | (17) |
| (Account 1568 - total amount allocated to classes) | | (679,243) | | | | | | | |
| Variance | | 0 | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Total Balance Allocated to each class (excluding 1589 and 1586)** | | **(6,274,994)** | | **(1,223,158)** | **0** | **0** | **0** | **(44)** | **(42,839)** |
| **Total Balance Allocated to each class from Account 1589** | | **(1,250,514)** | | **(28,543)** | **0** | **0** | **0** | **0** | **(13,190)** |
| **Total Balance Allocated to each class (including 1589 and excluding 1586)** | | **(7,525,508)** | | **(1,251,700)** | **0** | **0** | **0** | **(44)** | **(56,030)** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component | 1575 | 61,500 | | 56,201 | 0 | 0 | 0 | 0 | 2 |
| Accounting Changes Under CGAAP Balance + Return Component | 1576 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Balance Allocated to each class for Accounts 1575 and 1576** | | **61,500** | | **56,201** | **0** | **0** | **0** | **0** | **2** |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

| | | Amounts from Sheet 2 | Allocator | RESIDENTIAL | microFIT |
|---|---|---|---|---|---|
| LV Variance Account | 1550 | 15,559 | kWh | 4,634 | 0 |
| Smart Metering Entity Charge Variance Account | 1551 | 163,191 | kWh | 48,603 | 0 |
| RSVA - Wholesale Market Service Charge | 1580 | (5,350,768) | kWh | (1,593,622) | 0 |
| RSVA - Retail Transmission Network Charge | 1584 | 581,580 | kWh | 173,212 | 0 |
| RSVA - Retail Transmission Connection Charge | 1586 | (1,736,487) | kWh | (517,179) | 0 |
| RSVA - Power (excluding Global Adjustment) | 1588 | 5,024,770 | kWh | 1,496,530 | 0 |
| RSVA - Global Adjustment | 1589 | (1,250,514) | Non-RPP kWh | (28,543) | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2008) | 1595 | 0 | | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | 0 | | 0 | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | (736,696) | kWh | (219,410) | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2011) | 1595 | (677,883) | kWh | (201,894) | 0 |
| Disposition and Recovery/Refund of Regulatory Balances (2012) | 1595 | (150,510) | kWh | (44,826) | 0 |
| **Total of Group 1 Accounts (excluding 1589)** | | **(2,867,242)** | | **(853,952)** | **0** |
| | | | | | |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | 1,431,808 | kWh | 426,436 | 0 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | (5,973,776) | kWh | (1,779,173) | 0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | 0 | | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | 0 | | 0 | 0 |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | (0) | kWh | (0) | 0 |
| Retail Cost Variance Account - Retail | 1518 | (327,750) | # of Customers | (299,508) | 0 |
| Misc. Deferred Debits | 1525 | 0 | | 0 | 0 |
| Renewable Generation Connection Capital Deferral Account | 1531 | 0 | | 0 | 0 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | 431,555 | kWh | 128,530 | 0 |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | 0 | | 0 | 0 |
| Smart Grid Capital Deferral Account | 1534 | 0 | | 0 | 0 |
| Smart Grid OM&A Deferral Account | 1535 | 199,090 | kWh | 59,295 | 0 |
| Smart Grid Funding Adder Deferral Account | 1536 | 0 | | 0 | 0 |
| Retail Cost Variance Account - STR | 1548 | 1,376,010 | # of Customers | 1,257,439 | 0 |
| Board-Approved CDM Variance Account | 1567 | 0 | | 0 | 0 |
| Extra-Ordinary Event Costs | 1572 | 0 | | 0 | 0 |
| Deferred Rate Impact Amounts | 1574 | 0 | | 0 | 0 |
| RSVA - One-time | 1582 | (5) | kWh | (2) | 0 |
| Other Deferred Credits | 2425 | 0 | | 0 | 0 |
| **Total of Group 2 Accounts** | | **(2,863,069)** | | **(206,982)** | **0** |
| | | | | | |
| Deferred Payments in Lieu of Taxes | 1562 | (0) | | (0) | 0 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account) | 1592 | 1 | kWh | 0 | 0 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | (544,683) | kWh | (162,223) | 0 |
| **Total of Account 1562 and Account 1592** | | **(544,683)** | | **(162,223)** | **0** |
| | | | | | |
| LRAM Variance Account **(Enter dollar amount for each class)** | 1568 | (679,243) | | (620,714) | 0 |
| (Account 1568 - total amount allocated to classes) | | (679,243) | | | |
| Variance | | 0 | | | |
| | | | | | |
| **Total Balance Allocated to each class (excluding 1589 and 1586)** | | **(6,274,994)** | | **(1,223,158)** | **0** |
| **Total Balance Allocated to each class from Account 1589** | | **(1,250,514)** | | **(28,543)** | **0** |
| **Total Balance Allocated to each class (including 1589 and excluding 1586)** | | **(7,525,508)** | | **(1,251,700)** | **0** |
| | | | | | |
| IFRS-CGAAP Transition PP&E Amounts Balance + Return Component | 1575 | 61,500 | | 56,201 | 0 |
| Accounting Changes Under CGAAP Balance + Return Component | 1576 | 0 | | 0 | 0 |
| **Total Balance Allocated to each class for Accounts 1575 and 1576** | | **61,500** | | **56,201** | **0** |

Ontario Energy Board

# 2015 Deferral/Variance Account Workform

**Please indicate the Rate Rider Recovery Period (in years)** | **1**

## Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

| **Rate Class** (Enter Rate Classes in cells below) | **Units** | **kW / kWh / # of Customers** | **Allocated Balance (excluding 1589)** | **Rate Rider for Deferral/Variance Accounts** | |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 2,216,045,000 | -$ 1,223,158 | - **0.0006** | $/kWh |
| GENREAL SERVICE LESS THAN 50KW | kWh | 726,360,000 | -$ 635,933 | - **0.0009** | $/kWh |
| GENERAL SERVICE 50 TO 1,499 KW | kW | 7,027,979 | -$ 2,897,218 | - **0.4122** | $/kW |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | 1,847,365 | -$ 849,446 | - **0.4598** | $/kW |
| LARGE USE | kW | 1,121,449 | -$ 610,399 | - **0.5443** | $/kW |
| UNMETERED SCATTERED LOAD | kWh | 16,651,000 | -$ 15,957 | - **0.0010** | $/kWh |
| STANDBY POWER GENERAL SERVICE 5( | kW | - | $ - | - | $/kW |
| STANDBY POWER GENERAL SERVICE 1, | kW | - | $ - | - | $/kW |
| STANDBY POWER GENERAL SERVICE L/ | kW | - | $ - | - | $/kW |
| SENITEL LIGHTING | kW | 216 | -$ 44 | - **0.2038** | $/kW |
| STREET LIGHTING | kW | 123,144 | -$ 42,839 | - **0.3479** | $/kW |
| microFIT | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| **Total** | | | **-$ 6,274,994** | | |

## Rate Rider Calculation for RSVA - Power - Global Adjustment

| **Rate Class** (Enter Rate Classes in cells below) | **Units** | **Non-RPP kW / kWh / # of Customers** | **Balance of RSVA - Power - Global Adjustment** | **Rate Rider for RSVA - Power - Global Adjustment** | |
|---|---|---|---|---|---|
| RESIDENTIAL | kWh | 100,015,579 | -$ 28,543 | - **0.0003** | $/kWh |
| GENREAL SERVICE LESS THAN 50KW | kWh | 67,683,742 | -$ 19,316 | - **0.0003** | $/kWh |
| GENERAL SERVICE 50 TO 1,499 KW | kWh | 2,676,165,018 | -$ 763,731 | - **0.0003** | $/kWh |
| GENERAL SERVICE 1,500 TO 4,999 KW | kWh | 876,597,685 | -$ 250,166 | - **0.0003** | $/kWh |
| LARGE USE | kWh | 615,205,612 | -$ 175,569 | - **0.0003** | $/kWh |
| UNMETERED SCATTERED LOAD | kWh | - | $ - | - | $/kWh |
| STANDBY POWER GENERAL SERVICE 5( | kWh | - | $ - | - | $/kWh |
| STANDBY POWER GENERAL SERVICE 1, | kWh | - | $ - | - | $/kWh |
| STANDBY POWER GENERAL SERVICE L/ | kWh | - | $ - | - | $/kWh |
| SENITEL LIGHTING | kWh | - | $ - | - | $/kWh |
| STREET LIGHTING | kWh | 46,220,021 | -$ 13,190 | - **0.0003** | $/kWh |
| microFIT | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| | | - | $ - | - | |
| **Total** | | | **-$ 1,250,514** | | |

## Rate Rider Calculation for Accounts 1568

**Please indicate the Rate Rider Recovery Period (in years)** **1**

| **Rate Class** (Enter Rate Classes in cells below) | **Units** | **kW / kWh / # of Customers** | **Balance of** | **Rate Rider for** |
|---|---|---|---|---|
| RESIDENTIAL | kWh | 2,216,045,000 | -$620,714 | **- 0.0003** |
| GENREAL SERVICE LESS THAN 50KW | kWh | 726,360,000 | -$ 51,170 | **- 0.0001** |
| GENERAL SERVICE 50 TO 1,499 KW | kW | 7,027,979 | -$ 6,881 | **- 0.0010** |
| GENERAL SERVICE 1,500 TO 4,999 KW | kW | 1,847,365 | -$ 159 | **- 0.0001** |
| LARGE USE | kW | 1,121,449 | -$ 23 | **- 0.00002** |
| UNMETERED SCATTERED LOAD | kWh | 16,651,000 | -$ 280 | **- 0.00002** |
| STANDBY POWER GENERAL SERVICE 50 TO 1,499 KW | kW | - | $ - | **-** |
| STANDBY POWER GENERAL SERVICE 1,500 TO 4,999 KW | kW | - | $ - | **-** |
| STANDBY POWER GENERAL SERVICE LARGE USE | kW | - | $ - | **-** |
| SENITEL LIGHTING | kW | 216 | $ - | **-** |
| STREET LIGHTING | kW | 123,144 | -$ 17 | **- 0.0001** |
| microFIT | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| | | - | $ - | **-** |
| **Total** | | | **-$679,243** | |

Note - This tab used to calculate the Rate Rider for Account 1568, as the formulas to calculate this Rate Rider in tab '6. Rate Rider Calculations' is not producing results.