Response to Vulnerable Energy Consumers Coalition Interrogatory Question #1

Reference: E-A/T2/S1

Question #1:

a. Please provide the Canada/Ontario actual CPI and GDP IPI inflation rate for the first 6 months of 2015.

b. Please provide the actual CPI (annual) inflation for 2012 through 2014.

Response:

a. Canada/Ontario actual CPI and GDP IPI inflation rate for the first 6 months of 2015: The GDP-IPI is only available on a quarterly basis and is presently only finalized to Q1-2015.

Month	CPI Canada (Index)	CPI Canada (Percentage)	CPI Ontario (Index)	CPI Ontario (Percentage)
Jan-2015	124.3		125.3	
Feb-2015	125.4	0.9%	126.2	0.7%
Mar-2015	126.3	0.7%	127.1	0.7%
Apr-2015	126.2	-0.1%	126.9	-0.2%
May-2015	126.9	0.6%	127.7	0.6%
Jun-2015	127.2	0.2%	128.2	0.4%

Source: Stats Canada CANSIM Table 326-0020

Quarter	GDP-IPI Canada (Index)	GDP-IPI Canada (Percentage)
Q4-2014	112.8	
Q1-2015	112.2	-0.5%

Source: Stats Canada CANSIM Table 380-0066

b. Actual CPI (annual) inflation for 2012 through 2014:

Year	CPI Canada (Index)	CPI Canada (Percentage)
2011	119.9	
2012	121.7	1.5%
2013	122.8	0.9%
2014	125.2	2.0%

Source: Stats Canada CANSIM Table 326-0021

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #2

Reference Letter of Comment/Hershell Sax June 4, 2015; E-B/T1/S2/pg.188

Question #2:

a. In his letter of comment Mr. Sax notes that an Ottawa Sun Poll carried out in May 2015 showed that 97% of respondents opposed to HOL's rate increase. Please provide the referenced newspaper article and poll results.

Response:

a. On May 11, 2015, the *Ottawa Sun* published a news article titled "Hydro rate hike fans hard to find" by Keaton Robbins. The article, which can be retrieved online at www.ottawasun.com/2015/05/11/hydro-rate-hike-fans-hard-to-find included collecting opinions from eleven Ottawa residents. The article states, *"In one hour, 90% of people (10 out of 11) said the rate increase is unreasonable and opposed it.*

Q: What do you think of Hydro Ottawa's survey saying 70% of Ottawans are okay with a rate increase??

"It's complete BS. Not at all. I'm not happy about that (survey numbers)."
— Joe Merlo

"It's impossible. I don't think anybody wants hydro rates to go up. They're already the highest in the country."
— Ray Tetu

"That's terrible. Come on. I think it's bogus. They've been increasing for several years now and it keeps going up. Are we going to have to walk around with a candle?"
— Marie-Lynn Savoie.

"Give me a good reason and maybe I'll consider it. I'm not going to say yes for no reason."
— Claire Cameron

"I think it should be prorated, depending on how much you earn. Maybe they could have a rate for people on welfare and another rate for people."
— Dan Waselnuk

"The rates are nuts. I used $25 worth of hydro and my bill was $65 or more. They can't seem to get a handle on how to correct it."
— Lise Juno

"From an international perspective, prices are rising. My parents live in Serbia and they have increase of 30% (every year) ... I think we're a little bit spoiled in Canada. We're so used to low energy prices."
— Agatha Schwartz."

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #3

Reference: **Letter of Comment Kathleen Glasspool/James Hurd June 4, 2015**

Question #3:

a. A number of letters of comment, including the one referenced, are from customers who participated in a survey done by or on behalf of Hydro Ottawa. These writers suggest that the customer outreach was designed to solicit the response desired by Hydro Ottawa. Please respond to this criticism.

b. As part of any of the survey's completed were customers informed that the rate increase was necessary to maintain system safety and reliability?

Response:

a. Innovative Research Group Inc. (INNOVATIVE) was commissioned by 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 application. Based on its experience delivering similar customer engagement surveys for other Ontario utilities, INNOVATIVE 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.

The goal of the online survey 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.

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.

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.

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%) felt the information and question response options were biased. Over one-in-ten (13%) wanted information on salaries/bonuses for Hydro Ottawa staff.

b. The relationship between infrastructure investments and reliability is discussed within the surveys. The workbook used for online surveying and customer focus groups states on page two: “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.”

The topic of reliability is further addressed on pages 10, 12 and 13 of the workbook.

On page 10, the workbook states “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.”

Pages 12 and 13 include an explanation of Hydro Ottawa tracks its reliability performance using SAIDI, SAIFI and outage cause metrics. It outlines the company’s 2014 outage statistics, including explaining how the utility is addressing the two leading causes of power outages in 2014: defective equipment and weather/lightning damage. The workbook states:

“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."

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #4

Reference E-B/T1/S2/pg.48

Question #4:

a. Please provide the Productive time ratios for 2011 through 2014 and the associated projected (targets) for 2015 through 2020.

Response:

2011 – 70%
2012 – 71%
2013 – 69%
2014 – 71%
2015 – 75% June YTD actual (prior to summer vacation period)

The productive time ratio is tracked as a measure on the Balanced Productivity Metrics scorecard. Hydro Ottawa Limited is working on establishing forward looking targets for these measures by year end 2015.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #5

Reference E-B/T1/S2 pgs. 69/236

Question #5:

a. At page 69 of the DSP it lists projects designed to reduce outage frequency and duration. Please provide the 2014 through 2019 actual/forecast expenditures on these programs.

b. HOL states that reliability driven projects are almost exclusively driven by automation projects. Table 3.4.8 shows that HOL is proposing to spend more than 6 times its average annual spending in this category between between 2015 and 2018 as compared to 2011 and 2014 (approx. 5.0m vs. $807k vs). Please provide the metric/targets that will be used to assess the efficacy of these programs in reducing outages and outage duration.

c. If these investments have no impact on reliability frequency or duration of what consequence will this be for management compensation or future rates?

Response:

a. As shown in Exhibit B-1-2 Table 3.1.1 reliability projects are done under System Reliability and Distribution Automation programs. The 2014-2015 budgets are listed in Exhibit B-1-2 Table 3.4.7; however, it is not broken down into Budget Programs. The table below shows the budgets for 2014 and 2015 by budget program.

Table VECC #5 – 1: 2014 and 2015 System Service by Budget Program

Capital Program	Budget Program	$'000	
		2014	2015
Stations Capacity	Stations New Capacity	4,352	2,187
Distribution Enhancements	Line Extensions	6,666	4,685
	System Voltage Conversion	6,600	9,132
	System Reliability	785	470
	Dist. Enhancements	535	888
Automation	SCADA Upgrades	-	304
	SCADA - RTU Additions	53	170
	Distribution Automation	184	2834
	Stations Automation	122	136
Total		**19,298**	**20,806**

The proposed 2016-2020 budgets for the System Reliability and Distribution Automation programs can be found in Exhibit B-1-2 Table 3.5.10.

b. The increase in budget for Distribution Automation is due to the Telecommunications Master Plan project. The Telecom Plan was developed in 2014 to provide a complete picture of the core Wide Area Network required to accommodate all HOL distribution system communications needs. The plan includes a detailed investment roadmap which describes the necessary investments and outcomes over the next 10 years. The justification for this project and performance targets can be found in Section 4.1 Telecommunications Master Plan of Attachment B-1(A) – Materials Investments System Service.

c. Please see Interrogatory Response to OEB #14 part iii for impact of system reliability performance indicators to management performance appraisals processes.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #6

Reference E-B/T1/S2/pg.181

Question #6:

a. Please provide the number of customers in Casselman. Please also provide the growth in this service area from 2012 through 2014 and the forecast growth to 2020.

b. Please provide the estimated cost of the second transformer planned for this service area. Please also provide the estimated in-service date.

c. What other strategies have been considered/implemented to address the single supply issue for Casselman?

d. Please provide the business case/analysis for the transformer investment in Casselman.

Response:

a. The number of customers in Casselman is 1,723.
The peak loading from 2012 – 2014 is shown in the Table VECC #6 - 1:

Table VECC #6 - 1: Casselman historical peak loading 2012 - 2014

Cassleman MS	2012	2013	2014
Load in MVA	6.4	5.6	4.3

The forecasted conservative and 1-in-10 year peak loading for 2015 – 2020 is shown in the Table VECC #6 - 2:

Table VECC #6 - 2: Casselman forecasted peak loading 2015 - 2020

Cassleman MS	2015	2016	2017	2018	2019	2020

Load in MVA (conservative)	5.8	5.8	5.8	5.9	5.9	5.9
Load in MVA (1-in-10 year)	7.9	7.9	7.9	7.9	7.9	7.9

b. The total cost of the project is $4.74M. The estimated in-service date of the transformer is 2015.

c. The other option considered to address the single supply issue for Casselman was to remain a single transformer lineup. Issues with this approach include:

- Ongoing costs, reliability and power quality issues associated with reliance on with Hydro One system
- Existing fused transformer protection deemed a risk to safety & reliability
- No ability to add new circuits

d. The business case for the transformer investment in Casselman is located in Attachment B-1(A) - Material Investments System Service section 1.6, pages 196 – 200.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #7

Reference **E-B/T1/S2/pg.203**

Question #7:

a. Please provide the 2015 – 2020 SCADA project expenditures
b. Please provide the targets/metrics used to measure the efficacy of the SCADA and WiMAX investments on reliability.

Response:

a. The budgeted SCADA Project expenditures are in Table VECC #7 – 1.

Table VECC #7 – 1: Budgeted SCADA Project Expenditures

Year	2015	2016	2017	2018	2019	2020
Capital ($000's)	303	1,011	1,011	556	51	51

There was an error in Exhibit B-1-2, Table 3.1.8 – Material Capital Expenditures for 2015 and 2016 Projects (3/2) where the total budget for the SCADA Upgrade project should be $2,983,000.
There was an error in Attachment B-1(A) - Material Investments System Service, Section 5.1.3.2 Project/Program Timing & Expenditure where the reflected costs should be equal to Table VECC #7 – 1.

b. Please see Interrogatory Response to OEB #15 part ix and Interrogatory Response to CCC #5 part b.
The WiMAX pilot project has been one of technical and operational evaluation. These evaluations have served as a pathfinder project for future communications investments which will involve a wide variety of equipment and solutions, including WiMAX. Due to the fact that these communications investments will go

hand in hand with the deployment of automation devices and sensors, Hydro Ottawa Limited anticipates that the WiMAX investments will contribute to the improvement of customer reliability.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #8

Reference **E-B/T1/S2/pg.222**

Question #8:

a. The average annual system access commercial investments between 2011 and 2014 was $9,743,000. The average forecast investment for the period 2015 through 2018 is $12,830,000 or approximately 31% higher. We note a similar increase is not forecast for residential system access investments. Please explain why HOL believes it will see over 30% growth in the commercial system access expenditures over the next 4 years.

b. Please provide the 2015 actual (6 months) to date spending on this category. For comparison please provide the similar results for the 2014 Jan-June period.

Response:

a. Please refer to Interrogatory Response to CCC #20 part c.

b. Please refer to Interrogatory Response to EP #13 part c.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #9

Reference **E-B/T1/S2/pg.222**

Question #9:

a. The average investment between 2011 and 2014 for "Damage to Plant" has been $960m. Please explain why the forecast amounts for 2015 through 2020 are significantly higher?

b. Does the 2013 category of "Damage to Plant" include costs related to the 2013 ice-storm? If so please identify those costs.

Response:

a. The response is based on the assumption of average investment of $960 THOUSAND based on historical spends provided in Exhibit B-1-2, Table 3.4.3 (page 222). The forecast amounts from 2015 to 2020 represent approximately a 23% increase over the average investment over the 2011 – 2014 time period, however Hydro Ottawa has seen its two-year rolling average on Damage to Plant spending increase from $757k in 2011 – 2012 to $1.1M in 2013 – 2014. Due to the largely unknown and variable nature of this program, historical trends are used as the basis for budgeting and forecasting and the 2015 – 2020 forecasted amounts are in line with Hydro Ottawa's two-year rolling average historical spending. The 2015 forecast represents a 1% increase over the 2013 – 2014 average spend and the 2016 – 2020 forecasted amounts represent a 2% increase over the prior year's forecast.

b. None of the 2013 costs in "Damage to Plant" relate to the 2013 ice storm. While Hydro Ottawa did assist the City of Toronto in the aftermath of the storm, none of those efforts resulted in restorations of any of Hydro Ottawa's assets, therefore none of the costs associated were classified in Damage to Plant in 2013.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #10

Reference **E-B/T1/S2/pg.228**

Question #10:

a. Please provide a table identifying all station asset investments by year, with project start and in-service dates for the period 2015 through 2020.

Response:

a. System Renewal & System Service projects that start or are taking place during 2016, can be found in Attachment B-1(A) Material Investments. The 2017-2020 project lists are not yet optimized and thus specific projects with start dates and in service dates have not been confirmed. Please see table VECC.10-1 below for Hydro Ottawa station projects with start dates prior to 2017.

Table VECC #10 -1: Hydro Ottawa station projects with start dates prior to 2017

System Service Forecasted Spend				
Capital Program	**Budget Program**	**Project**	**Start Date**	**In-Service Date**
Stations Capacity	Stations New Capacity	92006303 - Casselman T1	Q1 2012	Q4 2015
		92005135 - Hinchey New Switchgear	Q2 2012	Q4 2015
		92008763 - Lisgar Transformer Upgrade	Q1 2014	Q4 2017
		92008899 - TFX New Leitrim T1 (Island)	Q1 2015	Q4 2018
		92008593 - Richmond South DS	Q1 2015	Q3 2019
		92008537 - New South 28KV Substation	Q1 2015	Q4 2020

System Renewal Forecasted Spend				
Capital Program	**Budget Program**	**Project**	**Start Date**	**In-Service Date**
Stations Assets	Stations Trans Repl.	92008491 - Longfields XFRM Base Rpl- Incl	Q1 2015	Q1 2016
		92008579 - TFX Repl-13/4kV AlbionUA T1&T2	Q1 2015	Q4 2016
		92008661 - XFRM Repl. Bronson SBT1 & SBT2	Q1 2016	Q4 2017
		92008485 - Merivale DS Rebuild	Q1 2014	Q3 2018
	Stations Switchgear Repl.	92006411 - Bayshore Primary CS	Q1 2013	Q2 2015
		92007348 - Startop Protection Upgrade	Q1 2013	Q4 2015
		92006413 - Borden Farms Switchgear Replacement	Q1 2013	Q4 2015
		92008497 - Prim Fuse to C-Switcher - Epworth T1	Q1 2014	Q4 2015
		92010241 - Overbrook TO Switchgear Rep	Q1 2015	Q4 2018
		92010156 - Munster Recloser	Q1 2016	Q4 2016
		92010243 - Casselman Reclosers	Q1 2016	Q4 2016
		92010319 - Henderson Switchgear Repl	Q1 2016	Q4 2016
		92008657 - Woodroffe TW - 13kV SG Replac	Q2 2016	Q4 2017

For additional information;

Please see Attachment B-1(A) Material Investments System Renewal:

- Section 1 – Station Transformer Replacement
- Section 2 – Station Switchgear Replacement

Please see B Attachment B-1(A) Material Investments System Service:

- Section 1 – Stations New Capacity

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #11

Reference: **E-B1/T1/S2/pg. 243**

Question #11:

a. For each year 2015 through 2020 please provide a table showing all the Hydro One projects for which a contribution (payment) is forecast and the amount forecast for that project. If the annual figures do not add up to the "Hydro One Payments" row shown in Table 3.4.11 please explain the difference.

Response:

a. Please refer to Interrogatory Response to EP #15 part c.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #12

Reference: **E-B1/T1/S3/pg. 16**

Question #12:

a. Using the table at page 16 showing the 2015-2020 IT Strategy, please provide the total cost of each IT program (capital and ongoing incremental OM&A) and the expected in-service/implementation date.

Response:

a. Please refer to Interrogatory Response to OEB Staff Question #15 – Technology-based Opportunities section part xiii.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #13

Reference **E-B-T5/S4**

Question #13:

a. Please provide a chart or table similar to that shown below which shows outages by cause code for each year 2011 through 2014

b. Please provide HOL's forecast of the same for the years 2015 through 2020.

	Reliability Event Causes Year	%
1	Unknown	
2	Loss of Supply (HON sources)	
3	Defective Equipment/Failure	
4	Adverse Weather (other than lightning)	
5	Scheduled Outages (maintenance, replacements)	
6	Foreign Interference (motor vehicle accidents)	
7	Lightning	
8	Tree Contacts	

Response:

a. Table Headings

U – Unknown/Other

SO – Scheduled Outage

LOS – Loss of Supply

TC – Tree Contacts

L – Lightning

DE – Defective Equipment
AW – Adverse Weather
AE – Adverse Environment
HE – Human Element
FI – Foreign Interference

Table – 1: Reliability Event Causes

	U	SO	LOS	TC	L	DE	AW	AE	HE	FI
2011	10%	4%	17%	7%	5%	24%	22%	0%	3%	6%
2012	7%	5%	37%	2%	3%	16%	12%	3%	4%	11%
2013	7%	6%	11%	8%	17%	27%	8%	1%	6%	10%
2014	3%	7%	21%	5%	9%	26%	13%	0%	9%	8%

b. Hydro Ottawa has not done a five year forecast of reliability. However reliability is forecasted annually for each month of the year at the start of each year based on historical values and tracked monthly. This information is shared across the company as well as reviewed monthly by the Chief Executive Officer and Chairman of the Board. Please see attachment Att-SIA-Q16-A – Monthly Reliability Report. In addition, HOL utilizes system reliability metrics as key performance indicators for the organization as a benchmark for continuous improvement (refer to Interrogatory Response to SIA #7).

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #14

Reference E-C/T1/S1, pg. 1

Question #14:

a. Please describe the purpose and provide the results of the "rate reclassification analysis" undertaken by Ottawa and referred to at lines 18-20.

b. With respect to the customer count historical and forecast values presented in the Itron report (i.e., Tables 5 and 6), please indicate for which years this "reclassification analysis" impacted the values shown and how.

c. Please provide a schedule that contrasts (where the results are different) the customer count and load forecast as developed by Itron versus what is proposed by Ottawa for the 2015-2020 as a result of the rate reclassification analysis.

d. Please describe how Ottawa developed load forecasts for the Sentinel Lights and Standby classes

e. Please explain how the Itron forecasts were adjusted in order to include Sentinel Lights and Standby loads and customers. As part of the response please provide a schedule that sets out for the years 2015-2020 the individual customer class and total load/customer count forecasts as prepared by Itron versus those proposed by Ottawa.

f. Please confirm that the adjustments Ottawa made to the Itron forecast for customer reclassification and to include Sentinel and Standby were to the Itron load forecast that include the CDM adjustments

Response:

a. According to Section 2.5 of the Distribution System Code non-residential customer's rate classification are to be reviewed annually. Please see answer c) of this question for the forecasted impact.

b. Hydro Ottawa adjusted the opening balance of the 2016 forecast to account for the rate reclassification.

Table 5 of Itron's report refers to the residential customer class; the residential customer class was not part of the customer reclassification process.

Table 6 of Itron's report refers to the commercial customer classes. All commercial rate classes with the exception of the Large Commercial class were forecasted to have customers move as a result of the rate reclassification. Please see answer c) of this question for how each class was effected by year.

c. As a result of the rate reclassification process please see Table 1 of this response for the change to the customer count forecast, Table 2 for the change in the sales forecast and Table 3 for the change in the demand forecast. The tables include 2016 through 2020 as no change was made to Hydro Ottawa's 2015 forecast as a result of the rate reclassification.

Table 1 - Rate Reclassification Customer Count Forecasted Impact

	Customer Count				
	2016	2017	2018	2019	2020
RESIDENTIAL	0	0	0	0	0
GENERAL SERVICE <50KW	294	294	294	294	294
GENERAL SERVICE 50-1000KW Non Interval	(294)	(294)	(294)	(294)	(294)
GENERAL SERVICE 50-1000KW Interval	18	18	18	18	18
GENERAL SERVICE 1000-1500KW	(6)	(6)	(6)	(6)	(6)
GENERAL SERVICE 1500-5000 KW	(12)	(12)	(12)	(12)	(12)
LARGE USER	0	0	0	0	0
STREET LIGHTING	0	0	0	0	0
MU	0	0	0	0	0
TOTAL CUSTOMERS	0	0	0	0	0

Table 2 - Rate Reclassification Sales Forecasted Impact

	Sale MWh				
	2016	2017	2018	2019	2020
RESIDENTIAL	0	0	0	0	0
GENERAL SERVICE <50KW	2,146	2,146	2,146	2,146	2,146
GENERAL SERVICE 50-1000KW Non Interval	(2,146)	(2,146)	(2,146)	(2,146)	(2,146)
GENERAL SERVICE 50-1000KW Interval	2,108	2,108	2,108	2,108	2,108
GENERAL SERVICE 1000-1500KW	1,181	1,181	1,181	1,181	1,181
GENERAL SERVICE 1500-5000 KW	(3,289)	(3,289)	(3,289)	(3,289)	(3,289)
LARGE USER	0	0	0	0	0
STREET LIGHTING	0	0	0	0	0
MU	0	0	0	0	0
TOTAL CUSTOMERS	0	0	0	0	0

Table 3 - Rate Reclassification Demand Forecasted Impact (kW)

	Demand MW				
	2016	2017	2018	2019	2020
RESIDENTIAL	0	0	0	0	0
GENERAL SERVICE <50KW	5,985	5,985	5,985	5,985	5,985
GENERAL SERVICE 50-1000KW Non Interval	(5,985)	(5,985)	(5,985)	(5,985)	(5,985)
GENERAL SERVICE 50-1000KW Interval	5,679	5,679	5,679	5,679	5,679
GENERAL SERVICE 1000-1500KW	958	958	958	958	958
GENERAL SERVICE 1500-5000 KW	(6,637)	(6,637)	(6,637)	(6,637)	(6,637)
LARGE USER	0	0	0	0	0
STREET LIGHTING	0	0	0	0	0
MU	0	0	0	0	0
TOTAL CUSTOMERS	0	0	0	0	0

Please note although the General Service < 50 KW class shows demand being shifted into the class, the General Service < 50 KW class is not invoiced based on demand.

d. As Hydro Ottawa no longer offers new sentinel lights and any changes requested by the Customer with an existing sentinel light(s) or major Hydro Ottawa Distribution System work on the specific sentinel light poles shall result in the removal of the light(s) or change of ownership of the light(s) to the Customer and any required revenue metering Hydro Ottawa has only forecasted a decline in the number of sentinel lights. Hydro Ottawa used the 2014 actuals to forecast the kWh Sales for Sentinel Light and estimated the declining count using historical number of lights.

Hydro Ottawa relied on historical forecasts for the 2 Standby customers demand for 2016 through 2020.

e. Hydro Ottawa added Sentinel light sales, demand and connection to the Itron forecast.

Hydro Ottawa added Standby demand and customer count to the Itron forecast.

Please see Tables 4, 5 and 6 which illustrates how Hydro Ottawa added to the Itron forecast for the inclusion of Sentinel Lights, Standby Customers and additional unmetered connections.

Table 4 – Additions to Itron's Customer Count and Connection Forecast

	Average Customer Count					
	2015	2016	2017	2018	2019	2020
Itron's Forecast	321,113	325,238	329,294	333,321	337,306	341,241
Stanby	2	2	2	2	2	2
Hydro Ottawa Forecast	321,115	325,240	329,296	333,323	337,308	341,243

	Average Customer Count					
	2015	2016	2017	2018	2019	2020
Itron's Forecast	58,960	58,960	58,960	58,960	58,960	58,960
Sentinel Lights	57	55	51	47	43	39
Unmetered Load additions	0	33	81	129	177	225
Hydro Ottawa Forecast	59,017	59,048	59,092	59,136	59,180	59,224

The Hydro Ottawa Forecast in Table 4 of this response balances to Table 3 of Exhibit C-1-1.

Table 5 – Additions to Itron's Sales Forecast

	Forecasted Sales (MWh) by class					
	2015	2016	2017	2018	2019	2020
Itron Forecast	7,460,067	7,444,004	7,383,034	7,369,403	7,367,477	7,367,816
Exclude DryCore	(16,594)	(3,428)	(3,438)	(3,447)	(3,454)	(3,466)
Add Sentinel Lights	48	48	48	48	48	48
Hydro Ottawa Forecast	7,443,521	7,440,624	7,379,644	7,366,004	7,364,071	7,364,398

The Hydro Ottawa Forecast in Table 5 of this response balance to Table 1 of Exhibit C-1-1.

Table 6 – Additions to Itron's Demand Forecast

	Forecasted Sales (MWh) by class					
	2015	2016	2017	2018	2019	2020
Itron Forecast	10,201,116	10,119,937	10,029,201	9,981,838	9,957,785	9,948,590
Standby		4,800	4,800	4,800	4,800	4,800
Add Sentinel Lights	216	216	216	216	216	216
Hydro Ottawa Forecast	10,201,332	10,124,953	10,034,217	9,986,854	9,962,801	9,953,606

The Hydro Ottawa Forecast in Table 6 of this response balances to Table 2 of Exhibit C-1-1.

f. Hydro Ottawa confirm that the adjustments Hydro Ottawa made to the Itron forecast for customer reclassification and to include Sentinel and Standby were to the Itron load forecast that included CDM adjustments.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #15

Reference E-C/Itron Report, pg. 1

Question #15:

Please provide a schedule that sets out the average annual customer/connection count by class starting in 2005 and the resulting geomean historical growth rate for each customer class.

Response:

Table 1 provides the average annual customer/connection count by class starting in 2012. It is not clear what is being requested regarding "the resulting geomean historical growth rate for each customer class", as a result it has not been provided.

Table 1 - Average Customers/Connections

	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
Residential	280,254	284,964	289,385	293,366	297,343	301,258	305,144	308,990	312,786
GS<50KW	23,767	23,936	23,968	24,099	24,512	24,626	24,739	24,850	24,959
GS 50-1999KW	3,416	3,408	3,514	3,549	3,296	3,323	3,351	3,380	3,408
GS 1500-5000 KW	74	76	87	88	75	76	76	76	76
Large User	11	11	11	11	11	11	11	11	11
Street lighting	55,674	55,757	55,524	55,516	55,516	55,516	55,516	55,516	55,516
UMSL	3,384	3,376	3,438	3,444	3,477	3,525	3,573	3,621	3,669
Sentinel Lights	61	57	57	57	55	51	47	43	39
Standby	2	2	2	2	2	2	2	2	2

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #16

Reference: E-C/Itron Report, pg. 4 and 13-14

Question #16:

Preamble: The Report states that, for the Residential sector, the end-use energy intensities were derived from historical and forecast data from the recent OPA end-use forecast for the province.

a. Please provide either the report or a link to the OPA report that sets out the residential historical and forecast saturation and annual energy estimates or unit of energy consumption data used by Iron.

b. Please provide the relevant references which would demonstrate that the forecast data prepared by the OPA represents expected results prior to the implementation of any future CDM programs.

c. As part of its recent long-term forecast for Ontario, did the OPA produce regional long-term energy forecasts (i.e. for total load)? If so, please provide the OPA's long term energy forecast for the region encompassing Ottawa and provide the supporting reference(s).

d. Does Figure 8 set out the HeatIntensity, CoolIntensity and Other Intensity variables as used in the Resdential Model? If not, please provide a schedule that sets out the historic and forecast values for these parameters.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Saturations and end-use energy estimates per household, measured in annual kWh or unit of energy consumed ("UEC"), were provided by the former Ontario Power Authority ("OPA") in an excel document. The data was provided by housing type; single family, multi res high rise, row house, multi res low rise, and other. Weighted end-use saturations and UECs are calculated based on the reported housing-type distribution in the OPA and Ministry of Energy *2013 Long-Term Energy Plan, Achieving Balance: Ontario's Long-Term Energy Plan (December 2013) Module 1, slide 13* (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-1-Demand-Forecast.pdf).

   The saturation data is provided in attachment Att-VECC-Q16-A. The OPA UEC data is provided in attachment Att-VECC-Q16-B.

b. OPA saturation and UEC forecasts are before any adjustment for future CDM. On page 4 of the document to which a link is provided to in part a, it stated "The gross demand forecast presents the expected electricity demand before the impacts of codes and standards, conservation policies and programs are considered"

c. Data provided by OPA was for the Province. The published *Long-Term Energy Plan, Achieving Balance: Ontario's Long-Term Energy Plan* does not provide detailed annual energy forecasts on a regional level.

d. Figure 8 shows the heating, cooling, and other use intensity used energy intensity figures used in the constructed residential monthly model variables XHeat, XCool, and XOther.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #17

Reference: E-C/Itron Report, pg. 4 and 13-14

Question #17:

Preamble: The Report states that, for the Commercial sector, the end-use energy intensities are based on forecast prepared by the US EIA.

a. Please provide either the report or a link to the EIA report that sets out the historical and forecast commercial energy intensities used by Itron.

b. Please provide relevant references which demonstrate that the forecast data prepared by the EIA represents expected results prior to the implementation of any future CDM programs.

c. Please provide a schedule that set outs the historic and forecast vales for EICool, EIHeat, and EIOther as used in the Commercial models.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Please find a link to the Energy Information Administration's ("EIA") Annual Energy Outlook for 2014 ("AEO2014") http://www.eia.gov/forecasts/archive/aeo14/.

b. The AEO2014 includes only current and future codes and standards. The AEO2014 does not include utility or state conservation program activity. The EIA state "the AEO2014 Reference case projection is a business-as-usual trend estimate, given

known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in AEO2014 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives."[1]

c. Please see Attachment Att-VECC-Q17-A for the Heating, Cooling, and Other variables used in the commercial models.

[1] Annual Energy Outlook 2014 with Projections Through 2040, DOE/EIA-0383(2014) \ April 2014

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #18

Reference E-C/Itron Report, pg. 6

Question #18:

a) Please explain why billing data prior to 2008 was not usable for estimating statistically acceptable forecast models.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response

a) Historical monthly sales data used in estimating the class sales forecast models are accounting based estimates; there is no actual measurement of what consumers' used on a calendar-month basis. The process used in calculating monthly sales estimates (prior to 2013) do not correlate well with monthly weather conditions (measured in heating degree days ("HDD") and cooling degree days ("CDD")). Sales estimates include the impact of current and prior month weather conditions (and the prior two-month period weather in the case of residential), the number of days in the billing period, estimates of unbilled sales, and other customer billing adjustments.

   The better an estimated model can explain the historical sales variation, the more confidence one can have that the estimated model will generate a reasonable sales forecast. The Adjusted R-Squared and Mean Absolute Percent Error (MAPE) are two statistics commonly used to evaluate the statistical "fit" of electric sales and demand regression models. The Adjusted R-Squared measures how well the model explains the monthly sales or demand variation; a value of 0.0

implies that the model explains none of the variation while a value of 1.0 implies perfect explanation of the monthly variation. There are no specific criteria for which a model can be deemed acceptable in terms of an Adjusted R-Squared and MAPE as they are a function of the data, but models with higher Adjusted R-Squared values and lower MAPE values are preferred over models with lower Adjusted R-Squared values and higher MAPE values.

b) For many of the rate classes, we cannot estimate models with even marginally acceptable model statistics using sales data prior to 2008. The Residential model (estimated with sales data beginning in 2008) has an adjusted R-Squared or 0.80 and a MAPE of 4.4%. When the model is estimated starting in January of 2005, the model Adjusted R-Squared drops to 0.74 and the MAPE increases to 5.8%. The GS50 model has an Adjusted R-Squared of 0.70 and a MAPE 4.2%, when the model is estimated starting in January of 2008; if that same model is estimated starting in January of 2005 the Adjusted R-Squared drops to 0.44 and the MAPE increases to 8.2%. The GS1000NI model has an Adjusted R-Squared of 0.91 and a MAPE of 2.5%, when the model is estimated starting in January, 2008; if that same model is estimated starting in January, 2005 the Adjusted R-Squared drops to 0.75 and the MAPE increases to 5.1%.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #19

Reference: E-C/Itron Report, pg. 6-7 and 26

Question #19:

a) Please clarify what the MU and DCL customer classes are.

b) Please provide a schedule that for each year 2015 to 2020 compares the sum of the individual customer class forecasts (as developed by Itron) with Itron's total sales forecast (per page 26).

c) Please provide a schedule that compares the 2015-2020 load forecasts for each class (before CDM adjustments): i) as initially developed by Itron versus ii) subsequent to any adjustments made by Irron to reconcile with the total sales forecast. Also, please explain how the total sales forecast was allocated to individual customer classes based on the individual rate class forecasts.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. MU is the classification for Unmetered Scattered Load. DCL represents Dry Core Transformer losses.

b. Please see Table 1 for the comparison of the bottom-up sales forecast derived by aggregating the rate class sales forecasts with the top-level forecast derived from the total purchase forecast model.

Table 1 - Comparison of Rate Class Sales Forecast versus Top-Level Purchase/Sales Forecast

Year	Rate Class Sales Forecast (A)	Total Sales; Purchase less losses (B)	(A) - (B)
2015	7,488,199	7,511,506	(23,307)
2016	7,505,047	7,551,272	(46,225)
2017	7,504,831	7,569,305	(64,473)
2018	7,544,218	7,628,087	(83,869)
2019	7,588,690	7,691,997	(103,307)
2020	7,630,356	7,758,165	(127,809)

c. Please see Tables 2 through 11 for the requested load forecast data comparisons. For each rate class the data shows the model generated forecast and the rate class forecast calibrated to the total system sales forecast.

The first step in allocating the purchase sales forecast to the rate classes is to apply a loss factor to the purchases forecast; this results in a total monthly sales forecast. Hydro Ottawa Limited defined two separate loss factors; a loss factor of 1.0062 for Large Users and a loss factor of 1.0338 for all other classes. To account for differences in loss factors a 1.0338 factor is applied to bottom-up class sales forecast (excluding large users) and a 1.0062 factor is applied to Large User sales forecast. The loss adjusted sales are then used to allocate total purchases between Large Users and all other rate classes. Calibrated Large User sales forecast is derived by applying the Large User loss factor to Large User purchases. Calibrated sales to all other rate classes (excluding Large Users) are derived by applying the loss factor for all other classes (1.0338 factor) to All Other purchases.

In the final step, calibrated All Other sales forecast is allocated to the rate classes (excluding Large Users) on a proportional basis. As the rate class forecasts

increase (or decrease) at different rates, the class allocation factors will change over time.

Table 2 – Residential Comparison

Year	Initial	After Allocation from Purchase Model	Adjustment
2015	2,236,456	2,241,257	0.2%
2016	2,220,406	2,232,769	0.6%
2017	2,209,273	2,226,833	0.8%
2018	2,222,571	2,245,849	1.0%
2019	2,235,315	2,264,296	1.3%
2020	2,240,660	2,276,815	1.6%

Table 3 – General Service <50kW

Year	Initial	After Allocation from Purchase Model	
2015	707,995	710,082	0.3%
2016	706,845	711,334	0.6%
2017	703,599	709,771	0.9%
2018	701,974	709,908	1.1%
2019	701,217	710,894	1.4%
2020	701,140	713,027	1.7%

Table 4 – General Service 50-1000 (Non-Interval)

Year	Initial	After Allocation from Purchase Model	
2015	1,459,338	1,463,207	0.3%
2016	1,441,411	1,450,111	0.6%
2017	1,415,289	1,427,265	0.8%
2018	1,395,495	1,410,826	1.1%
2019	1,378,512	1,397,088	1.3%
2020	1,363,882	1,386,525	1.7%

Table 5 – General Service 50-1000 (Interval)

Year	Initial	After Allocation from Purchase Model	
2015	1,174,008	1,179,844	0.5%
2016	1,207,697	1,215,423	0.6%
2017	1,236,068	1,247,004	0.9%
2018	1,266,843	1,281,251	1.1%
2019	1,298,686	1,316,704	1.4%
2020	1,331,415	1,354,052	1.7%

Table 6 – General Service General Service 1500-1500

Year	Initial	After Allocation from Purchase Model	
2015	348,969	350,053	0.3%
2016	352,737	355,011	0.6%
2017	355,364	358,529	0.9%
2018	358,903	363,006	1.1%
2019	362,786	367,839	1.4%
2020	366,972	373,224	1.7%

Table 7 – General Service General Service 1500-4999

Year	Initial	After Allocation from Purchase Model	
2015	880,351	883,241	0.3%
2016	896,869	902,777	0.7%
2017	908,618	916,868	0.9%
2018	924,117	934,838	1.2%
2019	940,774	954,038	1.4%
2020	958,554	975,022	1.7%

Table 8 – Large Use

Year	Initial	After Allocation from Purchase Model	
2015	618,151	620,305	0.3%
2016	616,025	620,219	0.7%
2017	613,563	619,254	0.9%
2018	611,257	618,467	1.2%
2019	608,342	617,036	1.4%
2020	604,676	615,194	1.7%

Table 9 – Street Lighting

Year	Initial	After Allocation from Purchase Model	
2015	43,136	43,504	0.9%
2016	43,262	43,550	0.7%
2017	43,262	43,654	0.9%
2018	43,262	43,765	1.2%
2019	43,262	43,875	1.4%
2020	43,262	44,015	1.7%

Table 10 – Unmetered Scattered Load

Year	Initial	After Allocation from Purchase Model	
2015	16,279	16,594	1.9%
2016	16,279	16,650	2.3%
2017	16,279	16,690	2.5%
2018	16,279	16,732	2.8%
2019	16,279	16,773	3.0%
2020	16,279	16,826	3.4%

Table 11 – Dry Core Transformer Losses

Year	Initial	After Allocation from Purchase Model	Adjustment
2015	3,516	3,418	-2.8%
2016	3,516	3,429	-2.5%
2017	3,516	3,437	-2.2%
2018	3,516	3,446	-2.0%
2019	3,516	3,455	-1.8%
2020	3,516	3,465	-1.4%

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #20

Reference: E-C/Itron Report, pg. 6 & 10
July 2014 Filing Guidelines, Chapter 2, Section 2.6.1.1
EB-2011-0054, C1/1/1, page 4

Question #20:

a. How long a period of AMI data will be needed in order to satisfactorily estimate sales regression models at the customer class level?

b. Please explain why the period used to define "weather normal" differs for the period over which the models were estimated.

c. The most recent Filing Guidelines issued by the Board state that Applicants are to provide "In addition to the proposed test year load forecast, the load forecasts based on a) 10-year average and b) 20-year trends in HDD and CDD". Please provide revised versions of Table 1 based on: i) HDD and CDD values using a 10-year average for weather normal and ii) HDD and CDD value using a 20-year trend as the definition of weather normal.

d. In its 2012 Rate Application, Ottawa used the 10-year average as its definition of weather normal stating:
A ten year average from 2000 to 2009 was adopted as the appropriate definition of normal weather. This most recent 10 year average is more consistent with recent years' weather and has been used by and accepted in other electricity distribution rate applications for 2008, 2009 and 2010 (Toronto Hydro Electric System Limited EB-2005-0421, EB-2007-0680 and Veridian EB-2009-0140).

Please explain why the definition was changed for the current application

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Ten years of historical monthly rate class data for estimating sales forecast models would be a preferred. A ten-year period is usually long-enough to capture the impact of variation in economic activity and weather conditions. This allows for models that are statistically strong with robust model variable coefficients.

b. The forecast models are estimated through August 2014 with 2013 as the last full year of calendar weather. The most current twenty-year weather period at the time the models were estimated is 1994 to 2013.

c. Table 1 provides the purchase forecasts with 10-year normal weather and twenty-year trended normal weather.

Table 1 - MWh Purchase Forecasts

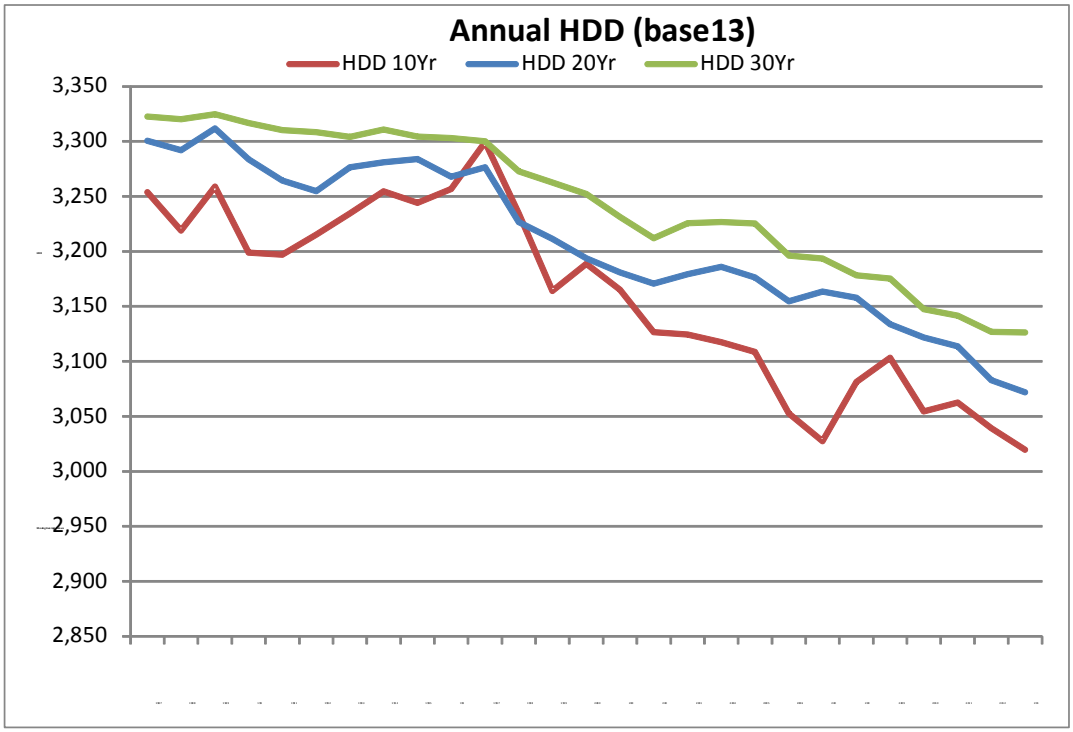
Year	20-Yr Normal	10-Yr Normal	20-Yr Trend Normal
2015	7,748,274	7,736,820	7,748,274
2016	7,789,387	7,778,056	7,789,844
2017	7,808,056	7,796,845	7,809,036
2018	7,868,846	7,857,682	7,870,421
2019	7,934,956	7,923,788	7,937,177
2020	8,003,412	7,992,220	8,006,334

The ten-year normal weather is based on the 10-year average from 2005 to 2013. The twenty year trended normal is based on a 20-year moving average. Temperatures have been increasing over time, as a result, the number of heating degree days ("HDD") have been decreasing and the number of cooling degree

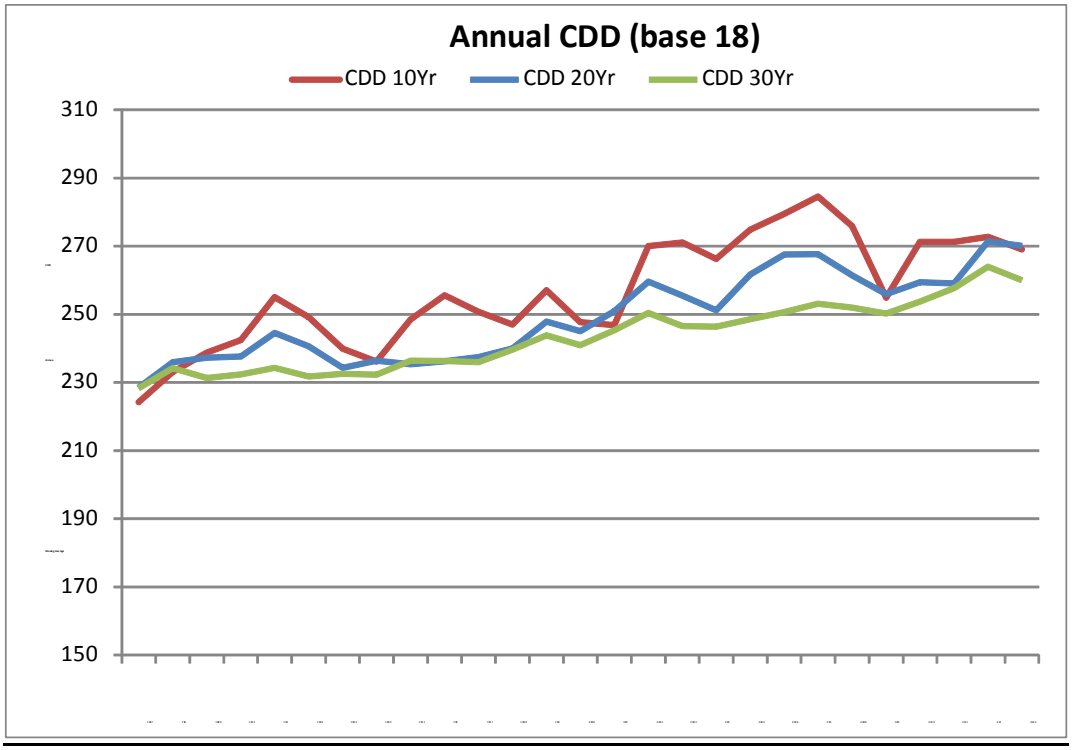
days ("CDD") have been increasing. Using the twenty-year trended data, HDD are decreasing 0.3% annually and CDD are increasing 0.7% annually. For the trended degree-day forecast, the calculated growth rates are applied to the 2015 twenty-year normal HDD and CDD.

d. Hydro Ottawa Limited ("Hydro Ottawa") elected to use a 20-year based normal after evaluating HDD and CDD trends. Graph 1 and 2 compare 10-year, 20-year, and 30-year HDD and CDD moving averages. While the 10-year HDD is lower, there is more month to month variation in the moving average. This is because a given month contributes 1/10 of the average over a 10-year period. One extremely cold month has a significant impact on calculated normal HDD. Similarly, one extremely hot summer month will have a significant impact on the calculated normal CDD series. Using a 10-year normal results in a normal weather series that can change significantly from year to year. Recognizing that temperatures are increasing over time, Hydro Ottawa elected to use a 20-year normal weather series.

Graph 1



Graph 2


Annual CDD (base 18)
CDD 10Yr
CDD 20Yr
CDD 30Yr
310
290
270
250
230
210
190
170
150

1

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #21

Reference: E-C/Itron Report, pg. 12

Question #21:

b. What is the source of the historical and forecast population values set out in Table 4?

c. Is there a more recent forecast from the Conference Board regarding the economic outlook (GDP and RPI) for the Ottawa and Gatineau area? If so, please provide.

Response:

b. The source of the historical and forecast population values as set out in Table 4 of Itron's Report is from the Conference Board of Canada ("CBofC"), the total Population of Ottawa and Gatineau. Please note at the time of the update in part c) of this question, the CBofC is forecasting to the end of 2019, the forecast for 2020 is calculated based on the trend of this forecasted data starting at 2015 using an average calculation.

c. Please see below for updated values in Table for Population, GDP and RPI, this data was extracted from the CBofC in July 2015 and confirmed with Itron.

1

Table 4: Ottawa Regional Economic Forecast - Updated July 31, 2015

Year	Population (000's)	Chg	GDP (Millions $)	Chg	RPI (Millions $)	Chg
2003	1140		52,596		36,692	
2004	1150	0.9%	54,117	2.9%	37,658	2.6%
2005	1160	0.9%	55,635	2.8%	38,650	2.6%
2006	1172	1.0%	57,480	3.3%	40,266	4.2%
2007	1188	1.4%	59,137	2.9%	42,100	4.6%
2008	1207	1.6%	60,175	1.8%	43,204	2.6%
2009	1229	1.8%	60,239	0.1%	44,899	3.9%
2010	1251	1.8%	62,345	3.5%	45,215	0.7%
2011	1270	1.6%	63,223	1.4%	45,795	1.3%
2012	1289	1.4%	63,457	0.4%	46,459	1.4%
2013	1303	1.1%	63,579	0.2%	46,279	-0.4%
2014	1318	1.2%	63,971	0.6%	46,690	0.9%
2015	1332	1.1%	64,804	1.3%	47,194	1.1%
2016	1347	1.1%	66,169	2.1%	47,850	1.4%
2017	1362	1.1%	67,759	2.4%	48,937	2.3%
2018	1378	1.2%	69,327	2.3%	49,978	2.1%
2019	1394	1.2%	70,998	2.4%	50,936	1.9%
2020	1410	1.1%	72,652	2.3%	51,900	1.9%
2003-14		1.33%		1.80%		2.23%
2015-20		1.13%		2.14%		1.78%

2

3

4

5

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #22

Reference: E-C/Itron Report, pg. 16-20

Question #22:

a. Please explain why the calendar-month HDD and CDD value were used starting in 2013. Was this when suitable AMI data was available to determine billed energy values on a calendar month basis?

b. Please explain the basis for the 50/50 weighting used for population and RPI.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Class sales data are based on AMI readings beginning in January 2013. The data before this period are derived from accounting estimates that reflect weather conditions in the current month and up to two prior months. In estimating the forecast models Hydro Ottawa Limited ("Hydro Ottawa") wanted to use HDD and CDD that are consistent with the billed sales period. As a result, calendar-month HDD and CDD beginning in January 2013 to reflect the change in the billing period to a calendar-month definition was used.

b. The economic driver in the residential model is a weighted average of population and real income. Population captures customer growth with real income capturing household economic activity. As there is no theoretical basis, to determine which is more important, it was elected to give equal weighting to the concepts and allow the regression model to determine the overall importance of the model variables and contribution to the forecast.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #23

Reference: E-C/Itron Report, pg. 20-24 and 44-48

Question #23:

a. Please explain the basis for the 50/50 weighting given to population and GDP.

b. Please describe the different explanatory variables used in the customer count models for the GS1000I, GS1000NI, GS1500 and GS5000 classes.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. In the commercial models, the economic driver is a weighted average of population and GDP. The logic is similar to that in the residential model, to capture both growth in number of customers and customer usage as a result of changes in business activity with GDP used as a proxy for business activity. As there is no theoretical basis for determining the weights and therefore gave equal weighting to both concepts.

b. The large commercial classes have either very few customers or are not correlated with any economic indicator such as employment or population. Forecast for these rate classes are based on simple trend specifications. The GS1000I customer forecast is based on a simple linear trend with an auto regressive term to correct for serial correlation. Serial correlation is when the error term in the current period is partly a function of the error term in the prior period, the auto regressive term corrects for this. The GS1000NI customer class is modeled with an exponential

smoothing model; customer growth is constant and there is no discernible seasonal customer pattern. The GS1500 customer forecast is also based on a simple trend model. The GS5000 customer class is modeled with an exponential smoothing model, which holds the forecast constant; there was no discernible consistent pattern of growth or seasonality. The GS5000 customer class has less than 90 customers.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #24

Reference: E-C/Itron Report, pg. 24-26 and 49-52

Question #24:

a. Were there any CDM programs implemented for Ottawa's Large User class during the historical period used to estimate the model?

b. If the response to part b) is affirmative, to what extent is the impact of these programs captured by the "GDPxTrend" variable?

c. What is the "AR(1)" variable used in the Street Lighting sales model?

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Yes.

b. There are 11 Large User customers that represent Hydro Ottawa Limited's largest customers. The GDPxTrend interaction variable captures the changing relationship of sales to GDP over the estimation period. Sales over the estimation period have been declining likely as a result of changes in business activity specific to these 11 customers, and efficiency improvements driven by productivity improvements, energy cost reduction, and Conservation Demand Management ("CDM") program activity. We cannot isolate the impact of the factors driving consumption downwards, and without an estimate of the historic CDM implemented for this class it is not possible to estimate

to what extent CDM is captured by the GDPxTrend variable. It is important to note that no CDM adjustments are made to the forecast for this rate class.

c. The AR(1) term is an auto regressive term to correct for serial correlation embedded in the monthly street light sales data. The serial correlation is likely the result of billing process and adjustments over the estimation period.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #25

Reference: E-C/Itron Report, pg. 6 and 26-28

Question #25

a. Please provide a schedule that sets out the historical and forecast values for each of the three SysEI variables used for the System Purchase equation.

b. Does Ottawa make any purchases from distributed generators in its service area or other local distributors? If yes, how much has been purchased annually (2005-2014) and have these purchases been included in the Purchase values used to estimate the System Purchase equation?

c. Is the System Peak forecast used at all in the determination of the forecast billing determinants for 2016-2020? If so, how?

d. For each of 2012 and 2013, please compare the model predicted values for system purchases using:
    i. The actual HDD and CDD values for the year versus
    ii. The weather normal HDD and CDD values for the year.

Response:

Itron assisted Hydro Ottawa Limited in the preparation of this response.

a. Please see attachment Att-VECC-Q25-A for the historical and forecasted values for each of the three SysEI variables used for the System Purchase equation.

b. Please see Table 1 for a summary Hydro Ottawa Limited's ("Hydro Ottawa") purchases from 2009 to 2014. The majority of Hydro Ottawa's purchases are delivered directly from the Independent Electricity System Operator ("IESO").

Table 1 – Hydro Ottawa Purchases (MWh)

	2009	2010	2011	2012	2013	2014
IESO	7,249,121	7,301,954	7,307,001	7,248,379	7,125,113	7,058,674
Hydro One	399,251	417,759	427,943	472,596	447,805	438,422
Generators	136,351	120,152	118,214	135,228	149,234	139,059
Total Purchase	7,784,723	7,839,865	7,853,159	7,856,204	7,722,152	7,636,154

c. The System Peak is not used for billing determinates. It is however used to forecast Transmission Charges in the Cost of Power Expense.

d. Please see Table 2 for the predicted sales for 2012 and 2013 with actual weather and what the model would predict with normal heating degree days ("HDD") and cooling degree days ("CDD") for those years.

Table 2 – System Predicated Actual and Normal Weather (MWh)

Year	System Predicted Actual Weather	System Predicted Normal Weather
2012	7,844,323	7,793,780
2013	7,698,240	7,728,752

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #26

Reference: E-C/Itron Report, pg. 32-33

Question #26

a. What is the basis for the 1.0062 and 1.0338 loss factors used to convert purchases to total sales?

Response:

Please refer to Exhibit H-9-1 for Hydro Ottawa's proposed loss factor. Also, please see response to VECC Interrogatory Question #14 part c.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #27

Reference: **E-C/Itron Report, pg. 33-35**
Attachment C-1-F-CDM Excel File
June Update, CDM Plan – Hydro Ottawa

Question #27:

a. Please confirm that the assumed annualized savings for 2014 from 2014 CDM programs as used in the forecast is the 42,400,000 kWh value shown in Appendix 2-I.

b. In order to help in understanding the calculation of the CDM adjustments (per the CDM Excel File), please provide an explanation as to how Ottawa:

i. Determined the manual adjustment required to 2014 sales in order to account for the impact of 2014 CDM programs implemented after August 2014.

ii. Determined the manual adjustment required to 2015-2020 sales to account for the impact of 2014 CDM programs implemented after August 2014.

c. Please provide any reports that Ottawa has received from the IESO/OPA regarding the results of 2014 CDM programs.

d. Please provide copies of any plans Ottawa has submitted to the IESO/ OPA regarding how it intends to achieved its 2015-2020 CDM target (in addition to that filed with the June Updates and submitted to the IESO in May 2015).

e. Please provide a schedule that sets out the annual CDM savings for 2015-2020 as shown in: i) the Application (Appendix 2-I) with the CDM savings for years 2015-2020 and ii) the CDM Plan filed with the June Updates and submitted to the IESO in May 2015. Where there are differences please explain and indicate the values Ottawa proposes to use (now) for purposes of its Application.

f. Please provide copies of any reports/reviews prepared by the IESO/OPA regarding Ottawa's 2015-2020 CDM plans.

g. Please provide a summary schedule that sets out the annual CDM adjustment made to the load forecast (as submitted) for the years 2015-2020 and for each year show the contribution of CDM programs implemented in that year and each of the previous years.

h. Please provide a schedule that incorporates both Tables 2 and 3 from the Itron Report (adding in the totals for each year) and which also shows the CDM by customer class for each year.

i. Please provide the equivalent of Table 1 (Exhibit C/Tab 1/Schedule 1, page 2) prior to the CDM adjustment total forecast sales for the years 2015-2020 both before and after the CDM adjustment.

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") confirms that the Conservation Demand Management ("CDM") target for 2014 was 42,400,000 kWh or 42,000 MWh. As the forecast is built on 8 months of actual 2014 data Hydro Ottawa incorporated a proportional amount of the 2014 targeted into the last 4 months of the forecasted for 2014.

b.

i) In 2014, 4 months of the remaining CDM Target was incorporated into the 2014 forecast. In order to incorporate the remaining CDM into a monthly number, taking into consideration the 50% rule and the CDM initiatives that occurred from January to August would continue to have an impact on

September to December; a unit per month was derived. The total amount for the 4 months was determined to be 7,611 MWh.

ii) The amount determined in part i) continued to reduce the forecast from 2015 to 2020.

c. Please find as attachment Att-VECC-Q27-A, the preliminary Hydro Ottawa 2014 CDM Report from the IESO.

d. Please find as attachment Att-VECC-Q27-B, Hydro Ottawa's CDM Plan for 2015 to 2020.

e. At the time of the rate application Hydro Ottawa forecasted the following for the completion of its CDM targets:

- Hydro Ottawa's CDM Target for 2016 to 2020 would be 395,000 MWh
- 50% of the Target would be achieved by the end of 2017, 197,000 MWh
    i. 20% (of the 50%) would be achieved in 2015, 39,500 MWh
    ii. 40% (of the 50%) would be achieved in each of 2016 and 2017, 79,000 MWh
- The remaining 50% would be achieved by the end 2020, 197,000 MWh
    i. One third (of the 50%) would be achieved in each of the remaining years, 65,833 MWh

The CDM Plan filed with the IESO in June 2015 has the following targets:

- Hydro Ottawa's CDM Target for 2016 to 2020 is 394,573 MWh
- 2015 target is 72,181 MWh
- 2016 target is 61,650 MWh
- 2017 target is 64,630 MWh
- 2018 target is 66,243 MWh
- 2019 target is 66,243 MWh
- 2020 target is 65,522 MWh

Given the timing with the rate application Hydro Ottawa does not intend to update its load forecast for the CDM plan. In addition, the CDM Plan details do not give rate class specific anticipated CDM results.

f. Please see part d of this response.

g. Please see Table 1 for the annual CDM adjustment made to the load forecast for the years 2015 to 2020.

Table 1 - CDM Adjustment to Load Forecast (MWh)

	Yearly Target	Savings related to Current Year A	Savings Related to Previous Year B	Total Savings in Year A+B	Cumulative Savings
2014	42,400	7,611		7,611	7,611
2015	39,500	19,750	20,656	40,406	48,017
2016	79,000	39,500	19,750	59,250	107,267
2017	79,000	39,500	39,500	79,000	186,267
2018	65,833	32,917	39,500	72,417	258,684
2019	65,833	32,917	32,917	65,834	324,518
2020	65,833	32,917	32,917	65,834	390,352
2015 to 2020 CDM Impact				390,352	

h. Please find in Table 2, 3 and 4, the Sales Load Forecast without CDM adjustments, with CDM adjustments and the difference between the two forecasts (the CDM Adjustments).

Table 2 - Unadjusted Class Sales Forecast (MWh)

Year	Residential	GS <50KW	GS 50-1000KW Non Interval	GS 50-1000KW Interval	GS 1000-1500KW	GS 1500-5000 KW	LARGE USER	Street Lighting	Unmetered	DCL	Total Sales
2014	2,209,986	706,581	1,489,888	1,135,002	338,244	860,536	615,653	44,419	16,392	3,387	7,420,088
2015	2,241,257	710,082	1,463,207	1,179,844	350,053	883,241	620,305	43,504	16,594	3,418	7,511,505
2016	2,232,769	711,334	1,450,111	1,215,423	355,011	902,777	620,219	43,550	16,650	3,429	7,551,273
2017	2,226,833	709,771	1,427,265	1,247,004	358,529	916,868	619,254	43,654	16,690	3,437	7,569,305
2018	2,245,849	709,908	1,410,826	1,281,251	363,006	934,838	618,467	43,765	16,732	3,446	7,628,088
2019	2,264,296	710,894	1,397,088	1,316,704	367,839	954,038	617,036	43,875	16,773	3,455	7,691,998
2020	2,276,815	713,027	1,386,525	1,354,052	373,224	975,022	615,194	44,015	16,826	3,465	7,758,165

Table 3 - CDM Adjusted Class Sales Forecast (MWh)

Year	Residential	GS <50KW	GS 50-1000KW Non Interval	GS 50-1000KW Interval	GS 1000-1500KW	GS 1500-5000 KW	LARGE USER	Street Lighting	Unmetered	DCL	Total Sales
2014	2,208,503	705,819	1,487,331	1,132,841	337,596	860,536	615,653	44,419	16,392	3,387	7,412,477
2015	2,233,420	705,280	1,446,533	1,165,427	345,766	883,241	620,305	43,504	16,594	3,418	7,463,488
2016	2,216,044	700,607	1,412,731	1,182,652	345,345	902,777	620,219	43,550	16,650	3,429	7,444,004
2017	2,198,259	691,144	1,362,581	1,189,466	341,685	916,868	619,254	43,654	16,690	3,437	7,383,038
2018	2,206,412	684,039	1,321,314	1,200,798	339,592	934,838	618,467	43,765	16,732	3,446	7,369,403
2019	2,214,984	678,442	1,285,150	1,215,257	338,471	954,038	617,036	43,875	16,773	3,455	7,367,481
2020	2,217,629	673,992	1,252,266	1,231,479	337,928	975,022	615,194	44,015	16,826	3,465	7,367,816

Table 4 - CDM Adjustments to Class Sales Forecast (MWh)

Year	Residential	GS <50KW	GS 50-1000KW Non Interval	GS 50-1000KW Interval	GS 1000-1500KW	GS 1500-5000 KW	LARGE USER	Street Lighting	Unmetered	DCL	Total Sales
2014	1,483	762	2,557	2,161	648	0	0	0	0	0	7,611
2015	7,837	4,802	16,674	14,417	4,287	0	0	0	0	0	48,017
2016	16,725	10,727	37,380	32,771	9,666	0	0	0	0	0	107,269
2017	28,574	18,627	64,684	57,538	16,844	0	0	0	0	0	186,267
2018	39,437	25,869	89,512	80,453	23,414	0	0	0	0	0	258,685
2019	49,312	32,452	111,938	101,447	29,368	0	0	0	0	0	324,517
2020	59,186	39,035	134,259	122,573	35,296	0	0	0	0	0	390,349

i. Please find in Table 5 the Sales Load Forecast as presented in Exhibit C-1-1 (Table 1) prior to CDM adjustments.

Table 5 - Class Sales Forecast prior to CDM Adjustments (MWh)

	2016	2017	2018	2019	2020
RESIDENTIAL	2,232,770	2,226,833	2,245,848	2,264,296	2,276,814
GENERAL SERVICE <50KW	737,087	735,523	735,660	736,645	738,779
GENERAL SERVICE 50-1000KW Non Interval	1,424,357	1,401,511	1,385,076	1,371,335	1,360,773
GENERAL SERVICE 50-1000KW Interval	1,240,717	1,272,300	1,306,547	1,341,999	1,379,346
GENERAL SERVICE 1000-1500KW	369,184	372,700	377,178	382,012	387,396
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	**7,547,893**	**7,565,911**	**7,624,689**	**7,688,588**	**7,754,747**

Independent Electricity System Operator
Conservation & Demand Management Status Report

Q4 2014 Preliminary Results Update

Hydro Ottawa Limited

Unverified IESO-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q4-2014	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**18.4**	**51.2**	60%	**51.2**	60%	**21**
Net Energy Savings (GWh)	**11.8**	**380.4**	102%	**380.4**	102%	**32**

Program-to-Date Progress Towards Target: Combination of verified (2011-13) and unverified (2014) results. The 2014 Q4 report reflects the most up-to-date inputs from the 2013 program evaluations. To align with savings counted towards OEB targets, peak demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.

Scenario 1: Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.

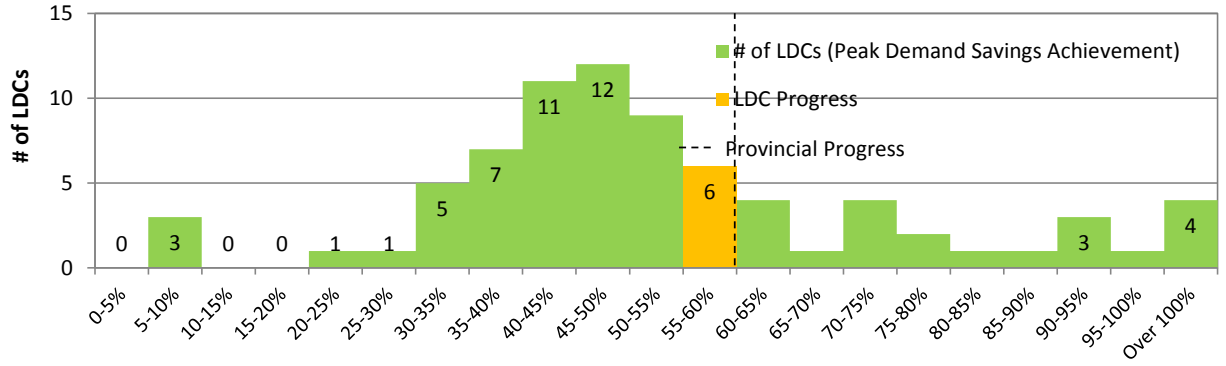
Scenario 2: Assumes that demand response resources remain in the LDC territory until 2014. Used to better assess progress towards demand targets.

Rank: Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using Scenario 2.

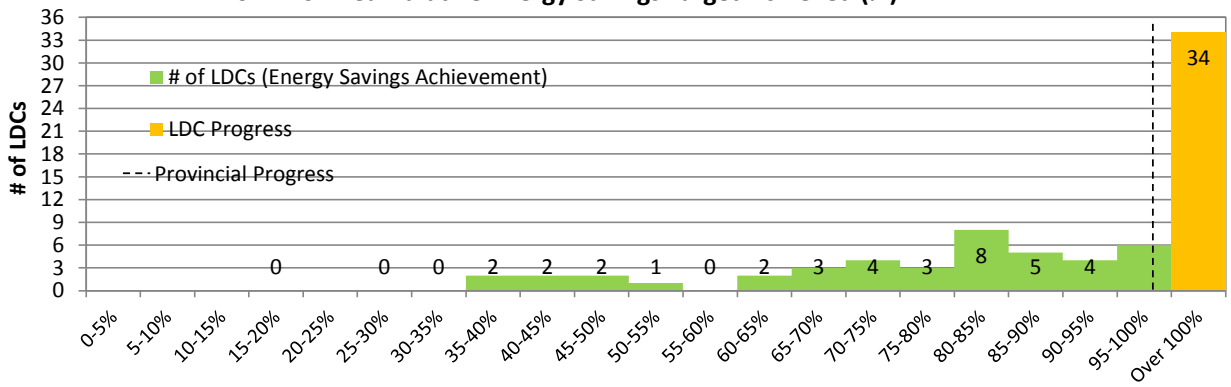
Comparison: LDC Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in the LDC territory until 2014 (aligns with Scenario 2)

2014 Annual Peak Demand Savings Target Achieved (%)



2011-2014 Cumulative Energy Savings Target Achieved (%)



Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@ieso.ca

Message from the Vice President

As we have reached the end of the 2011-2014 Conservation Framework, I'm pleased to present to you the Q4 2014 LDC status update. This quarter, we have achieved 98% (5,882 GWh) of the full OEB energy savings target. Peak demand savings increased to 798 MW, representing 60% of the 1,330 MW peak demand target.

Projects completed prior to December 31, 2014 will count towards your 2011-2014 CDM Targets and we encourage LDCs to submit these projects to the IESO prior to the initiative specific cut-off date. Please refer to the 2014 Final Results Reporting LDC.Support E-blast issued on March 3rd, 2015 for additional details.

Highlights from Q4 2014:

- LDCs achieved 334 MW peak demand and 186 GWh in incremental energy savings in Q4 2014.
- Bi-Annual COUPONS contributed over 100 GWh with 83% of energy savings coming from LEDs.
- RETROFIT participation in Q4 2014 increased by 25% over Q4 2013 contributing about 60 GWh in savings of Q4 2014
- Program enhancements, such as a new exterior lighting worksheet in RETROFIT and an increased cost cap in HOME ASSISTANCE are continuing to improve user experience.

We remain well positioned for continued success in the Conservation First Framework 2015-2020. Signed ECAs have been received from all LDCs and the IESO is in the process of reviewing and approving CDM Plans. As of March 31st, 2015 3 CDM Plans have been recieived and 2 have been approved. We look forward to continued successful collaboration to achieve and exceed our goals.

Please contact the IESO at LDC.Support@ieso.ca with any questions or comments regarding this report.

Sincerely,

Terry Young

About this Report

This report contains:

- Peak demand and energy savings for IESO-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q4 2014 using unverified quarterly results for 2014 and final verified results for 2011-2013
- Program activity data (i.e. projects completed, appliances picked up) completed on or before December 31st, 2014 and received and entered to the IESO processing systems per the dates specified in Table 5
- Updates to the previous quarters' participation with additional data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 contains:
  1. The date in which savings are considered to 'start';
  2. The point at which the data becomes available to the IESO;
  3. The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on January 6th, 2015
- Preliminary results for peaksaverPLUS® represent customers that have signed a Participant Agreement and have successfully uploaded information to the RDR settlement system
- ***peaksaverPLUS® device counts and corresponding savings for load control (switch/thermostat) and IHD are reported separately***

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through LDC programs.
Table 1 presents:

- Net peak demand savings results from 2011 to 2014 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist from program activity completed as of Q4 2014 using both Scenarios 1 and 2
- A comparison between reported, unverified results and final, verified results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using Scenario 1 for demand response resources (persistence of 1 year)

Please note: Demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. Q4 2011, Q4 2012, Q4 2013 and Q4 2014). Figures below and tables 3B and 4B present demand response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1A: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final	12.7	8.9	8.9	8.3	8.3
2	2012 - Final†	-0.2	16.6	8.5	8.4	8.4
3	2013 - Final†	0.0	0.5	22.5	8.8	8.8
4	2014 - Reported - Quarter 1				2.1	2.1
5	2014 - Reported - Quarter 2				2.3	2.3
6	2014 - Reported - Quarter 3				3.0	3.0
4	2014 - Reported - Quarter 4				18.4	18.4
Energy Efficiency		8.7	18.0	26.5	34.6	34.6
Demand Response		3.8	8.0	13.5	16.6	16.6
Net Annual Peak Demand Savings		12.5	25.9	39.9	51.2	51.2
	Unverified Net Annual Peak Demand Savings in 2014:				**51.2**	**51.2**
	2014 Annual Peak Demand Savings Target as per OEB:				**85.3**	**85.3**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**60%**	**60%**
Incremental Reported (Unverified)		8.3	16.8	20.2	25.8	
Incremental Final (Verified)		12.7	16.6	22.5	n/a	

Decline in savings due to demand response persistence assumption (scenario 1) and energy efficiency persistence decline

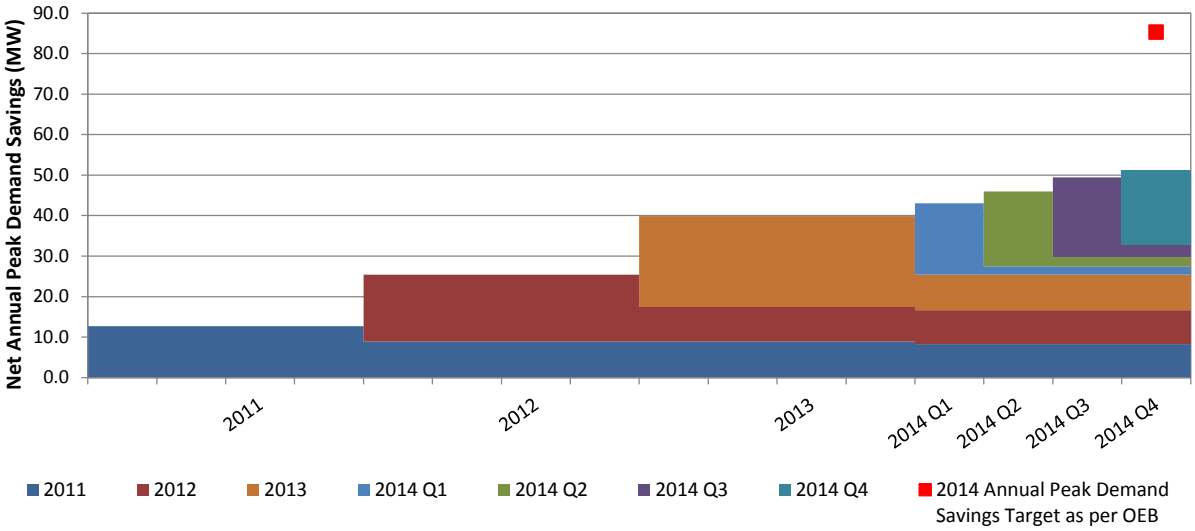
† Includes adjustments to previous year's verified results

Sums may not be exact due to rounding

Table 1B: Peak Demand Savings from DR3 Resources

Reported DR3 (Ex Ante) (MW)	1.4
Contracted DR3 (MW)	2.1

Figure 1: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through LDC programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported results (unverified) and final results (verified) for 2011, 2012, and 2013.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final	35.8	35.8	35.7	34.0	141.4
2	2012 - Final†	0.2	35.1	34.9	34.4	104.6
3	2013 - Final†	0.0	2.4	42.6	41.4	86.4
4	2014 - Reported - Quarter 1				8.8	8.8
5	2014 - Reported - Quarter 2				12.1	12.1
6	2014 - Reported - Quarter 3				15.3	15.3
7	2014 - Reported - Quarter 4				11.8	11.8
Energy Efficiency		36.1	73.2	113.1	157.8	380.2
Demand Response		0.0	0.1	0.1	0.0	0.2
Net Energy Savings		36.1	73.3	113.2	157.8	380.4
	Unverified Net Cumulative Energy Savings 2011-2014:					**380.4**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**374.7**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**102%**
Incremental Reported (Unverified)		19.8	35.8	35.7	48.0	
Incremental Final (Verified)		35.8	35.1	42.6	n/a	

† Includes adjustments to previous year's verified results

Sums may not be exact due to rounding

Figure 2: Net Cumulative Energy Savings (GWh)

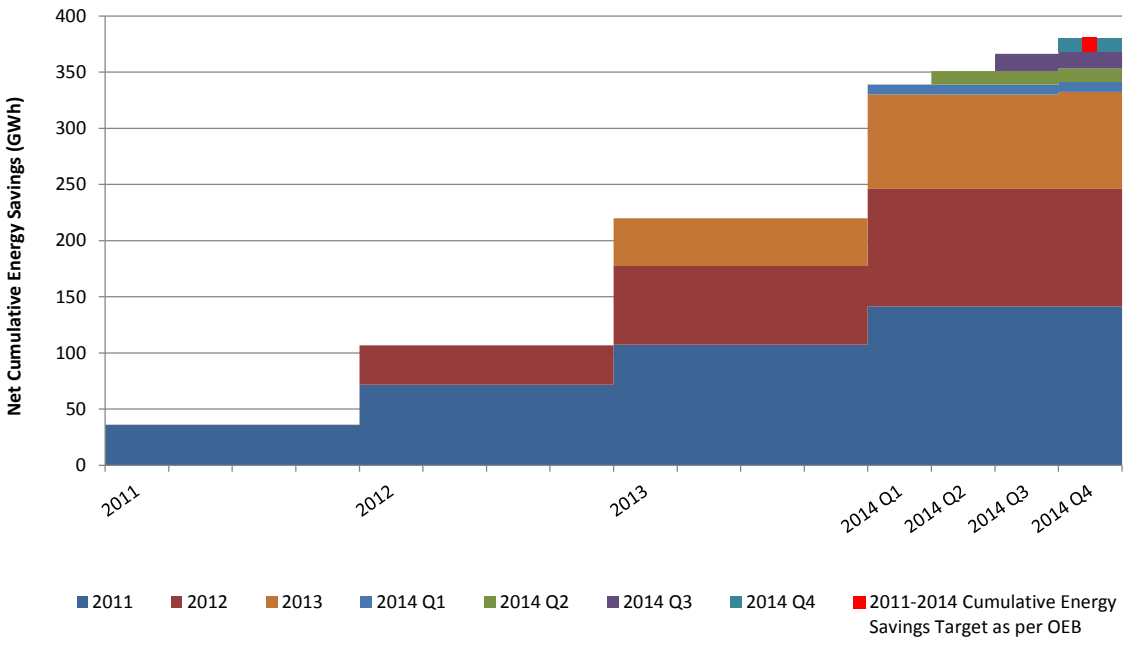


Table 3A: Hydro Ottawa Limited Initiative and Program Level Savings by Year

#	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 Unverified Progress to Target (excludes DR)	
															2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012 Adj.*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	4,110	2,604	1,602	1,643	246	146	104	107	1,754,416	1,040,845	681,703	700,263	594	12,196,698
2	Appliance Exchange	Appliances	183	178	191	196	19	25	40	41	22,795	43,987	70,563	72,532	113	426,461
3	HVAC Incentives	Equipment	7,863	7,269	6,674	6,439	2,880	1,606	1,448	1,473	5,465,411	2,835,583	2,563,561	2,573,292	7,408	38,068,804
4	Conservation Instant Coupon Booklet	Measures	29,787	1,728	19,410	33,733	69	13	29	51	1,104,610	78,235	431,268	790,610	162	6,306,293
5	Bi-Annual Retailer Event	Measures	53,276	59,361	52,864	271,329	94	83	66	357	1,644,342	1,498,537	961,278	5,601,945	600	18,597,480
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)†	Devices	5,701	16,134	23,018	27,515	3,193	7,249	11,608	14,892	8,266	55,891	48,406	-	14,892	112,564
8	Residential Demand Response (IHD)†	Devices	-	9,659	18,720	23,908	-	-	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	-	-	2	768	-	-	2	31	-	-	16,548	1,762,884	32	1,795,981
Consumer Program Total							**6,500**	**9,122**	**13,296**	**16,951**	**9,999,841**	**5,553,079**	**4,773,328**	**11,501,527**	**23,800**	**77,504,281**
Business Program																
10	Retrofit	Projects	338	594	777	709	2,832	5,116	4,897	4,460	14,868,304	22,549,482	26,220,638	25,316,142	16,889	203,342,622
11	Direct Install Lighting	Projects	1,063	1,107	1,133	2,471	1,416	843	1,011	2,304	3,870,853	3,365,166	3,655,868	8,386,165	4,936	39,343,347
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	-	5	9	6	-	14	125	53	-	16,176	117,105	157,508	192	440,246
14	Energy Audit	Audits	13	25	48	17	-	124	423	59	-	604,230	2,325,637	273,380	606	6,737,344
15	Small Commercial Demand Response (switch/pstat)†	Devices	7	33	215	426	4	21	138	273	16	120	46	-	273	182
16	Small Commercial Demand Response (IHD)†	Devices	-	-	25	50	-	-	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	10	11	12	12	597	644	1,520	1,256	23,305	9,354	24,274	-	1,256	56,934
Business Program Total							**4,850**	**6,761**	**8,115**	**8,404**	**18,762,479**	**26,544,529**	**32,343,568**	**34,133,195**	**24,151**	**249,920,676**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	-	-	17	36	-	-	109	199	-	-	816,987	1,954,076	260	3,291,384
21	Retrofit	Projects	12	-	-	-	81	-	-	-	533,952	-	-	-	81	2,135,807
22	Demand Response 3†	Facilities	-	1	2	2	-	42	189	189	-	1,010	4,299	-	189	5,309
Industrial Program Total							**81**	**42**	**297**	**388**	**533,952**	**1,010**	**821,286**	**1,954,076**	**530**	**5,432,500**
Home Assistance Program																
23	Home Assistance Program	Homes	-	394	534	945	-	26	32	34	-	319,766	384,041	448,314	91	2,173,171
Home Assistance Program Total							**-**	**26**	**32**	**34**	**-**	**319,766**	**384,041**	**448,314**	**91**	**2,173,171**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-	1	-	-	-	0	-	-	-	1,672	0	1,672
Aboriginal Program Total							**-**	**-**	**-**	**0**	**-**	**-**	**-**	**1,672**	**0**	**1,672**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	175	-	-	-	934	-	-	-	4,899,976	-	-	-	934	19,599,902
26	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
27	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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																
30	Program Enabled Savings	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**-**	**-**		**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results							**-**	**(209)**	**478**	**-**	**-**	**244,069**	**2,376,882**	**-**	**256**	**8,069,609**
Energy Efficiency Total							**8,893**	**8,803**	**8,571**	**9,167**	**35,815,751**	**34,783,066**	**40,144,378**	**48,038,783**	**34,312**	**372,153,114**
Demand Response Total (Scenario 1)							**3,794**	**7,956**	**13,455**	**16,609**	**31,588**	**66,376**	**77,026**	**-**	**16,609**	**174,989**
IESO-Contracted LDC Portfolio Total							**12,687**	**16,550**	**22,503**	**25,777**	**35,847,339**	**35,093,510**	**42,598,285**	**48,038,784**	**51,177**	**380,397,713**
														Full OEB Target:	**85,260**	**374,730,000**
														% of Full OEB Target Achieved to Date (Scenario 1):	**60%**	**102%**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

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

Table 3B: Hydro Ottawa Limited Initiative and Program Level Savings by Quarter for current reporting year**

#	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)			
			Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Consumer Program														
1	Appliance Retirement	Appliances	176	347	384	735	11	23	25	48	75,110	148,253	162,809	314,091
2	Appliance Exchange	Appliances	-	-	-	196	-	-	-	41	-	-	-	72,532
3	HVAC Incentives	Equipment	1,219	2,404	2,029	788	349	455	460	210	657,053	728,758	800,170	387,310
4	Conservation Instant Coupon Booklet	Measures	4,623	8,881	12,175	8,054	6	14	19	12	92,254	211,708	295,715	190,932
5	Bi-Annual Retailer Event	Measures	203	74,636	1,720	194,770	0	98	2	256	4,398	1,490,948	34,445	4,072,154
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)†	Devices	24,999	25,937	27,184	27,515	13,524	14,034	14,712	14,892	-	-	-	-
8	Residential Demand Response (IHD)†	Devices	20,365	21,610	23,469	23,908	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	13	301	240	214	0	22	4	5	27,601	641,463	466,044	627,776
Consumer Program Total							**13,890**	**14,644**	**15,222**	**15,464**	**856,416**	**3,221,131**	**1,759,184**	**5,664,796**
Business Program														
10	Retrofit	Projects	164	159	245	141	1,099	750	1,969	641	5,556,165	4,381,386	11,479,033	3,899,558
11	Direct Install Lighting	Projects	559	817	524	571	505	780	453	566	1,832,701	2,810,121	1,657,108	2,086,234
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	4	1	1	-	27	23	3	-	43,704	108,425	5,379	-
14	Energy Audit	Audits	7	1	7	2	24	3	24	7	112,568	16,081	112,568	32,162
15	Small Commercial Demand Response (switch/pstat)†	Devices	225	326	415	426	144	209	266	273	-	-	-	-
16	Small Commercial Demand Response (IHD)†	Devices	30	37	47	50	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	12	12	12	12	1,721	1,721	1,520	1,256	-	-	-	-
Business Program Total							**3,520**	**3,486**	**4,235**	**2,742**	**7,545,138**	**7,316,014**	**13,254,088**	**6,017,955**
Industrial Program														
18	Process & System Upgrades	Projects	-	-	-	-	-	-	-	-	-	-	-	-
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	8	20	5	3	30	144	10	15	321,508	1,527,268	31,934	73,367
21	Retrofit	Projects	-	-	-	-	-	-	-	-	-	-	-	-
22	Demand Response 3†	Facilities	2	2	2	2	203	201	189	189	-	-	-	-
Industrial Program Total							**232**	**345**	**199**	**203**	**321,508**	**1,527,268**	**31,934**	**73,367**
Home Assistance Program														
23	Home Assistance Program	Homes	160	91	410	284	7	4	17	6	101,222	53,546	223,216	70,330
Home Assistance Program Total							**7**	**4**	**17**	**6**	**101,222**	**53,546**	**223,216**	**70,330**
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	1	-	-	-	0	-	-	-	1,672	-
Aboriginal Program Total							**-**	**-**	**0**	**-**	**-**	**-**	**1,672**	**-**
Pre-2011 Programs completed in 2011														
25	Electricity Retrofit Incentive Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-
26	High Performance New Construction	Projects	-	-	-	-	-	-	-	-	-	-	-	-
27	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-
29	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Other														
30	Program Enabled Savings	Projects	-	-	-	-	-	-	-	-	-	-	-	-
31	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**2,059**	**2,315**	**2,987**	**1,806**	**8,824,284**	**12,117,958**	**15,270,094**	**11,826,447**
Demand Response Total (Scenario 1)							**15,591**	**16,164**	**16,687**	**16,609**	**-**	**-**	**-**	**-**
IESO-Contracted LDC Portfolio Total							**17,649**	**18,479**	**19,673**	**18,415**	**8,824,284**	**12,117,959**	**15,270,094**	**11,826,448**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Updates to the previous quarter's participation may occur as a result of further data received

Table 4A: Province-Wide Initiative and Program Level 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 Unverified Progress to Target	
															2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012 Adj.*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,146	20,952	22,365	3,299	2,011	1,433	1,547	23,005,812	13,424,518	8,713,107	9,245,202	8,151	158,848,273
2	Appliance Exchange	Appliances	3,688	3,836	5,337	3,685	371	556	1,106	764	450,187	974,621	1,971,701	1,361,386	2,559	9,817,312
3	HVAC Incentives	Equipment	92,743	87,427	91,581	92,618	32,037	19,060	19,552	20,853	59,437,670	32,841,283	33,923,592	36,056,671	91,502	440,178,385
4	Conservation Instant Coupon Booklet	Measures	567,678	30,891	346,896	662,997	1,344	230	517	994	21,211,537	1,398,202	7,707,573	15,299,793	3,085	119,755,693
5	Bi-Annual Retailer Event	Measures	952,149	1,060,901	944,772	4,849,164	1,681	1,480	1,184	6,372	29,387,468	26,781,674	17,179,841	100,117,270	10,717	332,371,849
6	Retailer Co-op	Items	152	-	-	-	0	-	-	-	2,652	-	-	-	0	10,607
7	Residential Demand Response (switch/pstat)†	Devices	19,550	98,388	171,733	213,493	10,947	49,038	93,076	115,509	24,870	359,408	390,303	-	115,509	774,582
8	Residential Demand Response (IHD)†	Devices	-	49,689	133,657	178,086	-	-	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	26	19	86	1,795	0	2	18	454	743	17,152	163,690	8,173,646	474	8,555,457
Consumer Program Total							**49,681**	**72,377**	**116,886**	**146,492**	**133,520,941**	**75,796,859**	**70,049,807**	**170,253,968**	**231,998**	**1,070,312,157**
Business Program																
10	Retrofit	Projects	2,819	6,134	8,785	8,797	24,467	61,147	59,678	58,377	136,002,258	314,922,468	345,346,008	351,079,954	201,208	2,519,577,657
11	Direct Install Lighting	Projects	20,741	18,691	17,782	23,120	23,724	15,284	18,708	23,827	61,076,701	57,345,798	64,315,558	83,720,596	73,713	603,413,953
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	22	69	87	122	123	764	1,584	1,533	411,717	1,814,721	4,959,266	6,001,243	4,005	23,010,807
14	Energy Audit	Audits	198	345	319	284	-	1,450	2,811	981	-	7,049,351	15,455,795	4,567,059	5,242	56,626,703
15	Small Commercial Demand Response (switch/pstat)†	Devices	132	294	1,211	2,688	84	187	773	1,709	157	1,068	373	-	1,709	1,597
16	Small Commercial Demand Response (IHD)†	Devices	-	-	378	658	-	-	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	145	151	175	180	16,218	19,389	23,706	22,822	633,421	281,823	346,659	-	22,822	1,261,903
Business Program Total							**64,617**	**98,221**	**107,261**	**109,249**	**198,124,253**	**381,415,230**	**430,423,659**	**445,368,853**	**308,698**	**3,203,892,619**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	3	7	-	-	294	12,384	-	-	2,603,764	89,544,578	12,678	94,752,105
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	-	42	205	236	-	1,086	3,558	2,771	-	7,372,108	21,994,263	21,713,663	5,964	76,602,233
21	Retrofit	Projects	433	-	-	-	4,615	-	-	-	28,866,840	-	-	-	4,613	115,462,282
22	Demand Response 3†	Facilities	124	185	281	336	52,484	74,056	162,543	165,646	3,080,737	1,784,712	4,309,160	-	165,646	9,174,609
Industrial Program Total							**57,098**	**75,141**	**166,395**	**180,800**	**31,947,577**	**9,156,820**	**28,907,187**	**111,258,240**	**188,901**	**295,991,229**
Home Assistance Program																
23	Home Assistance Program	Homes	46	5,033	26,756	15,799	2	566	2,361	1,426	39,283	5,442,232	20,987,275	12,529,701	4,329	70,479,614
Home Assistance Program Total							**2**	**566**	**2,361**	**1,426**	**39,283**	**5,442,232**	**20,987,275**	**12,529,701**	**4,329**	**70,479,614**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	584	943	-	-	267	561	-	-	1,609,393	3,612,886	828	6,831,672
Aboriginal Program Total							**-**	**-**	**267**	**561**	**-**	**-**	**1,609,393**	**3,612,886**	**828**	**6,831,672**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,028	-	-	-	21,662	-	-	-	121,138,219	-	-	-	21,662	484,552,876
25	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
26	Toronto Comprehensive	Projects	577	-	-	-	15,805	-	-	-	86,964,886	-	-	-	15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	-	-	-	1,981	-	-	-	7,595,683	-	-	-	1,981	30,382,733
28	LDC Custom Programs	Projects	8	-	-	-	399	-	-	-	1,367,170	-	-	-	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																
29	Program Enabled Savings	Projects	14	56	13	-	-	2,304	3,692	-	-	1,188,362	4,075,382	-	5,996	11,715,850
30	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**2,304**	**3,692**	**-**	**-**	**1,188,362**	**4,075,382**		**5,996**	**11,715,850**
Adjustment to Previous Year's Verified Results							**-**	**1,406**	**6,901**	**-**	**-**	**18,689,081**	**43,684,221**	**-**	**7,976**	**207,151,978**
Energy Efficiency Total							**136,610**	**109,191**	**117,536**	**132,842**	**603,144,419**	**482,474,435**	**554,528,447**	**743,023,649**	**484,033**	**5,663,766,960**
Demand Response Total (Scenario 1)							**79,733**	**142,670**	**280,099**	**305,685**	**3,739,185**	**2,427,011**	**5,046,495**	**-**	**305,685**	**11,212,691**
IESO-Contracted LDC Portfolio Total							**216,343**	**253,267**	**404,536**	**438,528**	**606,883,604**	**503,590,526**	**603,259,163**	**743,023,649**	**797,694**	**5,882,131,629**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

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

Full OEB Target:	**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**60%**	**98%**

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for Current Reporting Year**

#	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)			
			Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Consumer Program														
1	Appliance Retirement	Appliances	2,436	5,229	7,449	7,251	161	367	523	496	1,024,177	2,149,010	3,057,830	3,014,185
2	Appliance Exchange	Appliances	-	-	-	3,685	-	-	-	764	-	-	-	1,361,386
3	HVAC Incentives	Equipment	19,792	35,336	26,919	10,570	5,327	6,827	5,903	2,795	9,844,276	10,987,207	10,097,536	5,127,652
4	Conservation Instant Coupon Booklet	Measures	90,864	174,551	239,287	158,297	113	270	375	235	1,785,297	4,096,950	5,722,646	3,694,901
5	Bi-Annual Retailer Event	Measures	3,636	1,333,884	30,738	3,480,907	5	1,745	43	4,579	78,601	26,646,044	615,602	72,777,023
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)†	Devices	188,190	198,381	208,755	213,493	101,915	107,360	112,955	115,509	-	-	-	-
8	Residential Demand Response (IHD)†	Devices	152,019	162,554	173,365	178,086	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	27	305	246	1,217	3	22	4	425	35,350	654,323	467,843	7,016,129
Consumer Program Total							**107,524**	**116,591**	**119,803**	**124,803**	**12,767,702**	**44,533,534**	**19,961,456**	**92,991,276**
Business Program														
10	Retrofit	Projects	2,113	2,472	2,642	1,570	14,633	15,813	16,715	11,216	100,924,922	95,019,369	95,854,171	59,281,492
11	Direct Install Lighting	Projects	5,473	6,147	5,661	5,839	5,961	6,424	5,587	5,855	20,848,414	22,541,443	19,681,481	20,649,259
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	33	56	24	9	507	481	298	247	1,975,271	1,902,760	1,019,494	1,103,718
14	Energy Audit	Audits	86	83	94	21	297	287	325	73	1,382,983	1,334,739	1,511,632	337,705
15	Small Commercial Demand Response (switch/pstat)†	Devices	1,289	1,488	2,008	2,688	820	946	1,274	1,709	-	-	-	-
16	Small Commercial Demand Response (IHD)†	Devices	429	479	580	658	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	179	178	178	180	25,609	25,387	24,037	22,822	-	-	-	-
Business Program Total							**47,826**	**49,337**	**48,236**	**41,921**	**125,131,590**	**120,798,312**	**118,066,778**	**81,372,173**
Industrial Program														
18	Process & System Upgrades	Projects	2	2	2	1	237	3,778	7,501	868	2,092,778	31,209,000	48,692,800	7,550,000
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	50	86	86	14	610	1,396	579	185	4,504,954	9,693,954	5,188,171	2,326,584
21	Retrofit	Projects	-	-	-	-	-	-	-	-	-	-	-	-
22	Demand Response 3†	Facilities	301	324	335	336	167,962	171,552	177,630	165,646	-	-	-	-
Industrial Program Total							**168,809**	**176,726**	**185,710**	**166,699**	**6,597,732**	**40,902,954**	**53,880,971**	**9,876,584**
Home Assistance Program														
23	Home Assistance Program	Homes	5,859	4,365	3,326	2,249	591	485	222	128	4,737,618	4,058,973	2,329,163	1,403,947
Home Assistance Program Total			-				**591**	**485**	**222**	**128**	**4,737,618**	**4,058,973**	**2,329,163**	**1,403,947**
Aboriginal Program														
24	Aboriginal Program	Homes	64	161	479	239	102	75	291	92	308,516	673,102	1,869,579	761,689
Aboriginal Program Total							**102**	**75**	**291**	**92**	**308,516**	**673,102**	**1,869,579**	**761,689**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-
25	High Performance New Construction	Projects	-	-	-	-	-	-	-	-	-	-	-	-
26	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-
27	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-
28	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 Total			-				-	-	-	-	-	-	-	-
Other														
29	Program Enabled Savings	Projects	-	-	-	-	-	-	-	-	-	-	-	-
30	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							-	-	-	-	-	-	-	-
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**28,547**	**37,970**	**38,367**	**27,958**	**149,543,157**	**210,966,874**	**196,107,948**	**186,405,670**
Demand Response Total (Scenario 1)							**296,305**	**305,245**	**315,896**	**305,685**	-	-	-	-
IESO-Contracted LDC Portfolio Total							**324,852**	**343,215**	**354,262**	**333,644**	**149,543,157**	**210,966,874**	**196,107,948**	**186,405,670**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Updates to the previous quarter's participation may occur as a result of additional data received

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q4 2014 report includes all program activity completed (as per the savings 'start' date) on or before December 31st, 2014.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried. Up to date information is available.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the IESO by retailers and undergoes QA/QC by IESO staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date	Rebate Status = Approved, Cheque Issued and Cheque Cashed; Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the IESO by retailers and undergoes QA/QC by IESO staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data uploaded to RDR settlement system as of December 31, 2014	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to IESO	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC", "Returned for Edit(s) by Participant" and "Participant Incentive Not Approved by LDC") within iCON CRM as of December 31st, 2014	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to IESO and reviewed	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to IESO and reviewed	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to IESO and reviewed	Moderate
Small Commercial Demand Response	Device installation date	Data uploaded to RDR settlement system as of December 31st, 2014	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to IESO and reviewed	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to IESO and reviewed	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to IESO and reviewed	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

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). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

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.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: determines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

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). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative, the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	1-May-2015
CDM Plan Version	1

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Hydro Ottawa Limited	Renfrew Hydro Inc.								
Company Representative:										
Name:	Roger Marsh	Tom Freemark								
Title:	Chief Energy Management Officer, Hydro Ottawa	President-Renfrew Hydro								
Email Address:	rogermarsh@hydroottawa.com	jtfreemark@renfrewhydro.com								
Phone Number (XXX-XXX-XXXX):	613 738 5499 Ex 342	613 432-4884								

3.

Primary Contact for CDM Plan	
Name:	Bruce Bibby
LDC Name:	Hydro Ottawa Limited
Title:	Manager Conservation and Demand Management
Email Address:	brucebibby@hydroottawa.com
Phone Number (XXX-XXX-XXXX):	613 738 5499 Ex 379

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Aug-2015

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Quarterly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		
Other (Please specify reason)		

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Renfrew Hydro Inc.
Company Representative:	Tom Freemark
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	25-May-2015

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**398,710**	394,540.0	4,170.0								
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**398,757**	394,573	4,184	0	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$106,312,729**	$105,242,155.00	$1,070,574.00								
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$106,312,728**	$105,242,155	1,070,574	0	0	0	0	0	0	0	0

f.	**CDM Plan Cost Effectiveness** *Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool*		Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
		2015	$55,764,480.01	$38,561,858.48	1.4	$48,489,332.53	$1,382,444.10	35.1	$0.001
		2016	$53,854,356.98	$29,017,726.63	1.9	$46,713,248.89	$17,632,866.14	2.6	$0.024
		2017	$56,081,242.02	$27,259,282.19	2.1	$48,648,150.79	$17,314,240.00	2.8	$0.026
		2018	$79,064,316.28	$42,454,281.01	1.9	$68,633,433.36	$21,635,918.56	3.2	$0.032
		2019	$79,719,834.20	$41,725,918.96	1.9	$69,203,448.82	$21,315,758.70	3.2	$0.033
		2020	$79,340,421.05	$40,747,310.47	1.9	$68,873,524.47	$20,739,381.97	3.3	$0.033
		CDM Plan Total	**$403,824,651**	**$219,766,378**	1.8	**$350,561,139**	**$100,020,609**	3.5	

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Hydro Ottawa Limited

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Aug-2015			Yes	Yes	Yes	Yes	Yes	$1,332,250	2,144.4	$6,142,186	23,530.4	$6,845,940	27,612.8	$6,077,380	23,530.4	$6,118,828	23,530.4	$6,160,645	23,530.4	**$32,677,229**	**123,878.7**
	Heating and Cooling Program			1-Jan-2016	Yes	Yes								$3,308,912	3,376.0	$1,743,407	312.0	$1,742,068	312.0	$1,754,737	312.0	$1,797,520	312.0	**$10,346,644**	**4,624.0**
	Coupon Program			1-Jan-2016	Yes	Yes								$848,923	2,234.0	$852,955	2,234.0	$852,343	2,234.0	$856,425	2,234.0	$860,543	2,234.0	**$4,271,189**	**11,170.0**
	New Construction Program			1-Aug-2015	Yes							$10,000	0.0	$588,780	920.0	$592,408	920.0	$596,855	920.0	$600,685	920.0	$604,550	920.0	**$2,993,278**	**4,600.0**
	Home Assistance Program			1-Jan-2016		Yes								$608,077	784.0	$612,320	784.0	$617,520	784.0	$622,000	784.0	$626,520	784.0	**$3,086,437**	**3,920.0**
	Audit Funding Program			1-Jan-2016				Yes	Yes	Yes	Yes			$178,890	759.0	$179,707	759.0	$180,708	759.0	$181,570	759.0	$182,441	759.0	**$903,316**	**3,036.0**
	High Performance New Construction			1-Aug-2015				Yes		Yes	Yes	$10,000	0.0	$1,888,110	4,275.0	$1,900,361	4,275.0	$1,915,376	4,275.0	$1,928,313	4,275.0	$1,941,364	4,275.0	**$9,583,524**	**21,375.0**
	Process and Systems Upgrades Program			1-Aug-2015						Yes	Yes	$10,000	0.0											**$10,000**	**0.0**
	Monitoring and Targeting Program			1-Aug-2015				Yes		Yes	Yes	$10,000	0.0	$225,000	4,200.0									**$235,000**	**4,200.0**
	Energy Manager Program			1-Jan-2016				Yes		Yes	Yes			$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	**$2,250,000**	**26,250.0**
			Enhanced Small Commercial Direct Install	1-Jan-2016			Yes								4,322.0		6,483.0		7,204.0		7,204.0		6,483.0		**31,696.0**
		Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot		1-May-2015	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	5,000.0												**5,000.0**
			Proposed Conservation Voltage Regulation (CVR) Leveraging AMI Data Program	1-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes				12,000.0		16,000.0		0.0		0.0		0.0		**28,000.0**
			Shortfall-Consumer	1-Jan-2018	Yes	Yes													15,407.0		15,407.0		15,407.0		**46,221.0**
			Shortfall-Commercial	1-Jan-2018			Yes	Yes	Yes	Yes	Yes								5,568.0		5,568.0		5,568.0		**16,704.0**
		Residential Demand Response Wi-Fi Thermostat Pilot		1-May-2015	Yes							$0	20.0												**20.0**
FCR TOTAL												$1,372,250	7,164.4	$17,788,198	61,650.4	$17,826,321	64,629.8	$22,733,396	66,243.4	$22,845,395	66,243.4	$22,676,595	65,522.4	$105,242,155	330,694.7
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	peaksaverPLUS												0.0												0.0
	Audit Funding												**1,138**												**0**
	Bi-Annual Retailer Event												1,656.0												1,656.0
	Conservation Instant Coupon Booklet												**578**												**578**
	Direct Install Lighting												**7,204**												**7,204**
	Energy Manager (PSUI)												7,350.0												7,350.0
	Heating and Cooling Initiative												**3,386**												**3,386**
	High Performance New Construction												**855**												**855**
	Low Income Home Assistance Program												**784**												**784**
	Monitoring and Targeting (PSUI)												0.0												0.0
	Process and Systems Upgrades Program												20,800.0												20,800.0
	Residential New Construction												**920**												**920**
	Retrofit Initiative												20,346.0												20,346.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	65,016.6											**0.0**	**63,878.6**
TARGET GAP TOTAL																								**0.0**	
CDM PLAN TOTAL												$1,372,250	72,181.0	$17,788,198	61,650.4	$17,826,321	64,629.8	$22,733,396	66,243.4	$22,845,395	66,243.4	$22,676,595	65,522.4	$105,242,155	394,573.3
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Renfrew Hydro Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Aug-2015			Yes	Yes	Yes	Yes	Yes	$10,194	50.6	$102,049	470.8	$111,372	521.4	$110,534	521.4	$110,672	521.4	$110,811	521.4	**$555,634**	**2,607.0**
	Heating and Cooling			1-Jan-2016	Yes	Yes						$0	0.0	$32,578	40.0	$12,978	2.0	$13,031	2.0	$13,163	2.0	$13,296	2.0	**$85,046**	**48.0**
	Coupon Program			1-Jan-2016	Yes	Yes						$0	0.0	$9,989	22.0	$10,030	22.0	$10,069	22.0	$10,107	22.0	$10,144	22.0	**$50,339**	**110.0**
	New Construction Program			1-Aug-2015	Yes	Yes						$0	0.0	$4,388	6.0	$4,424	6.0	$4,469	6.0	$4,507	6.0	$4,546	6.0	**$22,334**	**30.0**
	Home Assistance Program			1-Jan-2016		Yes						$0	0.0	$8,456	12.0	$8,498	12.0	$8,550	12.0	$8,595	12.0	$8,640	12.0	**$42,739**	**60.0**
	Audit Funding Program			1-Jan-2016				Yes	Yes	Yes	Yes														**0.0**
	High Performance New Construction			1-Aug-2015				Yes		Yes	Yes														**0.0**
	Process and Systems Upgrades Program			1-Aug-2015						Yes	Yes														**0.0**
	Monitoring and Targeting Program			1-Aug-2015				Yes		Yes	Yes														**0.0**
			Enhanced Small Commercial Direct Install	1-Jan-2016			Yes						0.0		72.0		72.0		72.0		72.0		72.0		**360.0**
			Shortfall-Consumer	1-Jan-2018	Yes	Yes													154.1		154.1		115.5		**423.7**
			Shortfall-Commercial	1-Jan-2018			Yes	Yes	Yes	Yes	Yes								32.1		32.1		32.1		**96.4**
FCR TOTAL												**$10,194**	**50.6**	**$197,325**	**622.8**	**$187,412**	**635.4**	**$226,814**	**821.6**	**$227,468**	**821.6**	**$221,359**	**783.1**	**$1,070,574**	**3,735.0**
Pay for Performance Programs																									
P4P TOTAL												**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	peaksaverPLUS												0.0												0.0
	Audit Funding												0.0												0.0
	Bi-Annual Retailer Event												17.0												17.0
	Conservation Instant Coupon Booklet												6.0												6.0
	Direct Install Lighting												72.0												72.0
	Energy Manager (PSUI)												0.0												0.0
	Other												0.0												0.0
	Heating and Cooling Initiative												53.0												53.0
	High Performance New Construction												0.0												0.0
	Low Income Home Assistance Program												12.0												12.0
	Monitoring and Targeting (PSUI)												0.0												0.0
	Process and Systems Upgrades Program												0.0												0.0
	Residential New Construction												0.0												0.0
	Retrofit Initiative												289.0												289.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												**$0**	**449.0**											**0.0**	**449.0**
TARGET GAP TOTAL																								**0.0**	
CDM PLAN TOTAL												**$10,194**	**499.6**	**$197,325**	**622.8**	**$187,412**	**635.4**	**$226,814**	**821.6**	**$227,468**	**821.6**	**$221,359**	**783.1**	**$1,070,574**	**4,184.0**
MINIMUM ANNUAL SAVINGS CHECK													**True**		**True**		**True**		**True**		**True**		**True**		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**	Proposed Conservation Voltage Regulation	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***	1-Dec-2015		
c.	**Customer Segment(s) Served by Programs**	Residential	Commercial (inc. Multi-Family)	Other
d.	**Participating LDCs *(if applicable)***	Hydro Ottawa Limited		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	This program will utilize the installed smart meters and automated metering infrastructure to provide CVR software with service point voltages to deliver reduced voltage. Operating at reduced voltage will result in lower energy consumption. This program will impact all customer classes.		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**	Enhanced Small Commercial Direct Install	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***	TBD		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs *(if applicable)***	Hydro Ottawa Limited	Renfrew Hydro Inc.	
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	LDC Working Group will be sbmitting the business case for this program.		

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Hydro Ottawa/Renfrew Hydro will continue to work collaboratively with other LDC's in Eastern Ontario in ways such as: french language translation, technical and soft skills training, marketing creatives, and other support as needed. Will also consider collaboration on new program designs.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Hydro Ottawa/Renfrew Hydro will continue to collaborate with the gas company where possible such as the Home Assistance Program. Any future possibilites will be pursued.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Hydro Ottawa's Manager of Energy Conservation and Demand Management actively participates on behalf of both Hydro Ottawa and Renfrew Hydro in regional resource planning meetings in Eastern Ontario. The objective of this participation is to make other participants aware of the contribution of the CDM Plan towards overall resource requirements and to consider CDM in the IRRP process as a first alternative to meet resource needs. We will work to gain alignment between the CDM Plan and commitments required as part of the IRRP. This work will be resourced by CDM engineering and support staff.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Assumption summary provided.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	Included in the assumptions summary provided.
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	Included in the assumptions summary provided.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Used historical performance, therefore no additional information required.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	n/a
Other *Additional assumptions used in the CDM Plan*	n/a

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		O. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #28

Reference E-C/Itron Report, pg. 33-35
Appendix 2-I – last table

Question #28

a. Appendix 2-I indicates that the amount to be used for the 2015 LRAMVA is 39,500,000 kWh. Please clarify whether this is correct and, if so, why Ottawa would not use for any LRAM claim for 2015 the CDM included in its last (EB-2011-0054) rate application.

b. Please provide a schedule that sets out the LRAMVA amounts (i.e. total kWh) that Ottawa would propose for 2016-2020. In doing so, please explain how each of the annual values were derived from its currently proposed load forecast and CDM adjustments – recognizing that the LRAMVA amounts are based on annualized savings.

c. Please provide a breakdown by customer class of the LRAMVA amounts for each year per part (b) and explain how the values were established.

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") indicated in Appendix 2-I how the 2016 to 2020 load forecast was adjusted for conservation demand management targets ("CDM") and how the forecast would impact future lost revenue adjustment mechanism ("LRAM") calculations. For the purpose of the 2016 to 2020 LRAM calculations the 2015 target is being used. Hydro Ottawa will use the CDM target as per EB-2011-0054 in calculating its 2015 LRAM. Please note the updated Chapter 2 Appendices were not available at the time Hydro Ottawa submitted its

2016 to 2020 rate application, as a result Appendix 2-I assumes a rebase year of 2015.

b. Please see response to Vulnerable Energy Consumers Coalition Interrogatory Question #27 table 4 for the total kWh Hydro Ottawa would use of the 2016 to 2020 LRAM calculation.

Please see response to Vulnerable Energy Consumers Coalition Interrogatory Question #27 part b, e and g for how Hydro Ottawa derived it's 2016 to 2020 CDM targets and allocated them to the yearly forecast.

c. Please see response to Vulnerable Energy Consumers Coalition Interrogatory Question #27 table 4 for the kWh by class. Hydro Ottawa forecasted the total saving would be a achieved in the following distribution; 15% in the residential class, 10% in the small commercial class and 75% in the commercial classes greater than 50 KW.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #29

Reference: E-A/T2/S1, pg. 12

Question #29:

a. Please confirm that Hydro Ottawa's CIR proposal does not include any future updates or revisions to the load forecast over the 2016-2020 period.

Response:

a. Hydro Ottawa confirms that its 2016-2020 Custom IR proposal, as currently structured, does not contemplate future updates or revisions to its load forecast over the 2016-2020 period.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #30

Reference: E-C/T2/S1
Appendix 2-H

Question #30

a. Please provide the year to date Other Revenue for 2015 (broken down per Appendix 2-H) and indicate what months are included.

b. Please provide a breakdown of the Other Revenues forecast for 2017-2020 (per the RRWFs) per the categories used in Appendix 2-H.

Response:

a. Please refer to response to Energy Probe interrogatory question # 13 c) and d).

b. Please see table below for 2017-2020 Other Revenue forecast broken down per Appendix 2-H.

Table 1 – 2017-2020 Other Revenue Forecast

USoA #	USoA Description	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS
4235	Miscellaneous Service Revenues	5,934,229	6,014,982	6,039,578	6,064,123
4225	Late Payment Charges	720,000	720,000	720,000	720,000
4082	Retail Services Revenues	167,732	180,981	177,267	181,683
4084	Service Transaction Requests (STR) Revenues	5,912	5,946	6,192	6,200
4086	SSS Administration Revenue	902,964	914,049	925,018	935,849
4090	Electric Services Incidental to Energy Sales	349,836	368,760	383,388	405,937
4315	Revenues from Electric Plant Leased to Others	1,857,897	1,876,476	1,895,241	1,914,193
4325	Revenues from Merchandise, Jobbing, Etc.	5,514,031	5,569,172	5,624,863	5,681,112
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	(4,085,470)	(4,126,325)	(4,167,588)	(4,209,264)
4355	Gain on Disposition of Utility and Other Property	-	-	-	-
4360	Loss on Disposition of Utility and Other Property	-	-	-	-
4362	Loss from Retirement of Utility and Other Property	198,000	198,000	198,000	198,000
4375	Revenues from Non-Utility Operations				
4405	Interest and Dividend Income	-	-	-	-
Specific Service Charges		5,934,229	6,014,982	6,039,578	6,064,123
Late Payment Charges		720,000	720,000	720,000	720,000
Other Operating Revenues		1,426,444	1,469,736	1,491,865	1,529,669
Other Income or Deductions		3,484,458	3,517,323	3,550,516	3,584,041
Total		**11,565,131**	**11,722,041**	**11,801,959**	**11,897,833**

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #31

Reference: E-B-T1/S2/pg.35

Question #31

a. Please provide the annual membership and associated costs for each of the years 2011 through 2016 for:

   i. Electricity Distributors Association
   ii. Electrical Contractor Association
   iii. Canadian Standards Association
   iv. Center for Energy Advancement

Response:

a. Refer to the table below

Table 1: Annual Membership Costs (in dollars)

Annual Membership & Associated Costs	2011 - Actuals	2012 - Actuals	2013 - Actuals	2014 - Actuals	2015 - Budget	2016 - Budget
Electricity Distributors Association (EDA)	$101,000	$106,500	$103,171	$106,700	$116,400	$118,740
Electrical Contractor Association (ECA)*						
Canadian Standards Association (CSA)	1,300	2,150	1,500	1,513	1,500	1,500
Center for Energy Advancement*						
Total Memberships	**$102,300**	**$108,650**	**$104,671**	**$108,213**	**$117,900**	**$120,240**

* no annual membership

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #32

Reference: E-D/T1/S3/pg.11

Question #32

a. Please provide the vegetation management program costs for each of 2012 through 2016.

b. Please explain how Ottawa measures the reduction in outages associated with the vegetation program.

c. Please provide the tree contact outage reduction targets associated with this program.

Response:

a. The vegetation management program costs are provided in Exhibit D-1-3 Table 4.

b. Hydro Ottawa performs reliability analyses to determine cause and effect of system outages. For more details on the process for reporting outages refer to Attachment B-1(B) – Annual Planning Report - 2014 Reliability Plan. Hydro Ottawa is required to trim vegetation near its plant under Ontario Regulation 22/04 – Electrical Distribution Safety 4. (4) 3. and Electricity Act, 1998 c. 15, Sched, A s.40 (4). Since Hydro Ottawa is mandated to trim there is no baseline for tree related outages if no trimming occurred.

Hydro Ottawa will continue to complete reliability analyses to trend the influence of the Storm Hardening Project on tree and adverse weather related outages. For historical reliability figures by primary outage cause please see Interrogatory Response to SIA Question #15. For more information on our vegetation management program, please see Interrogatory Response to CCC Question #37.

c. Predicting reduction of outages from the Storm Hardening project is an extremely difficult task as there are many unpredictable external forces such as wind and freezing rain that affect vegetation. Hydro Ottawa proceeded with Storm Hardening Project as a recommendation of a Vegetation Consultant (refer to Att-CCC-Q37-B – SRL Corp Report Veg Management). Hydro Ottawa was influenced by the 2013 Toronto ice storm to remove overhang in order to storm harden its system. Removing the overhang vegetation will make the system more resilient to major storms; ice storms and extreme wind storms. Hydro Ottawa is going to continue to analyze vegetation related outages including outages during major storm events to confirm the effectiveness of the project. For more information on our Vegetation Management Program please see Interrogatory Response to CCC Question #37.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #33

Reference: E-D/T1/pg.7/Table 8

Question #33

a. Please provide the OM&A amounts for 2012 through 2016 for Customer & Community Relations showing separately the amounts for: (1) call center, (2) web site costs, and (3) other community relations.

Response:

Please see Interrogatory Response to CCC Question #14.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #34

Reference: E-D/T1/S4

Question #34:

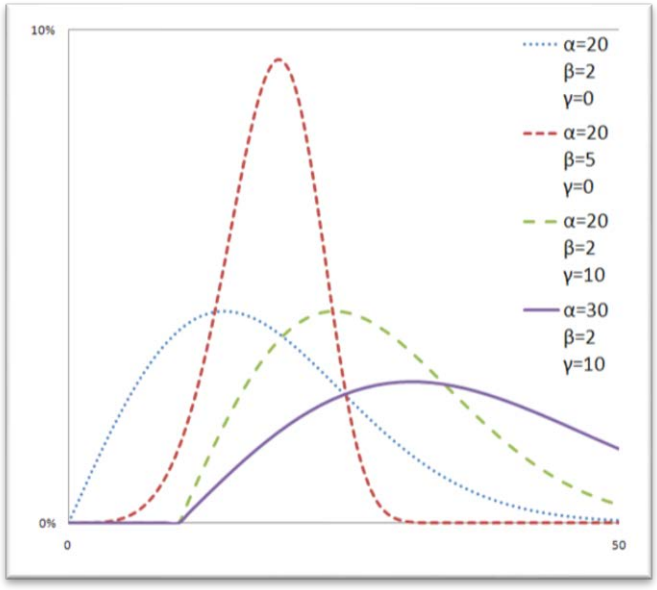
a. Please explain how the forecast of defective equipment contribution to SAIFI is derived.

Response:

a. The defective equipment contribution to SAIFI is forecasted based on the following steps, along with example diagrams. The diagrams and more information on Asset Replacement Projections can be found in Attachment B-1(B) – Annual Planning Report, 2014 Asset Management Plan section 5.3, page 15.

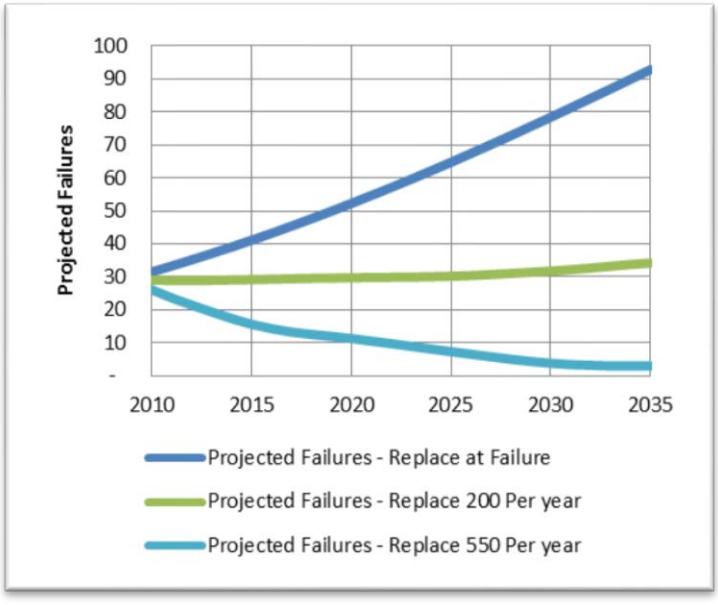
1. Weibull analysis is conducted on the following major asset classes to estimate the expected end-of-life. Note that the historic values shown in the chart represent only this subset of major assets as well. For more information on Weibull analysis refer to Interrogatory Response to OEB #17 part xvi.
    - Polemount transformers;
    - Padmount transformers;
    - Padmount switches;
    - XLPE Cable;
    - PILC Cable; and
    - Poles

Figure VECC #34 – 1: Example Weibull Curves



2. Using the failure curves from the Weibull analysis, scenarios are created to show the impact of run-to-failure versus varying levels of proactive replacement, in this case the replacement levels for current spending levels compared to proposed levels.

Figure VECC #34 – 2: Example Projected Failure Curves



3. The forecasted annual failure rates are multiplied by the historic average number of customers interrupted due to the failure of each asset class listed in Step 1 to develop the annual number of customers interrupted. Summing each of the asset classes together provides an estimated annual number of customers interrupted due to Defective Equipment.

4. The estimated annual number of customers interrupted is then divided by the annual forecasted customer count to develop the forecasted SAIFI due to Defective Equipment.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #35

Reference: E-D1/S8/pg.1-6

Question #35:

a. Please amend Appendix 2-K to show Board approved for 2012

b. Please show the calculation which underpins the statement that the wage increases for 2013-2016 are on average 10% lower than the previous three year collective agreement.

c. Does HOL provide post-retirement benefits to all new employees?

Response:

a. Hydro Ottawa's 2012 OM&A was approved by the Board on an envelope basis. As such, there is no Board approved breakdown of compensation costs for 2012.

b. The table below provides the annual and average wage increases as per the April 1, 2010 to March 31, 2013 (previous) collective agreement and the April 1, 2013 to March 31, 2017 (current) collective agreement.

	Collective Agreement 2010-2013	Collective Agreement 2013-2017
Year 1	3%	2.6%
Year 2	3%	2.7%
Year 3	3%	2.7%
Year 4	n/a	2.8%
Average Wage Increase	9% over 3 years = 3% average per year	10.8% over 4 years = 2.7% average per year

The difference between the 3% average wage increase in the previous collective agreement and the 2.7% average wage increase in the current collective agreement is 0.3%, which results in a 10% lower average wage increase.

c. As outlined in Exhibit D, Tab 1, Schedule 8, Page 5, Hydro Ottawa's post-retirement benefits for eligible employees consist only of life insurance and a small retirement grant. All employees are eligible for the life insurance, however, must have a minimum of 10 years of service to qualify. Unionized employees are eligible for the retirement grant, which is primarily linked to positive attendance and for which an employee must have a minimum of 25 years of service to qualify.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #36

Reference: E-D1/S8/pg.1-6

Question #36

a. Appendix 2-M appears to show that HOL is not seeking to recover any one-time regulatory costs associated with this application. Please confirm whether this is correct.

b. Please explain the ongoing intervenor and consultant costs ($131,722 and $160,711 respectively).

c. In the alternative please provide a table (below 2-M) which shows all one-time costs associated with this application. Please provide an update showing the legal and consulting costs incurred to date for the application.

Response:

a. Confirmed.

b. Ongoing intervenor and consultant costs for the 2016 test year include expenses that Hydro Ottawa Limited ("Hydro Ottawa") forecasts as the new normal based on an increasing number of regulatory consultations and proceedings that Hydro Ottawa is involved in, which require both intervenor and consultant costs.

c. No update required as per the response to parts a) and b) of this question, also please see Interrogatory Response to CCC Question #49 for the costs incurred / projected to incur for this application.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #37

Reference: E-D/T5/S2 – Table 2 Appendix D-5(A)

Question #37:

a. With respect to Table 2, please revise so as to include the kWh savings attributable to the non-Residential programs and reconcile the totals for each year with those reported by the OPA.

b. Please reconcile the reported kWh results by program as shown in Table 2 with the results set out in the OPA Report (Table 1). For example, the 2011 and 2012 totals for Residential do not appear to be consistent.

c. Please provide a schedule that sets out how the reported kW results as shown in Table 2 were derived from the results set out in the OPA Report (Table 1).

d. Please confirm that the kW values reported by the OPA represent the impact on the annual peak as opposed to the impact on monthly peak demand.

e. Please indicate how Ottawa derived the impact on billing kW from the OPA reported results.

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") has updated Table 2 of Exhibit D-5-2 to include the kWh's for GS<50 Customer Class. Below is a copy of the updated table.

Exhibit D-5-2, Table 2 - Updated July 31, 2015

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				3,979,730	3,428,701	3,655,868
Small Commercial Demand Response				16	120	46
GS< 50 kW Total	-	-	-	3,979,746	3,428,821	3,655,914
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**	**13,148,434**	**9,092,808**	**8,429,242**

b. The kWh's reported in Table 2 of Exhibit D-5-2 are net figures from the OPA report, attachment D-5(A), Table 1: Hydro Ottawa Initiative and Program Level Net Savings by Year (Scenario 1) and Table 2: Adjustments to Hydro Ottawa Limited Net Verified Results due to Variances on pages 4 and 5 respectively. Hydro Ottawa has

calculated the figures in Table 2 by netting the Results and Adjustments by year by Customer Class and Program please see the response to part c of this question for a more detailed breakdown.

c. The schedules below provide details as to how the kWh's and kW's in Table 2 are derived. Note the kW's, being the highest peak in the year are multiplied by 12 as the customer would save this amount of demand on each of the 12 monthly bills in a given year.

IR - VECC#37 part c - Schedule Reported Results from Table 2 in Exhibit D-5-2 as set out in OPA Tables 1 and 2 - kWh's

Customer Class - Program / Initiative	Net Incremental Energy Savings (kWh) - 2011	Net Incremental Energy Savings (kWh) - 2012	Net Incremental Energy Savings (kWh) - 2013
Residential			
Appliance Retirement Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 - No Adjustments)	**1,754,416**	**1,040,845**	**681,703**
Appliance Exchange Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 - No Adjustments)	**22,795**	**43,987**	**70,563**
HVAC Incentives			
OPA Table 1 - Net Incremental Energy Savings (kWh)	5,465,411	2,835,583	2,563,561
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kWh)	-968,746	110,909	0
HVAC Incentives Total as per Table 2 - Exhibit D-5-2	**4,496,665**	**2,946,491**	**2,563,561**
Conservation Instant Coupon Booklet			
OPA Table 1 - Net Incremental Energy Savings (kWh)	1,104,610	78,235	431,268
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kWh)	15,424	0	0
Conservation Instant Coupon Booklet Total as per Table 2 - Exhibit D-5-2	**1,120,034**	**78,235**	**431,268**
Bi-Annual Retailer Event			
OPA Table 1 - Net Incremental Energy Savings (kWh)	1,644,342	1,498,537	961,278
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kWh)	122,169	0	0
Bi-Annual Retailer Event Total as per Table 2 - Exhibit D-5-2	**1,766,511**	**1,498,537**	**961,278**
Residential Demand Response Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 - No Adjustments)	**8,266**	**55,891**	**48,406**
Residential New Construction Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 - No Adjustments)	**0**	**0**	**16,548**
Residential Program Total	**9,168,688**	**5,663,987**	**4,773,328**
GS< 50 kW			
Direct Install Lighting Total			
OPA Table 1 - Net Incremental Energy Savings (kWh)	3,870,853	3,365,166	3,655,868
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kWh)	108,877	63,534	0
Direct Install Lighting Total as per Table 2 - Exhibit D-5-2 - Updated July 31, 2015	**3,979,730**	**3,428,701**	**3,655,868**
Small Commercial Demand Response Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 - No Adjustments)	**16**	**120**	**46**
GS< 50 kW Total	**3,979,746**	**3,428,821**	**3,655,914**
GRAND TOTAL	**13,148,434**	**9,092,808**	**8,429,242**

IR - VECC#37 part c - Schedule Reported Results from Table 2 in Exhibit D-5-2 as set out in OPA Tables 1 and 2 - kW's

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
Commercial			
Retrofit - Business			
OPA Table 1 - Net Incremental Energy Savings (kW) monthly x 12 = annual	33,989	61,395	58,770
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kW) monthly x 12 = annual	1,944	4,792	0
Retrofit - Business Total as per Table 2 - Exhibit D-5-2	**35,933**	**66,187**	**58,770**
New Construction Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**0**	**163**	**1,500**
Energy Audit			
OPA Table 1 - Net Incremental Energy Savings (kW) monthly x 12 = annual	0	1,491	5,076
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kW) monthly x 12 = annual	311	62	0
Energy Audit Total as per Table 2 - Exhibit D-5-2	**311**	**1,553**	**5,076**
Demand Response 3 - Business Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**7,163**	**7,723**	**18,245**
Energy Manager Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**0**	**0**	**1,303**
Retrofit - Industrial Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**973**	**0**	**0**
Demand Response 3 - Industrial Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**0**	**503**	**2,266**
Home Assistance Program Total as per Table 2 - Exhibit D-5-2 (OPA Table 1 (kW) monthly x 12 = annual; No Adjustments)	**0**	**316**	**380**
Electricity Retrofit Incentive Program			
OPA Table 1 - Net Incremental Energy Savings (kW) monthly x 12 = annual	11,205	0	0
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kW) monthly x 12 = annual	325	0	0
Electricity Retrofit Incentive Program Total as per Table 2 - Exhibit D-5-2	**11,530**	**0**	**0**
High Performance New Construction			
OPA Table 1 - Net Incremental Energy Savings (kW) monthly x 12 = annual	3,858	9,686	3,432
OPA Table 2 - Adjustments to Net Incremental Energy Savings (kW) monthly x 12 = annual	521	0	0
High Performance New Construction Total as per Table 2 - Exhibit D-5-2	**4,378**	**9,686**	**3,432**
Commercial Total	**60,288**	**86,131**	**90,971**
GRAND TOTAL	**60,288**	**86,131**	**90,971**

d. The kW values reported by the OPA represent an annual peak demand. For the purposes of determining total demand savings this amount is multiplied by 12 monthly billing periods.

e. Please refer to the schedule in response to part c and d of this question for details on how the impact on billing kW's is derived from the OPA report.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #38

Reference E-D/T5/S2- Table 3

Question #38

a. Please provide a schedule that sets out the total CDM adjustments included in the load forecasts underpinning Ottawa's approved rates for 2011 through 2013 and provide references to the relevant rate application filing supporting each. In each case, please indicate program years the adjustments were meant to capture (e.g. did the load forecast underpinning the 2012 (and 2013) approved rates included a manual adjustment for the impact of 2011 CDM programs?).

b. Please provide a schedule that sets out the breakdown of the total adjustments per part (a) by customer class as incorporated in the load forecast for each of these years and provide references to the relevant rate applications.

c. Please provide a schedule that calculates , by year (2011-2013) and customer class, the difference between the actual reported impact for 2011-2013 CDM results from programs implemented in 2011-2013 and the CDM adjustment incorporate in the load forecast underpinning the year's rates.

d. Please reconcile results per part c) with the units of energy or demand used in Table 3.

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") did not have any CDM adjustments in approved rates for 2011, please refer to EB-2007-0713 Exhibit C1-2-1 Section 3.0. In 2012 CDM adjustments were initially 165 GW's during the rate application

proceedings this was reduced by 75 GW's to arrive at an adjusted amount of 90 GW's. Please refer to EB-2011-0054 Hydro Ottawa's Settlement Agreement Filed November 1, 2011, Section 3.3, page 13 for further details. The 2013 CDM adjustments are maintained the same as the 2012 CDM adjustments.

b. The following schedule outlines the total adjustments by customer class related to billing determents for each of these years. Please refer to part a) of this question for the references to the relevant rate applications.

CDM Forecast by Customer Class

Class	MWh's/kW's	2011	2012	2013
Residential	MWh's	-	20,681	20,681
GS< 50	MWh's	-	6,993	6,993
UMSL	MWh's	-	158	158
TOTAL	**MWh's**	**-**	**27,832**	**27,832**
Streetlighting	kW's	-	3,758	3,758
Commercial	kW's	-	319,193	319,193
TOTAL	**kW's**	**-**	**322,951**	**322,951**

c. Please refer to the Lost Revenue table below for a schedule that calculates, by year (2011-2013) and customer class, the difference between the actual reported impact for 2011-2013 CDM results from programs implemented in 2011-2013 and the CDM adjustment incorporate in the load forecast underpinning the year's rates.

Lost Revenue by Class (2011 to 2013)

		2011					
Customer Class	**Demand (kW) or Energy (kWh)**	**Original CDM built into forecast (units) [a]**	**Units of Demand or Energy [b]**	**Variable Rate[1] [c]**	**Original CDM built into forecast ($) [d = a x c]**	**Actual Lost Revenue ($) [e = b x c]**	**Lost Revenue [f = d - e]**
Residential	kWh	0	9,168,688	$0.0204	$0	$187,041	(187,041)
GS< 50 kW	kWh	0	3,979,746	$0.0182	$0	$72,564	(72,564)
Commercial	kWh	0					0
Unmetered	kWh	0	0	$0.0197	$0	$0	0
Streetlighting	kWh	0	0				0
Sub-Total		**0**	**13,148,434**		**$0**	**$259,605**	**$($259,605)**
Commercial	kW	0	60,288	$2.8557	$0	$172,163	(172,163)
Streetlighting	kW	0	0	$3.3916	$0	$0	0
Sub-Total		**0**	**60,288**		**$0**	**$172,163**	**$($172,163)**
TOTAL					**$0**	**$431,768**	**$(431,768)**
		2012					
Customer Class	**Demand (kW) or Energy (kWh)**	**Original CDM built into forecast (units) [a]**	**Units of Demand or Energy [b]**	**Variable Rate[1] [c]**	**Original CDM built into forecast ($) [d = a x c]**	**Actual Lost Revenue ($) [e = b x c]**	**Lost Revenue [f = d - e]**
Residential	kWh	22,228,164	14,824,409	$0.0231	$513,174	$342,246	170,928
GS< 50 kW	kWh	6,993,000	7,408,550	$0.0203	$141,958	$150,394	(8,436)
Commercial	kWh	44,653,660					
Unmetered	kWh	169,801	0	$0.0211	$3,583	$0	3,583
Streetlighting	kWh	402,528					
Sub-Total		**74,447,153**	**22,232,960**		**$658,715**	**$492,640**	**$166,075**
Commercial	kW	319,193	139,255	$3.3690	$1,075,358	$469,150	606,207
Streetlighting	kW	3,758	0	$3.8880	$14,611	$0	14,611
Sub-Total		**322,951**	**139,255**		**$1,089,969**	**$469,150**	**$620,819**
TOTAL					**$1,748,684**	**$961,790**	**$ 786,894**

[1] Variable Rate Rounded to 4 decimal places

		2013					
Customer Class	**Demand (kW) or Energy (kWh)**	**Original CDM built into forecast (units) [a]**	**Units of Demand or Energy [b]**	**Variable Rate[1] [c]**	**Original CDM built into forecast ($) [d = a x c]**	**Actual Lost Revenue ($) [e = b x c]**	**Lost Revenue [f = d - e]**
Residential	kWh	22,228,164	19,541,846	$0.0228	$506,802	$445,554	61,248
GS< 50 kW	kWh	6,993,000	11,064,344	$0.0204	$142,657	$225,713	(83,055)
Commercial	kWh	44,653,660					
Unmetered	kWh	169,801	0	$0.0213	$3,617	$0	3,617
Streetlighting	kWh	402,528					
Sub-Total		**74,447,153**	**30,606,190**		**$653,076**	**$671,267**	**$($18,191)**
Commercial	kW	319,193	222,001	$3.3654	$1,074,223	$747,131	327,092
Streetlighting	kW	3,758	0	$3.8939	$14,633	$0	14,633
Sub-Total		**322,951**	**222,001**		**$1,088,856**	**$747,131**	**$341,725**
TOTAL					**$1,741,932**	**$1,418,398**	**$ 323,534**

[1] Variable Rate Rounded to 4 decimal places

d. Please refer to the response to part c) of this question to reconcile results per part c) with the units of energy or demand.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #39

Reference E-D/T5/S2 – Tables 2 and 3 Appendix D-5(A)
EB-2014-0099, Exhibit 4, Appendix 4-N, pg. 3

Question #39

a. Does Ottawa agree that the kW values reported for Demand Response programs represent kW under contract and that the contracted kW may not have been exercised in each month of the actual years in question, if at all? If not, why not?

b. Like many other electricity distributors, North Bay Hydro Distribution Limited contracted with a 3rd party (in their case IndEco Strategic Consulting Inc.) to perform the LRAMVA calculations for its recent COS Application. In its Report (referenced above), IndEco offered the following explanation for excluding the kW impact of Demand Response Programs from the LRAMVA calculations:

> *For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW in the month), the system peak reductions are only partially relevant. For initiatives like lighting upgrades in businesses operating during normal business hours, the peak demand reductions are likely to be maintained throughout the year, including during the customer's monthly peaks, and so may be used to estimate lost revenue. For other programs, in particular demand response programs, the customer's monthly peak may not correspond to the system's peak. Further, even if they are coincident, if a demand response event is called, and the customer's monthly peak is shaved, it is likely that the customer's second highest peak in the month is only slightly less than their highest peak. Thus, the impact on distribution revenues of the demand response program is likely to be minimal, and is assumed to have zero impact on lost load.*
>
> *Thus, no distribution revenues are estimated to be lost from large*

general service customers' participation in demand response programs.

Does Ottawa concur with this rationale and agree that the impact of demand response programs should be excluded? If not, why not?

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") believes the KW values for Demand Response programs related to the LRAM calculation are under contract. As Hydro Ottawa is not managing the contract or its process, Hydro Ottawa cannot validate that the contracts are in place, when they are exercised or how often they are exercised as it is not privy to all these details.

b. According to the Ministry of Energy, "Demand response provides an excellent example of leveraging the economic value of conservation. More broadly, demand management initiatives provide price or financial incentives to residential, commercial and industrial users to shift or reduce their electricity usage away from peak periods. As well as benefiting the electricity system, demand response lowers energy costs for consumers and allows businesses to operate more competitively[1]".

In addition the Independent Electricity System Operator states "Demand response, which enables consumers to reduce their electricity consumption in response to prices and system needs, is playing an increasing role in Ontario's electricity sector. It has already had a significant impact on energy demand and

[1] http://www.energy.gov.on.ca/en/conservation-first/

helped reduced peaks, providing a valuable and cost-effective resource to the system.[2]"

Hydro Ottawa has calculated the LRAM amount according to the Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003. As can be seen in Hydro Ottawa's preliminary 2014 CDM Report from the IESO, provided in Interrogatory Response to Vulnerable Energy Consumers Coalition #27, demand response activities are occurring at least quarterly.

As stated in part a) of this response Hydro Ottawa is not privy to the details around demand response programs under contract. As a result, Hydro Ottawa cannot determine if the customer's second largest peak is significantly different than what the customer's highest peak would have been. In addition, other factors such as the Global Adjustment can impact customer behaviour which can result in peak load reduction outside the CDM programs. As such, the measures in determining the LRAM calculation are based on the CDM Report from the IESO, formerly the OPA which track customers CDM activities.

[2] http://iesoqa-public.sharepoint.com/Pages/Ontario's-Power-System/Evolving-the-Markets/Demand-Response.aspx

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #40

Reference E-D/T5/S2- Table 3
E-I/T8/S1, pg. 9 – Table 4

Question #40

a. Please reconcile the differences between the LRAM amounts by customer class set out in Table 4 (E-I/T8/S1) with the results in Table 3 of E-D/T5/S2.

Response:

a. The net total for lost revenue from 2011 to 2013 in Table 3 of Exhibit D-5-2 is $678k, please refer to the total Table 1 of Exhibit D-5-2, these tables are based on a kWh and kW breakdown by class. Table 4 of Exhibit I-8-1 provides a similar total of $679k, the difference is due to rounding of rates. This table is for the Rate Riders for Deferral and Variance accounts for the Lost Revenue Adjustment Mechanism ("LRAM"), the rate riders were based on customer numbers.

Please see Interrogatory Response to OEB Staff question #1 for updated rate riders.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #41

Reference: E-E/T1/S1/pg.1

Question #41

a. Please provide Appendix 2-OA for 2013 and 2014.

Response:

a. Please find the 2013 and 2014 information in attachment Att-VECC-Q41-A.

Year: 2013 (Actual)

Line No.	Particulars	Capitalization Ratio			Cost Rate		Return
		(%)			(%)		
	Debt						
1	Long-term Debt	53.88%		$356,445,274	4.91%		$17,506,311
2	Short-term Debt	5.36%	(1)	$35,469,318	1.96%		$695,553
3	**Total Debt**	59.2%		$391,914,592	4.64%		$18,201,864
	Equity						
4	Common Equity	40.75%		$269,594,000	9.44%		$25,449,674
5	Preferred Shares			$ -			$ -
6	**Total Equity**	40.8%		$269,594,000	9.44%		$25,449,674
7	**Total**	100.0%		$661,508,592	6.60%		$43,651,538

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Year: 2014 (Actual)

Line No.	Particulars	Capitalization Ratio			Cost Rate		Return
		(%)			(%)		
	Debt						
1	Long-term Debt	56.66%		$392,527,466	4.77%		$18,742,582
2	Short-term Debt	2.57%	(1)	$17,782,329	2.14%		$380,720
3	**Total Debt**	59.2%		$410,309,795	4.66%		$19,123,302
	Equity						
4	Common Equity	40.77%		$282,465,000	9.87%		$27,879,296
5	Preferred Shares			$ -			$ -
6	**Total Equity**	40.8%		$282,465,000	9.87%		$27,879,296
7	**Total**	100.0%		$692,774,795	6.78%		$47,002,597

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #42

Reference: E-E/T1

Question #42

a. Please clarify the cost of capital adjustment formula: Is the proposal to recalculate the revenue requirement with an adjustment for changes to long-term debt (forecast and embedded) only in 2018? If so why has HOL included its forecast for 2019 and 2020?

b. With respect to long-term debt what is the principle/rationale underpinning an adjustment to debt using a forecast as opposed to making the adjustment based on actual embedded debt at the time of the annual adjustment?

c. What is the principle/rationale underpinning an adjustment to long-term debt, but not short –term debt or return on equity?

Response:

a. Please refer to the response for OEB-Q26 regarding the cost of capital calculations and the response to EP-39(a) regarding the cost of capital update process. The 5 year custom rate application reflects the forecast for 2019 to 2020 to facilitate the determination of the 2019 & 2020 total revenue requirement and the resulting customer rates.

b. As outlined in E-1-1, section 2.3 Long Term Debt, in the absence of external financing (embedded or actual debt), Hydro Ottawa emulates the 2009 Cost of Capital Report

calculation, which uses both historical and forecast rates to calculate the cost of long term debt. The calculation in the model uses the Consensus 10-year Government of Canada forecast as a direct driver in determining the long term debt rate. As there is no actual or embedded debt rate in place for future borrowing requirements, the 2009 Report calculation is used for future forecasts, providing the forecast rate using the data available at that time. By using this approach, Hydro Ottawa primarily uses actual embedded debt but follows the deemed cost of capital calculation using the Consensus Forecast for current and forecast debt in the absence of external financing at the Holding Company. The adjustment in 2018 will reflect the, then current, actual / embedded cost of long term debt as well as utilizing the deemed cost of capital calculation incorporating the Consensus Forecast for the 2019 to 2020 borrowing requirements.

c. Hydro Ottawa's proposal is to "lock in" all of the Cost of Capital parameters (long term debt rate, short term debt rate and return on equity) for the 3-year period, ending December 31, 2018 as outlined in E-1-1. In 2018, Hydro Ottawa will review and update all of its Cost of Capital parameters and these updated parameters would then remain in effect for the 2-year period 2019 to 2020.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #43

Reference: E-E1/T1/S1

Question #43

a. For the table labeled 2015, please confirm the rates for all Promissory Notes which show a start date of July 15.

b. Have all these notes been finalized?

Response:

a. Please see interrogatory response to Energy Probe Q41 (a).

b. Please see interrogatory response to Energy Probe-Q41 (a).

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #44

Reference: E-G/T1/S1, pg. 2

Question #44

a. Please confirm that the revenue to cost ratio for Sentinel Lighting continues to be outside the Board's approved range even in 2020.

b. What would be the resulting revenue to cost ratios and total bill impacts for Sentinel Lighting if, starting 2017, the ratio was increased in equal amounts so as to reach 80% in 2020?

Response:

a. Hydro Ottawa Limited confirms that Sentinel Lights is proposed to remain outside the Board approved range from 2016 through 2020.

b. Please refer to attachment Att-VECC-Q44-A of this response for the total bill impacts if Sentinel Lights revenue-to-cost ratio was increased as per Table 1. Table 1 also shows a summary of rate impacts by year.

Table 1 - Rate Impacts - Sentinel Lighting (0.4KW) Within Range by 2020

	2015	2016	2017	2018	2019	2020
Revenue to Cost Ratio		60%	65%	70%	75%	80%
Distribution Charge	$ 6.63	$ 8.08	$ 8.96	$ 9.64	$ 10.28	$ 10.71
Change in Distribution Charge		$ 1.44	$ 0.88	$ 0.69	$ 0.64	$ 0.42
% Distribution Increase		21.73%	10.92%	7.65%	6.64%	4.12%
% Increase of Total Bill		6.91%	4.65%	3.16%	2.86%	1.84%

1 Please see response to OEB Staff Interrogatory Question #1 for revised rates.

Appendix 2-W
Bill Impacts

Customer Class: Sentinel Lights

TOU / non-TOU: TOU

Consumption 94 kWh / 0.40 KW

● 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	$ 2.62	1	$ 2.62	3.25	1	$ 3.25	$ 0.63	24.05%
Smart Meter Rate Adder			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%
Smart Meter Disposition Rider			94	$ -		94	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	0	$ -	$ -	0	$ -	$ -	
			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%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	0	$ -	-$ 0.2038	0	-$ 0.08	-$ 0.08	
Deferral/Variance Account Disposition Rate Rider - Global Adjustment	per kWh		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%
Line Losses on Cost of Power		$ 0.1021	3	$ 0.34	$ 0.1021	3	$ 0.32	-$ 0.02	-5.59%
Smart Meter Entity Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.99**			**$ 8.33**	**$ 1.34**	**19.20%**
RTSR - Network	per kW	$ 2.1461	0.4	$ 0.86	$ 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%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8.33**			**$ 9.67**	**$ 1.34**	**16.11%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	97	$ 0.43	$ 0.0044	97	$ 0.43	-$ 0.00	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	97	$ 0.13	$ 0.0013	97	$ 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	94	$ 0.65	$ 0.0069	94	$ 0.65	$ -	0.00%
TOU - Off Peak		$ 0.0800	60	$ 4.81	$ 0.0800	60	$ 4.81	$ -	0.00%
TOU - Mid Peak		$ 0.1220	17	$ 2.06	$ 0.1220	17	$ 2.06	$ -	0.00%
TOU - On Peak		$ 0.1610	17	$ 2.72	$ 0.1610	17	$ 2.72	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	94	$ 8.84	$ 0.0940	94	$ 8.84	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 19.38**			**$ 20.72**	**$ 1.34**	**6.91%**
HST		13%		$ 2.52	13%		$ 2.69	$ 0.17	6.91%
Total Bill (including				$ 21.90			$ 23.42	$ 1.51	6.91%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 21.90**			**$ 23.42**	**$ 1.51**	**6.91%**
Total Bill on RPP (before Taxes)				**$ 18.62**			**$ 19.96**	**$ 1.34**	**7.20%**
HST		13%		$ 2.42	13%		$ 2.59	$ 0.17	7.20%
Total Bill (including				$ 21.04			$ 22.55	$ 1.51	7.20%
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				**$ 21.04**			**$ 22.55**	**$ 1.51**	**7.20%**
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	$ 3.390	1	$ 3.39	$ 0.14	4.31%	$ 4.280	1	$ 4.28	$ 0.89	26.25%
Smart Meter Rate Adder		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 13.9201	0	$ 5.57	$ 0.74	15.38%	$ 13.4093	0	$ 5.36	-$ 0.20	-3.67%
Smart Meter Disposition Rider		94	$ -	$ -			94	$ -	$ -	
LRAM & SSM Rate Rider		0	$ -	$ -			0	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
Sub-Total A (excluding pass through)			$ 8.96	**$ 0.88**	**10.92%**			$ 9.64	**$ 0.69**	**7.65%**
Deferral/Variance Account Disposition Rate Rider		0	$ -	$ 0.08	-100.00%		0	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider - Global Adjustment		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
Low Voltage Service Charge	$ 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	$ 0.32	$ -	0.00%	$ 0.1021	3	$ 0.32	$ -	0.00%
Smart Meter Entity Charge	$ -	1	$ -	$ -		$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 9.29**	**$ 0.96**	**11.57%**			**$ 9.98**	**$ 0.69**	**7.38%**
RTSR - Network	$ 2.1461	0.4	$ 0.86	$ -	0.00%	$ 2.1461	0.4	$ 0.86	$ -	0.00%
RTSR - Line and Transformation Connection	$ 1.2058	0.4	$ 0.48	$ -	0.00%	$ 1.2058	0.4	$ 0.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 10.63**	**$ 0.96**	**9.97%**			**$ 11.32**	**$ 0.69**	**6.45%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	97	$ 0.43	$ -	0.00%	$ 0.0044	97	$ 0.43	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	97	$ 0.13	$ -	0.00%	$ 0.0013	97	$ 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	94	$ 0.65	$ -	0.00%	$ 0.0069	94	$ 0.65	$ -	0.00%
TOU - Off Peak	$ 0.0800	60	$ 4.81	$ -	0.00%	$ 0.0800	60	$ 4.81	$ -	0.00%
TOU - Mid Peak	$ 0.1220	17	$ 2.06	$ -	0.00%	$ 0.1220	17	$ 2.06	$ -	0.00%
TOU - On Peak	$ 0.1610	17	$ 2.72	$ -	0.00%	$ 0.1610	17	$ 2.72	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0940	94	$ 8.84	$ -	0.00%	$ 0.0940	94	$ 8.84	$ -	0.00%
Energy - RPP - Tier 2	$ 0.1100	0	$ -	$ -		$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 21.69**	**$ 0.96**	**4.65%**			**$ 22.37**	**$ 0.69**	**3.16%**
HST	13%		$ 2.82	$ 0.13	4.65%	13%		$ 2.91	$ 0.09	3.16%
Total Bill (including			$ 24.51	$ 1.09	4.65%			$ 25.28	$ 0.77	3.16%
Ontario Clean Energy Benefit [1]			$ -	$ -				$ -	$ -	
Total Bill on TOU (including OCEB)			**$ 24.51**	**$ 1.09**	**4.65%**			**$ 25.28**	**$ 0.77**	**3.16%**
Total Bill on RPP (before Taxes)			**$ 20.92**	**$ 0.96**	**4.83%**			**$ 21.61**	**$ 0.69**	**3.28%**
HST	13%		$ 2.72	$ 0.13	4.83%	13%		$ 2.81	$ 0.09	3.28%
Total Bill (including			$ 23.64	$ 1.09	4.83%			$ 24.42	$ 0.77	3.28%
Ontario Clean Energy Benefit [1]			$ -	$ -				$ -	$ -	
Total Bill on RPP (including OCEB)			**$ 23.64**	**$ 1.09**	**4.83%**			**$ 24.42**	**$ 0.77**	**3.28%**
Loss Factor (%)	3.3800%					3.3800%				

	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	$ 4.640	1	$ 4.64	$ 0.36	8.41%	$ 5.230	1	$ 5.23	$ 0.59	12.72%
Smart Meter Rate Adder		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
		1	$ -	$ -			1	$ -	$ -	
Distribution Volumetric Rate	$ 14.1092	0	$ 5.64	$ 0.28	5.22%	$ 13.6934	0	$ 5.48	-$ 0.17	-2.95%
Smart Meter Disposition Rider		94	$ -	$ -			94	$ -	$ -	
LRAM & SSM Rate Rider		0	$ -	$ -			0	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
Sub-Total A (excluding pass through)			$ 10.28	**$ 0.64**	**6.64%**			$ 10.71	**$ 0.42**	**4.12%**
Deferral/Variance Account Disposition Rate Rider		0	$ -	$ -			0	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider - Global Adjustment		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
		94	$ -	$ -			94	$ -	$ -	
Low Voltage Service Charge	$ 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	$ 0.32	$ -	0.00%	$ 0.1021	3	$ 0.32	$ -	0.00%
Smart Meter Entity Charge	$ -	1	$ -	$ -		$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 10.62**	**$ 0.64**	**6.42%**			**$ 11.04**	**$ 0.42**	**3.99%**
RTSR - Network	$ 2.1461	0.4	$ 0.86	$ -	0.00%	$ 2.1461	0.4	$ 0.86	$ -	0.00%
RTSR - Line and Transformation Connection	$ 1.2058	0.4	$ 0.48	$ -	0.00%	$ 1.2058	0.4	$ 0.48	$ -	0.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 11.96**	**$ 0.64**	**5.66%**			**$ 12.38**	**$ 0.42**	**3.54%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	97	$ 0.43	$ -	0.00%	$ 0.0044	97	$ 0.43	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	97	$ 0.13	$ -	0.00%	$ 0.0013	97	$ 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	94	$ 0.65	$ -	0.00%	$ 0.0069	94	$ 0.65	$ -	0.00%
TOU - Off Peak	$ 0.0800	60	$ 4.81	$ -	0.00%	$ 0.0800	60	$ 4.81	$ -	0.00%
TOU - Mid Peak	$ 0.1220	17	$ 2.06	$ -	0.00%	$ 0.1220	17	$ 2.06	$ -	0.00%
TOU - On Peak	$ 0.1610	17	$ 2.72	$ -	0.00%	$ 0.1610	17	$ 2.72	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0940	94	$ 8.84	$ -	0.00%	$ 0.0940	94	$ 8.84	$ -	0.00%
Energy - RPP - Tier 2	$ 0.1100	0	$ -	$ -		$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 23.01**	**$ 0.64**	**2.86%**			**$ 23.44**	**$ 0.42**	**1.84%**
HST	13%		$ 2.99	$ 0.08	2.86%	13%		$ 3.05	$ 0.06	1.84%
Total Bill (including			$ 26.01	$ 0.72	2.86%			$ 26.48	$ 0.48	1.84%
Ontario Clean Energy Benefit [1]			$ -	$ -				$ -	$ -	
Total Bill on TOU (including OCEB)			**$ 26.01**	**$ 0.72**	**2.86%**			**$ 26.48**	**$ 0.48**	**1.84%**
Total Bill on RPP (before Taxes)			**$ 22.25**	**$ 0.64**	**2.96%**			**$ 22.67**	**$ 0.42**	**1.90%**
HST	13%		$ 2.89	$ 0.08	2.96%	13%		$ 2.95	$ 0.06	1.90%
Total Bill (including			$ 25.14	$ 0.72	2.96%			$ 25.62	$ 0.48	1.90%
Ontario Clean Energy Benefit [1]			$ -	$ -				$ -	$ -	
Total Bill on RPP (including OCEB)			**$ 25.14**	**$ 0.72**	**2.96%**			**$ 25.62**	**$ 0.48**	**1.90%**
Loss Factor (%)	3.3800%					3.3800%				

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #45

Reference E-G/t1/S1, Appendix 2-P

Question #45

a) Please explain why, when the ratio for Standby is significantly below 100%, the Company is not proposing to move it closer to 100%.

Response:

Please see response to Ontario Energy Board Staff Interrogatory Question # 1 for updated rates.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #46

Reference: E-G/Elenchus Report, page 8

Question #46

a. What is the impact on the allocation results for 2016 of using the 2013 interval data for Large Use customer to establish the hourly load profile as opposed simply scaling the 2006 CAIF profile for the class?

Response:

Elenchus assisted Hydro Ottawa Limited in the preparation of this response.

a. The Elenchus Report stated in error that the hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes except the Large Use class. 2013 hourly data was available and used for both GS 1,500 to 4,999kW and Large Use classes. Therefore the hourly load profiles prepared by Hydro One were used for all classes except those two.

   Tables 1 indicates the cost allocations results as filed. Table 2 indicates the cost allocations should the 2006 CAIF load profiles be used for all classes. Table 3 indicates the impact of updating GS 1,500 to 4,999kW and Large Use classes using the 2013 interval data.

Table 1 - Cost Allocation Results as Filed

	Rate Base	Revenue Requirement	Revenue at Status Quo rates	Revenue to Cost
Residential	417,481,391	101,241,491	103,654,751	102.38%
GS <50	97,364,813	19,819,301	23,626,328	119.21%
GS 50 to 1,499 kW	278,153,818	45,860,732	40,275,676	87.82%
GS 1,500 to 4,999 kW	71,075,895	11,093,288	11,589,714	104.48%
Large Use	48,601,907	7,272,098	6,454,912	88.76%
Street Light	7,507,215	1,393,557	1,020,206	73.21%
Sentinel	33,191	9,263	5,137	55.45%
Unmetered Scattered Load	2,811,180	517,197	628,455	121.51%
Standby Power GS 1,500 to 4,999 kW	276,455	62,223	13,969	22.45%
Total	923,305,865	187,269,148	187,269,148	

Table 2 - Cost Allocation Results Using 2006 CAIF Load Profile for all Classes

	Rate Base	Revenue Requirement	Revenue at Status Quo rates	Revenue to Cost
Residential	417,701,355	101,301,915	103,657,467	102.33%
GS <50	97,385,872	19,832,441	23,627,120	119.13%
GS 50 to 1,499 kW	278,331,032	45,924,847	40,278,991	87.71%
GS 1,500 to 4,999 kW	71,230,774	11,082,121	11,587,739	104.56%
Large Use	48,018,375	7,143,020	6,449,957	90.30%
Street Light	7,517,615	1,395,990	1,020,304	73.09%
Sentinel	33,187	9,263	5,137	55.46%
Unmetered Scattered Load	2,810,019	517,086	628,456	121.54%
Standby Power GS 1,500 to 4,999 kW	277,635	62,467	13,978	22.38%
Total	923,305,865	187,269,148	187,269,148	

Table 3 - Impact of Updated Load Profiles for GS > 1,500 to 4,999 and Large Use

	Rate Base	Revenue Requirement	Revenue at Status Quo rates	Revenue to Cost
Residential	(219,964)	(60,424)	(2,716)	0.06%
GS <50	(21,059)	(13,140)	(792)	0.07%
GS 50 to 1,499 kW	(177,214)	(64,115)	(3,314)	0.12%
GS 1,500 to 4,999 kW	(154,879)	11,167	1,975	(0.09%)
Large Use	583,532	129,078	4,954	(1.53%)
Street Light	(10,400)	(2,433)	(98)	0.12%
Sentinel	5	1	0	0.00%
Unmetered Scattered Load	1,160	111	(1)	(0.03%)
Standby Power GS 1,500 to 4,999 kW	(1,180)	(245)	(9)	0.07%
Total	0	0	(0)	

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #47

Reference: Cost Allocation Models – Tab I5.2

Question #47

a. Please explain how the weighting factors for Services were established.

b. Please explain how the weighting factors for Billing & Collecting were established.

Response:

a. Hydro Ottawa Limited ("Hydro Ottawa") used the Services weighting factors from its 2012 Cost of Service application. In 2012 Hydro Ottawa assessed the weighting factor and determined that the default values were still relevant. As Hydro Ottawa's standards for services have not materially changed since the factors were first established, Hydro Ottawa's has not changed the service weighing factors.

b. Elenchus assisted Hydro Ottawa Limited in the preparation of this response.

Hydro Ottawa identified 22 billing and collecting related expense items. Each expense was allocated on the basis of customer count to the rate classes for which the expense was required to bill and collect.

A distinction was made for customers on e-billing and customers on paper billing. Costs for Canada Post and Bill Printing were allocated based on the count of customers receiving paper bills, while the costs of e-billing were allocated on the basis of the count of customers on e-billing.

The total costs allocated to each rate class were divided by the customer count to arrive at the weighting factor.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #48

Reference: E-H/T1/S1, pg. 3
E-H/T2/S1, pg. 1

Question #48

a. Please indicate what the Residential Service charge for 2016 would be if the Residential revenue requirement was to be recovered entirely through a fixed charge.

b. Please indicate what the 2016 Residential monthly service charge, would be assuming current fixed-variable split, was increased ¼ of the way to this value.

c. Please provide the resulting Residential bill impacts (i.e. the Residential tables in Appendix 2-W) if this service charge (per part (b)) was adopted and the variable charge decreased accordingly.

d. Based on the most recent 12 months of billing data please indicate how many Residential customers fall into each of the following average monthly use categories:
   - 0-100 kWh
   - >100-250 kWh
   - >250-500 kWh
   - >500-800 kWh
   - >800-1,000 kWh
   - >1,000-1,500 kWh
   - >1,500-2,000 kWh
   - >2,000 kWh

Response:

a. If the Originally submitted Residential revenue requirement for 2016 was recovered through a fully fixed charge the rate would be $26.85 a month.

b. If a quarter of the difference between a fully fixed rate of $26.85 and the current 2015 fixed rate of $9.67 was added to the current 2015 fixed rate, the monthly fixed charge would be $13.97.

c. Please refer to attachment Att-VECC-Q48-A for the 2016 bill impacts if the fixed rate in part b) was used and the variable rate adjusted accordingly.

d. Please see response to Energy Probe Interrogatory Question #48 part b.

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	100	$ 2.34	$ 0.0207	100	$ 2.07	-$ 0.27	-11.54%
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			$ 16.01	**$ 4.00**	**33.31%**
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**			**$ 17.09**	**$ 3.92**	**29.76%**
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**			**$ 18.32**	**$ 3.92**	**27.20%**
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**			**$ 30.07**	**$ 3.92**	**14.98%**
HST		13%		$ 3.40	13%		$ 3.91	$ 0.51	14.98%
Total Bill (including HST)				$ 29.55			$ 33.98	$ 4.43	14.98%
Ontario Clean Energy Benefit [1]				-$ 2.96			-$ 3.40	-$ 0.44	14.86%
Total Bill on TOU (including OCEB)				**$ 26.59**			**$ 30.58**	**$ 3.99**	**14.99%**
Total Bill on RPP (before Taxes)				**$ 25.34**			**$ 29.26**	**$ 3.92**	**15.46%**
HST		13%		$ 3.29	13%		$ 3.80	$ 0.51	15.46%
Total Bill (including HST)				$ 28.63			$ 33.06	$ 4.43	15.46%
Ontario Clean Energy Benefit [1]				-$ 2.86			-$ 3.31	-$ 0.45	15.73%
Total Bill on RPP (including OCEB)				**$ 25.77**			**$ 29.75**	**$ 3.98**	**15.43%**
Loss Factor (%)		3.5800%			3.3800%				

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)

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	250	$ 5.85	$ 0.0207	250	$ 5.18	-$ 0.68	-11.54%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	250	$ -	-$ 0.0003	250	-$ 0.08	-$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 15.52			$ 19.07	**$ 3.55**	**22.87%**
Deferral/Variance Account Disposition Rate Rider		$ -	250	$ -	-$ 0.0006	250	-$ 0.15	-$ 0.15	
			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%
Line Losses on Cost of Power		$ 0.1021	9	$ 0.91	$ 0.1021	8	$ 0.86	-$ 0.05	-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)				**$ 17.24**			**$ 20.59**	**$ 3.35**	**19.44%**
RTSR - Network	per kWh	$ 0.0077	259	$ 1.99	$ 0.0077	258	$ 1.99	-$ 0.00	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	259	$ 1.09	$ 0.0042	258	$ 1.09	-$ 0.00	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.32**			**$ 23.67**	**$ 3.35**	**16.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	259	$ 1.14	$ 0.0044	258	$ 1.14	-$ 0.00	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	259	$ 0.34	$ 0.0013	258	$ 0.34	-$ 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	250	$ 1.74	$ 0.0069	250	$ 1.74	$ -	0.00%
TOU - Off Peak		$ 0.0800	160	$ 12.80	$ 0.0800	160	$ 12.80	$ -	0.00%
TOU - Mid Peak		$ 0.1220	45	$ 5.49	$ 0.1220	45	$ 5.49	$ -	0.00%
TOU - On Peak		$ 0.1610	45	$ 7.25	$ 0.1610	45	$ 7.25	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	250	$ 23.50	$ 0.0940	250	$ 23.50	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 49.32**			**$ 52.66**	**$ 3.34**	**6.78%**
HST		13%		$ 6.41	13%		$ 6.85	$ 0.43	6.78%
Total Bill (including HST)				$ 55.73			$ 59.51	$ 3.78	6.78%
Ontario Clean Energy Benefit [1]				-$ 5.57			-$ 5.95	-$ 0.38	6.82%
Total Bill on TOU (including OCEB)				**$ 50.16**			**$ 53.56**	**$ 3.40**	**6.77%**
Total Bill on RPP (before Taxes)				**$ 47.28**			**$ 50.62**	**$ 3.34**	**7.07%**
HST		13%		$ 6.15	13%		$ 6.58	$ 0.43	7.07%
Total Bill (including HST)				$ 53.43			$ 57.21	$ 3.78	7.07%
Ontario Clean Energy Benefit [1]				-$ 5.34			-$ 5.72	-$ 0.38	7.12%
Total Bill on RPP (including OCEB)				**$ 48.09**			**$ 51.49**	**$ 3.40**	**7.06%**
Loss Factor (%)		3.5800%			3.3800%				

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	500	$ 11.70	$ 0.0207	500	$ 10.35	-$ 1.35	-11.54%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	500	$ -	-$ 0.0003	500	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 21.37			$ 24.17	**$ 2.80**	**13.10%**
Deferral/Variance Account Disposition Rate Rider		$ -	500	$ -	-$ 0.0006	500	-$ 0.30	-$ 0.30	
			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%
Line Losses on Cost of Power		$ 0.1021	18	$ 1.83	$ 0.1021	17	$ 1.73	-$ 0.10	-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)				**$ 24.02**			**$ 26.42**	**$ 2.40**	**10.00%**
RTSR - Network	per kWh	$ 0.0077	518	$ 3.99	$ 0.0077	517	$ 3.98	-$ 0.01	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	518	$ 2.18	$ 0.0042	517	$ 2.17	-$ 0.00	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 30.18**			**$ 32.57**	**$ 2.39**	**7.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	518	$ 2.28	$ 0.0044	517	$ 2.27	-$ 0.00	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	518	$ 0.67	$ 0.0013	517	$ 0.67	-$ 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	500	$ 3.47	$ 0.0069	500	$ 3.47	$ -	0.00%
TOU - Off Peak		$ 0.0800	320	$ 25.60	$ 0.0800	320	$ 25.60	$ -	0.00%
TOU - Mid Peak		$ 0.1220	90	$ 10.98	$ 0.1220	90	$ 10.98	$ -	0.00%
TOU - On Peak		$ 0.1610	90	$ 14.49	$ 0.1610	90	$ 14.49	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	500	$ 47.00	$ 0.0940	500	$ 47.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 87.92**			**$ 90.31**	**$ 2.39**	**2.71%**
HST		13%		$ 11.43	13%		$ 11.74	$ 0.31	2.71%
Total Bill (including HST)				$ 99.35			$ 102.05	$ 2.70	2.71%
Ontario Clean Energy Benefit [1]				-$ 9.94			-$ 10.21	-$ 0.27	2.72%
Total Bill on TOU (including OCEB)				**$ 89.41**			**$ 91.84**	**$ 2.43**	**2.71%**
Total Bill on RPP (before Taxes)				**$ 83.85**			**$ 86.24**	**$ 2.39**	**2.84%**
HST		13%		$ 10.90	13%		$ 11.21	$ 0.31	2.84%
Total Bill (including HST)				$ 94.76			$ 97.45	$ 2.70	2.84%
Ontario Clean Energy Benefit [1]				-$ 9.48			-$ 9.75	-$ 0.27	2.85%
Total Bill on RPP (including OCEB)				**$ 85.28**			**$ 87.70**	**$ 2.43**	**2.84%**

Loss Factor (%) 3.5800% 3.3800%

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	800	$ 18.72	$ 0.0207	800	$ 16.56	-$ 2.16	-11.54%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	800	$ -	-$ 0.0003	800	-$ 0.24	-$ 0.24	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 28.39			$ 30.29	**$ 1.90**	**6.69%**
Deferral/Variance Account Disposition Rate Rider		$ -	800	$ -	-$ 0.0006	800	-$ 0.48	-$ 0.48	
			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%
Line Losses on Cost of Power		$ 0.1021	29	$ 2.93	$ 0.1021	27	$ 2.76	-$ 0.16	-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)				**$ 32.16**			**$ 33.42**	**$ 1.26**	**3.93%**
RTSR - Network	per kWh	$ 0.0077	829	$ 6.38	$ 0.0077	827	$ 6.37	-$ 0.01	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	829	$ 3.48	$ 0.0042	827	$ 3.47	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.02**			**$ 43.26**	**$ 1.25**	**2.96%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	829	$ 3.65	$ 0.0044	827	$ 3.64	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	829	$ 1.08	$ 0.0013	827	$ 1.08	-$ 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	800	$ 5.55	$ 0.0069	800	$ 5.55	$ -	0.00%
TOU - Off Peak		$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
TOU - Mid Peak		$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%
TOU - On Peak		$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	200	$ 22.00	$ 0.1100	200	$ 22.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 134.25**			**$ 135.49**	**$ 1.24**	**0.92%**
HST		13%		$ 17.45	13%		$ 17.61	$ 0.16	0.92%
Total Bill (including HST)				$ 151.71			$ 153.10	$ 1.40	0.92%
Ontario Clean Energy Benefit [1]				-$ 15.17			-$ 15.31	-$ 0.14	0.92%
Total Bill on TOU (including OCEB)				**$ 136.54**			**$ 137.79**	**$ 1.26**	**0.92%**
Total Bill on RPP (before Taxes)				**$ 130.94**			**$ 132.18**	**$ 1.24**	**0.94%**
HST		13%		$ 17.02	13%		$ 17.18	$ 0.16	0.94%
Total Bill (including HST)				$ 147.96			$ 149.36	$ 1.40	0.94%
Ontario Clean Energy Benefit [1]				-$ 14.80			-$ 14.94	-$ 0.14	0.95%
Total Bill on RPP (including OCEB)				**$ 133.16**			**$ 134.42**	**$ 1.26**	**0.94%**

Loss Factor (%) 3.5800% 3.3800%

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	1000	$ 23.40	$ 0.0207	1000	$ 20.70	-$ 2.70	-11.54%
Smart Meter Disposition Rider			1000	$ -		1000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	1000	$ -	-$ 0.0003	1000	-$ 0.30	-$ 0.30	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 33.07			$ 34.37	**$ 1.30**	**3.93%**
Deferral/Variance Account Disposition Rate Rider		$ -	1000	$ -	-$ 0.0006	1000	-$ 0.60	-$ 0.60	
			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%
Line Losses on Cost of Power		$ 0.1021	36	$ 3.66	$ 0.1021	34	$ 3.45	-$ 0.20	-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)				**$ 37.58**			**$ 38.08**	**$ 0.51**	**1.35%**
RTSR - Network	per kWh	$ 0.0077	1036	$ 7.98	$ 0.0077	1034	$ 7.96	-$ 0.02	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	1036	$ 4.35	$ 0.0042	1034	$ 4.34	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.90**			**$ 50.39**	**$ 0.48**	**0.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1036	$ 4.56	$ 0.0044	1034	$ 4.55	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1036	$ 1.35	$ 0.0013	1034	$ 1.34	-$ 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	1000	$ 6.94	$ 0.0069	1000	$ 6.94	$ -	0.00%
TOU - Off Peak		$ 0.0800	640	$ 51.20	$ 0.0800	640	$ 51.20	$ -	0.00%
TOU - Mid Peak		$ 0.1220	180	$ 21.96	$ 0.1220	180	$ 21.96	$ -	0.00%
TOU - On Peak		$ 0.1610	180	$ 28.98	$ 0.1610	180	$ 28.98	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	400	$ 44.00	$ 0.1100	400	$ 44.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 165.14**			**$ 165.61**	**$ 0.47**	**0.29%**
HST		13%		$ 21.47	13%		$ 21.53	$ 0.06	0.29%
Total Bill (including HST)				$ 186.61			$ 187.14	$ 0.53	0.29%
Ontario Clean Energy Benefit [1]				-$ 18.66			-$ 18.71	-$ 0.05	0.27%
Total Bill on TOU (including OCEB)				**$ 167.95**			**$ 168.43**	**$ 0.48**	**0.29%**
Total Bill on RPP (before Taxes)				**$ 163.40**			**$ 163.87**	**$ 0.47**	**0.29%**
HST		13%		$ 21.24	13%		$ 21.30	$ 0.06	0.29%
Total Bill (including HST)				$ 184.64			$ 185.17	$ 0.53	0.29%
Ontario Clean Energy Benefit [1]				-$ 18.46			-$ 18.52	-$ 0.06	0.33%
Total Bill on RPP (including OCEB)				**$ 166.18**			**$ 166.65**	**$ 0.47**	**0.28%**

Loss Factor (%) 3.5800% 3.3800%

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)

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	1500	$ 35.10	$ 0.0207	1500	$ 31.05	-$ 4.05	-11.54%
Smart Meter Disposition Rider			1500	$ -		1500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	1500	$ -	-$ 0.0003	1500	-$ 0.45	-$ 0.45	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 44.77			$ 44.57	**-$ 0.20**	**-0.45%**
Deferral/Variance Account Disposition Rate Rider		$ -	1500	$ -	-$ 0.0006	1500	-$ 0.90	-$ 0.90	
			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%
Line Losses on Cost of Power		$ 0.1021	54	$ 5.48	$ 0.1021	51	$ 5.18	-$ 0.31	-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)				**$ 51.14**			**$ 49.75**	**-$ 1.39**	**-2.72%**
RTSR - Network	per kWh	$ 0.0077	1554	$ 11.96	$ 0.0077	1551	$ 11.94	-$ 0.02	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	1554	$ 6.53	$ 0.0042	1551	$ 6.51	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 69.63**			**$ 68.20**	**-$ 1.43**	**-2.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1554	$ 6.84	$ 0.0044	1551	$ 6.82	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1554	$ 2.02	$ 0.0013	1551	$ 2.02	-$ 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	1500	$ 10.41	$ 0.0069	1500	$ 10.41	$ -	0.00%
TOU - Off Peak		$ 0.0800	960	$ 76.80	$ 0.0800	960	$ 76.80	$ -	0.00%
TOU - Mid Peak		$ 0.1220	270	$ 32.94	$ 0.1220	270	$ 32.94	$ -	0.00%
TOU - On Peak		$ 0.1610	270	$ 43.47	$ 0.1610	270	$ 43.47	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	900	$ 99.00	$ 0.1100	900	$ 99.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 242.35**			**$ 240.91**	**-$ 1.44**	**-0.60%**
HST		13%		$ 31.51	13%		$ 31.32	-$ 0.19	-0.60%
Total Bill (including HST)				$ 273.86			$ 272.23	-$ 1.63	-0.60%
Ontario Clean Energy Benefit [1]				-$ 27.39			-$ 27.22	$ 0.17	-0.62%
Total Bill on TOU (including OCEB)				**$ 246.47**			**$ 245.01**	**-$ 1.46**	**-0.59%**
Total Bill on RPP (before Taxes)				**$ 244.54**			**$ 243.10**	**-$ 1.44**	**-0.59%**
HST		13%		$ 31.79	13%		$ 31.60	-$ 0.19	-0.59%
Total Bill (including HST)				$ 276.33			$ 274.70	-$ 1.63	-0.59%
Ontario Clean Energy Benefit [1]				-$ 27.63			-$ 27.47	$ 0.16	-0.58%
Total Bill on RPP (including OCEB)				**$ 248.70**			**$ 247.23**	**-$ 1.47**	**-0.59%**

Loss Factor (%) 3.5800% 3.3800%

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 3

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	2000	$ 46.80	$ 0.0207	2000	$ 41.40	-$ 5.40	-11.54%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0003	2000	-$ 0.60	-$ 0.60	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 56.47			$ 54.77	**-$ 1.70**	**-3.01%**
Deferral/Variance Account Disposition Rate Rider		$ -	2000	$ -	-$ 0.0006	2000	-$ 1.20	-$ 1.20	
			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%
Line Losses on Cost of Power		$ 0.1021	72	$ 7.31	$ 0.1021	68	$ 6.90	-$ 0.41	-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)				**$ 64.70**			**$ 61.41**	**-$ 3.29**	**-5.08%**
RTSR - Network	per kWh	$ 0.0077	2072	$ 15.95	$ 0.0077	2068	$ 15.92	-$ 0.03	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	2072	$ 8.70	$ 0.0042	2068	$ 8.68	-$ 0.02	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 89.35**			**$ 86.01**	**-$ 3.34**	**-3.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2072	$ 9.12	$ 0.0044	2068	$ 9.10	-$ 0.02	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2072	$ 2.69	$ 0.0013	2068	$ 2.69	-$ 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	2000	$ 13.88	$ 0.0069	2000	$ 13.88	$ -	0.00%
TOU - Off Peak		$ 0.0800	1280	$ 102.40	$ 0.0800	1280	$ 102.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak		$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	1400	$ 154.00	$ 0.1100	1400	$ 154.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 319.57**			**$ 316.21**	**-$ 3.36**	**-1.05%**
HST		13%		$ 41.54	13%		$ 41.11	-$ 0.44	-1.05%
Total Bill (including HST)				$ 361.11			$ 357.32	-$ 3.80	-1.05%
Ontario Clean Energy Benefit [1]				-$ 36.11			-$ 35.73	$ 0.38	-1.05%
Total Bill on TOU (including OCEB)				**$ 325.00**			**$ 321.59**	**-$ 3.42**	**-1.05%**
Total Bill on RPP (before Taxes)				**$ 325.69**			**$ 322.33**	**-$ 3.36**	**-1.03%**
HST		13%		$ 42.34	13%		$ 41.90	-$ 0.44	-1.03%
Total Bill (including HST)				$ 368.03			$ 364.23	-$ 3.80	-1.03%
Ontario Clean Energy Benefit [1]				-$ 36.80			-$ 36.42	$ 0.38	-1.03%
Total Bill on RPP (including OCEB)				**$ 331.23**			**$ 327.81**	**-$ 3.42**	**-1.03%**
Loss Factor (%)		3.5800%			3.3800%				

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	100	$ 2.34	$ 0.0207	100	$ 2.07	-$ 0.27	-11.54%
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			$ 16.01	**$ 4.00**	**33.31%**
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**			**$ 17.09**	**$ 3.92**	**29.76%**
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**			**$ 18.32**	**$ 3.92**	**27.20%**
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**			**$ 30.07**	**$ 3.92**	**14.98%**
HST		13%		$ 3.40	13%		$ 3.91	$ 0.51	14.98%
Total Bill (including HST)				$ 29.55			$ 33.98	$ 4.43	14.98%
Ontario Clean Energy Benefit [1]				-$ 2.96			-$ 3.40	-$ 0.44	14.86%
Total Bill on TOU (including OCEB)				**$ 26.59**			**$ 30.58**	**$ 3.99**	**14.99%**
Total Bill on RPP (before Taxes)				**$ 25.34**			**$ 29.26**	**$ 3.92**	**15.46%**
HST		13%		$ 3.29	13%		$ 3.80	$ 0.51	15.46%
Total Bill (including HST)				$ 28.63			$ 33.06	$ 4.43	15.46%
Ontario Clean Energy Benefit [1]				-$ 2.86			-$ 3.31	-$ 0.45	15.73%
Total Bill on RPP (including OCEB)				**$ 25.77**			**$ 29.75**	**$ 3.98**	**15.43%**
Loss Factor (%)		3.5800%			3.3800%				

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)

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	250	$ 5.85	$ 0.0207	250	$ 5.18	-$ 0.68	-11.54%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	250	$ -	-$ 0.0003	250	-$ 0.08	-$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 15.52			$ 19.07	**$ 3.55**	**22.87%**
Deferral/Variance Account Disposition Rate Rider		$ -	250	$ -	-$ 0.0006	250	-$ 0.15	-$ 0.15	
			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%
Line Losses on Cost of Power		$ 0.1021	9	$ 0.91	$ 0.1021	8	$ 0.86	-$ 0.05	-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)				**$ 17.24**			**$ 20.59**	**$ 3.35**	**19.44%**
RTSR - Network	per kWh	$ 0.0077	259	$ 1.99	$ 0.0077	258	$ 1.99	-$ 0.00	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	259	$ 1.09	$ 0.0042	258	$ 1.09	-$ 0.00	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.32**			**$ 23.67**	**$ 3.35**	**16.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	259	$ 1.14	$ 0.0044	258	$ 1.14	-$ 0.00	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	259	$ 0.34	$ 0.0013	258	$ 0.34	-$ 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	250	$ 1.74	$ 0.0069	250	$ 1.74	$ -	0.00%
TOU - Off Peak		$ 0.0800	160	$ 12.80	$ 0.0800	160	$ 12.80	$ -	0.00%
TOU - Mid Peak		$ 0.1220	45	$ 5.49	$ 0.1220	45	$ 5.49	$ -	0.00%
TOU - On Peak		$ 0.1610	45	$ 7.25	$ 0.1610	45	$ 7.25	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	250	$ 23.50	$ 0.0940	250	$ 23.50	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 49.32**			**$ 52.66**	**$ 3.34**	**6.78%**
HST		13%		$ 6.41	13%		$ 6.85	$ 0.43	6.78%
Total Bill (including HST)				$ 55.73			$ 59.51	$ 3.78	6.78%
Ontario Clean Energy Benefit [1]				-$ 5.57			-$ 5.95	-$ 0.38	6.82%
Total Bill on TOU (including OCEB)				**$ 50.16**			**$ 53.56**	**$ 3.40**	**6.77%**
Total Bill on RPP (before Taxes)				**$ 47.28**			**$ 50.62**	**$ 3.34**	**7.07%**
HST		13%		$ 6.15	13%		$ 6.58	$ 0.43	7.07%
Total Bill (including HST)				$ 53.43			$ 57.21	$ 3.78	7.07%
Ontario Clean Energy Benefit [1]				-$ 5.34			-$ 5.72	-$ 0.38	7.12%
Total Bill on RPP (including OCEB)				**$ 48.09**			**$ 51.49**	**$ 3.40**	**7.06%**
Loss Factor (%)		3.5800%			3.3800%				

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	500	$ 11.70	$ 0.0207	500	$ 10.35	-$ 1.35	-11.54%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	500	$ -	-$ 0.0003	500	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 21.37			$ 24.17	**$ 2.80**	**13.10%**
Deferral/Variance Account Disposition Rate Rider		$ -	500	$ -	-$ 0.0006	500	-$ 0.30	-$ 0.30	
			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%
Line Losses on Cost of Power		$ 0.1021	18	$ 1.83	$ 0.1021	17	$ 1.73	-$ 0.10	-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)				**$ 24.02**			**$ 26.42**	**$ 2.40**	**10.00%**
RTSR - Network	per kWh	$ 0.0077	518	$ 3.99	$ 0.0077	517	$ 3.98	-$ 0.01	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	518	$ 2.18	$ 0.0042	517	$ 2.17	-$ 0.00	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 30.18**			**$ 32.57**	**$ 2.39**	**7.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	518	$ 2.28	$ 0.0044	517	$ 2.27	-$ 0.00	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	518	$ 0.67	$ 0.0013	517	$ 0.67	-$ 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	500	$ 3.47	$ 0.0069	500	$ 3.47	$ -	0.00%
TOU - Off Peak		$ 0.0800	320	$ 25.60	$ 0.0800	320	$ 25.60	$ -	0.00%
TOU - Mid Peak		$ 0.1220	90	$ 10.98	$ 0.1220	90	$ 10.98	$ -	0.00%
TOU - On Peak		$ 0.1610	90	$ 14.49	$ 0.1610	90	$ 14.49	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	500	$ 47.00	$ 0.0940	500	$ 47.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	0	$ -	$ 0.1100	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 87.92**			**$ 90.31**	**$ 2.39**	**2.71%**
HST		13%		$ 11.43	13%		$ 11.74	$ 0.31	2.71%
Total Bill (including HST)				$ 99.35			$ 102.05	$ 2.70	2.71%
Ontario Clean Energy Benefit [1]				-$ 9.94			-$ 10.21	-$ 0.27	2.72%
Total Bill on TOU (including OCEB)				**$ 89.41**			**$ 91.84**	**$ 2.43**	**2.71%**
Total Bill on RPP (before Taxes)				**$ 83.85**			**$ 86.24**	**$ 2.39**	**2.84%**
HST		13%		$ 10.90	13%		$ 11.21	$ 0.31	2.84%
Total Bill (including HST)				$ 94.76			$ 97.45	$ 2.70	2.84%
Ontario Clean Energy Benefit [1]				-$ 9.48			-$ 9.75	-$ 0.27	2.85%
Total Bill on RPP (including OCEB)				**$ 85.28**			**$ 87.70**	**$ 2.43**	**2.84%**

Loss Factor (%) 3.5800% 3.3800%

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	800	$ 18.72	$ 0.0207	800	$ 16.56	-$ 2.16	-11.54%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	800	$ -	-$ 0.0003	800	-$ 0.24	-$ 0.24	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 28.39			$ 30.29	**$ 1.90**	**6.69%**
Deferral/Variance Account Disposition Rate Rider		$ -	800	$ -	-$ 0.0006	800	-$ 0.48	-$ 0.48	
			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%
Line Losses on Cost of Power		$ 0.1021	29	$ 2.93	$ 0.1021	27	$ 2.76	-$ 0.16	-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)				**$ 32.16**			**$ 33.42**	**$ 1.26**	**3.93%**
RTSR - Network	per kWh	$ 0.0077	829	$ 6.38	$ 0.0077	827	$ 6.37	-$ 0.01	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	829	$ 3.48	$ 0.0042	827	$ 3.47	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.02**			**$ 43.26**	**$ 1.25**	**2.96%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	829	$ 3.65	$ 0.0044	827	$ 3.64	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	829	$ 1.08	$ 0.0013	827	$ 1.08	-$ 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	800	$ 5.55	$ 0.0069	800	$ 5.55	$ -	0.00%
TOU - Off Peak		$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
TOU - Mid Peak		$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%
TOU - On Peak		$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	200	$ 22.00	$ 0.1100	200	$ 22.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 134.25**			**$ 135.49**	**$ 1.24**	**0.92%**
HST		13%		$ 17.45	13%		$ 17.61	$ 0.16	0.92%
Total Bill (including HST)				$ 151.71			$ 153.10	$ 1.40	0.92%
Ontario Clean Energy Benefit [1]				-$ 15.17			-$ 15.31	-$ 0.14	0.92%
Total Bill on TOU (including OCEB)				**$ 136.54**			**$ 137.79**	**$ 1.26**	**0.92%**
Total Bill on RPP (before Taxes)				**$ 130.94**			**$ 132.18**	**$ 1.24**	**0.94%**
HST		13%		$ 17.02	13%		$ 17.18	$ 0.16	0.94%
Total Bill (including HST)				$ 147.96			$ 149.36	$ 1.40	0.94%
Ontario Clean Energy Benefit [1]				-$ 14.80			-$ 14.94	-$ 0.14	0.95%
Total Bill on RPP (including OCEB)				**$ 133.16**			**$ 134.42**	**$ 1.26**	**0.94%**

Loss Factor (%) 3.5800% 3.3800%

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 3

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	2016 Proposed Rate ($)	Volume	Charge ($)	Impact 2016 vs 2015 $ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	1000	$ 23.40	$ 0.0207	1000	$ 20.70	-$ 2.70	-11.54%
Smart Meter Disposition Rider			1000	$ -		1000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	1000	$ -	-$ 0.0003	1000	-$ 0.30	-$ 0.30	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 33.07			$ 34.37	**$ 1.30**	**3.93%**
Deferral/Variance Account Disposition Rate Rider		$ -	1000	$ -	-$ 0.0006	1000	-$ 0.60	-$ 0.60	
			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%
Line Losses on Cost of Power		$ 0.1021	36	$ 3.66	$ 0.1021	34	$ 3.45	-$ 0.20	-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)				**$ 37.58**			**$ 38.08**	**$ 0.51**	**1.35%**
RTSR - Network	per kWh	$ 0.0077	1036	$ 7.98	$ 0.0077	1034	$ 7.96	-$ 0.02	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	1036	$ 4.35	$ 0.0042	1034	$ 4.34	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.90**			**$ 50.39**	**$ 0.48**	**0.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1036	$ 4.56	$ 0.0044	1034	$ 4.55	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1036	$ 1.35	$ 0.0013	1034	$ 1.34	-$ 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	1000	$ 6.94	$ 0.0069	1000	$ 6.94	$ -	0.00%
TOU - Off Peak		$ 0.0800	640	$ 51.20	$ 0.0800	640	$ 51.20	$ -	0.00%
TOU - Mid Peak		$ 0.1220	180	$ 21.96	$ 0.1220	180	$ 21.96	$ -	0.00%
TOU - On Peak		$ 0.1610	180	$ 28.98	$ 0.1610	180	$ 28.98	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	400	$ 44.00	$ 0.1100	400	$ 44.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 165.14**			**$ 165.61**	**$ 0.47**	**0.29%**
HST		13%		$ 21.47	13%		$ 21.53	$ 0.06	0.29%
Total Bill (including HST)				$ 186.61			$ 187.14	$ 0.53	0.29%
Ontario Clean Energy Benefit [1]				-$ 18.66			-$ 18.71	-$ 0.05	0.27%
Total Bill on TOU (including OCEB)				**$ 167.95**			**$ 168.43**	**$ 0.48**	**0.29%**
Total Bill on RPP (before Taxes)				**$ 163.40**			**$ 163.87**	**$ 0.47**	**0.29%**
HST		13%		$ 21.24	13%		$ 21.30	$ 0.06	0.29%
Total Bill (including HST)				$ 184.64			$ 185.17	$ 0.53	0.29%
Ontario Clean Energy Benefit [1]				-$ 18.46			-$ 18.52	-$ 0.06	0.33%
Total Bill on RPP (including OCEB)				**$ 166.18**			**$ 166.65**	**$ 0.47**	**0.28%**

Loss Factor (%) 3.5800% 3.3800%

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)

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	1500	$ 35.10	$ 0.0207	1500	$ 31.05	-$ 4.05	-11.54%
Smart Meter Disposition Rider			1500	$ -		1500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	1500	$ -	-$ 0.0003	1500	-$ 0.45	-$ 0.45	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 44.77			$ 44.57	**-$ 0.20**	**-0.45%**
Deferral/Variance Account Disposition Rate Rider		$ -	1500	$ -	-$ 0.0006	1500	-$ 0.90	-$ 0.90	
			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%
Line Losses on Cost of Power		$ 0.1021	54	$ 5.48	$ 0.1021	51	$ 5.18	-$ 0.31	-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)				**$ 51.14**			**$ 49.75**	**-$ 1.39**	**-2.72%**
RTSR - Network	per kWh	$ 0.0077	1554	$ 11.96	$ 0.0077	1551	$ 11.94	-$ 0.02	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	1554	$ 6.53	$ 0.0042	1551	$ 6.51	-$ 0.01	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 69.63**			**$ 68.20**	**-$ 1.43**	**-2.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1554	$ 6.84	$ 0.0044	1551	$ 6.82	-$ 0.01	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1554	$ 2.02	$ 0.0013	1551	$ 2.02	-$ 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	1500	$ 10.41	$ 0.0069	1500	$ 10.41	$ -	0.00%
TOU - Off Peak		$ 0.0800	960	$ 76.80	$ 0.0800	960	$ 76.80	$ -	0.00%
TOU - Mid Peak		$ 0.1220	270	$ 32.94	$ 0.1220	270	$ 32.94	$ -	0.00%
TOU - On Peak		$ 0.1610	270	$ 43.47	$ 0.1610	270	$ 43.47	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	900	$ 99.00	$ 0.1100	900	$ 99.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 242.35**			**$ 240.91**	**-$ 1.44**	**-0.60%**
HST		13%		$ 31.51	13%		$ 31.32	-$ 0.19	-0.60%
Total Bill (including HST)				$ 273.86			$ 272.23	-$ 1.63	-0.60%
Ontario Clean Energy Benefit [1]				-$ 27.39			-$ 27.22	$ 0.17	-0.62%
Total Bill on TOU (including OCEB)				**$ 246.47**			**$ 245.01**	**-$ 1.46**	**-0.59%**
Total Bill on RPP (before Taxes)				**$ 244.54**			**$ 243.10**	**-$ 1.44**	**-0.59%**
HST		13%		$ 31.79	13%		$ 31.60	-$ 0.19	-0.59%
Total Bill (including HST)				$ 276.33			$ 274.70	-$ 1.63	-0.59%
Ontario Clean Energy Benefit [1]				-$ 27.63			-$ 27.47	$ 0.16	-0.58%
Total Bill on RPP (including OCEB)				**$ 248.70**			**$ 247.23**	**-$ 1.47**	**-0.59%**

Loss Factor (%) 3.5800% 3.3800%

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 3

		Current Board-Approved			2016 Proposed			Impact 2016 vs 2015	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 9.6700	1	$ 9.67	$ 13.9700	1	$ 13.97	$ 4.30	44.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0234	2000	$ 46.80	$ 0.0207	2000	$ 41.40	-$ 5.40	-11.54%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0003	2000	-$ 0.60	-$ 0.60	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 56.47			$ 54.77	**-$ 1.70**	**-3.01%**
Deferral/Variance Account Disposition Rate Rider		$ -	2000	$ -	-$ 0.0006	2000	-$ 1.20	-$ 1.20	
			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%
Line Losses on Cost of Power		$ 0.1021	72	$ 7.31	$ 0.1021	68	$ 6.90	-$ 0.41	-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)				**$ 64.70**			**$ 61.41**	**-$ 3.29**	**-5.08%**
RTSR - Network	per kWh	$ 0.0077	2072	$ 15.95	$ 0.0077	2068	$ 15.92	-$ 0.03	-0.19%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	2072	$ 8.70	$ 0.0042	2068	$ 8.68	-$ 0.02	-0.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 89.35**			**$ 86.01**	**-$ 3.34**	**-3.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2072	$ 9.12	$ 0.0044	2068	$ 9.10	-$ 0.02	-0.19%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2072	$ 2.69	$ 0.0013	2068	$ 2.69	-$ 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	2000	$ 13.88	$ 0.0069	2000	$ 13.88	$ -	0.00%
TOU - Off Peak		$ 0.0800	1280	$ 102.40	$ 0.0800	1280	$ 102.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak		$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0940	600	$ 56.40	$ 0.0940	600	$ 56.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.1100	1400	$ 154.00	$ 0.1100	1400	$ 154.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 319.57**			**$ 316.21**	**-$ 3.36**	**-1.05%**
HST		13%		$ 41.54	13%		$ 41.11	-$ 0.44	-1.05%
Total Bill (including HST)				$ 361.11			$ 357.32	-$ 3.80	-1.05%
Ontario Clean Energy Benefit [1]				-$ 36.11			-$ 35.73	$ 0.38	-1.05%
Total Bill on TOU (including OCEB)				**$ 325.00**			**$ 321.59**	**-$ 3.42**	**-1.05%**
Total Bill on RPP (before Taxes)				**$ 325.69**			**$ 322.33**	**-$ 3.36**	**-1.03%**
HST		13%		$ 42.34	13%		$ 41.90	-$ 0.44	-1.03%
Total Bill (including HST)				$ 368.03			$ 364.23	-$ 3.80	-1.03%
Ontario Clean Energy Benefit [1]				-$ 36.80			-$ 36.42	$ 0.38	-1.03%
Total Bill on RPP (including OCEB)				**$ 331.23**			**$ 327.81**	**-$ 3.42**	**-1.03%**
Loss Factor (%)		3.5800%			3.3800%				

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #49

Reference: E-H/T4/S1, pg. 1

Question #49:

a. Please confirm that Ottawa has informed Retailers of the proposed change in Retail Service Charges.

Response:

As indicated in Hydro Ottawa's Affidavit of Service dated June 5, 2015, Retailers were informed of the proposed changes in Retail Service Charges.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #50

Reference: E-H/T7/S1, pg. 2 and Tables 1 & 2

Question #50:

a. Please describe the formulaic inflation adjustment that will be used for the years 2017-2020.

b. With the exception of the Disconnect/Reconnect and Service Call charges, all of the revised and new service charges set out in Tables 1 and 2 escalate over the 2016-2020 period. In all cases, is this escalation the result of the application of the formulaic inflation adjustment described in part (a)? If not, please explain the basis for the annual changes.

Response:

a. The inflation adjustment that was applied to the years 2017 through 2020 was the same rate applied to OM&A, or 2.1 percent.

b. With the exception of depreciation and capital carrying cost, the cost drivers were inflated according to the Conference Board of Canada inflation rates from the year the respective rate was set, in order to determine the 2016 rate.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #51

Reference E-H/T7/S1, pg. 3-5

Question #51

a. Over the past couple of years what has been the average time required to respond to an individual "special billing service request"?

b. What types of billing related information will Ottawa provide its customers without charging (I.e. what constitutes a non-special billing request)?

c. With respect to the proposed revised Temporary Service charges, please explain why in all three cases the proposed rate exceeds the calculated cost.

Response:

a. Hydro Ottawa has not historically tracked the actual time for each special billing request. These requests are not typically from residential customers. Rather, they are being received from commercial accounts and energy services companies on behalf of commercial accounts. Request response times have ranged from approximately one to several hours. In most cases, requests engage resources from Meter Data Services, Billing and Customer Service departments to gather information, produce and issue the requested information. In some instances, customized reports need to be created, which can add to the timeframe and associated costs. The volume of these requests is increasing and Hydro Ottawa is focusing attention on efficiently and effectively responding to these increasing demands for information.

b. Hydro Ottawa provides billing information free of charge to residential and small commercial customers through a web portal access to MyHydroLink (MHL) on Hydro Ottawa's website, enabling customers to view and export financial and kWh data. Other inquiries that are requested, such as historical interval data, load summaries, aggregated load from bulk metered customers, billable load history for sizing of service upgrades, etc. are chargeable requests.

c. The calculated costs are based upon year end 2013 actuals. Hydro Ottawa has applied the forecasted inflation rate from the Conference Board of Canada to establish the proposed 2016 Temporary Services rates.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #52

Reference E-H/T7/S1, pg.5 (Section 3.3) and Attachment 7(A)

Question #52

a. Please confirm that in developing the specific charge for access to power poles Ottawa has followed the Board's methodology as approved in RP-2003-0249.

b. With respect to Admin costs, please indicate what each of the three activities identified in the worksheet are for and the how the level of work activity was determined.

c. Also, with respect to Admin-Permits, please indicate how the $123,906 cost was determined – as there are no activity "units" shown.

d. With respect to Loss In Productivity, please indicate what each of the three activities are for and how the level of work activity was determined in each case.

e. What do the rates used (i.e. the $95, $5.80, $44 and $33) include. Is it just direct labour and vehicle costs or are there any overheads also included?

f. Please explain how each of the four line items under Indirect costs were determined.

g. What was the basis for the assumption there are 2 third party attachers?

h. Please show the derivation of the 25.9% allocation factor.

i. Given the calculation based on 2013 costs, what inflationary adjustment should be applied to derive 2016 costs?

j. Have the 3rd party pole attachers been advised of Ottawa's proposal to increase their rates?

Response:

a. Hydro Ottawa Limited has followed the Board's methodology as approved in RP-2003-0249 in developing the updated specific charge for access to power poles with the exception to direct costs, per attacher. Please see Interrogatory Response to Allstream Question #1 parts a. and b.

b. Please see Interrogatory Response to Carriers Question #12.

c. Please see Interrogatory Response to Carriers Question #12.

d. Please see Interrogatory Response to Carriers Question #13.

e. The $95 represents the labour rate. Please see Interrogatory Response to OEB Staff Question #21, part ii for additional details, including the components above the direct labour costs included in the rate.

- The $5.80, $33.00 and $ 44.00 rates pertain to Hydro Ottawa's vehicle costs. The rates vary depending on the type of vehicle used:
- $ 5.80 per hour represents a small vehicle (i.e. car)
- $ 33.00 per hour represents a medium RBD truck
- $ 44.00 per hour represents a medium bucket truck
- These hourly fleet rates are based on total maintenance and operating costs, per vehicle type, plus an allocation of the Fleet departments' overhead.

f. Please see Interrogatory Response to OEB Staff Question #21 – Access to Power Poles, part ix.

g. Please see Interrogatory Response to OEB Staff Question 21 – Access to Power Poles, part vii.

h. Please see Interrogatory Response to Carriers Question #4.

i. The calculated costs are based upon year end 2013 actuals. An inflationary adjustment of 2.1 percent, per year should be applied to derive 2016 costs. The forecasted inflation rate of 2.1 percent is from the Conference Board of Canada and is consistent with this rate application.

j. Yes. On June 5, 2015 HOL submitted an affidavit to the OEB that notice of a proposed increase was sent to all customers directly affected, along with courier tracking details.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #53

Reference: **E-H/T7/S1, pg. 6 – Section 4.0**

Question #53:

a. The first paragraph in section 4.0 suggests that the proposed revised retail service charges are based on a "detailed review and analysis of costs". However, the second paragraph suggests the proposed rates were determined by applying the 2013-2015 IRM rate increases and the percentage increase in revenue requirement for the years thereafter. Please clarify how the new charges for 2016 were determined.

b. Please provide any analysis undertaken regarding the costs of providing Retailer services.

Response:

Please see response to OEB Staff Interrogatory Question # 21 parts xiii. and xiv.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #54

Reference: E-H/T7/S1, pg. 6 – Section 5.1

Question #54

a. What activities are included in the cost determination (e.g. meter reading, meter maintenance, etc.)?

b. Does the costing include any allowance to recover overheads such as Administration costs and/or General Plant costs?

Response:

a. The cost includes meter data reading, meter maintenance, bill production, customer support, general plant and general administration costs.

b. Yes, per above.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #55

Reference E-H/T7/S1, pg. 7 (Section 6.1)

Question #55

a. In the case of the Disconnect/Reconnect at Meter – New Account, who does Ottawa Hydro propose to recover the charge from if the "financially responsible account holder" is unknown?

Response:

a. The service charge would be recovered from the "unknown account holder" once they contact Hydro Ottawa to confirm responsibility of the account and have the service reconnected. The service charge would be clearly stated on the disconnect notice left at the premise to encourage customers to contact Hydro Ottawa and confirm that they are responsible for the electricity consumption. This procedure also encourages landlords to assume financial responsibility of accounts when their tenants vacate their rental units.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #56

Reference E-H/T7/S1, pg. 8 (Section 6.4)

Question #56

a. Given that Ottawa is proposing to "charge" customers for missed appointments, is Ottawa willing to compensate (i.e. pay customers) in the event that its crews fail to attend at an arranged appointment time? If not, why not?

b. How much advance notice is required from the customer in order avoid the missed appointment charge?

Response:

a. Since the year 2012, Hydro Ottawa has succeeded in completing 99.49% of all arranged appointments. It is a rare event when Hydro Ottawa fails to attend an arranged appointment, and in these cases it would be due to an extenuating circumstance. Any issues that arise from a missed appointment would be dealt with on an individual case basis.

b. A minimum of one hour advanced notice from the customer, from the arranged appointment time, would be considered adequate to avoid the missed appointment charge.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #57

Reference :E-H/T10/S1, Current 2015 Rates, pg. 7 and Proposed 2016 Rates, pg. 7

Question #57

a. Please explain why the current Standby Rates have charges for GS 50-1499; GS 1500-4999 and Large Use customers whereas the 2016 proposed rates only has Standby Rates for GS 1500-4999 customers.

Response:

a. Hydro Ottawa Limited intends to continue Standby rates for all the current classes that have standby rates. Please see response to Ontario Energy Board Staff question #1 for revised rates.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #58

Reference: E-I/T4/S1

Question #58

The Board's policy with respect to account 1508 states:

> *A. A distributor shall use this account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates.*
> *B. The costs authorized for recording in this account shall be incremental one-time administrative costs caused by the transition of accounting policies, procedures, systems and processes to IFRS. The incremental costs eligible for inclusion in this account may include professional accounting and legal fees, salaries, wages and benefits of staff added to support the transition to IFRS and associated staff training and development costs.*
>
> Ontario Energy Board Issued: December 2011 Accounting Procedures Handbook (pg.17).

a) HOL is seeking to dispose of $982,326 and $5,869 in internal staff costs. Please explain why this proposal is not in contravention of the Board's policy. Specifically please what staff costs are being sought for recovery.

Response:

a. The costs Hydro Ottawa Limited ("Hydro Ottawa") is seeking to dispose of are related to salaries, wages and benefits of staff required to support the transition to

IFRS - $982,326 and associated staff training and development costs - $5,869. Please refer to Appendix 2-U Updated June 29, 2015 which states these costs are for internal project lead and temporary staff – associated with the transition to IFRS. As per the reference in this question '*the incremental costs eligible for inclusion in this account may include … salaries, wages and benefits of staff added to support the transition to IFRS and associated staff training and development costs'.* Hydro Ottawa confirms these incremental costs are in alignment with the Board's policy.

Response to Vulnerable Energy Consumers Coalition Interrogatory Question #59

Reference: E-I/T8/S1

Question #59:

a. Please provide the order showing Board approval for account 1535. Please explain what is booked into this account and why HOL is seeking continuation of the account.

Response:

a. As per the details on the Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions – October 2009 – copied below, the Board approved deferral accounts under the Green Energy and Green Economy Act for Account 1535, Smart Grid OM&A Deferral Account, under this guidance Hydro Ottawa did not request an order specifically to approve the account 1535. Expenses from 2010 and 2011 and related carrying charges associated with Smart Grid OM&A qualified projects are booked in account 1535. Hydro Ottawa Limited ("Hydro Ottawa") is seeking continuance of this account to use in the event of further related expenses.

Excerpt from Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions – October 2009

New approved deferral and variance accounts arising from the requirements of Green Energy and Green Economy Act:

Q.7 Has the Board approved deferral accounts for distributors spending in relation to distribution system planning under Green Energy and Green Economy Act?

A.7 On June 16, 2009, the Board issued Guidelines: Deemed Conditions of Licence: Distribution System Planning (G-2009-0087). As part of these guidelines, the Board has established four new deferral accounts in the Uniform System of Accounts that electricity distributors may use to begin recording capital investments and expenses incurred in relation to qualifying projects undertaken to accommodate renewable generation or towards the development a smart grid. The four approved accounts are as follows:

- Account 1531, Renewable Connection Capital Deferral Account
- Account 1532, Renewable Connection OM&A Deferral Account
- Account 1534, Smart Grid Capital Deferral Account
- Account 1535, Smart Grid OM&A Deferral Account