OAKVILLE HYDRO
ELECTRICITY
DISTRIBUTION

February 20, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms. Walli

**RE: Oakville Hydro, 2014 Electricity Distribution Rate Application
Responses to Interrogatories, Board File No.: EB-2013-0159**

Oakville Hydro is pleased to provide the enclosed interrogatories received in the above noted proceeding.

Yours truly,

Jim Collins
Chief Financial Officer

P.O. Box 1900 • 861 Redwood Square • Oakville, ON • L6K 0C7
Tel: 905-825-9400 • Fax: 905-825-4447 • Email: hydro@oakvillehydro.com • www.oakvillehydro.com

Oakville Hydro Electricity Distribution Inc.

2014 Electricity Distribution Rate Application

Interrogatory Responses

EB-2013-0159

In Submission to:

The Ontario Energy Board

February 20, 2014

1-Foundation

Issue 1.1 *Does the planning (regional, infrastructure investment, asset management etc.) undertaken by the applicant and outlined in the application support the appropriate management of the applicant's assets*?

1.1- Staff-1

Ref: Exhibit 2/Appendix A-Distribution System Plan/p. 11

Distribution System Plan

The reference states that Hydro One expects that the Regional Planning Process to develop a Regional Infrastructure Plan will be initiated in the fourth quarter of 2013 and that Oakville Hydro is unable to assess whether the regional planning consultation will affect its DS Plan. The reference also states that Oakville Hydro recently entered into a 10-year connection agreement with Milton Hydro to provide two feeder positions at Glenorchy Municipal Transformer Station located in Milton to serve a portion of Milton Hydro's service area.

a) Please provide an update on the status of the Regional Infrastructure Plan including the expected completion date.

RESPONSE:

Oakville Hydro is a member of two regional planning groups:

- Burlington to Nanticoke Planning region
- GTA West Planning Region

As noted in Oakville Hydro's Distribution System Plan ("DS Plan") on page 37, Hydro One informed Oakville Hydro in a letter dated September 5, 2013 that regional Planning Process had not been initiated and a Regional Infrastructure Plan had not been developed. Since that time, the Regional Planning Process has progressed and the process for the two regional planning groups of which Oakville Hydro is a member, was initiated in November 2013.

Currently Hydro One is leading a Needs Screening ("NS") Process for each identified region. Oakville Hydro has been asked to participate in the NS Process for the two planning regions identified above and Oakville Hydro has attended a number of meetings.

The NS Plan is the first step in the Regional Planning process and includes the collection of planning information from LDCs, the OPA and the IESO to enable Hydro One to conduct a needs screening for each region to establish if coordinated regional planning is required and to identify any localized solutions (connections) in the near-term.

At this time, all LDCs within each planning region have been asked to provide historical load data and forecasted load data for ten years, by February 6th 2014. Within 60 days, or by April 16th 2014, Hydro One will complete and publish a NS Report. Oakville Hydro submitted its historical and forecasted load to Hydro One on February 6, 2014.

Hydro One has not provided a Regional Infrastructure Plan to date, however, the NS Process that has been initiated to determine if coordinated regional planning is required.

b) Please comment on the potential impact that the Regional Infrastructure Plan may have on Oakville Hydro's DS Plan, focussing on portions of the DS plan where infrastructure needs may be impacted by the Regional Infrastructure Plan.

RESPONSE:

At this time, Oakville Hydro is not aware of and does not anticipate that the Regional Infrastructure Plan will have an impact on Oakville Hydro's DS Plan.

c) Please describe if/how regional issues and requirements were considered in Oakville Hydro's DS Plan.

RESPONSE:

Apart from the 10-year connection agreement with Milton Hydro to provide two feeder positions at Glenorchy Municipal Transformer Station, the DS Plan did not consider regional issues or requirements. There was insufficient information available on regional planning at the time the DS Plan was completed. As more information becomes available, Oakville Hydro will update its DS Plan accordingly. As stated earlier, Oakville Hydro does not anticipate that Regional Planning will have a significant impact on Oakville Hydro's DS plan; however, it is believed that there is sufficient flexibility and adaptability in the plan to make any necessary adjustments

d) Please explain if/how Oakville Hydro considers impact of regional issues on:

- reliability of supply; and
- Distribution rates.

RESPONSE:

At this time, Oakville Hydro does not anticipate that regional issues will have an impact on the short to medium reliability of supply or distribution rates. During the Regional Infrastructure Planning needs assessment phase various issues and drivers will be brought forward for discussion and consideration. Oakville Hydro will be assessing these proposals from the perspective of impact to customers and overall system reliability.

e) Please file a copy of the connection agreement between Milton Hydro and Oakville Hydro which relates to Milton Hydro's status as an embedded distributor.

RESPONSE:

A copy of the connection agreement between Milton Hydro and Oakville Hydro is provided as Appendix 1-A.

1.1-Staff-2

Ref: Exhibit 2/Appendix A-Distribution System Plan/p. 30

<u>Distribution System Plan</u>

On this page of the Distribution System Plan, Oakville Hydro displays a pie chart that shows the Strategic Weights of each of the 7 objectives. Please provide background information as to how these weights were determined. Eg. How was it determined that Environmental was given a weight of 20%?

RESPONSE:

The original weightings were provided as typical settings for the UMS Optimizer Software purchased from Abicus Management Solutions Inc. The typical weightings were established by the LDCs who had already used this application to optimize their capital and maintenance portfolios. The typical weightings were reviewed by Oakville Hydro in 2009 to evaluate the criteria and their weightings prior to use for Oakville Hydro's project portfolio. Oakville Hydro determined that no changes to the original typical weightings were required at that time. In early 2013, the Asset Management group initiated another review in order to assess the appropriateness of typical weightings, and again after reviewing the weightings it was decided that the weightings were appropriately set.

1.1-Staff-3

Ref: Exhibit 2/Appendix A-Distribution System Plan/pp. 26 – 28

Distribution System Plan

Under "Asset Capacity Utilization", it is stated that Oakville Hydro reviews capacity utilization at the transformer station connection points and at the 27.6 kV feeder level, on an individual feeder basis annually.

Under "Asset Maintenance Strategy", it is stated that decisions to replace assets versus proceeding with ongoing maintenance to extend the life of the asset are determined based on a business case assessment.

Under "Asset Life Cycle Risk Management Policies and Practices" it is stated that Oakville Hydro considers the impact on SAIFI and SAIDI through completion of the proposed projects.

A Please describe the methods and criteria used by Oakville Hydro to determine adequate capacity utilization of its feeders including load levels at which additional capacity is determined to be required.

RESPONSE:

At peak times, Oakville Hydro's feeder load levels and capacity utilization are managed by the Control Room Operators and System Control Supervisor. Oakville Hydro's SCADA system actively monitors the loading on all feeders in Oakville Hydro's distribution system, and activates an alarm if the load level reaches a pre-determined set-point. These alarms then initiate a collaborative discussion between Engineering and the Control Room in order to develop action plans and/or projects to re-distribute the load throughout the distribution system. In this context, the capacity utilization assessment will drive operational feeder configuration changes to re-distribute the feeder loads if needed. As a result of this switching flexibility in Oakville Hydro's distribution system, it is the transformer station capacity utilization analysis that will drive requirements for additional capacity when required, as was done for the Glenorchy Municipal Transformer Station project justification.

a) Please provide the rationale for the methods and criteria described in (a) above.

RESPONSE:

Due to the network style switching flexibility of the Oakville Hydro distribution system, feeders are dynamically reconfigured when necessary to accommodate changing load levels. With this capability in the distribution system, feeder capacity requirements drive operational reconfiguration rather than capital investment, and have minimal impact on distribution rates.

b) Please explain if/how distribution rate impacts are considered in b).

RESPONSE:

Oakville Hydro manages rate impacts from a full program perspective. Oakville Hydro determines the overall annual affordability level, and optimization of projects based upon strategic objectives is completed. The annual capital program, within that affordability level, is established based on the assessment of these projects and their impacts on meeting these objectives.

c) Please describe the business case assessment used by Oakville Hydro to make replacement vs. ongoing maintenance decisions including the criteria used, with examples.

RESPONSE:

To ensure that prudent task based decision making takes place when evaluating replacement vs. ongoing maintenance, the "RCM II Decision Diagram" (included) is followed. For example, a cable failure is not a hidden failure and will become evident under normal circumstances. The only time this is not true would be if the cable is grounded and unused, but is planned for use at a later time. The cable failure would not represent a risk to personal safety due to its location underground, and there would be no risk to the environment as it would not breach any known environmental standard or regulation. It is however an operational failure and would have a direct adverse effect on operational capability output, quality, customer service and operating costs in addition to the direct costs of repair. Currently, Oakville Hydro is in the process of researching technologies that may be able to proactively detect cable faults. Until such time as those investigations are complete, Oakville Hydro has determined under certain circumstances, such as direct buried cables, that a restoration activity such as cable injection to reduce the failure rate, is technically feasible and a viable method to extend cable life. In other situations such as where cables are in ducts, or it is determined that the area is a candidate for voltage conversion, is has been determined that a scheduled removal and replacement of the underground distribution cables in an area is viable and preferable.

d) Please describe the methods with examples of how Oakville Hydro determines the impact of a project/program on:

- SAIFI and SAIDI; and
- Oakville Hydro's rates


START
RCM II Decision Diagram ©1991 Aladon Ltd.
Hidden failure? Will the loss of function caused by this failure mode on its own become evident under normal circumstances?
Safety Failure? Does the failure mode cause a loss of function or other damage that could injure or kill someone?
Environmental Failure? Does the failure mode cause a loss of function or other damage that could breach any known environmental standard or regulation?
Operation Failure? Does the failure mode have a direct adverse effect on operational capability (output, quality, customer service or operating costs in addition to the direct cost of repair)?
Is a task to detect whether the failure is occurring or about to occur technically feasible and worth doing?
Schedule on-condition task
Is a scheduled restoration task to reduce the failure rate technically feasible and worth doing?
Scheduled restoration task
Is a scheduled restoration task to avoid failures technically feasible and worth doing?
Is a schedule restoration task to reduce the failure rate technically feasible and worth doing?
Is a scheduled discard task to reduce the failure rate technically feasible and worth doing?
Scheduled discard task
Is a scheduled discard task to avoid failures technically feasible and worth doing?
Combination of tasks
Is a combination of tasks to avoid failures technically feasible and worth doing?
Is a failure-finding task to detect the failure technically feasible and worth doing?
Scheduled failure-finding task
Could the multiple failure affect safety or the environment?
Redesign is compulsory
No scheduled maintenance, redesign may be desirable
Yes
No

RESPONSE:

SAIFI and SAIDI:

Projects/programs are reviewed to determine where they are located in the distribution grid, along with the feeders they are connected to, in order to determine the potential impact on SAIFI and SAIDI service reliability metrics. Projects/programs are also reviewed to determine possible outage time due to an asset failure within the project/program area.

Oakville Hydro's rates:

Please see response to part c) of this interrogatory.

1.1-Staff-4

Ref: Exhibit 2/Appendix A- Distribution System Plan/pp. 31 – 33

System Access Investments

Page 31 of the reference provides a Table of year by year capital expenditures for the period 2014-2018 for the cost categories of System Access, System Renewal, System Service and General Plant.

Under "System Access", it is stated that investments in this category are considered mandatory and allocation of the associated capital expenditure is non-discretionary.

a) For projects in the category of System Access which are considered mandatory, please describe methods used by Oakville Hydro to minimize costs. For example, did Oakville Hydro consider alternative solutions in order to arrive at a preferred solution? If so, please describe the methodology by which the alternatives are compared and a preferred solution is selected.

RESPONSE:

Oakville Hydro considers alternatives in all of its capital planning, if available, and the most prudent cost solution that meets its asset management objectives selected and optimized according to Oakville Hydro's investment objectives (see Distribution System Plan pp28-29). To minimize costs, Oakville Hydro utilizes standard materials and standard designs for the majority of distribution capital projects, including System Access projects. Although System Access projects are considered mandatory, the same due diligence and scrutiny is applied to these as to other distribution capital projects.

b) Please explain if/how distribution rate impacts are considered in a).

RESPONSE:

Distribution rate impacts are always considered in the Distribution System Plan and Capital Expenditure Plan. This is normally done at a program level, not on an individual project basis. If mandatory projects are added in a year or vary within the year, the capital program is reviewed to determine if other projects need to be deferred, or additional capital funds secured.

1.1-Staff-5

Ref: Exhibit 2/Appendix A- Asset Management Objectives/pp. 33 – 55

Asset Evaluation

In this section of Oakville Hydro's DSP, the descriptions under the Asset Evaluation heading for various asset categories indicate that Oakville Hydro has chosen a 'run-to-failure' strategy when considering asset replacement.

Please provide a rationale for using the 'run-to-failure' strategy for the various asset categories so identified, such as Overhead Transformers, Padmount Transformers, Submersible Transformers, Overhead Primary Wires, Overhead Secondary Wires, Underground Secondary Cable, and Primary Meters, with specific reference to reliability performance considerations as well as customer preferences regarding cost-vs.-service trade-offs.

RESPONSE:

Ref: Exhibit 2/Appendix A-Asset Management Objectives/pp. 17

"Additional assets have been designated as 'run to failure' entities (e.g. distribution transformers) based on localized impacts and ability to replace in a timely manner in the event of failure. Processes are in-place to manage these cases expediently."

The assets that are designated as 'run to failure' will be replaced upon failure, or generally ten years after their Typical Useful Life ("TUL"). Oakville Hydro has taken this approach to balance its customers' desire for lower rates, which may be achieved through delayed investment, with their desire for system reliably. These assets, for the most part, individually impact fewer customers per unit. As a result, the impacts of failure in the field are somewhat mitigated. Those assets that do fail before the ten-year past TUL replacement point, will have some impact on Oakville Hydro's reliability performance, but the impact will be mitigated for these assets because they can be replaced relatively quickly and a lower number of customers impacted.

1.1-Staff-6

Ref: Exhibit 2/Appendix A- Distribution System Plan/pp. 33 – 34, 63

System Renewal Investments

Page 63 of the reference states that system renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

On Page 34 Oakville Hydro states that investments in this category are considered non-mandatory.

Please explain why system renewal investments that extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services are considered non-mandatory.

RESPONSE:

The Board's Investment Categories are defined in Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications ("Filing Requirements"). On page 23 of the Filing Requirements, the Board notes that "projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits.

Consistent with the Filing Requirements, Oakville Hydro has defined System Renewal projects as non-mandatory as they are not driven by mandated service obligations such as the Distribution System Code or Oakville Hydro's Conditions of Service. Oakville describes its Asset Lifecycle Optimization Policies and Practices on page 26 and 27 of its Distribution System Plan. As stated in paragraph d) and e), Oakville Hydro optimizes its capital and maintenance costs throughout the lifecycle of the asset and makes its investment decisions using a conditions based system analysis with a goal to extend the life of its assets. Oakville Hydro uses a proactive approach to prevent the need for the mandatory replacement required as a result of equipment failure.

1.1-Staff-7

Ref: Exhibit 2/Appendix A- Distribution System Plan/pp. 49–51

Capital Expenditure Summary

At Page 50 of the reference Oakville Hydro states that it does not have historical capital planning detail broken into the Board's investment categories: System Access, System Renewal, System Service and General Plant. Yet Table 2 on page 51 shows historical year by year expenditures from 2009-2013 for those same categories. Please explain.

RESPONSE:

Historical annual expenditures by project are available from Oakville Hydro's financial system while Oakville Hydro's budget categories are summarized at a higher level. Oakville Hydro has made its best efforts to map its investments to the Board's investment categories in the table below.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated
Distribution System Plan Filing Requirements

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)														
	2009			2010			2011			2012			2013		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	3,602	$ 5,782	60.5%	2,372	$ 3,307	39.4%	18,444	$ 29,215	58.4%	3,107	$ 3,090	-0.5%	$ 3,291	$ 3,822	16.1%
System Renewal	11,787	13,001	10.3%	8,662	11,146	28.7%	6,847	6,939	1.3%	6,593	7,571	14.8%	5,573	5,535	-0.7%
System Service	671	1,449	115.9%	781	916	17.2%	840	838	-0.3%	1,094	11,351	937.6%	79	201	155.0%
General Plant	2,172	2,535	16.7%	2,906	1,247	-57.1%	2,893	3,055	5.6%	2,769	1,984	-28.3%	2,549	2,137	-16.2%
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%
System O&M	n/a	$ 5,852	--	$ 6,135	$ 5,568	-9.2%	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,140	$ 10,794	6.4%

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)														
	2009			2010			2011			2012			2013		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	3,602	$ 4,967	37.9%	2,372	$ 3,307	39.4%	7,358	$ 6,354	-13.6%	3,107	$ 2,931	-5.7%	$ 3,291	$ 3,822	16.1%
System Renewal	11,787	13,001	10.3%	8,662	11,146	28.7%	6,847	6,939	1.3%	6,593	7,571	14.8%	5,573	5,535	-0.7%
System Service	671	1,449	115.9%	781	916	17.2%	840	783	-6.8%	1,094	1,232	12.6%	79	201	155.0%
General Plant	2,172	1,635	-24.7%	2,906	1,247	-57.1%	2,893	3,055	5.6%	2,769	1,984	-28.3%	2,549	2,137	-16.2%
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,493	11,695	1.8%
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-	
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-	
New Customer Information System	-	-		-	-		-	-		-	-		-	-	
Remaining 3rd Tranche CDM Activities	-	1,715		-	-		-	-		-	-		-	-	
3rd Party IRU	-	-		-	-		-	-		-	-		-	-	
TOTAL EXPENDITURE	$ 18,232	$ 22,767	24.9%	$ 14,721	$ 16,615	12.9%	$ 29,024	$ 40,046	38.0%	$ 13,562	$ 23,996	76.9%	$ 11,493	$ 11,695	1.8%

1.1-Staff-8

Ref: Exhibit 1/Tab 1/Schedule 1

2013 Ice Storm

In late December 2013, many parts of southern Ontario experienced a significant ice storm.

a) Please identify any impacts that Oakville Hydro estimates that the December 2013 ice storm has had or will have on the test year capital and OM&A budget levels (e.g., in terms of infrastructure replacement or maintenance and vegetation management).

RESPONSE:

Oakville Hydro can identify some impacts on both Capital and OM&A on the Test Year as a result of the December 2013 ice storm. From a capital perspective, Oakville Hydro had a motorized switch damaged as a result of the storm which was replaced in January 2014. In addition, approximately 220 meters were damaged in the ice storm. However, Oakville Hydro has not fully determined the number of meters that will need to be discarded.

From an OM&A perspective, vegetation management will be impacted as a result of the storm. However, Oakville Hydro had already proposed changes to its program in the 2014 Test Year and included additional costs for standardized clearances, which is referenced at Exhibit 4, Tab 2, Schedule 3, Page 10 of 11.

b) Will Oakville Hydro be updating its Application in light of this event? If so, by when does it intend to file any updated evidence?

RESPONSE:

Oakville Hydro will be requesting a clearance of account 1572 for the costs associated with the 2013 Ice Storm through a standalone application (Z-factor Application) as not all costs have been invoiced at this time.

1.1-Staff-9

Ref: Exhibit 2/Tab 5/Schedule 1

Update of 2013 and 2014 Capital Expenditures

Since October 1, 2013 when the current application was filed, and considering that the 2013 year is now complete, please file an update of 2013 capital expenditures, noting significant changes from the 2013 Bridge Year as filed and if any components of the Capital Expenditure plan for the test year will be updated.

RESPONSE:

Oakville Hydro's unaudited 2013 actual capital expenditures were $11,728,990 as compared to the 2013 Bridge Year of $11,694,747 included in the application. This represents an overall increase of $34,243. A more detailed analysis is provided in response to 4.3-SEC-22. Oakville Hydro is updating its 2014 Capital Expenditure plan by $1,789,238. This increase is a net amount and reflects the value of 2013 capital projects not yet complete or in service as anticipated in 2013 (in 2013 ending WIP), (those projects will now be completed and in service in the 2014 Test Year) offset by a decrease in the 2014 Capital expenditures for the re-evaluation of the hybrid vehicles.

Description	Amount
2014 Capital Addition from 2013 WIP	$ 1,846,560
2014 Capital expenditures for the re-evalution of the hybrid vehicles	- 56,762
Total	**$ 1,789,798**

1.1-Staff-10

Ref: Exhibit 2/Appendix A- Distribution System Plan/Appendix 1 Asset Management Process

<u>Asset Condition Assessment</u>

a) Please prepare a table showing: (I) Number of Failures; and (II) Total cost of Repair or Replacements, for each of the five Asset Categories (Pole Mounted Transformers; Overhead Line Switches; Pad Mounted Transformers; Pad Mounted Switchgear; Underground Cables), for each of the five years 2009 to 2013.

RESPONSE:

The number of failures and total cost of repair or replacements for each of the five Asset Categories (Pole Mounted Transformers; Overhead Line Switches; Pad Mounted Transformers; Pad Mounted Switchgear; Underground Cables), for each of the five years 2009 to 2013 is provided in the following table.

Year	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Pole Mounted Transformer and Accessories Failures	50	39	50	30	24
Pole Mounted Transformer Failure Cost	$85,007	$83,300	$76,019	$66,018	$82,000
Overhead Line Switch and Accessories Failures	10	15	7	11	13
Overhead Line Switch Failure Cost	$81,896	$77,966	$24,680	$54,604	$50,127
Pad Mounted Transformer and Accessories Failures	18	15	12	34	20
Pad Mounted Transformer Failure Cost	$151,144	$140,901	$108,506	$194,308	$225,064
Pad Mounted Switchgear and Accessories Failures	6	4	4	4	2
Pad Mounted Switchgear Failure Cost	$23,163	$97,461	$203,281	$43,034	$78,521
Underground Cable Failures	29	20	22	35	12
Underground Cable Failure Cost	$161,895	$269,860	$247,672	$338,009	$236,648

b) Please provide the same forecasted information for the bridge year and test year and explain any variance from historical data.

RESPONSE:

Oakville Hydro has estimated failures for the Test Year based upon the previous three year average of failures and costs. The previous three year average was used rather than the previous five due to the fact that replacement planning has been based on the formal Asset Management Policy that has been used in the past three years for Asset Condition Assessments.

Year	2013 Actual Bridge Year	2014 Forecasted Test Year
Pole Mounted Transformer and Accessories Failures	24	35
Pole Mounted Transformer Failure Cost	$82,000.11	$74,679.29
Overhead Line Switch and Accessories Failures	13	10
Overhead Line Switch Failure Cost	$50,126.68	$43,136.59
Pad Mounted Transformer and Accessories Failures	20	22
Pad Mounted Transformer Failure Cost	$225,064.39	$175,959.54
Pad Mounted Switchgear and Accessories Failures	2	3
Pad Mounted Switchgear Failure Cost	$78,521.45	$108,279.05
Underground Cable Failures	12	23
Underground Cable Failure Cost	$236,647.62	$274,109.29

1.1-Energy Probe-1

Ref: Exhibit 2, Tab 1, Schedule 2

The evidence indicates that capital additions closed to rate base in 2010 were $1,894,084, or 13% above the Board approved level. What measures has the applicant put in place to ensure that such variances from plan do not occur in the future?

RESPONSE:

As discussed on page 54 of Oakville Hydro's Distribution System Plan, the primary reason that capital additions were $1.9M higher than the Board approved level in 2010 was due to increased spending that was beyond Oakville Hydro's control. Actual expenditures for 27.6 kV additions, new development and services and road widening were $1.3M higher than budgeted.

Oakville Hydro also added a transformer replacement and voltage conversion project to the 2010 capital program. Although this project had not been budgeted, conditions were such that the replacement was required in 2010. The project was associated with other work that was carried out in 2009. This portion of the larger project was deferred from 2009 to 2010 due to project scheduling and scope changes required due to field conditions.

As discussed on page 12 of Oakville Hydro's Distribution System Plan, Oakville Hydro monitors the cost efficiency and effectiveness of its performance as compared to it budgeted plans to ensure that capital spending is in accordance with its plans. This is demonstrated in Appendix 2-AB on page 51 of Oakville Hydro's Distribution System plan and reproduced below for convenience. As shown in Appendix 2-AB Oakville Hydro's normalized capital expenditures for were on average 0.5 per cent lower than planned from 2011 to 2013.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		$ 5,782	--		$ 3,307	--		$ 29,215	--		$ 3,090	--	$ 3,291	$ 3,822	16.1%	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal		13,001	--		11,146	--		6,939	--		7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service		1,449	--		916	--		838	--		11,351	--	79	201	155.0%	5,589	559	581	605	629
General Plant		2,535	--		1,247	--		3,055	--		1,984	--	2,549	2,137	-16.2%	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931
System O&M	n/a	$ 5,852	--	$ 6,135	$ 5,568	-9.2%	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,140	$ 10,794	6.4%	$11,108	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	-	$ 4,967	--	2,372	$ 3,307	39.4%	-	$ 6,354	--	-	$ 2,931	--	$ 3,291	$ 3,822	16.1%	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal	-	13,001	--	8,662	11,146	28.7%	-	6,939	--	-	7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service	-	1,449	--	781	916	17.2%	-	783	--	-	1,232	--	79	201	155.0%	589	559	581	605	629
General Plant	-	1,635	--	2,906	1,247	-57.1%	-	3,055	--	-	1,984	--	2,549	2,137	-16.2%	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,493	11,695	1.8%	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-		5,000	-	-	-	-
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-		-	-	-	-	-
New Customer Information System	-	-		-	-		-	-		-	-		-	-		-	-	486	-	-
Remaining 3rd Tranche CDM Activities	-	1,715		-	-		-	-		-	-		-	-		-	-	-	-	-
3rd Party IRU	-	-		-	-		-	-		-	-		-	-		738	-	-	-	-
TOTAL EXPENDITURE	$ 18,232	$ 22,767	24.9%	$ 14,721	$ 16,615	12.9%	$ 29,024	$ 40,046	38.0%	$ 13,562	$ 23,996	76.9%	$ 11,493	$ 11,695	1.8%	$16,607	$10,251	$11,401	$10,752	$ 10,931

1.1-Energy Probe-2

Ref: Exhibit 2, Tab 5, Schedule 2

Please confirm that based on Appendix 2-AB, the distributor has no planned capital expenditures out of the ordinary in 2015 through 2018, other than a small amount for a new customer information system in 2016.

RESPONSE:

At this time, Oakville Hydro does anticipate planned capital expenditures out of the ordinary in 2015 through 2018, other than a small amount for a new customer information system in 2016.

1.1-SEC-1

Please provide a copy of all material provided to Applicant's Board of Directors approving this application and the associated budgets?

RESPONSE:

Materials provided to Oakville Hydro's Board of Directors are attached.

ITEM 4b

OAKVILLE HYDRO

Report to the Board of Directors

Oakville Hydro Corporation

September 11, 2013

Regulatory and Cost of Service

Purpose of Report:

For information.

Report:

Background

Oakville Hydro Electricity Distribution Inc. (OHEDI), like all electricity distributors in Ontario, is subject to licensing and regulation by the Ontario Energy Board (OEB). At a basic financial level, the OEB's decisions impact the rates that OHEDI may charge its customers, establish the allowed regulated rate of return, the assets it may acquire, construct or replace, as well as many aspects of day-to-day operations and reporting. OHEDI is scheduled to apply to the OEB on October 1, 2013 for updated distribution rates effective May 1, 2014.

The OEB announced on September 14th, 2012, the Renewed Regulatory Framework (RRF) that will change the way in which OHEDI and other LDCs establish their regulated revenue requirements. Within this new framework there are three choices for an LDC to establish its distribution rates. These are 1) a traditional type of Cost of Service based on the current system with approvals every five years referenced to a single test year, 2) a multi-year custom application where five years of rates are examined and tested and 3) an annual indexed method. As previously presented to the Board, OHEDI has chosen the traditional Cost of Service method with the five year term.

Throughout the summer there have been numerous OEB releases and guidelines published in order to establish the filing requirements and in mid July 2013 the final guideline was released. OEB required tables and appendices were released through July and early August.

The primary focus of the new regulatory framework is the change to more of a scorecard approach to regulation with the following four key performance outcomes:

- Customer focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

These four outcomes partially align with OHC's Strategic imperatives of:

- Profit
- Service
- People
- Community

Current Application

The current application is being finalized for submission to the OEB on October 1, 2013. Attached is the current draft of the Executive Summary of the application that is substantially in the form that is expected to be submitted to the OEB on October 1, 2013. Within this application OHEDI is looking to recover a revenue deficiency of $5.3 million relative to the rates that were approved in 2010 Cost of Service plus the incremental rate increases. This deficiency has been broken down into the following:

- Glenorchy Station for $1.8 million (2011 rate rider will expire April 30, 2014)
- Smart Meter implementation for $2.1 million (2012 rate rider will expire April 30, 2014)
- Current distribution system operations and maintenance for $1.4 million

Key components in the application are a request for approval of an emergency transformer for the Glenorchy Transformer station, additional costs associated with a proposal to move to monthly billing and general business cost increases. Capital expenditures are expected to remain reasonably stable throughout the term of the application and are in line with the last 10 year plan presented to the Board in December 2012.

Because of the expiration of the current rate riders for the Glenorchy Transformer Station and Smart Meter Implementation, the anticipated bill impact is approximately $1.62 per residential customer per month or approximately 5.1% impact on the customer bill. This information will be published in the Oakville Beaver in late October or early November as part of the approval process. This figure could change slightly as the application is finalized with new information throughout the month of September. For example the results of Conservation Demand Management efforts released on September 1 need to be incorporated into the application.

Implicit in this application is the following high-level budget for OHEDI compared with the 2013 budget.

Oakville Hydro Electricity Distribution Inc. ($ 000's)	2014 Year Proposed	2013 Budget
Total Revenues	39,783	38,574
Operating Costs (including depreciation)	21,297	16,853
EBITDA	**18,486**	**21,721**
Depreciation	8,611	12,069
Interest Expense	5,562	6,014
Net Income before Taxes	**4,313**	3,638

A significant change to the 2013 budget is the accounting for Depreciation and Burdens. The 2013 budget deducts from the operating costs approximately $3.0 million in overhead burdens that are then capitalized. This accounting is not allowable under the International Accounting Standards (IFRS) and the OEB has specified that the capitalization of burdens under Canadian Generally Accepted Accounting Principles (CGAAP) must be in compliance with IFRS. Similarly, depreciation under IFRS results in a reduced depreciation expense of approximately $2.9 million, which according to OEB requirements must be incorporated into the CGAAP financial statements.

Recommendation:

OHEDI is seeking Board approval of the following resolution:

On a motion duly made and seconded IT WAS RESOLVED THAT the Board hereby approves in principle the financial information that is presented in the Executive Summary of the Cost of Service Application which will be formally presented to the Finance and Audit Committee for recommendation to the Board during the normal business planning process. Material changes that the Finance and Audit Committee or Board make to 2014 budget will be incorporated into Cost of Service Application process.

Jim Collins
Chief Financial Officer, Vice President Corporate and Regulatory Affairs

1.1-AMPCO-1

Ref: Exhibit 1, Tab 1, Schedule 1, Page 4

Preamble: Oakville Hydro indicates it is introducing a Sustainability Program into its strategic direction as a multi-year initiative to minimize incremental costs to its customers and ultimately improve the sustainability of services offered to the residents of Oakville.

a) Please provide more details on this program and discuss the need, timing, key milestones and multi-year costs of this initiative including the costs included in the 2014 Test Year.

RESPONSE:

Sustainability Program

An outcome of the 2012 Strategic Planning process was the direction to incorporate Sustainability into Oakville Hydro strategy. This initiative was to include development of a plan to incorporate Sustainability into the business philosophy, planning, operations, processes and decision making.

Management has committed to advancing the strategy and implementation planning for a Sustainability Program. Oakville Hydro's Sustainability Plan Development Process and Timeline are provided as Appendix 1-B.

Building Sustainability into corporate strategy assists improved engagement with key stakeholders, reduce costs and increase operational efficiencies and manage risks. As a result, Sustainability was incorporated into the 2012 Strategic Plan and remains an initiative for 2013 and subsequent years.

The following action plans are work-in-progress for early 2014:

- Waste Audit to be performed in January 2014
- Strategy to be developed for responsible removal and recycling of electronic waste
- Battery recycling to be started in January 2014
- Stewardship Ontario Registration in January 2014

Costs included into the 2014 Test Year

$20,000 budget for Sustainability

Sustainability touches at all levels of Oakville Hydro's strategic imperatives being Profit, Service, People and Community. A copy of Oakville Hydro's Vision, Mission and Values along with Strategic Imperatives was provided in Exhibit 1, Tab 1, Schedule 1, Page 2 of 24.

Below are the details of Oakville Hydro's Sustainability initiatives:

Employees

- Ensuring employee safety, engagement, training through Oakville Hydro Health and Safety Management System / Stayin' Alive Health and Safety Program
- Promoting employee wellness through the Stayin' Alive program and annual initiatives
- Employee Events and Awards
- Employee skills development training

Community

- Strong community relationships – United Way, Community events, Energy Fairs, Quarterly Shareholder presentation
- Community outreach initiatives - involvement in the Oakville Rib Fest; Halton Eco Festival; Oakville Conserves Energy Fair, Midnight Madness participation and various retailer events.
- Assisting Low Income Customers
- Customer Conservation and Demand Management programs
- Paperless billing
- Completed an initiative with students from Sheridan College's Process Management program to redesign a key internal 'Service Call' process
- Supported the Powerline Technician Program at Conestoga College as well as employing powerline co-op students from both Conestoga and Cambrian Colleges
- Featured on **MySafeWork** website and Corporate lead and had key representatives at a **MySafeWork** event at **Holy Trinity Catholic High School** in 2013 with Rob Ellis

Corporate

- Sustainable and long term financial performance

Operations

- System Automation to minimize calling in line staff and improving restoration times. Oakville Hydro has an expansive automated distribution systems with 123 automated (remotely controllable from SCADA Control) switches across the system

Governance

- Paperless Board and Committee meetings
- Corporate Governance Best Practices

Environment

- Generating clean solar electricity
- Light efficiency within the building through the building automation system control
- Waste reduction, source separation and recycling program

b) Please discuss how the Sustainability Program interacts with Oakville Hydro's other strategic programs.

RESPONSE:

See Oakville Hydro's response to part a) of this interrogatory.

1.1-AMPCO-2

Ref: Exhibit 4, Tab 2, Schedule 1, Page 5

a) Please provide a summary of the established cycles in 2014 for the following maintenance activities: infrared thermography testing planned visual inspections, planned tree trimming, overhead and pad-mounted load break switch maintenance, transformer room maintenance, insulator washing, and cleaning and inspection of underground vaults compared to the 2010 cost of service application.

RESPONSE:

See below table for maintenance activities:

Maintenance Activity	2014 Cycle Per Year	2010 Cycle Per Year
Predictive Maintenance (PdM) Infrared Thermography Testing	1/6 of Overhead Wire system *All voltages	1/5 of Overhead Wire System *Only 27.6kV
PdM Radio Frequency Testing	1/6 of Overhead Wire system *All voltages	Technology was not implemented
Condition Based Maintenance (CBM) Insulator Washing	N/A. Insulator washing has been discontinued. Investigation showed little value in continuing	1/5 of Overhead Wire System *Only 27.6kV porcelain insulators
Preventative Maintenance (PM) Tree Trimming	1/3 of Overhead Wire System	1/3 of Overhead Wire System
PM Overhead Transformer	1/6 All Units - Visual Inspection & Asset Condition Assessment (ACA)	1/6 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Readings, & ACA	1/6 All Units - Visual Inspection, Readings, & ACA
PM Pad Mounted Transformer	1/6 All Units - Visual Inspection & Asset Condition Assessment (ACA)	1/6 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Readings, & ACA	1/6 All Units - Visual Inspection, Readings, & ACA

Maintenance Activity	2014 Cycle Per Year	2010 Cycle Per Year
PM Vault Transformer	1/6 All Units - Visual Inspection & Asset Condition Assessment (ACA)	1/6 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Readings, & ACA	1/6 All Units - Visual Inspection, Readings, & ACA
PM PoleTran Transformer	N/A. All PoleTran Transformers have been eliminated from the distribution system	1/6 All Units - Visual Inspection
		1/6 All Units - Visual Inspection, Readings, & ACA
PM Residential Submersible Transformer Vaults	1/6 All Units - Visual Inspection & Asset Condition Assessment (ACA)	1/3 All Units - Visual Inspection & Readings
	1/6 All Units - Vault Cleaning, Readings, ACA & Infrared Scan	
PM Commercial Submersible Transformer Vaults	All Units twice per year - Vault Cleaning, & ACA	All Units twice per year - Vault Cleaning & Readings
PM Overhead Gang Operated Switches Loadbreak, SCADAMate, Vacuum)	1/6 All Units - Visual Inspection & ACA	1/6 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Adjust, Lube, & ACA	1/6 All Units - Visual Inspection, Adjust & Lube
PM Overhead Blade	1/6 All Units - Visual	1/6 All Units - Visual

Maintenance Activity	2014 Cycle Per Year	2010 Cycle Per Year
Switches	Inspection & ACA	Inspection
	1/6 All Units - Visual Inspection, Adjust, Lube, & ACA	1/6 All Units - Visual Inspection, Adjust & Lube
PM Overhead Cutout Switches	1/3 All Units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
PM Pad Mounted Switchgear - Air Insulated Switchgear (AIS)	1/6 All Units - Visual Inspection & ACA	1/6 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Dry Ice Clean, & ACA	1/6 All Units - Visual Inspection & Dry Ice Clean
PM Pad Mounted Switchgear - Gas Insulated Switchgear (GIS)	1/3 All Units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
PM Vault Switchgear - GIS	Every 3 years all units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
PM Underground Cable	1/3 Underground System Visual Inspection	1/3 Underground System Visual Inspection
PM Poles - Wood	1/6 All Units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
	1/6 All Units - Visual Inspection, Wood Pole Testing, & ACA	1/5 All Units - Visual Inspection & Wood Pole Testing
PM Poles - Other	1/3 All Units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
PM Concrete Vaults	1/3 All Units - Visual Inspection & ACA	1/3 All Units - Visual Inspection
PM Customer Specific	All Units Yearly - Visual	All Units Yearly - Visual

Maintenance Activity	2014 Cycle Per Year	2010 Cycle Per Year
Substations	Inspection & ACA	Inspection

1.1-VECC-1

Ref: E1/T3/Schedule 3

With respect to the pilot project to install photovoltaic devices on pole tops ($38,000):

a) Please provide the business case for this project and the pilot project results.

RESPONSE:

This project was a limited trial to establish the technical feasibility for installation of photovoltaic devices on our poles providing support for localized service bus, a formal business case was not completed for this limited trail. It also provided an initial opportunity for Oakville Hydro to potentially gauge feedback from customers / residents on the visible effect of this new technology. The trial also established that the installation of photovoltaic devices on our poles was technically viable.

b) Are there any plans to expand this project? If yes, please describe.

RESPONSE:

Our plans to expand this project are outlined in the "Harvester Solar Panels" initiative description on page 15 of the Smart Grid Strategy in Appendix 5.

Issue 1.2 *Are the customer engagement activities undertaken by the applicant commensurate with the approvals requested in the application?*

1.2-Staff-11

Ref: Exhibit 1/Tab2/Schedule 1

Evolution of Customer Engagement

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

RESPONSE:

The enhanced customer engagement conducted in preparation for the current application is described in detail in Exhibit 1, Tab 2, Schedule 1, Page 9 of 18 under "Customer engagement Undertaken for the 2014 Cost of Service Application". Specifically, street lighting customers, the new embedded distributor and intervenors from the previous cost of service application were engaged. This level of customer engagement did not exist in the past. For example, Oakville Hydro was not in the practice of informing streetlight customers of their expected rates, or of the cost of service process. This enhanced engagement was well received. Another enhanced customer engagement conducted in preparation for the current application is the specific questions included in the customer engagement survey that was not previously done. Oakville Hydro asked questions regarding a move to monthly billing (for which the OM&A costs are included in the 2014 Test Year) and knowledge of Smart Grid (which forms part of Oakville Hydro's Distribution System Plan).

1.2-Staff-12

Ref: Exhibit 1/Tab1/Schedule 1

Reflecting Customer Needs in the Application

Chapter 2 of the Filing Requirements states, "Distributors should specifically discuss in the application how their customers were engaged in order to determine their needs. This could include references to any communications sent to customers about the application such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers and explain to them how the application serves their needs and expectations and the feedback heard from customers through these engagement activities." (Emphasis added)

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

RESPONSE:

The Board's Filing Requirements were released on July 17, 2013. In the absence of clear direction prior to that date and in the spirit of the Boards Renewed Regulatory Framework for Electricity Distributors Oakville Hydro undertook to the following actions to engage customers and explain how the current application serves their needs and expectations:

- Customer satisfaction survey
- Meetings with Embedded Distributor and Streetlight customer
- Meeting with previous intervenors of record
- Publication of the Board's Notice of Application and Hearing

Oakville Hydro will explore in the future other opportunities to engage its customers in the rate setting process.

1.2-Energy Probe-3

Ref: Exhibit 1, Tab 2, Schedule 1

Please provide the customer feedback received from each of the town council meetings shown in the table on page 4.

RESPONSE:

Oakville Hydro's makes presentations to the Town Council which have public and customers in attendance. To date in these Town Council meetings there have not been any direct feedback or questions from the public. Town Councillors are contacted at times by their constituents and may have feedback, questions, and concerns by customers which are forwarded directly to Oakville Hydro. Town council meetings are all available on Town TV.

1.2-Energy Probe-4

Ref: Exhibit 1, Tab 2, Schedule 1

Please confirm that the distributor did not have customer engagement meetings with residential or general service customers that were focused on the 2014 rate application. If this cannot be confirmed, please provide the dates of any such meetings, along with the material presented to the customers and the feedback received from the customers.

RESPONSE:

Oakville Hydro did not have a formal customer engagement meeting with its Residential customers that was specifically focused on the 2014 rate application. However, as discussed in Exhibit 2, Tab 2, Schedule 1, Oakville Hydro did engage its residential customers, through its customer satisfaction survey, on a number of items that are directly related to 2014 proposed program initiatives included in its rate application. The customer survey asked direct questions regarding a move to monthly billing referenced in Exhibit 1, Appendix A, Page18, questions regarding Smart Grid referenced in Exhibit 1, Appendix A, Page 13 and their responses to questions regarding value for money, cost effectiveness and whether Oakville Hydro works with customers to keep their energy costs affordable in Exhibit 1, Appendix 1, Page 22. While these areas were identified as being areas in need of more proactive engagement, Oakville Hydro's results exceed the Ontario results.

For the general service class of customers, Oakville Hydro had several meetings, conference calls and consultations with Milton Hydro a new general service customer whom will become an "Embedded Distributor" effective May 1, 2014. The meetings commenced in late 2012 which originally involved reaching a connection agreement between the parties and Milton Hydro estimating a load forecast for the Glenorchy Transformer station. The agreement was signed on May 1, 2013. On July 19, 2013 Oakville Hydro received from Milton Hydro the estimated 2014 Load at the Glenorchy Transformer Station. On September 16, 2013, Oakville Hydro provided Milton Hydro with a draft bill impact and cost allocation details for the embedded distributor class. Milton Hydro reviewed the spreadsheet and had a call for some clarifications. The customers' feedback was provided via letter. The letter was provided evidence in Exhibit 7, Appendix B.

Finally, the notice to customers in the local paper is another form, albeit regulated, to inform, encourage and engage customers in the current rate application.

1.2-SEC-2

Ref: Ex.4/Appendix 3

With respect to the UtilityPULSE 15th Annual Electric Utilities Customer Satisfaction Survey. Please provide:

a) A breakdown of Oakville customer respondents by customer class.

RESPONSE:

As noted in Exhibit 4, Appendix A: Monthly Billing Report, Appendix 3 UtilityPULSE 15th Annual Electric Utility Satisfaction Survey, Page 2, 402 customers completed the survey. Of that number 85% were residential and 15% were General Service < 50 kW customers.

b) A list of all other participating Ontario utilities.

RESPONSE:

UtiliyPULSE has advised Oakville Hydro that this information is confidential and proprietary and that it is not prepared to place this information on the public record.

c) Copy of all questions asked to Oakville customers.

RESPONSE:

Oakville Hydro has provided the questions asked to customers in Appendix 1-C.

d) The full results (raw data) for all Oakville customers.

RESPONSE:

UtiliyPULSE has advised Oakville Hydro that this information is confidential and proprietary and that it is not prepared to place this information on the public record.

1.2-AMPCO-3

Ref: Exhibit 1, Tab 2, Schedule 1

Preamble: In this Exhibit Oakville Hydro provides information on its customer engagement activities.

a) Please discuss how Oakville Hydro evaluates the success of its customer engagement activities.

RESPONSE:

As discussed in Exhibit 1, Tab 2, Schedule 1, Oakville Hydro developed a balanced scorecard in 2011 which includes a measurement related to customer focus. Oakville Hydro conducts a customer satisfaction survey each year and creates a plan to improve in the lowest performing areas. The success of its customer engagement is assessed by evaluating the change in the survey results in the following year(s).

In addition, there are other measures which are used to evaluate specific customer engagement activities. For example the number of Tweets send and received is used to evaluate the success of the social media program and the number of community events attended is used to measure the success of Oakville Hydro's community outreach program.

b) Page 17 – Please discuss the uptake of the GS>1000 kW customer class regarding attendance at planned information sessions and level of contact with the key account manager. Please provide a summary of key issues discussed with the account manager.

RESPONSE:

Oakville Hydro had two events targeting the general service customers from both a GS>50 and GS>1000 customers.

- "Oakville Saves" on November 19, 2013 held by Oakville Hydro with approximately 80 members in attendance. This was well received event that included recognition for customers with successful CDM programs. An agenda and other details are included in Appendix 1-D.

- "Unlock Hidden Savings" on October 8, 2013 was a co-hosted events with our neighbouring distributors. Information and details are included in Appendix 1-E.

1.2-AMPCO-4

Ref: Exhibit 1, Tab 2, Schedule 1, Page 2

Preamble: Over the past three years Oakville Hydro has engaged a third party to conduct customer satisfaction surveys.

a) Please identify the customer engagement activities that are new/incremental (beyond the customer survey) since Oakville's 2010 Cost of Service application.

RESPONSE:

As discussed in Exhibit 1, Tab 2, Schedule 1, Oakville Hydro engages its customers in a variety of ways. In addition to its annual customer satisfaction survey, Oakville Hydro has added the following customer engagement activities since its 2010 Cost of Service Application:

- Public forum town council meetings
- Public forum for the Glenorchy Municipal Station
- Lunch and learn sessions – Conservation and Demand Management
- Website improvements
- Social Media – Facebook, Twitter
- Class specific consultations – street lighting, embedded distributor
- Meeting with previous intervenors
- Smart meter and Time-of-Use billing communication
- Attending Chamber of Commerce events with the intent to talk and listen to business customers and residents including:
    - Breakfast meetings,
    - Business after hours events
    - Policy and roundtable discussions
- Education and communication through Town of Oakville councillors

These initiatives are discussed in detail in Exhibit 1, Tab 2, Schedule 1.

b) Please identify the customer engagement activities that have been halted since Oakville's 2010 Cost of Service application.

RESPONSE:

Oakville has converted over 99% of its residential and General Service < 50 kW customers to time-of-use billing and, as discussed on page 41 of the Distribution System Plan Oakville Hydro will now refocus its customer engagement on smart grid and other relevant issues rather than time-of-use billing. Oakville Hydro has not conducted a public forum for a material project since 2010 as it has not had a project of the same magnitude as the Glenorchy Municipal Transformer Station.

c) In Oakville Hydro's experience, please discuss the customer engagement activities that have proven to be ineffective and why.

RESPONSE:

As discussed in Exhibit 1, Tab 2, Schedule 1, Oakville Hydro believes that customer engagement is important in understanding and meeting the customers' needs and expectations. Oakville Hydro believes that different customer engagement activities are better suited for specific purposes. Consideration is given to a variety of customer engagement activities with consideration of the costs of holding such events.

1.2-VECC-2

Ref: E1/T1/S1/pg.6

a) Does Oakville Hydro carry out any transactional surveys (e.g. after outage or a customer service contact)? If so, please provide a summary of the results of these surveys.

RESPONSE:

Oakville Hydro does not currently do not carry out any transactional surveys. However, Oakville Hydro is exploring alternative methods to conduct transactional surveys in a manner which provides the appropriate feedback in a cost effective way.

1.2-VECC-3

Ref: E1/T1/S1

Does Oakville Hydro track and categorize customer enquiries and complaints? If so please provide a summary of the annual results for 2010 through 2013.

RESPONSE:

A Customer escalation log is maintained. Customer enquiries and/or complaints that are received from or directed to the following are documented in the log:

- Town of Oakville Councillors
- Town of Oakville Mayor
- MP's and MPP's
- Addressed to Vice Presidents or President of Oakville Hydro
- Government bodies including the Ontario Energy Board and the Ministry of Energy
- Other Utilities

2011 – 4 – process to track started Oct/11

2012 - 26

2013 – 26

1.2-VECC-4

Ref: E1/T3/S3/pg.50 & E4/T3/S9

Please explain how Oakville Hydro communicates the availability of LEAF bill assistance?

RESPONSE:

Oakville Hydro communicates the availability of LEAP bill assistance in the following manner:

- Website
- Collection notice
- Collection and Customer Service representatives
- Final phone call to customer prior to disconnection – if contact made
- Oak Park Neighbourhood Centre (administers this program on behalf of Oakville Hydro) and advertises assistance on their website.

As discussed in response to 5.1-EP-26, Oakville Hydro's LEAP Program has been very successful. As at December 31, 2013, 99.7 per cent of the cumulative contributions have been disbursed to provide funding for emergency financial assistance to eligible low-income customers and to defray the costs of the distributor's social agency partner to deliver and administer the program.

1.2-VECC-5

Ref: E1/Appendix A/ & E4/Appendix 3

Customer Survey

In respect to the Customer Satisfaction Survey:

a) No data is provided in the Survey for 2010, 2011, 2012 or 2013. When was the last survey completed?

RESPONSE:

The last survey was conducted in March 2013. A customer satisfaction survey was also conducted in 2011 and in 2012.

b) What questions were asked in respect to whether customers believe that they were receiving value for money for the services provided by Oakville Hydro? Specifically what questions (and results) were asked to determine the B+ score for Price and Value?

RESPONSE:

The question regarding value for money from the survey is as follows:

Customers were asked to agree strongly, somewhat agree, disagree strongly, somewhat disagree, neither or don't know to the question:

- Does Oakville hydro provide good service for your money?
- Does Oakville hydro work with customers to keep their electricity costs affordable?
- The cost of electricity is reasonable when compared to other utilities such as gas, cable or telephone?

c) With respect the question of whether paying for electricity is a worry or problem, the survey reports better results (i.e. less worried) than the Ontario average. How was the variable of household income (as compared to other Ontario service areas)?

RESPONSE:

For the participating 2013 LDCs, the range of "Not a Worry" was from a low of 59% to a high of 78%. Oakville Hydro was amongst the highest respondents to "Not a Worry".

Appendix 1 – A

Milton Hydro Connection Agreement

THIS CONNECTION AGREEMENT made as of the **1st of May, 2013** (the "**Effective Date**")

BETWEEN:

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

("OHEDI")

- and -

MILTON HYDRO DISTRIBUTION INC.

("Milton Hydro")

RECITALS:

1. On or about February 3, 2012 Milton Hydro advised OHEDI that it wished to connect to and to use two feeder positions at Glenorchy Municipal Transformer Station located at 4322 Sixth Line in the Town of Milton, Ontario ("**MTS 1**"), to serve a portion of Milton Hydro's service area.

2. OHEDI will own, install and provide, the feeder lines ("**Feeder Lines**") to be connected at and from MTS 1 to the Milton Hydro distribution system at the Milton Hydro termination poles located at (the "**Connection Points**").

3. The Parties wish to enter into this Connection Agreement (the "**Agreement**") to set out the terms and conditions of their agreement with respect to the connection of the Feeder Lines from MTS 1 to the Milton Hydro distribution system;

NOW THEREFORE, the Parties agree as follows:

Article 1

INTERPRETATION

1.1 Capitalized terms used in this Agreement and not defined in it will have the meanings set out in Schedule A.

1.2 The division of this Agreement into Articles, Sections and Subsections, the insertion of headings and the provision of any table of contents are for convenience of reference only and will not affect the construction or interpretation of this Agreement.

1.3 Unless the context requires otherwise, words importing the singular include the plural and vice versa and words importing gender include all genders. The word "including" means including without limitation.

1.4 Subject to any provision contained herein which requires immediate action, if any payment is required to be made or other action required to be taken pursuant to this Agreement on a day, which is not a Business Day, then such payment or action will be made or taken on the next Business Day.

1.5 Any reference in this Agreement to any statute, order or code or any section thereof will, unless otherwise expressly stated, be deemed to be a reference to such statute or section as amended, restated or re-enacted from time to time.

1.6 Unless the context requires otherwise, references in this Agreement to Sections or Schedules are to Sections or Schedules of this Agreement.

1.7 The following Schedules form part of and are hereby incorporated by reference into this Agreement:

Schedule A - Definitions
Schedule B – Description of Feeder Lines and Equipment
Schedule C – Contacts

1.8 Each of the Parties hereby agree to be bound by and at all times to comply with the Code, and each Party acknowledges and agrees that the other is bound at all times to comply with the Code in addition to complying with the provisions of this Agreement.

1.9 Milton Hydro agrees to comply with the terms and conditions set out in the OHEDI's Conditions of Service.

Article 2

OWNERSHIP AND USE OF FEEDER LINES

2.1 The Feeder Lines and all equipment and hardware connecting the Feeder Lines to the MTS 1 and to the Connection Points and described as **"OHEDI Equipment"** as listed on Schedule B, are owned wholly by OHEDI and form part of the OHEDI Distribution System.

2.2 Except as specifically provided in this Agreement, Milton Hydro will have no rights to access any of the OHEDI Distribution System, lands or property owned by OHEDI, and OHEDI will have no rights to access any of the Milton Hydro Distribution System, lands or property owned by Milton Hydro.

2.3 Milton Hydro acknowledges and agrees that all metering and other equipment and other hardware listed in Schedule B as the OHEDI Equipment is owned wholly by OHEDI. OHEDI acknowledges and agrees that all metering and other equipment and other hardware listed in Schedule B as the Milton Hydro Equipment is owned wholly by Milton Hydro.

2.4 Milton Hydro will notify OHEDI of any proposed embedded generation facility that Milton Hydro proposes to connect to Glenorchy MTS1 under normal circuit configuration or potential alternate switching conditions. Milton Hydro agrees that:

(a) OHEDI has the right to participate in all discussions, planning and interconnection designs for such proposed embedded generation facility; and

(b) Milton Hydro will not connect any proposed embedded generation facility without the prior written consent of OHEDI, which consent will not be unreasonably withheld or delayed.

(c) For any proposed embedded generation facilities over 10kW, a connection impact assessment (CIA) will be required for the OHEDI system and Hydro One system. The costs of the CIA(s) are to be borne by Milton Hydro and/or the embedded generator proponent. OHEDI will not be subject to any costs if the Ontario Power Authority, or any other regulatory body, changes existing rules or introduces new programs during the initial or any subsequent renewal terms of the agreement. Any additional costs due to such changes are to be borne by Milton Hydro and/or the embedded generator proponent.

Article 3

CAPACITY ALLOCATION; CONNECTION

3.1 OHEDI agrees to allocate to Milton Hydro capacity at MTS 1 ("**Capacity Allocation**"). The Parties agree that the Capacity Allocation at any particular time during the Initial Term will be 40 MW. Milton Hydro agrees to abide by the terms of their existing TCA (Transmission Connection Agreement) with Hydro One.

(a) Milton Hydro will deliver to OHEDI the Initial Load Forecast within sixty (60) days of the acceptance of this agreement. In subsequent years Milton Hydro will deliver annual load forecasts ("Load Forecast") no later than sixty (60) days prior to the end of each calendar year. The Load Forecast shall include a forecast of kW demand for each month during the remaining term of the agreement. Milton Hydro acknowledges that its initial estimated Load Forecast will form the basis for OHEDI's most recent cost of service application.

(b) Milton Hydro further acknowledges that the Initial Load Forecast will form the basis for the Average Annual Load Forecast, which, subject to Article 11, Milton Hydro commits to meet over the course of each calendar year until OHEDI's next Cost of Service Application, thereby providing OHEDI with no Customer Connection Risk. Milton Hydro further acknowledges that the Load Forecast that forms the basis for the Average Annual Load Forecast will be reset at the time of OHEDI's subsequent Cost of Service Applications based upon the new Load Forecast provided by Milton Hydro in preparation for OHEDI's subsequent Cost of Service Applications.

(c) Oakville Hydro shall perform a True-up based on the difference between the Actual Load and the Average Annual Load Forecast once annually. If the result of a True-up is that Actual Load is less than the Average Annual Load Forecast, Milton Hydro agrees to pay Oakville Hydro an amount equal to the revenue shortfall. If the result of a True-up is that Actual Load is higher than the Average Annual Load Forecast no True-up payment will be required.

(d) The Capacity Allocation for a Renewal Term will be determined by OHEDI, acting reasonably and with consideration of the current load forecasts of OHEDI and Milton Hydro and system capacity constraints of the OHEDI Distribution System. Milton Hydro will submit its Load Forecasts and Average Annual Load Forecast to OHEDI with any request for a Renewal Term pursuant to Section 8.4.

3.2 In addition to granting the Capacity Allocation, OHEDI grants Milton Hydro, access to and use of the overhead facilities of the OHEDI Distribution System for the period beginning on the Effective Date and ending on the day on which OHEDI installs and connects its underground cable from Milton Hydro's overhead Connection Point to the cable termination point on the switchgear. OHEDI will incur the cost to purchase and install the underground cable. Milton Hydro agrees to pay OHEDI for all other connection and commissioning costs which OHEDI charges to its other regular customers in accordance with the Conditions of Service.

Article 4

OPERATING PROCEDURES AND COMMUNICATION

4.1 OHEDI provides no guarantee and/or makes no representation or warranty regarding the reliability of electricity supply from the MTS 1 to the Feeder Lines at the Connection Points.

4.2 OHEDI will retain all operational and maintenance responsibilities beginning with the terminations on the cable at Milton Hydro's overhead Connection Point and continuing upstream through the breaker to the transmission connection point. OHEDI will retain control over the breakers supplying the Feeder Lines from MTS 1. Milton Hydro agrees to coordinate feeder switching with OHEDI's system operators and to adhere to OHEDI's system requirements as they pertain to the MTS 1 when switching or transferring load between stations. The Parties agree to communicate with each other in accordance with this Section.

(a) All communications between the Parties about day-to-day operating and maintenance matters shall at all times go through the Controlling Authorities of each Party, or those other persons to whom a Controlling Authority has delegated the communication authority listed in Schedule "C".

(b) Each Party shall provide the other with the name of a current 24-hour contact to respond to operating and maintenance matters, which shall be listed in Schedule "C", as amended from time to time.

(c) Each Party shall provide the other with its Emergency Operations Plan, identifying reporting procedures and the names of site Emergency coordinators upon acceptance of this agreement.

(d) Each Party shall provide the other with all required Work Protection documentation and written notices.

(e) Where one Party's work requires the other's participation or cooperation, or in the other's opinion could adversely affect normal operation of its facilities and equipment, the Parties shall establish procedures for the work and adhere to them in performing the work unless they agree otherwise in writing.

4.3 The Parties will comply with the protocol for switching set out in this Section.

(a) A Party's Controlling Authority shall be responsible for establishing in writing for agreement by the other Party, the appropriate conditions for and the co-ordination of switching on the equipment under its control from time to time throughout the term of the Agreement.

(b) When the Parties have so agreed in writing, one Party may appoint an employee of the other as its designate for switching purposes.

(c) The Parties shall comply with all switching instructions issued by the Controlling Authority to maintain the security and reliability of the MTS 1. The Controlling Authorities shall agree to procedures prior to undertaking any switching operations.

4.4 Isolation of Milton Hydro Equipment

(a) If Milton Hydro requires isolation from MTS 1, then Milton Hydro's Controlling Authority shall request OHEDIs' Controlling Authority to provide a Supporting Guarantee or alternative method of work protection and isolation. The notice shall set out OHEDI's assigned equipment operating designations if applicable. Milton Hydro Equipment designations shall be set out in the notice whenever OHEDIs' equipment operating designations have not been assigned.

(b) Upon the request of one Party's Controlling Authority, the other Party's Controlling Authority or its designate shall provide the required timely isolation of equipment as required for Emergency switching or to establish a Supporting Guarantee or alternative method of work protection and isolation.

(c) OHEDI shall provide to Milton Hydro the isolation and reconnection at Milton Hydro's request. Milton Hydro shall pay OHEDI's incurred costs for isolating and reconnecting Milton Hydro Equipment and other station related services in accordance with the Conditions of Service.

4.5 Isolation of OHEDI Facilities and Equipment

(a) If OHEDI requires isolation from Milton Hydro Equipment then OHEDI shall request Milton Hydro's Controlling Authority to provide a Supporting Guarantee or alternative method of work protection and isolation.

(b) The Supporting Guarantee shall identify OHEDI's assigned equipment operating designations if applicable.

4.6 Forced Outages

(a) When a Forced Outage by one Party adversely affects the other's facilities, the first Party's Controlling Authority shall give Prompt notice to the Controlling Authority of the other Party.

(b) Each Party's Controlling Authority shall have sole authority to identify the need for and initiate a Forced Outage on equipment under its control.

4.7 Planned Outages

(a) Each Party shall schedule all planned work with the other Party's Controlling Authority to co-ordinate Planned Outages that directly affect the other Party's facilities and equipment.

(b) At least five Business Days in advance of planned work, Milton Hydro's Controlling Authority shall provide written requests to the appropriate OHEDI contact identified in "Schedule C" of this Agreement if the planned work involves:

(i) any Disconnection from the MTS 1; or

(ii) load changes to or from another TS, transfers or switching operations that will involve another TS, or load transfers between MTS 1 supply points that will exceed agreed upon feeder loading limits.

(c) Either Party's Controlling Authority shall provide notice of a change in the date and time of pre-planned work at least three (3) Business Days in advance of the planned date. If a changed date cannot be agreed upon, OHEDI will have the right to set the date of the Planned Outage upon providing Milton Hydro with not less than three (3) Business Days prior notice.

4.8 Insurance

(a) Milton Hydro will be responsible for taking out and maintaining, at its sole expense, commercial general liability insurance covering liability arising from use of the MTS 1 and connection to the OHEDI Feeder Lines, in accordance with this Agreement, with a limit of five million ($5,000,000) dollars per occurrence. Milton Hydro will provide OHEDI with a certificate or certificates of insurance evidencing continuity and compliance with the insurance requirements set forth in this, Section 4.8(a), not less than thirty (30) days prior to the expiration of the then-current policy, and shall deposit promptly with OHEDI, insurance certificates for every policy of and renewal certificate for such insurance (or a certified copy thereof). The insurance certificates will provide that OHEDI is named as an additional insured on such liability policy. The insurance certificates will provide that OHEDI will receive thirty (30) days' prior written notice from the insurer of any termination or material reduction in the amount or scope of coverage. Delivery to and examination by OHEDI of any policy of insurance or certificate thereof or other evidence of insurance in no way will relieve Milton Hydro of any of its obligations to insure in strict compliance with the provisions of this Section 4.8(a) and in no way shall operate as a waiver by OHEDI of any of its rights.

Article 5

MAINTENANCE

5.1 Only Qualified persons will perform operations and maintenance.

5.2 Milton Hydro will, at its sole cost, be responsible for operating and maintaining, repairing and replacing from time to time, on a timely basis, the Milton Hydro Equipment in accordance with Good Utility Practice, all Applicable Law, the Code and this Agreement.

5.3 OHEDI will, at its sole cost, be responsible for operating and maintaining, repairing and replacing from time to time, on a timely basis, the Feeder Lines and the OHEDI Equipment in accordance with Good Utility Practice, all Applicable Law, the Code and this Agreement.

Article 6

EMERGENCY OPERATING PROCEDURES

6.1 OHEDI may be required from time to time to interrupt the connection to Milton Hydro during an Emergency to protect the stability, reliability, and integrity of MTS 1, or to maintain its equipment availability. During an Emergency, either Party may take whatever immediate action it deems necessary and is Qualified to perform to safeguard public safety, life, and property without first notifying the other Party.

Article 7

FEES AND CHARGES

7.1 During the term of this Agreement, OHEDI will be responsible for all connection and commissioning costs and expenses associated with connecting to the MTS 1. Milton Hydro will be responsible for the cost of any additional communication and monitoring equipment installed at the request of Milton Hydro. Milton Hydro will be responsible for all initial protection and control costs, associated with the connection to MTS1, such costs to be in accordance with the Conditions of Service which apply to OHEDI's regular customers. Milton Hydro will reimburse OHEDI for all costs associated with the initial administration of this Agreement including, but not limited to, OHEDI's legal fees, consulting fees and management and other administrative costs, such amount to be paid by Milton Hydro within thirty (30) days of the later of Milton Hydro's acceptance of this Agreement and receipt by Milton Hydro of an invoice from OHEDI.

7.2 The Demarcation Point will be the OHEDI disconnect switches, C4213-B and C4214-B, on the Milton Hydro termination poles, #10150 & #10201. OHEDI owns the drop leads from the Milton Hydro conductor to the OHEDI switches.

7.3 During the term of this Agreement, OHEDI will invoice Milton Hydro for fees and charges for the provision of distribution services by OHEDI, and all other applicable charges approved or authorized by the OEB, pursuant to OHEDI's Rate Order or Applicable Law, (all such fees and charges collectively, the "Fees") in accordance with

OHEDI's regular billing cycle. Milton Hydro agrees to pay the Fees on or before the due date as set out in the invoice in accordance with the Conditions of Service. OHEDI will adjust the Fees by the applicable loss factors, as approved in OHEDI's Rate Order, for purposes of determining Milton Hydro's non-competitive electricity costs. Any amount required to be paid under this Agreement which is not paid on the applicable due date, will bear interest at the rate approved by the OEB and in accordance with the Conditions of Service.

7.4 Notwithstanding the OHEDI Equipment will be owned wholly by OHEDI, the Parties agree that if Milton Hydro is not a wholesale market participant registered with the IESO, OHEDI will provide revenue metering information for the settlement and billing of Milton Hydro for commodity charges and associated charges, and will assume the associated responsibilities and obligations of a registered wholesale market participant in accordance with the Market Rules and Applicable Law. If Milton Hydro becomes a wholesale market participant registered with the IESO, then Milton Hydro will settle its commodity and other associated charges directly with the IESO.

7.5 In addition to the Fee, Milton Hydro will be responsible for paying all commodity charges relating to electricity delivered to Milton Hydro and Regulatory Charges in accordance with the Rate Order including all transmission charges imposed by OHEDI or any other Transmission Service Provider plus any applicable Taxes thereon, as specified in the Rate Order.

Article 8

TERM AND TERMINATION

8.1 This Agreement will be effective and will bind the Parties from the Effective Date.

8.2 Unless terminated earlier in accordance with the terms of this Agreement, the initial term of this Agreement will commence on the Effective Date and end on the day that the OEB issues a rate order for OHEDI in 2022 (the "**Initial Term**").

8.3 Upon termination of this agreement Milton Hydro will, at its own cost, remove the Milton Hydro Equipment installed at MTS 1, unless both parties agree in writing that OHEDI will acquire such assets from Milton Hydro at a mutually agreed price.

8.4 Provided Milton Hydro is not in default of any material obligations under this Agreement, Milton Hydro may request that this Agreement be renewed in accordance with this Section 8.4 for a successive four (4) year period (each agreed renewal, a "**Renewal Term**") by providing OHEDI with a written notice of such request for renewal no more than two (2) years and no less than one (1) years before the last day of the Initial Term or Renewal Term, as applicable. Milton Hydro must deliver to OHEDI, together with such notice of renewal request, its load forecast for the applicable Renewal Term.

The load forecast must include a forecast of kW demand for each month remaining in the term of the Agreement and in the proposed Renewal Term. OHEDI's acceptance of any request by Milton Hydro for a Renewal Term will be in its sole discretion.

8.5 Milton Hydro may, at any time (subject to the other provisions of this Section 8.5), terminate this Agreement by providing OHEDI with prior written notice of its intention to terminate the Agreement no less than one year prior to the date of filing of OHEDI's then following Cost of Service rate application with the OEB and specifying the effective date of termination. If Milton Hydro terminates this Agreement pursuant to this Section 8.5 where the effective date of termination is:

(a) as of or after the date of the Rate Order established by the OEB for OHEDI's then following Cost of Service rate application, then no amount whatsoever will be payable to OHEDI arising from Milton Hydro's termination of this Agreement in accordance with this Section 8.5;

(b) prior to the date of the next Rate Order established by the OEB for OHEDI's then following Cost of Service rate application, Milton Hydro will pay OHEDI (in accordance with the payment provisions of Section 7.3 which shall be calculated in accordance with the Load Forecasts established by Milton Hydro as set out in Section 3.1 of this Agreement) an amount equal to the present value of the foregone distribution charges for the period from the effective termination date until the effective date of rates approved by the OEB in OHEDI's then following Cost of Service rate application.

For example, if: (1) the date of OHEDI's then following Cost of Service rate application with the OEB is April 30, 2017, (2) Milton Hydro gives written notice of termination to OHEDI in accordance with this Section 8.5 on or before April 30, 2016, (3) the date of the next Rate Order established by the OEB for OHEDI's then following Cost of Service rate application is January 1, 2018 and (4) if the effective date of termination specified in Milton Hydro's notice of termination is on or after December 31, 2016; then no amount whatsoever will be payable to OHEDI by Milton Hydro arising from the termination of this Agreement.

The following table illustrates two examples of the calculation of the foregone revenue.

Table 1 - Example of Foregone Distribution Charge Calculations

		Cost of Service Application		
Notice of Termination Date	**Termination Date**	**Submission Date**	**Effective Date**	**NPV of Foregone Distribution Charges**
Prior to April 30, 2016	March 31, 2017	April 30, 2017	January 1, 2018	April 1, 2017 to December 31, 2017
Prior to April 30, 2016	January 1, 2018	April 30, 2017	January 1, 2018	Not Applicable

(c) In order for Milton Hydro to comply with this Section 8.5, OHEDI will provide Milton Hydro with 14 months written notice of OHEDI's then following Cost of Service rate application filing date and requested date of OHEDI's Rate Order.

(d) Milton Hydro shall not be penalized in the case where OHEDI submits its next rate application after the dates provided to Milton Hydro in (c) above and the implementation of the Rate Order is deferred or in the event OHEDI elects to defer its then following Cost of Service rate application.

8.6 OHEDI may terminate this Agreement by providing Milton Hydro with prior written notice of its intention to terminate the Agreement not less than two years prior to the submission date of OHEDI's then following Cost of Service rate application and specifying the effective date of termination which effective date of termination shall be not earlier than the effective date of the next Rate Order established by the OEB for OHEDI's then following Cost of Service rate application.

8.7 The occurrence of any of the following will constitute an event of default ("**Event of Default**") on the part of the defaulting party:

(a) failure to pay any sum due and owing hereunder within thirty (30) days of receipt of a written notice of failure to pay; or

(b) failure to comply with any other material covenant or obligation set forth in this Agreement within sixty (60) days receipt of written notice of default from the non-defaulting party.

8.8 Upon the occurrence of an Event of Default, the non-defaulting party will have the right to give written notice of termination to the defaulting party whereupon the Agreement will terminate as at the effective date of termination specified in the written notice.

8.9 Without prejudice to any other rights which the non-defaulting party, if applicable, may have hereunder, upon termination of the Agreement for any reason:

(a) all amounts then owing pursuant to this Agreement will immediately become due and payable by the defaulting party, and if and only if this Agreement is terminated by OHEDI in circumstances where Milton Hydro is the defaulting party then Milton Hydro shall be required to pay the net present value of the foregone distribution charges for the period from the date of termination until the effective date of the next Rate Order established by the OEB for OHEDI's then following Cost of Service rate application with such amount to be calculated as set out in Section 8.5 hereof;

(b) the relevant provisions of this Agreement will continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the date of termination of this Agreement and for the payment of any monies due and owing pursuant to this Agreement with respect to the period prior to the termination date;

(c) the termination of this Agreement will not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and will not affect any continuing obligations of either party under this Agreement, which are intended to continue after termination of such Agreement; and

(d) OHEDI may disconnect Milton Hydro at the MTS 1 from the OHEDI Distribution System where OHEDI is the non-defaulting party.

8.10 Any obligation of either Party to the other pursuant to the terms and conditions of this Agreement which is outstanding or due upon the termination of this Agreement will survive such termination including any obligation to indemnify hereunder.

Article 9

REPRESENTATIONS AND WARRANTIES

9.1 Representations and Warranties of OHEDI

OHEDI represents and warrants to Milton Hydro as follows and acknowledges that, except as otherwise expressly provided herein, Milton Hydro is relying on such representations and warranties in connection with this Agreement.

(a) OHEDI is a corporation duly incorporated and validly subsisting under the laws of Ontario and has the corporate power, capacity and authority to enter into this Agreement and perform its commitments and obligations under this Agreement. OHEDI has taken, or has caused to be taken all action required to be taken by OHEDI to authorize the execution and delivery of this Agreement.

(b) This Agreement has been duly executed by OHEDI and will, upon delivery, constitute a valid and binding obligation of OHEDI, enforceable against it in accordance with its terms.

9.2 Representations and Warranties of Milton Hydro

Milton Hydro represents and warrants to OHEDI as follows and acknowledges that, except as otherwise expressly provided herein, OHEDI is relying on such representations and warranties in connection with this Agreement.

(a) Milton Hydro is a corporation duly incorporated and validly subsisting under the laws of Ontario and has the corporate power, capacity and authority to enter into this Agreement and perform its commitments and obligations under this Agreement. Milton Hydro has taken, or has caused to be taken all action required to be taken by Milton Hydro to authorize the execution and delivery of this Agreement.

(b) This Agreement has been duly executed by Milton Hydro and will, upon delivery, constitute a valid and binding obligation of Milton Hydro, enforceable against it in accordance with its terms.

Article 10

INDEMNIFICATION

10.1 Subject to Section 14.3 hereof, each Party (the "**Indemnifying Party**") will indemnify, defend and hold harmless the other Party and the other Party's affiliates, and its and their directors, officers, employees, and agents (each an "**Indemnified Party**"), from and against all claims, losses, damages, costs, liabilities, obligations, and expenses (including reasonable legal fees) suffered by the Indemnified Party caused by, or arising directly from a claim by a third party relating to:

(a) the inaccuracy, incorrectness or breach of any representation or warranty made by the Indemnifying Party in this Agreement;

(b) the operation, control and/or maintenance of the Indemnifying Party's electricity distribution system; or

(c) the Indemnifying Party's performance or failure to perform its obligations under this Agreement including, where Milton Hydro is the Indemnifying Party, Milton Hydro's failure to pay any amounts with respect to the consumption of electricity to the IESO or any Regulatory Charges as provided in Section 7.4;

in each case except to the extent that the claims, losses, damages, costs, liabilities, obligations or expenses are determined to have resulted solely from the acts, omissions, negligence or intentional misconduct of the Indemnified Party.

Article 11

FORCE MAJEURE

11.1 "**Force Majeure**" means, any event or circumstance which is (i) beyond the reasonable control of a Party, (ii) does not result from the negligence or fault of such Party or any of its Representatives and (iii) results in, or causes, the inability of a Party to perform any of its obligations under the Agreement or results in electricity not flowing from the OHEDI Distribution System to the Connection Points or causes the OHEDI Distribution System to be incapable of being operated lawfully, safely or at all, or causes the Milton Hydro Distribution System to be incapable of being operated lawfully, safely or at all; provided however that lack of funds will not be interpreted as a cause beyond the reasonable control of a Party. If a Party is unable to carry out any of its obligations under this Agreement because of the occurrence of an event of Force Majeure, the obligations of such Party and the corresponding obligations of the other Party will be suspended to the extent necessary by and during the continuance of such Force Majeure. In the event of the occurrence of an event of Force Majeure, the Party who is unable to perform as a result of such event shall give written notice to the other Party. Immediately after the end of the event giving rise to the Force Majeure each Party shall forthwith proceed to satisfy its obligations pursuant to this Agreement.

Article 12

DISPUTE RESOLUTION

12.1 In the event of any dispute arising out of this Agreement, OHEDI and Milton Hydro agree as follows:

(a) to attempt, in good faith, to negotiate a settlement of the dispute between themselves within forty-five (45) days from the date of the dispute arose;

(b) in the event that the parties cannot settle the dispute between themselves, either party may, following the passage of at least forty-five (45) days from the date the dispute arose (as evidenced by writing between the parties) either party may submit the dispute for arbitration by a single arbitrator in accordance with the *Arbitration Act, 1991 (Ontario)*; provided that, in the event the dispute relates solely to the payment of money under this Agreement, the submitting of the dispute for arbitration will operate as a stay in respect of the payment of monies to the extent of the amount in dispute until such time as the decision of the arbitrator is rendered; and

(c) the decision of the arbitrator will be final and binding with no right of appeal.

Article 13

NOTICES

13.1 Any notice, consent, payment or other communication required or permitted to be given or made in writing under this Agreement will be in writing and will be effectively given and made if (i) delivered personally, (ii) sent by prepaid courier service or mail, or (iii) sent by fax or other similar means of electronic communication, in each case to the applicable address set out below:

if to OHEDI, to:

P.O. Box 1900
861 Redwood Square
Oakville, ON L6K 0C7

Attn: Mike Brown
Vice President – Engineering and Operations, Chief Operating Officer
Fax No: 905-825-4469
Email: mbrown@oakvillehydro.com

if to Milton Hydro, to:

8069 Lawson Road
Milton, Ontario L9T 5C4

Attn: Frank Lasowski

Fax No: 905-876-2044
Email: lasowskif@miltonhydro.com

Any such communication so given or made will be deemed to have been given or made and to have been received on the day of delivery if delivered, or on the day of faxing or sending by other means of recorded electronic communication, provided that such day in either event is a Business Day and the communication is so delivered, faxed or sent prior to 4:30 p.m. on such day. Otherwise, such communication will be deemed to have been given and made and to have been received on the next following Business Day. Any such communication sent by mail will be deemed to have been given and made and to have been received on the fifth Business Day following the mailing thereof, provided however that no such communication will be mailed during any actual or apprehended disruption of postal services. Any such communication given or made in any other manner will be deemed to have been given or made and to have been received only upon actual receipt.

Any Party may from time to time change its address or contact person under this Section by prior written notice to the other Party given in the manner provided by this Section.

13.2 All other notice or communication required or permitted under this Agreement will be made by facsimile, telephone call or other simultaneous voice communication at the number(s) and to the persons and/or departments set out in Schedule C. The deposit of a voice message will not be considered prior notice under this Agreement where such notice is required.

13.3 Each Party will be able to contact the other party by telephone or other simultaneous voice communication at the number(s) as set out in Schedule C on a twenty-four (24) hour basis at all times.

13.4 In no circumstances will the Parties make any change to the contact information contained in Schedule C without (a) delivering prior written notice to the other Party in accordance with Section 13.1 and (b) receiving written confirmation back of receipt of such written notice. The Parties hereby acknowledge that the nature of the operation of the Party's distribution systems is that instantaneous and/or emergency communication may be required from time to time and therefore, the contact information contained in Schedule C must be correct at all times and within the actual knowledge of each Party in order to safeguard life and property.

Article 14

GENERAL

14.1 Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction will, as to that jurisdiction, be ineffective to the extent of such prohibition or unenforceability and will be severed from the balance of this Agreement, all without affecting the remaining provisions of this Agreement or affecting the validity or enforceability of such provision in any other jurisdiction.

14.2 This Agreement constitutes the entire Agreement between the Parties pertaining to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written. There are no conditions, warranties, representations or other agreements between the Parties in connection with the subject matter of this Agreement (whether oral or written, express or implied, statutory or otherwise) except as specifically set out in this Agreement

14.3 Notwithstanding anything to the contrary in this Agreement, neither party will be liable to the other for special, indirect or consequential damages (including, without limitation, lost profit) arising from or in connection with this Agreement including, without limitation, out of the performance or non-performance of this Agreement, whether arising out of negligence, tort, strict liability, breach of contract, or breach of warranty, including but not limited to damages in the nature of loss of profits or revenues, loss of use of facilities or equipment, and claims of third parties. The provisions of this Section 14.3 will survive termination or expiry of this Agreement.

14.4 Neither Party may assign this Agreement without the prior written consent of the other Party which consent will not be unreasonably withheld.

14.5 The Parties acknowledge that an amalgamation or change of Control of a Party shall be deemed to be an assignment of this Agreement which requires the consent of the other Party pursuant to Section14.4.

14.6 This Agreement will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable in that Province and will be treated, in all respects, as an Ontario contract. The Parties hereby attorn to the exclusive jurisdiction of the courts of Ontario.

14.7 Time will be of the essence of this Agreement in all respects.

14.8 Each Party will, promptly do, execute, deliver or cause to be done, executed and delivered all further acts, documents and things in connection with this Agreement that the other Party may reasonably require, for the purposes of giving effect to this Agreement and the spirit and intent of this Agreement.

14.9 No amendment of this Agreement will be effective unless made in writing and signed by the Parties.

14.10 A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. No waiver will be inferred from or implied by any failure to act or delay in acting by a Party in respect of any default, breach or non-observance or by anything done or omitted to be done by the other Party. The waiver by a Party of any default, breach or non-compliance under this Agreement will not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-observance (whether of the same or any other nature).

14.11 This Agreement will ensure to the benefit of, and be binding on, the Parties and their respective successors and permitted assigns.

14.12 This Agreement may be executed in any number of counterparts, each of which will be deemed to be an original and all of which taken together will be deemed to constitute one and the same instrument. Counterparts may be executed either in original or faxed form and the Parties adopt any signatures received by a receiving fax machine as original signatures of the Parties; provided, however, that any Party providing its signature in such manner will promptly forward to the other Party an original of the signed copy of this Agreement which was so faxed.

14.13 Subject to the Section 14.9 (the requirement that any amendment made hereto be made in writing and signed by the Parties), either Party, acting reasonably, may request that the Parties review this Agreement. In any event, the Parties will meet at least every two (2) years (the "Bi-Annual Review"), commencing within fifteen (15) Business Days of the second anniversary of this Agreement, to review the terms and conditions of this Agreement. The Parties agree to meet within fifteen (15) Business Days of the anniversary date of this Agreement during each year in which a Bi-Annual Review is to take place.

IN WITNESS WHEREOF the Parties hereto by their duly authorized representatives have executed this Agreement as of the date first written above.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

By: ______________________
Name: Mike Brown,
Title: Vice President, Engineering & Operations, Chief Operating Officer

By: ______________________
Name: Dan Steele,
Title: Director, Engineering & Construction

I/We have the authority to bind the Corporation

MILTON HYDRO DISTRIBUTION INC.

By: ______________________
Name: Frank Lasowski
Title: President & CEO

By: ______________________
Name: Mary-Jo Corkum
Title: Vice President, Finance

I/We have the authority to bind the Corporation

SCHEDULE A

DEFINITIONS

In this Agreement, the following terms will have the meanings set out below unless the context requires otherwise.

"**Agreement**" means this Connection Agreement including the Schedules to this Connection Agreement as it or they may be amended or supplemented from time to time, and the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Connection Agreement and not to any particular Section or other portion of this Connection Agreement.

"**Applicable Law**" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments, or decree or any requirements or decision or agreement with or by any government or governmental department, commission, board, court authority or agency.

"**Business Day**" means any day except Saturday, Sunday or any day on which banks are generally not open for business in the Town of Oakville and the Town of Milton.

"**Capacity Allocation**" means the maximum load that Milton Hydro can take from the MTS 1.

"**Code**" means the code, approved by the OEB, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of electricity distribution systems.

"**Conditions of Service**" means the conditions of service document as developed by OHEDI in accordance with the Code that describes OHEDI's operating practices and connection rules, as it may be amended or re-issued from time to time.

"**Connection Points**" means the points of interconnection between the OHEDI Distribution System and the Milton Hydro Distribution System. The Milton Hydro termination poles are located in the northwest quadrant of Sixth Line and the entrance to Glenorchy MTS1. The connection points are:

- At Milton Hydro pole #10150, the drop lead from the Milton Hydro conductor to OHEDI switch C4213-B
- At Milton Hydro pole #10201, the drop lead from the Milton Hydro conductor to OHEDI switch C4214-B

"**Control**" means, with respect to any Person at any time, (i) holding, whether directly or indirectly as owner or beneficiary, other than solely as the beneficiary of an unrealised security interest, securities or ownership interests of that Person carrying votes or ownership interests sufficient to elect or appoint a majority of the individuals who are responsible for the supervision or management of that Person, or (ii) the exercise of de-facto control of that Person, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract or trust or otherwise.

“**Controlling Authority**” means a person or officer responsible for performing, directing, or authorizing changes in the conditions or physical position of specific apparatus or devices;.

“**Cost of Service**” means the OEB Cost of Service application.

“**Demarcation Point**” means the physical location(s) identified in Section 7.2 at which a Party’s responsibility for operational control and ownership of distribution equipment, including but not limited to, connection assets, ends.

“**Effective Date**” means the date first written above in this Agreement.

"**Emergency**" means an imminent or existing condition or situation which in the reasonable judgment of OHEDI will affect the ability of OHEDI to maintain a condition of safety in relation to either of the Feeder Lines and the OHEDI Distribution System.

“**Feeder Lines**” means the OHEDI cables, terminations, splices, and associated equipment between the connections at Glenorchy MTS1 and OHEDI switches C4213-B & C4214-B, at Milton Hydro poles #10150 & #10201.

“**Fees**" are defined in Article 7.3.

“**Forced Outage**” means the automatic or manual limitation of service by a Party's Controlling Authority, owing to de-rating or limitation of equipment, or the unavailability of equipment as a result of actual or potential failure of that equipment or equipment related to it.

“**Good Utility Practice**” has the meaning given to such term in the Code.

"**IESO**" means the Independent Electricity System Operator of Ontario or any successor or other person of competent authority exercising the same functions as the IESO.

"**Indemnified Party**" is defined in Section 10.1.

"**Indemnifying Party**" is defined in Sections 10.1.

“**Initial Term**” will have the meaning set out in Section 8.2

"**Milton Hydro Distribution System**" means the electricity distribution system owned and operated by Milton Hydro.

"**Milton Hydro Equipment**" has the meaning set out in Schedule B.

"**MTS 1**" is defined in the Recitals.

"**Market Rules**" means the rules made pursuant to Section 32 of the *Electricity Act, 1998* (Ontario) as they may be amended from time to time.

"**OHEDI Distribution System**" means the electricity distribution system owned and operated by OHEDI.

"**OHEDI Equipment**" is defined in Section 2.1.

"**OEB**" means the Ontario Energy Board or any successor or other competent authority exercising the same functions as the OEB from time to time.

"**Party**" means a party to this Connection Agreement and any reference to a Party includes its successors and permitted assigns; "Parties" means every Party.

"**Person**" means a natural person, individual, firm, trust, partnership, limited partnership, company or corporation, joint venture, sole proprietorship, Governmental Authority or other entity of any kind.

"**Planned Outage**" means an outage that results when a component is deliberately taken out of service at a pre-selected time, usually for the purpose of construction, preventive maintenance or repair.

"**Qualified**" means assessed by a party as satisfactory in personal competency, familiarity with and knowledge of all applicable rules, regulations, guidelines, policies, codes, procedures, apparatus and equipment, and dangers of work and operation;

"**Regulatory Charges**" means any regulated or non-competitive charges or rates including any congestion, uplift, transmission or other charges that may be assessed or imposed from time to time by the IESO, OEB, Transmission Service Provider or other governmental authority or regulatory agency relating to the ownership or control of the Feeder Lines and any electricity consumed by Milton Hydro through the Feeder Lines.

"**Rate Order**" means an order of the OEB that is in force at the relevant time which, among other things, regulates distribution rates and charges to be charged by a licensed distributor;

"**Renewal Term**" will have the meaning set out in Section 8.4.

"**Taxes**" means any and all taxes imposed by a governmental authority including HST, ad valorem, (including any provincial sales, excise or similar taxes), generation, conservation, transmission, utility, sales, use, consumption, excise, transaction and other taxes, or increases therein.

"**Term**" will mean the Initial Term together with each Renewal Term, if any.

SCHEDULE B

DESCRIPTION OF FEEDER LINES AND EQUIPMENT

1. OHEDI Equipment

- MTS 1 infrastructure existing prior to the Effective Date.
- Revenue meters to be installed at the Milton Hydro distribution poles
- Terminations
- Feeder cables to Milton Hydro termination poles
- disconnect switches on the Milton Hydro termination poles.

2. Milton Hydro Equipment

- Primary metering instrument transformers
- Protection & Control studies and/or settings
- Infrastructure to bring Milton Hydro's communication network into MTS 1
- Milton Hydro distribution poles and associated equipment

SCHEDULE C

CONTACTS

OHEDI

System Control
OHEDI Control Room
Tel: 905-825-8774
Email: ohcontrolroom@oakvillehydro.com

System Control
Mark Cybulski
System Control Supervisor
Tel: 905-825-9400 ext. 2338
Email: mcybulski@oakvillehydro.com

MTS1 / Protection & Control
Jeff Mocha
Manager, Assets & Control
Tel: 905-825-6366
Email: jmocha@oakvillehydro.com

System Planning / Load Forecasts
Dan Steele
Director, Engineering & Construction
Tel: 905-825-4474
Email: dsteele@oakvillehydro.com

Emergency
OHEDI Control Room
Primary Tel: 905-825-8774
Alternate Tel: 416-931-3913

Milton Hydro

System Control
Kyle Gervais
Operations Supervisor
Tel: 905-693-2517
Email: gervaisk@miltonhydro.com

System Control
Randy Coulson,
Operations Supervisor
Tel: 905-693-2902

Email: coulsonr@miltonhydro.com

System Control
Ron Brajovic
Manager, System Planning & Reliability
Office: (289)429-5206
Cell: (905)693-2901
ronbrajovic@miltonhydro.com

System Planning / Load Forecasts
Ron Brajovic
Manager, System Planning & Reliability
Office: (289)429-5206
Cell: (905)693-2901
ronbrajovic@miltonhydro.com

System Planning / Load Forecasts
Bruno Pereira
Director, Engineering
Office: (289)429-5213
Cell: (905)693-2900

Emergency - During Business Hours
Kyle Gervais
Operations Supervisor
Tel: 905-693-2517
Email: gervaisk@miltonhydro.com

Emergency - During Business Hours
Randy Coulson,
Operations Supervisor
Tel: 905-693-2902
Email: coulsonr@miltonhydro.com

Emergency - During Business Hours
Ron Brajovic
Manager, System Planning & Reliability
Office: (289)429-5206
Cell: (905)693-2901
ronbrajovic@miltonhydro.com

Emergency – After Normal Business Hours
On Call Lineman 1
905-693-2518

Emergency – After Normal Business Hours
On Call Lineman 2
905-693-2519
Emergency – After Normal Business Hours
Kyle Gervais
Operations Supervisor
Tel: 905-693-2517
Email: gervaisk@miltonhydro.com

Emergency – After Normal Business Hours
Randy Coulson,
Operations Supervisor
Tel: 905-693-2902
Email: coulsonr@miltonhydro.com

Appendix 1 – B

Sustainability Timeframe

Oakville Hydro Corporation

Corporate Sustainability Plan (CSP) Development Process and Timeline

Appendix 1 – C

Customer Survey Questions

TABLE OF CONTENTS

TABLE OF CONTENTS

Page #

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

Page #

Appendix 1 – D

Oakville Saves!

Welcome

Today's Agenda

Welcome

12 p.m.

Rob Lister, President and CEO of Oakville Hydro Corporation
Rob Lister has decades of experience in the energy industry. He is one of the region's foremost thought leaders in business and energy savings.

Mayor Rob Burton
Mayor Rob Burton is passionate about energy conservation and helping Oakville businesses improve operational efficiencies through energy cost savings.

Presentation of Oakville Saves! recognition certificates

12:45 p.m.

Stew Lawson, Senior Energy Technologist

OAKVILLE HYDRO
ELECTRICITY
DISTRIBUTION

Media Release

Oakville Hydro Electricity Distribution Inc. recognizes community businesses with Oakville Saves! recognition certificates

(Oakville, ON) November 20, 2013 – On Tuesday November 19, 2013, Oakville Hydro Electricity Distribution Inc. held a business luncheon event, recognizing local community businesses who have undertaken significant energy retrofit projects in their facilities, by honouring them with Oakville Saves! recognition certificates. These energy efficiency projects received financial incentives through a program called saveONenergy run by the Ontario Power Authority and delivered in Oakville by Oakville Hydro Electricity Distribution Inc.

"We congratulate businesses that have had outstanding success in reducing their energy consumption," said Rob Lister, President and CEO of Oakville Hydro Corporation. "Their actions have helped to improve their business efficiency and contribute to our efforts to make Oakville a leader in energy conservation."

"Our priority is to inspire Oakville businesses to take advantage of the saveONenergy programs," said Lister. "We have provided over $1.77 million in incentives to almost 180 local businesses and we want more organizations to access the financial incentives available for energy efficiency projects."

Town of Oakville councillors and Oakville Mayor Rob Burton were also in attendance to celebrate. "In the next few years we are confident more businesses will continue to move to Oakville, one of North America's most livable communities," commented Mayor Rob Burton. "Initiatives such as the saveONenergy retrofit program help give these businesses a competitive advantage and enhance our community's sustainability."

Businesses who received recognition certificates were: Canlan Ice Sports, GWL Realty Advisors, Henniges Automotive Schlegel Canada Inc., Metrican Mfg. Co. Inc., Morguard Corporation, the Regional Municipality of Halton, RioCan Real Estate Investment Trust, Sobeys Inc., Tim Hortons Inc., the Town of Oakville, UTC Aerospace Systems, and Xerox Canada. Examples of saveONenergy projects completed by these organizations include replacements and upgrades to more energy efficient lighting, motors and compressors, heating, ventilation and cooling systems, and refrigeration systems.

For additional information about Oakville Hydro Electricity Distribution Inc.'s energy conservation programs, please visit www.oakvillehydro.com/ohedi/conservation.aspx

-More-

About saveONenergy for business

The saveONenergy electricity conservation programs are developed by the Ontario Power Authority and delivered by local utilities. They offer incentives for businesses to reduce energy usage, and improve their bottom line. Financial incentives are available for activities such as energy audits, replacing old equipment and reducing electricity demand at peak times.

About Oakville Hydro Electricity Distribution Inc.

As a trusted utility, Oakville Hydro Electricity Distribution Inc., a subsidiary of Oakville Hydro Corporation, has been providing electricity distribution and asset management for the residents of Oakville for over 106 years. We commit to providing more than 65,000 residential and business customers with the best energy and conservation solutions. For more information, please visit www.oakvillehydro.com/ohedi/.

-30-

Contact:
Bridget Bacik
Oakville Hydro Electricity Distribution Inc.
905-825-4464
bbacik@oakvillehydro.com

Appendix 1 – E

Unlock Hidden Savings

saveONenergy
FOR BUSINESS

Unlock Hidden Savings

LUNCH provided!

Learn about incentive programs to help offset the cost of implementing energy efficient projects and **network with vendors and advisors** who can assist with retrofit projects.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
INVITES YOU TO JOIN US

TUESDAY, OCTOBER 8, 2013

Teatro Conference & Event Centre • 121 Chisholm Drive, Milton, ON L9T 4A6

Agenda

8:00 – 9:00 a.m.
Registration and vendor trade show

9:00 a.m.
Seminars

12:15 – 2:00 p.m.
Lunch and vendor trade show

Seminars

- Why companies should plan energy conservation as a budget item
- Planning a major renovation? Learn about available incentives
- Learn how retrofitting and right sizing air compressors can help to lower your energy bill
- How reducing peak time usage can earn you an incentive
- Maximizing energy savings while achieving optimal lighting levels
- New and improved HVAC incentives
- Monitor and track your energy usage

Seminars and lunch are complimentary, however **PRE-REGISTRATION IS REQUIRED.**
To register, please contact your local distribution company listed below.

RSVP: Wednesday, October 2, 2013.

In partnership with:

Burlington hydro inc.
Gail Boulton
conservation@burlingtonhydro.com
905-332-1851 ext. 236

Halton Hills Hydro
Linda Boyer
LindaB@haltonhillshydro.com
519-853-3700 ext. 239

Milton Hydro
Ted Robinson
robinsont@miltonhydro.com
289-429-5218

Oakville Hydro Electricity Distribution
Vivian Partridge
vpartridge@oakvillehydro.com
905-825-9400 ext. 2331

2-Performance Measures

Issue 2.1 *Does the applicant's performance in the areas of: (1) delivering on Board-approved plans from its most recent cost of service decision; (2) reliability performance; (3) service quality, and (4) efficiency benchmarking, support the application?*

2.1-Staff-13

Ref: 1) Exhibit 2/Appendix A- Asset Management Process Overview/p. 14
2) Exhibit 2/Tab5/Schedule 7

Reliability

The graph on this page of the Asset Management Process Review shows Oakville Hydro's record for historical reliability performance from 2006 to 2013. Considering that Oakville Hydro's performance has been good compared to province wide levels in this time period, how did Oakville Hydro consider this factor when budgeting to increase capital spending in future years?

RESPONSE:

As discussed in response to Board staff interrogatory number 1.1-Staff-6, Oakville Hydro optimizes its capital and maintenance costs throughout the lifecycle of the asset and makes its investment decisions using a condition based system analysis with a goal to extend the life of its assets rather than establishing budgets based on historical performance. Oakville Hydro's decision on the need for capital investments in future years is based upon its Asset Life Cycle Optimization Policies and Practices as discussed in its Distribution System Plan. One consideration that goes into the capital investment decisions is the need to maintain a balanced investment over many years and avoid systematic long-term depletion of distribution system assets that would essentially transfer enormous rebuilding costs to future ratepayers.

2.1-Staff-14

Ref: Exhibit 4/Tab 1/Schedule 2/p. 2 and Appendix A – Appendix 3

Customer Satisfaction Survey

Oakville Hydro indicates that its customer service has consistently met or exceeded minimum standards and this is also shown in the results of the Customer Satisfaction Survey, where Oakville Hydro consistently scores higher than the Ontario composite in many areas. How do these consistently high scores inform Oakville Hydro's planning to increase OM&A budgets for the test year?

RESPONSE:

The Customer Satisfaction survey and general feedback from customers has significant impact on Oakville Hydro's planning for 2014 and beyond. While Oakville Hydro has been able to deliver good customer service to its ratepayers, requests for service enhancements have been increasing. One such request is to provide self-serve options so that customers can access their information 24 hours a day, seven days a week. As discussed in Exhibit 1, Tab 2, Schedule 1, Pages 11 to 18 Oakville Hydro will undertake a number of the initiatives to improve its performance in the area of customer engagement. Some of the initiatives included in the 2014 Test Year are:

- Implementation of monthly billing
- Implementation of online forms – application for service and Pre-Authorized payment
- Interactive Voice Response system (IVR) to provide 24 hour access to account information
- Review of options to improve customer access to information during power outages
- Upgraded Web Presentment tool for Time-of-use data
- Targeted/specific customer survey(s) throughout the year to obtain additional feedback Benchmarking exercises to understand best practices
- Meter to Cash initiative – process re-engineering
- Social media

Oakville Hydro continues to work to understand customer needs and requirements and continues to incur costs for analysis and studies to ensure that the level of customer service does not deteriorate through lack of attention.

2.1-Staff-15

Ref: Exhibit 4/Tab3/Schedule 4

Headcount/Compensation Benchmarking

It appears that Oakville Hydro did not undertake any relevant studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators, and appears to have justified its proposed increases solely on the basis of its anticipated needs without any specific reference to any external comparators.

Please confirm whether or not Oakville Hydro took into account any external comparators when determining these increases. If yes, please state what they were and how they impacted on what is proposed in the application. If not, please state why not.

RESPONSE:

Please see Oakville Hydro's response to Board staff interrogatory number 4.2-Staff-29.

2.1-Energy Probe-5

Ref: Most Recent Cost of Service Decision

a) Please provide a list of all Board-approved plans from the most recent cost of service decision.

   RESPONSE:

   Oakville Hydro's last cost of service application (EB-2009-0271) of was the subject of a settlement agreement that was approved by the Board. In the settlement agreement, the parties agreed, for the purpose of complete settlement of all issues, that the 2014 Test Year capital expenditures would be reduced to $14,721,227. Since it last cost of service decision, the Board has approved two Oakville Hydro applications related to capital expenditures

- Incremental Capital Module – EB-2010-0104
- Smart Meter Prudence Review – EB-2012-0154

b) Please provide the evidence references in the current application that illustrates that the distributor is delivering on these approved plans.

RESPONSE:

Cost of Service Application – EB-2009-0271

As discussed in Oakville Hydro's Distribution System Plan, Oakville Hydro's 2010 capital expenditures were $1.9M higher than the capital expenditures agreed upon in Oakville Hydro's settlement agreement. As discussed on page 54 of Oakville Hydro's Distribution System Plan, the primary reason that capital additions were $1.9M higher was due to increased spending that was beyond Oakville Hydro's control. Actual expenditures for 27.6 kV additions, new development and services and road widening were $1.3M higher than budgeted.

Oakville Hydro also added a transformer replacement and voltage conversion in the Woodhaven Park Area to the 2010 capital program. Although this project was not part of planned capital spending, conditions were such that the replacement was required in 2010.

Incremental Capital Module – EB-2010-0104

In 2011, Oakville Hydro completed the construction of the Glenorchy Municipal Transformer Station in order to service the customers of North Oakville. In its 2011 IRM application (EB-2010-0104), Oakville Hydro received approval for the recovery of the incremental capital costs associated with the design and construction of the Glenorchy Municipal Transformer Station. In its Decision and Order, the Board found that the capital costs incurred were prudent and that Oakville Hydro had provided adequate evidence that potential alternatives were analyzed, and that the completion of the project represented the most cost-effective alternative for ratepayers.

The evidence that illustrates that Oakville Hydro has delivered on the Board approved capital expenditures in its 2011 Incremental Capital Module is provided in Exhibit 2, Tab 5, Schedule 6, pages 1 to 5.

As discussed in the evidence, actual capital spending was $1.5M or 7% higher than the estimate set out in that application. The main area in which actual capital spending exceeded the Board-approved amount was in the Duct and Civil and Building category. This was largely due to the condition of the site location which could not have been foreseen at the time of the application. Ground water flows were higher than the geotechnical survey predicted which affected the cost of the access road, infrastructure and storm water management.

Smart Meter Prudence Review – EB-2012-0154

On April 3, 2012, Oakville Hydro filed an application seeking approval for the recovery of its audited costs as at December 31, 2011 and its ongoing capital and OM&A costs associated with its smart meter deployment. In its decision, the Board approved Oakville Hydro's anticipated capital spending of $200,000 for upgrades to its Customer Information System ("Harris") and its ongoing OM&A costs of $415,887

Capital Spending

The evidence that illustrates that Oakville Hydro has delivered on the anticipated expenditures on its Customer Information System is provided in Exhibit 2, Tab 5, Schedule 2, page 51 and Exhibit 2, Tab 5, Schedule 2, page 62.

As discussed in the evidence, Oakville Hydro incurred capital costs of $67,014 in 2012 for an upgrade to its Harris Customer Information System. Oakville Hydro was unable to complete the planned upgrades in 2011 and a further $110,000 for Harris upgrades was planned for 2013. The difference between Board approved capital spending and actual capital spending was $22,986, which is considered immaterial.

OM&A Costs

The evidence that illustrates that Oakville Hydro has delivered on the Board approved OM&A expenditures for Oakville Hydro's ongoing smart meter costs is provided in Exhibit 4, Tab 2, Schedule 2, page 3 and Exhibit 4, Tab 3, Schedule 1, page 2.

As discussed in the evidence, Oakville Hydro incurred OM&A costs of $427,224 in 2012 associated with its smart meter deployment. The difference between Oakville Hydro's Board approved OM&A costs and its actual costs of $11,337, which is considered immaterial.

2.1-Energy Probe-6

Ref: All Exhibits

a) Please provide the references to any performance efficiency benchmarking undertaken by the distributor.

RESPONSE:

Oakville Hydro undertook the following performance efficiency benchmarking:

1. Oakville Hydro has compared its system reliability with the province. Please see Table 1-3 in Exhibit 1, Tab 1, and Schedule 1.

2. Oakville Hydro has compared its customer satisfaction survey results with the province and on a Canada-wide basis. Please see Appendix A in Exhibit 1.

3. Oakville Hydro has used various sources in the past for compensation benchmarking. Please see Exhibit 4, Tab 3, and Schedule 4.

b) Has the distributor considered benchmarking in relation to other distributors and/or to its own past historical performance? Please indicate where in the evidence this information has been provided for capital expenditures and OM&A expenses.

RESPONSE:

Oakville Hydro does consider benchmarking both to other distributors and its own past historical performance on an informal basis, including the analysis and review of industry data provided by the Board's annual Year Book of Electricity Distributors. For this rate Application however, there is no specific requirement in Chapter 2 the Board's Filing Requirements (issued on July 17, 2013) to provide this information as evidence.

Upon review of the Application, Oakville Hydro has made some references in its evidence to benchmarking in:

- Exhibit 2, Tab 5, Schedule 7, Page 1 of 4, Table 2-51 Service Reliability Indicators. Oakville Hydro continues to monitor these indicators on a year-to-year basis and continues to have performance that exceeds the Board's objectives.
- Exhibit 2, Tab 5, Schedule 7, Page 3 of 4, Table 2-52 Service Quality Indicators. Oakville Hydro continues to monitor these indicators on a year-to-year basis and continues to have performed in excess of the minimum standard of the OEB.
- Exhibit 2, Tab 5, Schedule 2, Page 2 of 76, Appendix 2-AB Capital Expenditures Summary. The "Total Normalized Expenditure" line shows that for the 2011 and 2012 years, its actual spending has been very close to its Board of Directors approved annual capital budgets.
- Exhibit 4, Tab 3, Schedule 4, Page 19 of 25 Union pay. Oakville Hydro references on line 9 "current union contract developments with other electricity distributors". Oakville Hydro reviewed other neighboring union contract settlements before reaching its own.

In light of the recent release of PEG's benchmarking report, updated December 4th, 2013 and the upcoming finalized OEB scorecard Oakville Hydro will continue to perform benchmarking analysis.

2.1-Energy Probe-7

Ref: Exhibit 2, Tab 1, Schedule 2

a) Please provide more details on the increase in capital expenditures of $1,894,084 from the Board approved level in 2010.

RESPONSE:

Please see Oakville Hydro's response to Energy Probe interrogatory number 2.1-EP-5.

b) Please explain why these additional capital expenditures were required in 2010 rather than being carried forward to 2011. Please explain why other capital expenditures in 2010 were not deferred to 2011 when these additional capital expenditures became known.

RESPONSE:

The majority of the additional capital expenditure was system access projects and considered mandatory to meet the timelines for customer connections and relocation for road authorities. These projects could not be carried forward to 2011. Oakville Hydro decided to proceed as planned with the other capital expenditures, most of which were in progress or scheduled for construction.

2.1-SEC-3

Please provide details and copies of all performance efficiency benchmarking undertaken by the Applicant.

RESPONSE:

Oakville Hydro has referenced details to performance efficiency benchmarking in 2.1-EP-6a and 6b. Oakville Hydro also performs its own internal analysis from the Board's Yearbook of Electricity Distributors.

2.1-AMPCO-5

Ref: Exhibit 2, Tab 5, Schedule 7, Reliability Performance

a) Please provide information on interruptions by cause (cause code statistics) for the years 2008 to 2013.

RESPONSE:

Oakville Hydro has provided information on interruptions by cause code for the years 2008 to 2013 in tables below.

Code (Description)	2008 SAIDI	2008 SAIFI	2008 CAIDI	2009 SAIDI	2009 SAIFI	2009 CAIDI
0 (Unknown/Other)	0.0241	0.9847	0.0245	0.0581	1.5959	0.0364
1 (Scheduled Outage)	0.2426	0.0998	2.4299	0.0934	0.0749	1.2473
2 (Loss of Supply)	0.3336	0.3198	1.0432	0.0002	0.0001	3.25
3 (Tree Contacts)	0.2067	0.3398	0.6084	0.0893	0.1928	0.4632
4 (Lightning)	0.0058	1.2239	0.0047	0.1541	1.1265	0.1368
5 (Defective Equipment)	0.4949	1.3755	0.3598	0.3321	1.524	0.2179
6 (Adverse Weather)	0.1413	0.2178	0.6488	0.0548	0.1738	0.3154
7 (Adverse Environment)	0.0462	0.1769	0.2611	0.005	0.0563	0.0894
8 (Human Element)	0.001	0.0066	0.1583	0.0229	0.135	0.1697
9 (Foreign Interference)	0.0464	0.2341	0.1984	0.0316	0.5753	0.055
Total (Excluding Code 2)	1.2065	1.2837	0.9399	0.7735	1.571	0.4923

Code (Description)	2010 SAIDI	2010 SAIFI	2010 CAIDI	2011 SAIDI	2011 SAIFI	2011 CAIDI
0 (Unknown/Other)	0.0089	1.12	0.008	0.0523	1.7126	0.0305
1 (Scheduled Outage)	0.1143	0.0658	1.7365	0.0921	0.0369	2.4957
2 (Loss of Supply)	0.011	0.144	0.0762	0.0024	0.0737	0.0322
3 (Tree Contacts)	0.1168	0.2362	0.4946	0.0811	0.0782	1.0378
4 (Lightning)	0.0003	0.1526	0.0021	0.0319	1.4464	0.0221
5 (Defective Equipment)	0.4715	1.0492	0.4494	0.1179	1.3167	0.0896
6 (Adverse Weather)	0.0004	0.0891	0.0042	0.0178	0.0387	0.4601
7 (Adverse Environment)	0	0.2406	0	0.0121	0.0895	0.1354
8 (Human Element)	0.0009	0.0092	0.1008	0.0074	0.1719	0.0431
9 (Foreign Interference)	0.0212	0.4854	0.0437	0.0521	0.6325	0.0823
Total (Excluding Code 2)	0.7335	1.0787	0.68	0.4649	1.0058	0.4622

Code (Description)	2012 SAIDI	2012 SAIFI	2012 CAIDI	2013 SAIDI	2013 SAIFI	2013 CAIDI
0 (Unknown/Other)	0.0483	1.3267	0.0364	0.0489	1.3908	0.0351
1 (Scheduled Outage)	0.177	0.0715	2.4743	0.0921	0.0434	2.1218
2 (Loss of Supply)	0	0.0096	0	0.4116	0.7361	0.5591
3 (Tree Contacts)	0.0101	0.1458	0.0691	0.1546	0.1612	0.9591
4 (Lightning)	0.0071	0.5344	0.0132	0.0094	0.8749	0.0108
5 (Defective Equipment)	0.4211	2.2353	0.1884	0.4312	1.3779	0.3129
6 (Adverse Weather)	0.0841	0.1297	0.648	0.0864	0.2243	0.3853
7 (Adverse Environment)	0.0023	0.0103	0.2259	0.0076	0.0078	0.9713
8 (Human Element)	0.0008	0.264	0.0029	0.0125	0.0829	0.1511
9 (Foreign Interference)	0.072	0.7034	0.1024	0.1509	1.0916	0.1383
Total (Excluding Code 2)	0.8108	0.9666	0.8389	2.6897	2.3122	1.1633

b) Please provide a further breakdown of interruptions based on causes related to defective equipment for the years 2008 to 2013. Please explain how this information has been used in asset management planning.

RESPONSE:

Table blow provides the 2008 data, see 1.1-Staff-10a for failures from 2009 – 2013.

The failure information has only been used in the past three years in order to verify and validated that replacement plans and programs are correctly aligned. The failure history is also considered when forecasting emergency replacement capital budgets for future years.

Asset Type	2008
Pole Mounted Transformer & Accessories Failures	42
Overhead Line Switch and Accessories Failures	19
Pad Mounted Transformer and Accessories Failures	6
Pad Mounted Switchgear and Accessories Failures	1
Underground Cable Failures	14

c) Does Oakville Hydro track momentary outages (i.e. MAIFI)? If yes, please summarize this indicator for 2008 to 2013 and explain how it is used in asset management planning. If no, please discuss Oakville Hydro’s ability and future plans to track this information.

RESPONSE:

The following table provides this indicator for 2008 to 2013.

Year	MAIFI
2008	2.788
2009	4.0051
2010	1.5981
2011	4.5322
2012	4.3858
2013	4.9551

Currently, MAIFI is not specifically used in Asset Management Planning. Oakville Hydro tracks MAIFI regularly and focus is underway to identify opportunities to alleviate what is a minor irritant to customers. Momentary outages are actually is a reflection of the distribution system's protection and control devices operating properly and efficiently by resetting after a minor fault. It is Oakville Hydro's view that the majority of its momentary interruptions are attributed to errant tree branches falling and contacting overhead feeders. Oakville Hydro has historically worked closely with the Town of Oakville on its tree clearance program and has currently re-structured its vegetation management program for 2014 to minimize these interruptions and improve customer satisfaction; this is referenced in Exhibit 4, Tab 2, Schedule 3. In addition, Oakville Hydro is researching and planning to implement deterrents to animal contacts at such connection points as overhead transformers.

d) Please discuss Oakville Hydro's use of customer specific reliability indicators.

RESPONSE:

Currently, Oakville Hydro is only able to track outages by feeder and not by customer. Once the Outage Management System is operational in 2014, outages will be tracked on a customer basis, and Oakville Hydro will be able to use more customer-specific reliability indicators in order to assist in more focused analysis.

2.1-VECC-6
Ref: E 2/T5/S7

Please provide a breakdown of the service reliability performance metrics into the different category of reasons for the outage (excluding supply loss Code 2 outages). The table below provides an example format.

Description	2010 Totals	2011 Totals	2012 Totals	2013 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Animals, Vehicle				
Unknown				
Total				

RESPONSE:

Oakville Hydro has provided a breakdown of service reliability performance metrics in tables below.

Description	2010 SAIDI	2010 SAIFI	2010 CAIDI	2011 SAIDI	2011 SAIFI	2011 CAIDI
Scheduled	0.1143	0.0658	1.7365	0.0921	0.0369	2.4957
Supply Loss	0.0110	0.1440	0.0762	0.0024	0.0737	0.0322
Tree Contact	0.1168	0.2362	0.4946	0.0811	0.0782	1.0378
Lightning	0.0003	0.1526	0.0021	0.0319	1.4464	0.0221
Def. Equip (other than pole)	0.4715	1.0492	0.4494	0.1179	1.3167	0.0896
Pole Failure	-	-	-	-	-	-
Weather	0.0004	0.0891	0.0042	0.0178	0.0387	0.4601
Foreign Interference	0.0212	0.4854	0.0437	0.0521	0.6325	0.0823
Unknown	0.0089	1.1200	0.0080	0.0523	1.7126	0.0305
Total	0.7335	1.0787	0.6800	0.4649	1.0058	0.4622

Description	2012 SAIDI	2012 SAIFI	2012 CAIDI	2013 SAIDI	2013 SAIFI	2013 CAIDI
Scheduled	0.1770	0.0715	2.4743	0.0921	0.0434	2.1218
Supply Loss	-	0.0096	-	0.4116	0.7361	0.5591
Tree Contact	0.0101	0.1458	0.0691	0.1546	0.1612	0.9591
Lightning	0.0071	0.5344	0.0132	0.0094	0.8749	0.0108
Def. Equip (other than pole)	0.4211	2.2353	0.1884	0.4312	1.3779	0.3129
Pole Failure	-	-	-	-	-	-
Weather	0.0841	0.1297	0.0648	0.0864	0.2243	0.3853
Foreign Interference	0.0720	0.7034	0.1024	0.1509	1.0916	0.1383
Unknown	0.0483	1.3267	0.0364	0.0489	1.3908	0.0351
Total	0.8108	0.9666	0.8389	2.6897	2.3122	1.1633

3-Customer Focus

Issue 3.1 *Are the applicant's proposed capital expenditures and operating expenses appropriately reflective of customer feedback and preferences?*

3.1-Staff-16

Ref: Exhibit 4/Tab2/Schedule 4/p. 1

OM&A per customer Costs

For 2014, Oakville Hydro's OM&A/customer is forecast to be $293.69, an increase of 6.1% from 2013 levels (on a New GAAP basis). For 2013, the OM&A/customer shows a similar 6.1% increase ($231.75/$218.50) (on an Old GAAP basis). In 2012, the increase was 5.8%.

a) Please discuss the drivers for these increases, with specific reference and contrast to the Board's inflation factor of 1.7% and its labour/capital composition.

RESPONSE:

In 2012, the OM&A cost per customer represents a 5.8% increase over 2011. The drivers for the increases are the new transformer station operating costs that were fully operational in 2012 versus 2011, which accounts for 1.01% increase, smart meter operating costs expensed in 2012 and not expensed in 2011 which accounts for 3.23% of the increase, the remaining 1.6% is the inflationary increase for the year. The 1.6% increase shown in the table below. This inflationary increase is consistent with the Board's inflationary factor of 1.7%.

As noted in the questions, for 2014, there is a 6.1% increase over the 2013 Forecast. The drivers for the increases are composed of:

- Incremental costs of the Monthly billing initiative, which represents 2.1% of the increase

- The additional costs incurred for the Halton Hills Hydro 24/7 control room services initiative (for which the recovery is recorded in revenue offsets in Exhibit 3) which represents 0.41% of the increase

- The one-time cost of this application reflected in Exhibit 4 which are not inflationary which represent 0.84% the increase

- Tree trimming costs in excess of inflation for the move to meeting standardized clearances described in Exhibit 4, Tab 2, Schedule 3 which represents an increase of 0.44%

- The remaining inflationary factor of 2.32% (shown in the table below), represents mainly wage increases for unionized and non-unionized staff that exceeds the Board's inflation factor of 1.7%. Oakville Hydro believes this inflationary factor is reasonable in order to continue to maintain and attract personnel to Oakville Hydro and keep its distribution system running adequately.

b) Please outline the outcomes and higher level of services that customers will receive for the relatively higher rates they are paying as a result of these increases.

RESPONSE:

Based on the proposed 2014 Test Year OM&A, the OM&A cost per customer rates give customers a change to monthly billing, which, according to the results of the Customer Satisfaction survey, is something that a majority of the customers support. The increased control room services benefit Oakville Hydro's customers, but they are not forced to bear the full cost of that improvement as a result of the revenue offset received from Halton Hills Hydro. Customers will also continue to enjoy the high level of service through system reliability that they demand, specifically from increased tree trimming. The additional 0.62% increase in labour costs over the Board's inflation factor of 1.7% is intended to avoid detrimental service standards by retaining and compensating the appropriate skilled labour force.

c) Please identify any customer engagement that supports the further increases proposed in this application.

RESPONSE:

As discussed in Exhibit 1, Tab 2, Schedule 1, Oakville Hydro conducts an annual customer satisfaction survey. Oakville Hydro engaged its customers with respect to its move to monthly billing as part of its 2013 customer satisfaction survey. This is referenced in Exhibit 1, Appendix A, Page 18.

d) Please provide the analysis that was performed to assess whether this applicant's planning decisions reflect best practices of Ontario distributors.

RESPONSE:

For OM&A planning and decision making, Oakville Hydro's efforts are evident when considering Ontario distributor best practices in the areas of Asset Management, Operations, Staffing, and Engineering Standards.

<u>Asset Management</u>

The Asset Management Program has been shaped using the strategies from the Publicly Available Specification 55 (PAS55) regarding Asset Management. Applying the PAS55 framework has allowed Oakville Hydro to properly structure its Asset Management Program from the top down using the recommended requirements. Using this framework enables best practices to be developed and realized. The scope of the program encompasses all aspects of the asset lifecycle, from first recognition of a need, to design, acquisition, construction, commissioning, operation, maintenance, renewal, modification and/or disposal.

Regarding Asset Maintenance Management, both the Supervisor of Asset Management and the Asset Management Technician has undergone training in order to achieve their Maintenance Management Professional designations. Courses include:

- Strategy for Maintenance Management
- Production and Operations Management for the Maintenance Manager
- Human Resources management for the Maintenance Manager
- Financial Management for the Maintenance Manager
- Developing and Implementing Maintenance Tactics
- Maintenance Work Management
- Computerized Maintenance Management Systems

During course time, opportunities arose to benchmark current practices with other industries in order to establish best practices not only among utilities, but also in consideration of other industries. The teachings from these courses and their resources have helped shape the current Oakville Hydro plans, and will help further optimize those plans into the future. Through ongoing refinement of the strategy, people, work management, materials management, basic care, performance management, support systems, asset reliability, teamwork and processes Oakville Hydro continues to drive asset management best practices.

<u>Operations</u>

Health & Safety is a key benchmark for Operations, and Oakville Hydro's award-winning Stayin' Alive Safety Program is in the final stages of implementation of its overall Integrated Occupational Health and Safety Management System under the CSA Z1000 framework. As an outcome demonstrating the success of this program, Oakville Hydro received the President's Award from the Infrastructure Health and Safety Association (IHSA) in September 2013 for achieving 250,000 consecutive hours without a lost time injury (LTI), and by year-end 2013 had achieved 350,000 consecutive hours. Oakville Hydro also strives to find innovative ways to improve performance while controlling costs. In September 2013, Oakville Hydro established a 'shared services' Control Room Operations arrangement between Oakville Hydro and Halton Hills Hydro. This provided a more sustainable staffing model for Oakville Hydro's control room while at the same time providing control room operations and management capabilities to Halton Hills.

Staffing

Oakville Hydro's process for establishing the appropriate staffing levels starts with the business planning process. All opportunities for hiring are considered against opportunities to improve business processes, use of technology or outsourcing. Any positions approved for hiring are supported by examining outside factors, increase policy or regulatory changes, improving customer focus and operational requirements.

To attract and retain a highly skilled, and knowledgeable workforce Oakville Hydro employs a strategy of hiring from universities and colleges through their co-op and apprentice programs, recruiting highly skilled employees from not only the distribution industry but complementary industries and developing a succession plan that identifies key roles and individuals to be developed.

Engineering Standards

Oakville Hydro has established a program of continuous improvement that includes business process review and improvement, systems development and standardization. Based on business process review, Oakville Hydro has developed systems to increase the productivity and accuracy of estimating; improve customer focus; and improve project management. Oakville Hydro utilizes standard materials and standard designs, and incorporates these into standard assemblies for planning purposes. This approach both increases productivity and accuracy. Oakville Hydro is developing further techniques to compare and measure actual results to planned work, and use this information to continuously improve the planning process.

In addition, Oakville Hydro is engaged, as part of the GridSmartCity Consortium (a collaboration of 10 mid-sized LDCs across Ontario), to work towards common material/equipment standards among LDCs in order to derive additional efficiencies in future years.

e) Has Oakville Hydro conducted an analysis comparing its OM&A costs per customer with other Ontario distributors? If so please provide details of that analysis.

RESPONSE:

It has been very difficult to conduct an OM&A cost per customer comparative because different distributors:

a. have significantly different capitalization policies;
b. adopted IFRS earlier than others;
c. have different treatment for their smart meters in 2012;
d. have distributor owned transformer stations and are subject to the associated OM&A costs and others do not (this information is not easily accessible or available); and

Oakville Hydro prepared a comparative rate analysis and distributed it to its Board of Directors on May 3, 2013. This is provided in Appendix 3-A.

Most recently, Oakville Hydro conducted an analysis of two similar size distributors which are before the Board for their 2014 Cost of Service applications. This analysis is based on their evidence in their respective applications. Oakville Hydro believes this is a representative comparison since all parties are adopting the changes in accounting policies, are of similar customer size and within a close area of proximity. The table below shows the proposed OM&A cost per customer. Oakville Hydro is comparable to these utilities.

Description	Reference	Burlington Hydro	Oakville Hydro	Cambridate Hydro
		(EB-2013-XXXX)	(EB-2013-0159)	(EB-2013-XXXX)
OM&A per Cost of Service Application		18,553,350	19,215,000	15,803,310
Less: Transformer station operating & maintenance costs			(281,138)	(195,935)
Less: Monthly billing			(380,000)	
		18,553,350	18,553,862	15,607,375
# of customers		66,621	65,428	53,634
	OM&A per customer	**$ 278**	**$ 284**	**$ 291**
Revenue Offsets		$ 1,938,014	$ 2,035,753	$ 1,299,379
# of customers		66,621	65,428	53,634
	Revenue Offsets per customer	**$ 29**	**$ 31**	**$ 24**
	Net cost per customer	**$ 249**	**$ 252**	**$ 267**

f) Please identify any initiatives considered and/or undertaken by the applicant, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

RESPONSE:

Oakville Hydro assesses its capital spending quarterly to evaluate its capital investments to date, any new information and/or if unanticipated capital projects have surfaced. At that time, Oakville Hydro will assess whether it can defer any of the planned projects and/or maintain some assets for one more year rather than replace them, while ensuring there is no significant risk for compromising the operation of the distribution system. This balancing ensures that Oakville Hydro continues to be financial stable from a cash flow perspective.

g) The Board's letter of November 28, 2012, established the stretch factor assignments for 2013 rates. The applicant was assigned to Stretch Factor Group 2 out of three groups. On November 21, 2013, the Board established the stretch factor assignments for 2014 rates in the *Report of the Board: Rate Setting Parameters and Benchmarking under the renewed Regulatory Framework for Ontario's Electricity Distributors.* Oakville Hydro was assigned to Group IV out of five groups. Please provide details on any initiatives undertaken to improve Oakville Hydro's assignment in future years.

Regulatory Framework for Ontario's Electricity Distributors. Oakville Hydro was assigned to Group IV out of five groups. Please provide details on any initiatives undertaken to improve Oakville Hydro's assignment in future years.

RESPONSE:

In the November 21, 2013, Oakville Hydro was assigned Group IV (10.2% over predicted costs) of the five groups. Oakville Hydro has had the opportunity to examine this report after submitting this Application and has noted that Oakville Hydro has numerous costs included in OM&A costs for which recoveries have always been recorded and classified as "revenue offsets" in Exhibit 3, and the amounts have been material in nature. However, these cost recoveries were not considered of as part of this exercise.

As shown in Oakville Hydro's response to Board staff interrogatory number 3.1-Staff-16, Oakville Hydro's revenue offsets are higher than other distributors of similar size. Therefore, in future Oakville Hydro will properly allocate these cost recoveries in OEB account 5625 – Administrative Expenses Transferred Credit. These cost recoveries are identified below by year from 2010 to 2014:

Description	Cost recoveries	2010 Actual	2011 Actual	2012 Actual	2013 Actual (unaudited)	2014 Test Year
Point of presence site	4220	27,900	27,900	27,900	27,900	28,500
Data Centre & generator - Rogers	4220	113,575	123,900	125,377	125,511	128,000
Duct rental	4220	19,922	21,733	22,720	22,810	23,500
Burlington Hydro - line rental	4220	156,000	156,000	156,000	156,000	13,000
Intercompany billing services	4220	85,766	75,058	100,599	75,578	106,750
Intercompany - head office occupancy recovery from affiliates	4220	179,705	111,200	83,216	119,900	127,900
Control room services - Halton Hills Hydro	4220				25,000	100,000
Long Island, New York Sorm assistance-cost recoveries	4375			199,776		
Benefit refund	4390		111,455	127,779		
Office space rental- Town of Oakville	4390			36,707	146,829	146,820
Cost recoveries		**554,968**	**599,346**	**852,174**	**671,628**	**645,970**

If these recoveries had been reflected in the Board's report, Oakville Hydro would likely have moved to a more efficient group.

Oakville Hydro is committed to continue looking for opportunities for sharing services with other distributors and to continuing to examine current practices and look for efficiencies in the customer areas such as promotion of e-billing and pre-authorized payments. For any upcoming employee retirements in the future IRM periods, Oakville Hydro will re-examine the roles and responsibilities of these positions and make appropriate changes to headcount with the intent to improve the effectiveness of delivering safe and reliable services to its customers.

3.1-Staff-17

Ref: Exhibit 4/Tab2/Schedule 2

<u>Benefits from OM&A Increases</u>

Oakville Hydro has provided OM&A costs on a 'normalized' basis, adjusting for such factors as Smart Meters, the Glenorchy Transformer Station, capitalization changes and the monthly billing initiative. When including all OM&A costs, except for the capitalization changes, Oakville Hydro shows a 19.2% increase in 2011, a 6.7% increase in 2012, a 6.8% increase in 2013 and an 8.2% increase in 2014.

a) Please identify what improvements in services and outcomes the applicant's customers will experience in 2014 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2014.

RESPONSE:

Since Oakville Hydro's last rebasing it has provided improvements in services which are reflected in the OM&A in the 2014 Test Year. These are identified below:

i. Installation of smart meters – this provides customers with increased control of their consumption and ultimately their energy costs.

ii. Glenorchy Transformer Station – Oakville Hydro designed and constructed the Glenorchy Transformer Station to meet the electricity demand of its customers. This ensured that customers had reliable electricity services. The revenue requirement associated with the capital costs required for the Glenorchy Transformer Station formed part of an ICM proceeding (EB-2010-0104). The ICM process does not provide for the recovery of operating costs but they are being incurred and Oakville Hydro seeks their recovery in this Application.

iii. Safety Program – the development of this program is discussed in Exhibit 4, Tab 1, Schedule 2, Page 4 of 11.

iv. Asset Management – this will reduce the probability of failures for critical assets in the distribution system through asset condition assessments, preventative maintenance programs and repair versus replace decision making. Proactive asset management will help maintain the reliability of service and level of safety that is expected by Oakville Hydro's customers.

v. Communications – personnel additions to focus on customer communication. This is discussed in Exhibit 4, Tab 1, Schedule 2 Lines 3-6.

vi. Locates – Oakville Hydro has been able to meet its substantial increase in the customer demand for locates. This is discussed in Exhibit 4, Tab 2, Schedule 3, Page 6 of 11.

vii. Monthly billing – this provides customers with lower bill balances and facilitates customer budgeting for electricity. Details are provided in Exhibit 4, Appendix A.

b) How has the applicant communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.

RESPONSE:

These initiatives are being communicated to customers in the following ways:

Initiative	Method of Communication	Response Feedback
Installation of Smart Meters	Bill inserts, door hangers, and website. Referenced in Exhibit 1, Tab 2, Schedule 1, Page 10 of 18	Minimal mixed feedback.
Glenorchy Transformer station	Public Forum meeting Referenced in Exhibit 1, Tab 2, Schedule 1, Page 4 of 18	Well received by attendees
Safety program	Elementary and High School sessions, and quarterly internal employee sessions	Safety - see response above to 3.1-Staff-16 (d) Operations. From tabulated reviews of internal sessions, there has been over a 90% approval result.
Communications	Website development, Social Media (Facebook & Twitter)	Very effective during recent ice storm in getting information to and from customers
Locates	OneCall	Referenced in Exhibit 4, Tab 2, Schedule 3 - page 6 of 11
Monthly Billing	Customer survey	Referenced in Exhibit 1, Appendix A, Page 18

3.1-Energy Probe-8

Ref: Exhibit 1, Tab 2, Schedule 1

a) Please provide all customer feedback and preferences received from residential customers with respect to capital expenditures in the bridge and test years.

RESPONSE:

Oakville Hydro does not have specific documented feedback and preferences from residential customers with respect to capital expenditures in the bridge and test years. Oakville Hydro's construction management process includes sending letters to impacted customers, prior to construction, describing project details and timelines. The letter provides Oakville Hydro contacts to customers, for any follow up questions or if customers would like further information. Customers that do contact Oakville Hydro are dealt with individually by the appropriate Oakville Hydro resource as situations arise.

b) Please provide all customer feedback and preferences received from non-residential customers with respect to capital expenditures in the bridge and test years.

RESPONSE:

As with residential customers, Oakville Hydro does not have specific documented feedback and preferences from non-residential customers with respect to capital expenditures in the bridge and test years. Oakville Hydro's construction management process includes sending letters to impacted customers, prior to construction, describing project details and timelines. The letter provides Oakville Hydro contacts to customers, for any follow up questions or if customers would like further information. Customers that do contact Oakville Hydro are dealt with individually by the appropriate Oakville Hydro resource as situations arise.

c) Please provide all customer feedback and preferences received from residential customers with respect to OM&A expenses in the bridge and test years.

RESPONSE:

Oakville Hydro has always received feedback from residential customers in different forms and for a variety of reasons. During the last few years, Oakville Hydro commenced performing customer satisfaction surveys, which were initially generic but covered a broad spectrum of questions (from reliability to affordability) and were not specifically directed to general OM&A costs. However, with the progress of the Board's Renewed Regulatory Framework and Oakville Hydro's filing of the cost of service application, Oakville Hydro in their 2013 Customer Satisfaction survey asked customers to provide their views on a move to monthly billing which is requested as an OM&A expense in the Test Year. Oakville Hydro plans to continue to evolve and explore this area and assess how it may go about obtaining appropriate and constructive feedback and preferences from its residential customers with respect to OM&A expenses.

d) Please provide all customer feedback and preferences received from non-residential customers with respect to OM&A expenses in the bridge and test years.

RESPONSE:

For the General Service < 50kW customers, these customers were also part of the 2013 Customer Satisfaction Survey described in (c). For the General Service > 50 kW and General Service > 1,000 kW customers, there has been no direct outreach to this class of customers with respect to specific feedback or preferences with OM&A expenses. For the Streetlight class and the new Embedded Distributor class Oakville Hydro provided details regarding the OM&A costs for their classes in relation to their cost allocation. Both of these classes asked questions during the meetings with those customers and provided their thoughts on the reasonableness of the OM&A costs.

e) Did the distributor ask customers (residential or non-residential) for feedback and preferences on employee compensation, including, but not limited to salary levels, salary increases, benefits and pensions? If yes, please provide the feedback received.

RESPONSE:

Oakville Hydro did not directly ask customers for feedback on employee compensation, salary increases, benefits and pensions. However, Oakville Hydro's collective agreement for its unionized employees is a public document and details regarding salaries, wages and benefits are provided in the collective agreement. In addition, benefit and pension costs and detailed plans are readily available in Oakville Hydro's notes to the annual audited financial statements which are posted on its website.

3.1-SEC-4

Ref: 4/1/2/p.1

Please confirm the 2013 customer satisfaction survey referenced is the UtilityPULSE 15th Annual Electric Utilities Customer Satisfaction Survey provided in Ex.4/Appendix 3

RESPONSE:

Oakville Hydro confirms that the 2013 customer satisfaction survey referenced in Exhibit 4, Tab 1, Schedule 2 page 1 is the UtilityPULSE 15th Annual Electric Utilities Customer Satisfaction Survey provided in Exhibit, Appendix 3.

3.1-SEC-5

Ref: Ex.4/1/2/p.2

Does the Applicant consider schools to be part of Commercial and Industrial customers that it intends to increase its focus in the Test Year?

RESPONSE:

Oakville Hydro does consider schools to be part of Commercial and Industrial customers that it intends to increase its focus in the Test Year.

3.1-SEC-6

Please provide all customer feedback and preferences received, by customer class, with respect to the Applicant's Test Year:

a) Capital expenditures

RESPONSE:

Please see response 3.1-EP-8a-d.

b) OM&A expenses

RESPONSE:

Please see response 3.1-EP-8a-d.

3.1-SEC-7

Please provide a copy of any surveys, questionnaires, and/or other methods that the Applicant used to collecting customers feedback and preferences?

RESPONSE:

Oakville Hydro collects customer's feedback and preferences from the following sources:

- Customer Engagement Surveys (- see survey in Exhibit 1)
- Letters to Customers (a sample is attached) see Appendices 3-C and 3-D
- Social Media (Facebook and Twitter which commenced in 2013)
- Direct correspondence from customers to Town Councillors, MPs, MPPs, and the Mayor of Oakville via emails (samples attached) see Appendices 3-E, 3-F & 3-G. Please note that personal information has been redacted from the samples.
- Public Forum held for the construction of the Glenorchy Transformer station (see Exhibit 1, Tab 2, Schedule 1, Page 5

- Inbound phone call, emails, faxes, letters and customers attending Oakville Hydro's offices

3.1-HVAC-1

Ref: Ex. 1/1/1, p. 1

Please confirm that the utility's Mission is intended to refer only to regulated activities. If it is intended to refer to unregulated activities as well, please list the unregulated activities to which it applies.

RESPONSE:

Oakville Hydro Corporation and all its subsidiaries (including Oakville Hydro) have one broad Mission which was developed a few years ago. In the context of Oakville Hydro (as electricity distributor, not Oakville Hydro Corporation) the mission applies to the Applicant's activities as a regulated electricity distributor. All the subsidiaries are listed in Exhibit 1, Tab 3, Schedule, 3, Page 16 of 51.

3.1-AMPCO-6

Ref: Exhibit 1, Tab 2, Schedule 1, Page 13, Billing Accuracy

Preamble: Oakville Hydro customer survey results indicate that although many customers would prefer monthly billing they would not be willing to pay more to acquire monthly billing.

a) Please summarize the rationale to move to monthly billing for residential and GS<50 kW customers.

RESPONSE:

The statement in Exhibit 1, Tab 2, Schedule 1, Page 113 should have stated "Customers also indicated that they would not be willing to pay $1- $2 more to acquire monthly billing". This is based on the Customer Satisfaction survey in Exhibit 1, Appendix A, Page 18 - last bullet point. Based on the statement above, the calculated cost of $0.53 per bill included in the 2014 Test Year could reasonably be assumed to an acceptable cost to incur for monthly billing since this substantially lower than the $1-2 amount included in the survey.

Other points of interest, as provided in the Customer survey in Exhibit 1, Appendix A page 18 include:

- 58% of customers agree that monthly billing would be preferred by most customers
- 63% of customers agree that hydro bills should be monthly
- 72% of customers agree that monthly billing would assist in managing their expenses.

In addition the monthly billing is expected to reduce invoice shock for customers and, consistent with the customer survey, allow for better customer budget planning. The monthly billing is expected to reduce the bad and doubtful accounts expense and facilitate other efficiencies identified in the meter-to-cash process review. These savings partially mitigate the additional costs of monthly billing.

3.1-AMPCO-7

Ref: Exhibit 1, Tab 3, Schedule 3, Page 47

a) Please provide the rationale for including non-utility business activities in Oakville Hydro's rate base.

RESPONSE:

As discussed in Exhibit 1, Tab 3, Schedule 3, Oakville Hydro installed a small number of photovoltaic devices on distribution pole-tops as a pilot project. While there is a generation component to this project, Oakville Hydro undertook the project primarily for the benefits provided to the distribution system. In the interest of full disclosure, Oakville Hydro stated that, while it is not currently engaged in renewable generation activities, it had installed the photovoltaic devices and in doing so, it was generating a small amount of green energy. Oakville Hydro was not suggesting that the photovoltaic devices should not be considered part of the distribution assets.

Oakville Hydro also notes that, in its 2012 cost of service application, Halton Hills Hydro requested approval of its proposal to install 1,400 photovoltaic devices on distribution pole-tops, at an installed cost of $1,000 each which would add $1,400,000 to Halton Hills Hydro's 2012 rate base. While the Board did not approve Halton Hills Hydro's proposal as filed, the Board recognized that the proposal might provide benefits in terms of cost savings which will ultimately flow through to customers and accepted that there would also be benefits that are difficult to quantify. The Board approved an addition to their pilot project on a scale of not more than 200 units. Oakville Hydro believes that it is equally appropriate for Oakville Hydro to include the costs of $38,000 associated with this pilot project in Oakville Hydro's rate base.

On July 25, 2013, Halton Hills Hydro submitted a report entitled *Distribution System Solar Integration Project Report* to the LDC Tomorrow Fund which identifies the benefits of photovoltaic devices. A copy of the report is provided as Appendix 3-B to Oakville Hydro's responses to these interrogatories. In its report, Halton Hills Hydro identified three key benefits of this system based on their experience:

1. The pole mounted solar modules provide clean renewable energy generation.
2. Having generation on hydro utility poles, close to the load, reduces line losses.
3. The pole mounted solar modules create an intelligent grid infrastructure that provides real time monitoring, and troubleshooting on the secondary distribution system.

It its report, Halton Hills Hydro stated that it believed that its Solar Integration Project had been a valuable pilot project which demonstrated that this technology can be implemented within existing rate base and that it complements the Province of Ontario's "Renewed Vision for Energy Conservation".

Appendix 3 – A

Benchmarking - Strategy Board Retreat

ITEM 4

Benchmarking

Purpose:

To review and discuss benchmarking information for OHEDI, and to achieve a better understanding of OHEDI's positioning relative to industry peers.

Report:

The Four Year Work Prioritization Plan identifies industry benchmarking as a priority initiative for 2014 (Q2/Q3), as the Cost of Service application will have been completed. More definition and structure will be introduced into benchmarking for business analysis and reporting. The OEB is also increasing its emphasis on benchmarking and trend analysis as an indicator of relative efficiencies for LDCs. Current benchmarking evaluations divide the Ontario industry into three efficiency "cohorts" for the purposes of assigning stretch factors in determining the Interim Rate Mechanism calculations. Oakville Hydro Electricity Distribution Inc. (OHEDI) is positioned in the middle cohort.

Attached as Appendix 1 is the Draft Balanced Scorecard Report is being proposed by the OEB and expected to be the source document for comparative analysis under the Renewed Regulated Framework. This Scorecard is expected to be a significant component of the annual reporting requirement for OHEDI to the OEB. This is generally a "trend-line" analysis with data from a specific utility over a period of time. Some of this historic information is available as it has been tracked for a number years, however, additional information will need to be gathered and annually tracked for inclusion in this report. There is currently ongoing industry discussion on specific inclusions and exclusions of data and costs in this Scorecard and how items are to be calculated in order to ensure comparability between LDCs.

In addition to this "trend-line" Scorecard, comparative benchmarking between LDCs is available from data currently reported to the OEB by all LDCs and published in the annual yearbook.

As indicated in the OEB Yearbook for 2011, illustrated below, OHEDI is the 13th largest LDC in the province. Other industry wide comparatives include Appendix 2, OM&A Costs per Customer by LDC Size, and Appendix 3 Capital and OM&A Costs per Customer by LDC, illustrate where OHEDI lies from a cost efficiency perspective. It should be noted that Attachment 2 excludes Hydro One and Toronto Hydro in the comparison. Appendix 4 illustrates the Administrative Cost per Customer Relative to Average, for LDCs in Ontario. Finally, attached is a summary of the historical trends for OHEDI on selected data.

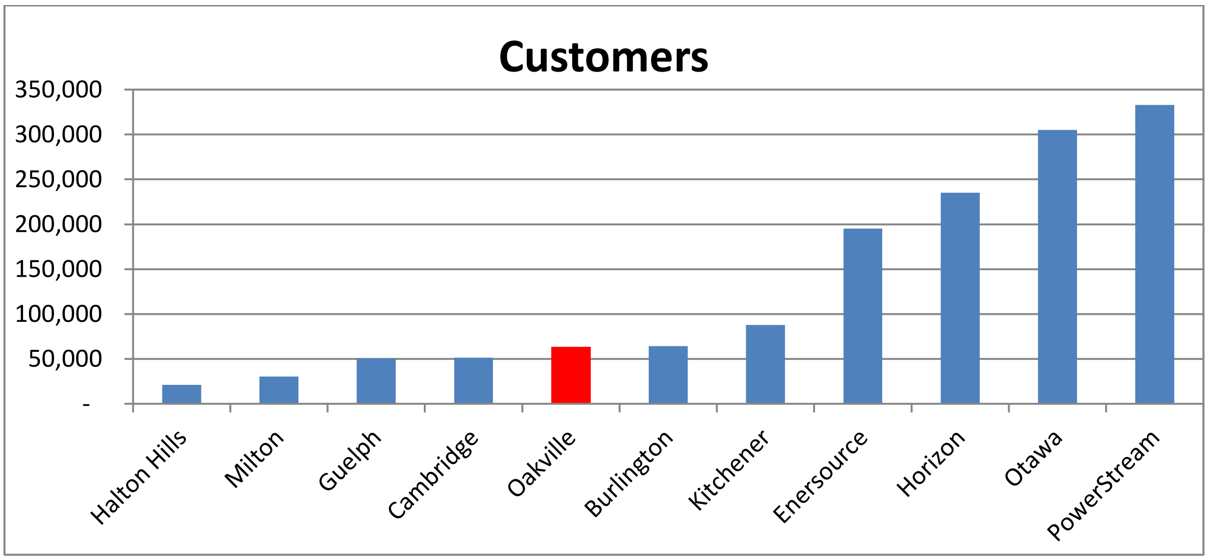
Using the 2011 OEB Yearbook the following comparative benchmarking has been prepared using a peer group of GTA utilities, six of which have more customers than Oakville Hydro and four have fewer customers.

The specific comparatives are:

- Burlington (Larger)
- Cambridge
- Enersource (Larger)
- Guelph
- Halton Hills
- Horizon Utilities (Larger)
- Kitchener-Wilmot (Larger)
- Milton
- Ottawa (Larger)
- PowerStream (Larger)

Customers

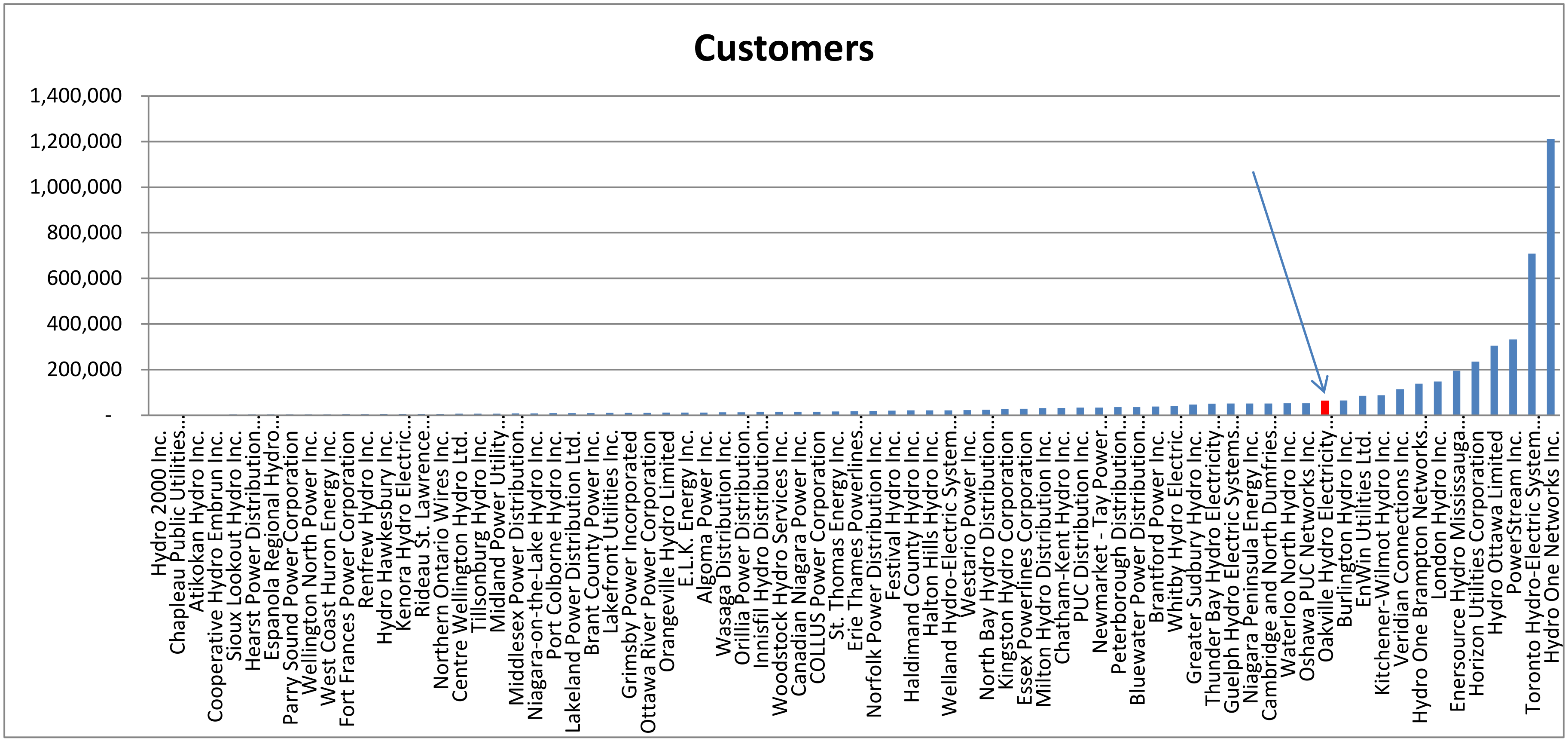
The number of customers is intended to provide a relative size of a utility. This statistic does not take into account the type of customers (residential, General Service < 50kW etc.)



Conclusion

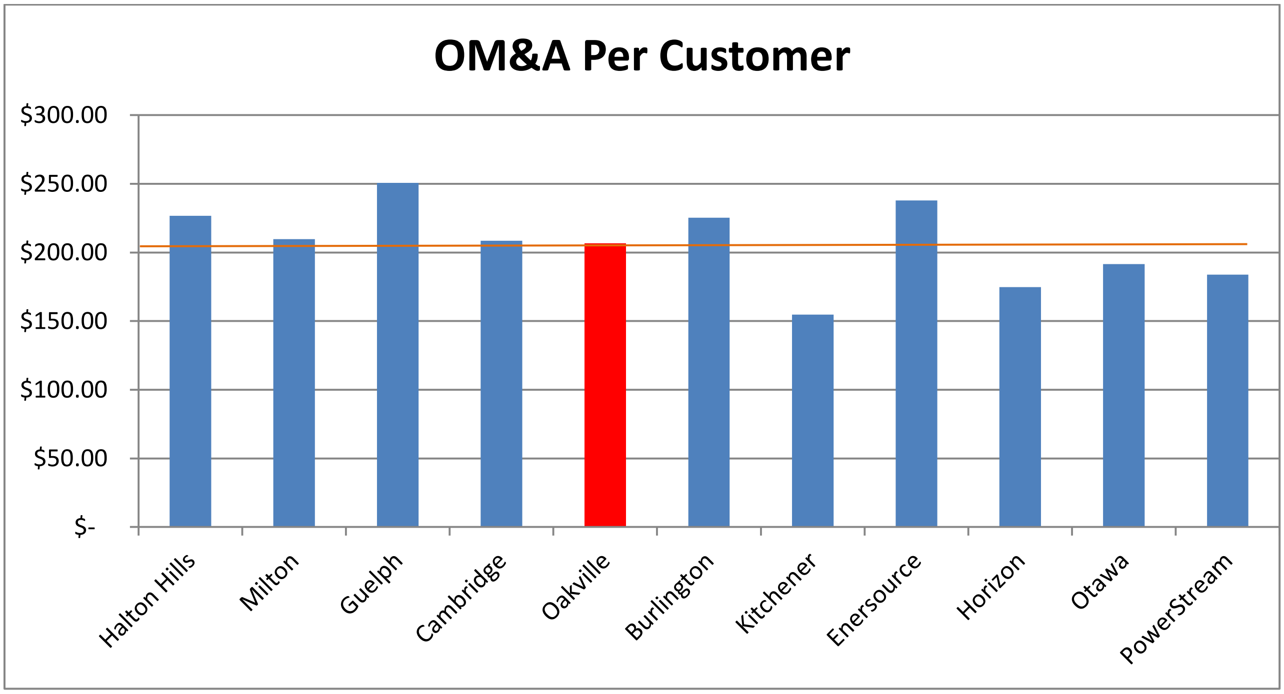
The above comparative companies represent 29.8% of all customers in Ontario and excluding Toronto Hydro and Hydro One Networks the above group represents 49.4% of customers.

On the next page is the Total Customers by LDC in 2011 per the Ontario Energy Yearbook of Electricity Distributors Data.


Customers
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
Hydro 2000 Inc.
Chapleau Public Utilities...
Atikokan Hydro Inc.
Cooperative Hydro Embrun Inc.
Sioux Lookout Hydro Inc.
Hearst Power Distribution...
Espanola Regional Hydro...
Parry Sound Power Corporation
Wellington North Power Inc.
West Coast Huron Energy Inc.
Fort Frances Power Corporation
Renfrew Hydro Inc.
Hydro Hawkesbury Inc.
Kenora Hydro Electric...
Rideau St. Lawrence...
Northern Ontario Wires Inc.
Centre Wellington Hydro Ltd.
Tillsonburg Hydro Inc.
Midland Power Utility...
Middlesex Power Distribution...
Niagara-on-the-Lake Hydro Inc.
Port Colborne Hydro Inc.
Lakeland Power Distribution Ltd.
Brant County Power Inc.
Lakefront Utilities Inc.
Grimsby Power Incorporated
Ottawa River Power Corporation
Orangeville Hydro Limited
E.L.K. Energy Inc.
Algoma Power Inc.
Wasaga Distribution Inc.
Orillia Power Distribution...
Innisfil Hydro Distribution...
Woodstock Hydro Services Inc.
Canadian Niagara Power Inc.
COLLUS Power Corporation
St. Thomas Energy Inc.
Erie Thames Powerlines...
Norfolk Power Distribution Inc.
Festival Hydro Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Welland Hydro-Electric System...
Westario Power Inc.
North Bay Hydro Distribution...
Kingston Hydro Corporation
Essex Powerlines Corporation
Milton Hydro Distribution Inc.
Chatham-Kent Hydro Inc.
PUC Distribution Inc.
Newmarket - Tay Power...
Peterborough Distribution...
Bluewater Power Distribution...
Brantford Power Inc.
Whitby Hydro Electric...
Greater Sudbury Hydro Inc.
Thunder Bay Hydro Electricity...
Guelph Hydro Electric Systems...
Niagara Peninsula Energy Inc.
Cambridge and North Dumfries...
Waterloo North Hydro Inc.
Oshawa PUC Networks Inc.
Oakville Hydro Electricity...
Burlington Hydro Inc.
EnWin Utilities Ltd.
Kitchener-Wilmot Hydro Inc.
Veridian Connections Inc.
Hydro One Brampton Networks...
London Hydro Inc.
Enersource Hydro Mississauga...
Horizon Utilities Corporation
Hydro Ottawa Limited
PowerStream Inc.
Toronto Hydro-Electric System...
Hydro One Networks Inc.

Operating Efficiency

The Operating, Maintenance and Administration per customer is a proxy for the relative operating efficiency of the utilities. OHEDI is $206.45 per customer compared with the average of the group at $206.39 per customer. The lowest OM&A per customer is $148 at Hydro One Brampton and the highest is $839 at Algoma Power. Toronto Hydro is $328 per customer, and Hydro One Networks is $454 per customer.



Conclusion

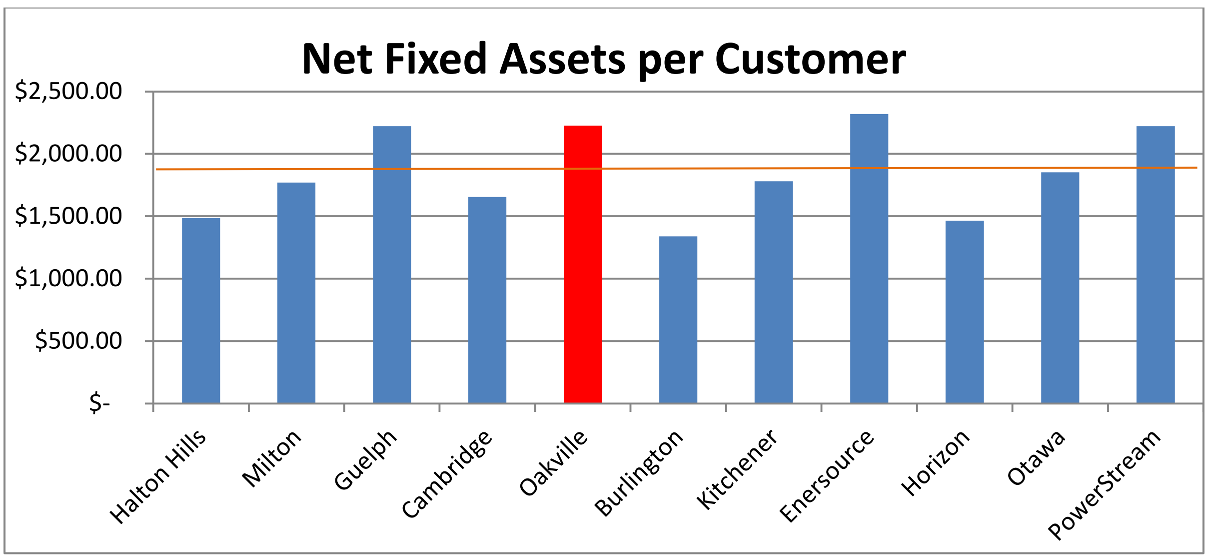
Oakville Hydro’s OM&A per customer is equal to the average of the comparator group and is below the other utilities in the Halton region. For the entire province the weighted average OM&A per customer is $292. OHEDI is efficient in the delivery of electricity to its customers.

Capital investment

The Net Fixed Assets per customer is an indication of the historical book value investment by the utilities in distribution infrastructure and operations. This measure does not include the total historical cost of the distribution assets as it excludes the cost developers incur and transfer to the local utility. This measure does not reflect the nature of asset purchases, for example OHEDI has invested in the Glenorchy Transformer Station over the past three years at a cost of $22 million (about $345 per customer) while others may have a recent investment in the building from which it operates. The net fixed assets per customer for OHEDI is $2,226 compared with the weighted average net fixed assets per customer of $1,925 for the entire comparator group.

This benchmark can give an indication of the under or over utilization of fixed assets but also can give an indication of the relative age of the distribution assets. Lower net fixed assets per customer may indicate that the assets have been in service longer and the accumulated depreciation is higher relative to the gross investment. Oakville Hydro's accumulated depreciation is 40% of the gross capital investment compared to the average for the comparator group of 47%, indicating that OHEDI assets are newer relative to the average. This is consistent with the timing of the commissioning of the Glenorchy Transformer Station.

For all LDCs in Ontario the range is $260 to $6,554 per customer with the average cost per customer for the entire province at $2,713.

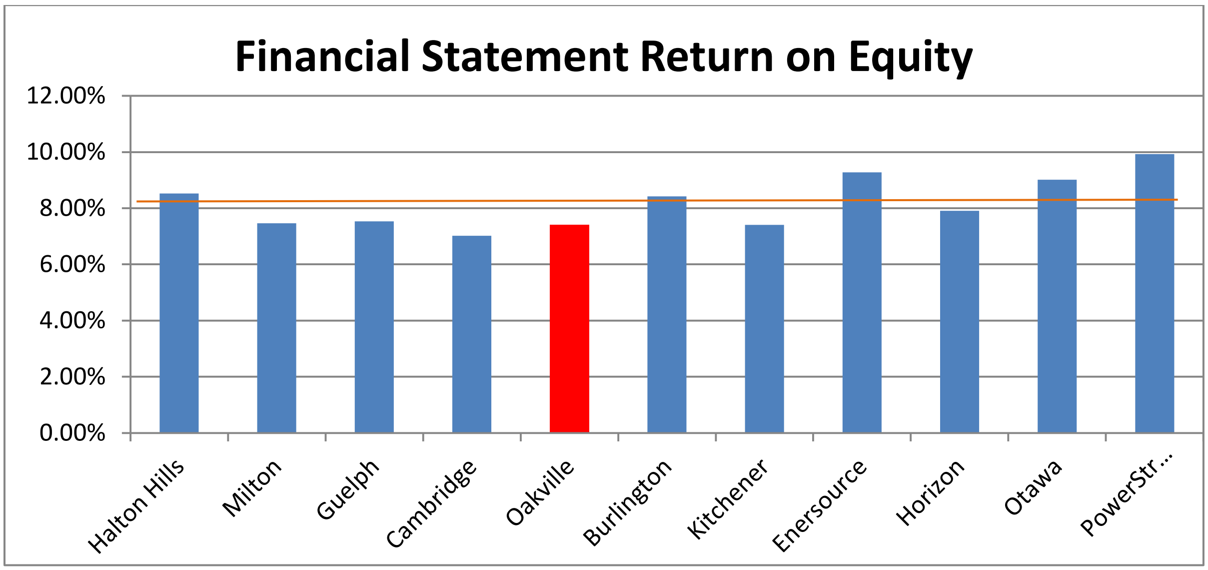


Conclusion

While OHEDI is higher than the comparator group on a per customer basis, it remains below the provincial average. OHEDI has historically had a good investment program resulting in newer distribution assets.

Return

As a measure of the fair return for the shareholder the Return on Equity is a generally a strong indicator. Direct comparatives, however, can be misleading as the nature of the relationships with the Shareholder also needs to be considered. For example, OHEDI borrows from the Town of Oakville at the deemed rate of interest determined during the Cost of Service. This rate of interest may be higher than that which could be obtained from third party lenders. In addition, a specific utility may have other non-regulated assets generating higher returns such as PowerStream having solar assets within its LDC.



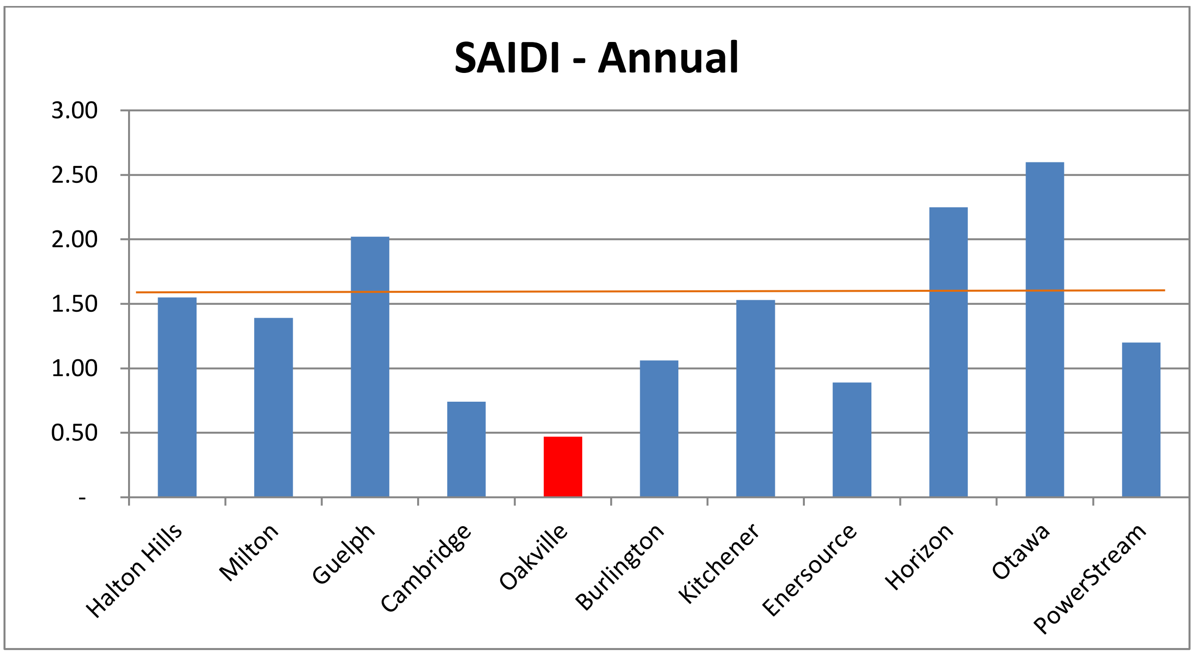
Conclusion

Overall, OHEDI generates a strong reliable and stable long term after tax return on the equity for the Shareholder and is industry comparable.

System reliability performance indicators

Finally the system reliability performance indicators are intended to provide comparative information on the current condition of the distribution assets.

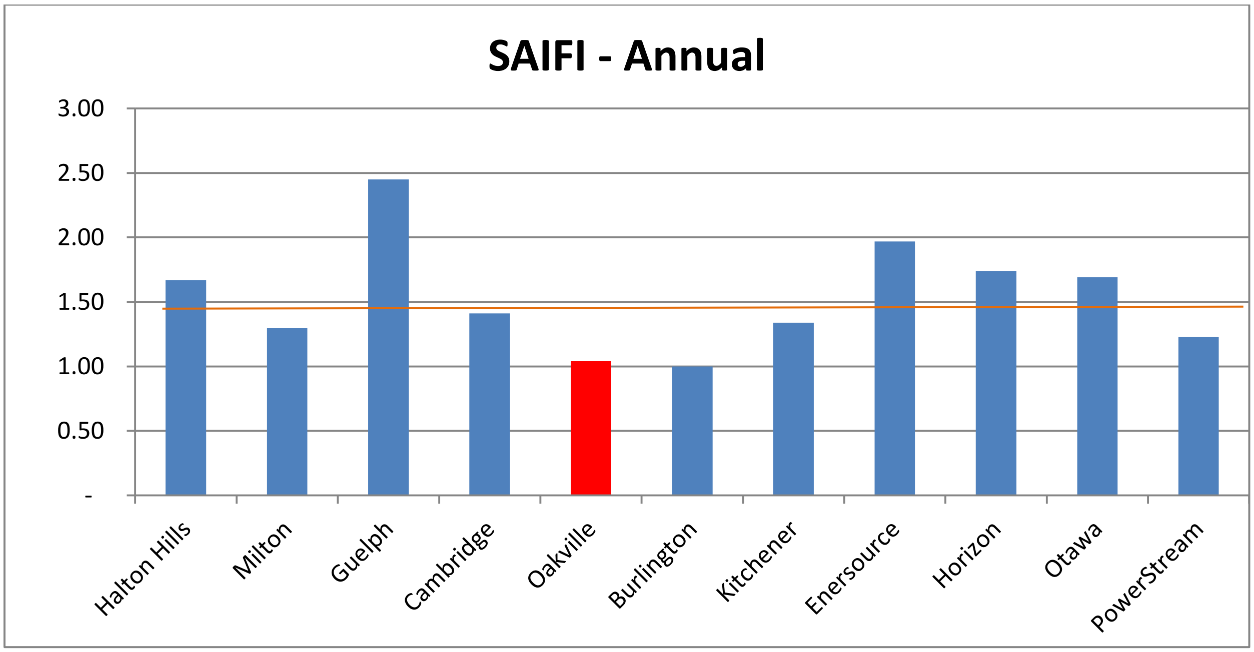
SAIDI is the System Average Interruption Duration Index which is the average outage duration for each customer served, measured in hours. A lower SAIDI score is indicative of higher reliability, although it may indicate that there is a good system in place to repair the distribution assets and restore service. OHEDI has the best SAIDI score for the comparator group. For all LDCs in Ontario the lowest is Fort Frances at 0.09, compared to OHEDI at 0.47, representing 28 minutes of interruption per customer. The highest is 52.37 at West Coast Huron Energy, both Fort Frances and West Coast have less than 4,000 customers and less than 100 km of power lines. The average for the entire province is 4.56 hours. Toronto Hydro reported 1.43 hours.



LOWER IS BETTER

System reliability performance indicators (cont'd)

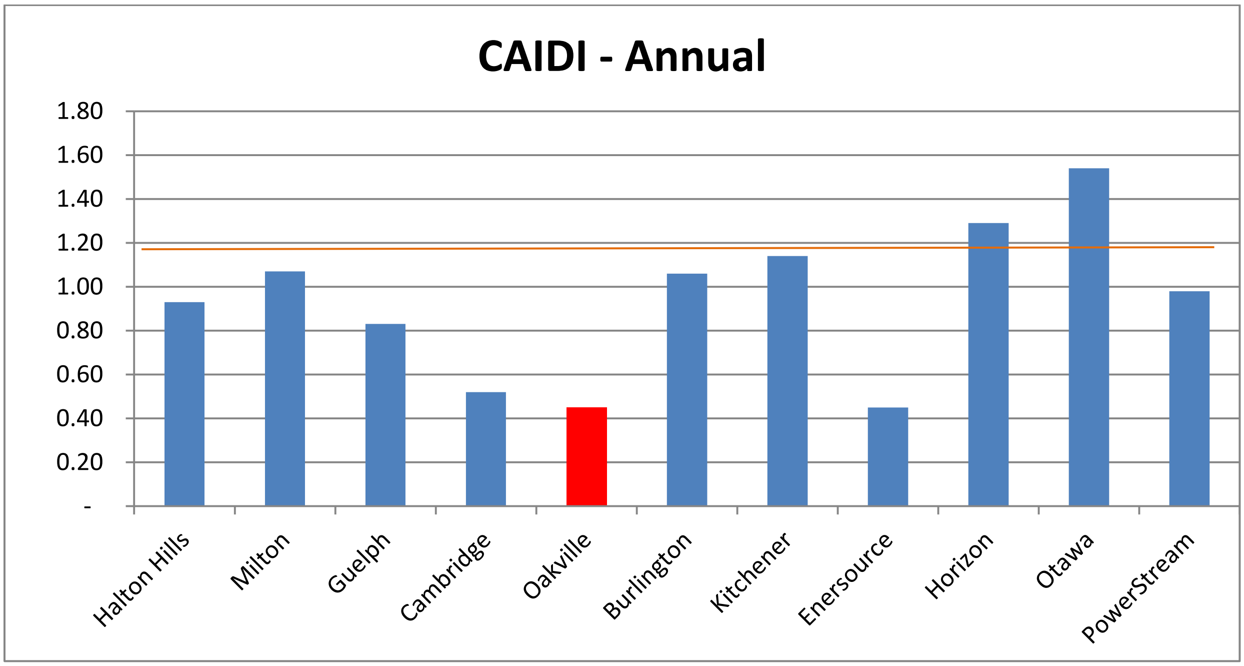
SAIFI is the System Average Interruption Frequency Index which is the average number of interruptions that a customer would experience during the year. A lower number indicates higher reliability. The lowest is again Fort Frances at 0.21 or 21 customers for every hundred have an outage and the highest is Kenora Hydro where each customer would expect to have 8.3 outages per year. OHEDI was slightly over one outage per customer per year at 1.04. Toronto Hydro was 1.62.



LOWER IS BETTER

System reliability performance indicators (cont'd)

CAIDI is the Customer Average Interruption Duration Index and measures the average outage duration that any given customer would experience measured in hours. This could be viewed as the average time to restore power. For OHEDI the CAIDI is 0.45 hours or about 27 minutes. The lowest in Ontario is 0.32 or 19 minutes for Woodstock and the highest is 10.33 hours for West Coast Huron. Toronto Hydro is 0.88 hours or 53 minutes.



LOWER IS BETTER

Conclusion

OHEDI has a very reliable system the design and operation of which ensures a relatively low duration of any outages. The frequency of outages is the second lowest in the comparator group (behind Burlington at 1.0) but the duration of the outage is considerably less than the comparator group.

Benchmarking Conclusion

In 2011, Oakville Hydro provided extremely reliable service at a price level better than the provincial average and comparable to the average of a comparable sampling of utilities in the GTA area. The amount of capital per customer OHEDI invests is below that of the provincial average and while a little higher than the comparable sample of GTA utilities it is newer.

Appendix 3 – B

Halton Hills – Distribution System Solar Integration Project Report




July 25, 2013

Distribution System Solar Integration Project

Report to the LDC Tomorrow Fund

Submitted by Halton Hills Hydro

Distribution System Solar Integration Project

Report to the LDC Tomorrow Fund

Contents

Project Overview

Halton Hills Hydro installed 187 solar panels on hydro poles throughout the Town of Halton Hills as a pilot project to study the benefits to Ontario LDCs of integrating the distribution system with pole mounted solar modules. This innovative rate based pilot project was approved in Halton Hills Hydro's 2012 Cost of Service Application to the Ontario Energy Board. This project was undertaken with contribution from the LDC Tomorrow Fund.

> The objective of the project was to quantify the benefits to LDCs of installing pole mounted solar modules, enabling a new and innovative technology and ensuring the results are transferable to all Ontario LDCs. It is a highly visible and scalable community focused project which provides fully distributed renewable energy coupled with smart grid features within the community.

The three key benefits of this system as seen by Halton Hills Hydro are:

1. The pole mounted solar modules provide clean renewable energy generation.

2. Having generation on hydro utility poles, close to the load, reduces line losses.

3. The pole mounted solar modules create an intelligent grid infrastructure that provides real time monitoring, and troubleshooting on the secondary distribution system.

Halton Hills Hydro's experience

Halton Hills Hydro has experienced each of these benefits.

1. The pole mounted solar modules provide clean renewable energy generation. For Halton Hills Hydro and our shareholder, the Town of Halton Hills, this was a highly visible project in the community which complements the Mayor's Green Plan and the Town's Community Energy Plan. Halton Hills Hydro chose to place the solar modules on poles on major thoroughfares within the community so that they would be highly visible to customers and visitors. Halton Hills Hydro staff received a few inquiries about the panels, mostly from customers curious about the project and interested in the solar energy being produced.

2. Having generation on existing hydro utility poles, close to the load, reduces line losses. The energy generated by the panels and the resulting line loss reductions are passed on directly to Halton Hills Hydro's rate payers. Halton Hills Hydro has been pleased with the amount of energy generated which exceeded expectations. The anticipated line loss reduction is 0.02% per 100kW of installed panels. The line loss reduction is primarily on-peak losses which have been identified by the Ontario Government in their "*Conservation First – A Renewed Vision for Energy Conservation in Ontario"* as being an important factor in energy conservation and improved system efficiency.

3. The pole mounted solar modules create an intelligent grid infrastructure providing real time monitoring, and troubleshooting on the secondary distribution system. It is these “Smart Grid” benefits which were of the most interest to the utility. Halton Hills Hydro has found the capability of the smart energy modules to provide voltage information particularly useful in identifying areas with high or low voltages. Usually, the LDC only finds out about these over or under voltages when a customer calls, whereas now Halton Hills Hydro can proactively send crews to investigate and make adjustments before potential damage to customer or utility owned equipment occurs. In particular, voltages can be proactively monitored during both on and off peak periods to further improve system efficiencies.

Halton Hills Hydro retained Kinectrics Inc. to perform a detailed third party evaluation of the distribution system solar integration project to quantify the costs and benefits associated with the system and verify the claims made by the manufacturer regarding system monitoring. Their detailed report is attached. Kinectrics found that the solar modules reduce line losses through renewable energy generation and provide a “smart grid” benefit by measuring and reporting such parameters as voltage and frequency.

It is Halton Hills Hydro’s belief that this has been a valuable pilot project demonstrating that this technology can be implemented within existing rate base and with benefits which are easily transferable and scalable to any LDC in the province. Halton Hills Hydro recognizes this project as the type of initiative which complements the Province of Ontario’s “Renewed Vision for Energy Conservation”. Halton Hills Hydro will be looking at expanding the roll out of the pole mounted solar modules in the coming years.

KINECTRICS

DISTRIBUTION SYSTEM SOLAR INTEGRATION EVALUATION FOR HALTON HILLS HYDRO

.

Kinectrics Inc. Report No.: K-418480-RA-001-R00

Client Purchase Order: 64566

July 23, 2013

Nicolas Wrathall, P.Eng.

Distribution Asset Management Department

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario M8Z 5G5

DISTRIBUTION SYSTEM SOLAR INTEGRATION EVALUATION FOR HALTON HILLS HYDRO

Kinectrics Inc. Report No.: K-418480-RA-001-R00

July 23, 2013

Prepared by:

Nicolas Wrathall, P. Eng.
Senior Engineer, Distribution Asset Management
Transmission & Distribution Technologies

Reviewed by:

Stephen Cress, P. Eng.
Department Manager, Distribution Asset Management
Transmission & Distribution Technologies

Approved by: per

Yury Tsimberg, P. Eng.
Director, Asset Management
Transmission & Distribution Technologies

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Halton Hills Hydro Inc.

REVISIONS

Revision Number	Date	Comments	Approved

DISTRIBUTION SYSTEM SOLAR INTEGRATION EVALUATION FOR HALTON HILLS HYDRO

EXECUTIVE SUMMARY

Kinectrics studied Halton Hills Hydro's Distribution System Solar Integration pilot project to determine and quantify the costs and benefits associated with the Pole-Mounted Solar Module (PSM) installations. The study involved a validation of the system measurements provided by the PSMs, using field measurements collected during the study, and a cost/benefit analysis to determine the net present value of the PSM installations.

The key findings of this study were:

1. The PSM measurements are sufficiently accurate for practical utility engineering applications, such as reliability assessment, voltage regulation analysis, losses studies, fault detection, and general troubleshooting.

2. The PSMs provide a benefit to Halton Hills Hydro (HHH) by producing energy. This energy reduces the amount of energy purchased by the utility and reduces losses, providing a benefit to both HHH and its customers. The forecasted annual energy output of the PSMs in the pilot project is approximately 46 MWh. It is estimated that this will reduce HHH's distribution loss factor by 0.01%. Because PSM generation typically coincides with peak loading (daytime hours), a reduction in peak losses would be expected.

3. The PSMs provide a "smart grid" benefit by measuring and reporting system parameters, such as voltage and frequency. A new version of the PSM (2014) is expected to incorporate power quality measurements and automated alert messaging.

4. The PSMs produce renewable energy, which provides an environmental benefit and a benefit to Halton Hills Hydro's reputation. The energy output from the Distribution System Solar Integration pilot project is estimated to offset approximately 26 metric tons of equivalent carbon emissions annually. This is equivalent to 0.58 metric tons per installed kW.

5. The results of the net present value (NPV) analysis indicate that:

    a. Although the pilot project will not provide a net positive value when all costs and benefits are considered, because of decreasing equipment costs future PSM installations are expected to provide a net positive value when the benefits of smart grid are considered. The 30-year NPV of the pilot project and future PSM installations, with and without the added benefits of smart grid and renewable energy, are summarized in Table 1. This table also shows the number of years required for the PSM installations to achieve neutral value (break even) for each scenario.

Table 1: Pilot Project and Future PSM 30-Year Cost/Benefit NPV Summary

Cost/Benefits Scenario	Pilot Project		Future PSMs	
	NPV (2012 $)	Years to Break Even	NPV (2012 $)	Years to Break Even
Smart Grid and Renewable Benefits	-$46,186	>30	$36,174	16
Renewable Benefits (no smart grid benefit)	-$166,474	>30	-$84,114	>30
Smart Grid Benefits (no renewable benefit)	-$66,474	>30	$10,814	24
Actual Benefits (no smart grid or renewable benefit)	-$186,762	>30	-$109,474	>30

b. The maximum total installation costs per Watt required for a PSM installation to achieve a neutral net present value after 30 years was calculated for each scenario. When the actual installation costs are less than these "break even" costs, PSM installations will provide a net positive value within a 30-year time period.
   i. When only the benefits associated with energy production and loss reduction are considered, the break even cost was calculated to be $1.75/W.
   ii. When the benefits of the smart grid functionality are also considered, the break even cost was $3.75/W.
   iii. Similarly, when the benefits of energy production and loss reduction are considered with the benefits of renewable energy, the break even cost was found to be $2.17/W.
   iv. Finally, when all benefits are considered together, the break even cost was $4.17/W.
   v. For comparison, the costs associated with the pilot project were $5.76/W and the expected cost for PSM installations in 2014 is $3.57/W.

c. The NPV analysis indicates that, of the three primary benefits associated with the PSMs (energy and loss reduction, smart grid, and renewable energy), the smart grid features provide the greatest benefit to HHH.

Based on the results of this study, Kinectrics recommends the following:

1. Provided the costs and power densities of future PSMs are less than $3.75/W, as they are predicted to be[1], HHH may wish to consider expanding the PSM program up to the point where the smart grid benefits are maximized. The maximum smart grid benefit would be achieved by having one PSM connected to each phase of each circuit. The installation of more than one PSM unit on one phase of a given circuit will not provide additional smart grid benefits and therefore would not be cost effective.

2. HHH should install the new versions of the PSM, once available, to take advantage of the additional smart grid features, such as improved power quality monitoring and automated alerts. If technically possible and cost-effective, existing PSM units should also be upgraded with this functionality.

[1] The most recent pricing from the manufacturer indicates that the 2014 price will be $1,071 for a 300W installation, or $3.57/W

3. Should the total installation price for PSM installations fall below $1.75/W, HHH should consider installing PSM units beyond the point where the maximum smart grid benefit is achieved. When the installation price is below this level, the PSMs will provide a direct financial benefit to HHH's customers.

4. It is recommended that Halton Hills Hydro confirm the effectiveness of the PSM anti-islanding protections for multiple PSM installations connected in close proximity to one another before installing large numbers of PSMs. It is also recommended that Halton Hills Hydro work with Hydro One to ensure that Hydro One is aware of the PSM installations.

Contents

KINECTRICS

To: **Jennifer Gordon**
Halton Hills Hydro Inc.
43 Alice St.
Acton, ON L7J 2A9

DISTRIBUTION SYSTEM SOLAR INTEGRATION EVALUATION FOR HALTON HILLS HYDRO

1.0 INTRODUCTION

Halton Hills Hydro (HHH) undertook a pilot project in 2012 to install photovoltaic (PV) solar panels on some of their distribution utility poles. Each Pole-Mounted Solar Module (PSM) installation consists of one PV solar panel and one Smart Energy Module (SEM); each PV panel is connected to the distribution system through a SEM. A total of 187 PSMs were installed during the pilot project. An additional 9 communicator units, used to relay the data transmitted by the PSMs, were also installed.

The PSM installations connect to HHH's system on the 120/240 V secondary system. In addition to exporting energy to the grid, the PSM units also measure system parameters and report this information back to HHH. This information is reported through a web-based software system, IntelliView, which is owned and maintained by the equipment vendor, Petra Solar Inc. (Petra).

Figure 1 shows an example of a typical installation.

HHH hired Kinectrics to perform a cost/benefit evaluation of the PSM installations. This evaluation was performed using information about the Distribution Solar System Integration pilot project and future installations, provided by HHH and Petra.

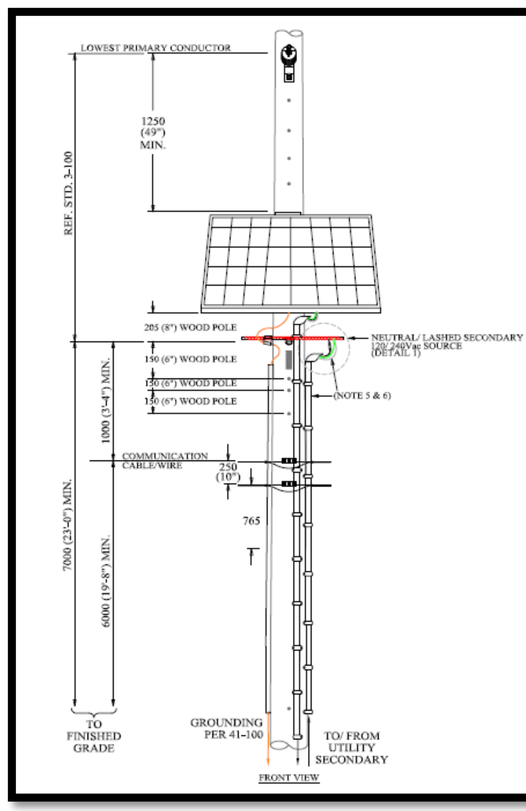


Figure 1: Typical PSM Installation

2.0 OBJECTIVES AND SCOPE

2.1 Objectives

The objective of this project was to investigate and provide commentary on a number of claims by the manufacturer (Petra) with respect to PSMs, as outlined in the proposal submitted by Halton Hills Hydro to the LDC Tomorrow Fund[2]. The investigation was performed using independent measurements and data from the 187 PSMs that were installed as part of a pilot project at HHH.

The primary objectives were to:

1. Verify the accuracy of the following parameters that are measured by the Smart Energy Modules:
    a. System secondary voltage
    b. Frequency
    c. AC current output
    d. AC real power output
    e. AC reactive power output
    f. Cumulative energy generation
2. Evaluate the impact of the Smart Energy Modules on the following:
    a. Increased reliability
    b. Power system voltage stabilization
    c. Monitoring of voltage and power quality
    d. Real-time system data
    e. Fault detection and troubleshooting
    f. Improved response time to issues
    g. Ability to proactively address system issues
3. Determine the effect of the Distribution System Solar Integration pilot project on losses
4. Investigate the voltage regulation capabilities of the Smart Energy Modules
5. Identify power quality issues that were found using the Smart Energy Modules

2.2 Scope

The scope of this project was divided into two parts. Part A involved an evaluation of the accuracy of measurements of the PSMs; this was required to determine if the quantities reported by the PSMs were sufficiently accurate to be used in Part B.

Part B was an assessment of the costs and benefits to HHH for the installation of the PSMs. This analysis assessed the Net Present Value (NPV) of the costs and benefits associated with the PSM installations. Section 3.0 describes the methodology used in this project.

---

[2] *Distribution System Solar Integration Project – A proposal to the LDC Tomorrow Fund*, Halton Hills Hydro

3.0 METHODOLOGY

The following sections describe the methodology used in the two phases of this project.

3.1 Part A - Measurement Validation

The methodology used in the validation of the PSM measurements is described by the following steps:

1. A calibrated Kinectrics power quality analyzer was connected to the PSM outputs at two different locations. The outputs were measured over three-hour time intervals. The following parameters were recorded:
   a. AC RMS voltage
   b. AC RMS current
   c. AC Real Power
   d. AC Reactive Power
   e. AC Apparent Power
   f. Cumulative energy output
   g. Voltage and current THD
   h. Flicker

2. The power quality analyzer measurements were then compared with the measurements reported by the PSMs through their online system, IntelliView.

3. The accuracy of the PSM measurements were calculated with respect to the power quality analyzer measurements.

3.2 Part B - Cost/Benefit Analysis

Kinectrics evaluated the costs and benefits to HHH of the PSMs using the methodology described in this section. The cost/benefit analysis involved the following steps:

1. Information about costs, maintenance, revenue, and usage was collected from HHH and Petra.

2. This information was analyzed to determine the costs and benefits associated with the Distribution System Solar Integration Pilot Project and the broader deployment of PSM installations. The benefits were grouped into the following three categories:
   a. Power production and losses
   b. Smart grid
   c. Renewable energy

3. The overall cost or benefit of the PSM installations was quantified using a Net Present Value (NPV) calculation. The value was calculated using the following formula:

$$Value = NPV\begin{bmatrix} (Energy\ Production) + (Loss\ Reduction) + (Smart\ Grid) \\ +(Renewable\ Energy) - (Installation\ Costs) - (Maintenance) \end{bmatrix}$$

4.0 PART A - MEASUREMENT VALIDATION

The results of the measurement validation phase of this project were provided in a separate report. A copy of this report is provided in Appendix A. The conclusions and recommendations are included here for the reader's benefit. Please note that the Pole-Mounted Solar Installations (PSMs) were referred to as Smart Energy Modules (SEMs) in the report for Part A.

Conclusions

1. The measurements recorded by the SEMs are sufficiently accurate for practical utility applications, including: reliability assessment, voltage regulation analysis, losses studies, fault detection, and general troubleshooting.
2. The measurements recorded by the SEMs may not be sufficiently accurate to be used as a substitute for field or laboratory measurements with calibrated instruments. However, the practical applications for which the SEM measurements would typically be used by a utility do not generally require highly accurate measurements.
3. SEM harmonic and flicker measurements were not available in the IntelliView system and could not be compared with the Fluke measurements. The availability of harmonic and flicker measurements should be confirmed during Part B.

Recommendations

1. The measurement data recorded by the SEMs were found to be sufficiently accurate for practical applications, including Part B of this project. Therefore, it is recommended that Part B – Cost/Benefit Analysis proceed.
2. A SEM should be tested in a controlled laboratory environment to determine the accuracy of the active power, reactive power, and energy measurements under controlled conditions. Moreover, laboratory testing can also verify the SEM's various operating, protection, and maximum power point tracking (MPPT) functions, if required.
3. The availability of harmonic and flicker measurements should be confirmed during Part B.

5.0 COST/BENEFIT ANALYSIS

The evaluation of the costs and benefits of the PSM installations is presented in this section. This information was used in the NPV calculations in Section 6.0.

5.1 Costs

5.1.1 Purchase and Installation

The total cost of the pilot project was $258,660; this cost includes $225,000 for equipment and $33,660 for labour. 187 PSMs were installed, so the cost per unit was $1,383.21. Each PSM has a rated capacity of 240W, so the cost per Watt was $5.76/W.

According to Petra Solar, the unit costs have decreased and the power density of solar panels is expected to increase from 240W to 300W per panel in the future. According to Petra Solar and HHH, the cost for a 300W unit will be $1,071 in 2014, including installation. Assuming the cost per Watt is the same for a 300W unit or a 240W unit, the expected cost for a 240W unit in 2014 would be $887, including installation.

The NPV calculation for the pilot project uses the actual pilot project costs. The NPV calculation for future installations uses a cost of $887 for each 240W unit and $1,071 for each 300W unit.

5.1.2 Maintenance

According to Petra and HHH, the units do not require scheduled maintenance. The PV panels are treated with a coating that self-cleans with rain. The panels may need to be washed if there are extended periods without precipitation, but this is unlikely in Ontario's climate.

The PV panels are covered by a 20-year warranty and the SEMs are covered by a 10-year warranty. There are some indications that the SEMs will be covered by a 15-year warranty in the future, although this has not yet occurred. Although Petra Solar indicates that the expected failure rate for PSM installations is less than 1% per year, it has been assumed that the PSM installations will have a 30-year useful lifespan on average; this assumption results in a failure rate of approximately 3.2%, which is more conservative than the manufacturer's estimates, but is justified because the historical information relating to this technology is limited.

The NPV calculations assume that no maintenance is required for the first 10 years because all equipment is covered by warranty. In years 11 to 20, the SEMs are no longer covered by warranty and it is assumed that between one and six SEMs will require replacement each year at a cost of $150 each. After year 20, it is assumed that six complete PSM installations (PV panel and SEM) will require replacement per year. The replacement costs used in the NPV calculation were $150 per SEM, $737 per 240W PV panel for the pilot project, and $921 per 300W PV panel for future installations, including installation costs. These costs are subject to inflation, but like other new technologies, the costs are also expected to decrease as the technology matures. For the NPV calculations, it was assumed that these two effects would counteract one another, resulting in the replacement costs remaining constant over time.

Table 2 shows the estimated replacement schedule and associated costs.

Table 2: Estimated Replacement Schedule

Year	0-10	11	12	13	14	15	16	17	18	19	20	21+
SEM Replacement	0	1	1	2	2	3	3	4	4	5	5	6
PV Panel Replacement	0	0	0	0	0	0	0	0	0	0	0	6
Maintenance Cost Pilot Project – 240W units ($)	0	150	150	300	300	450	450	600	600	750	750	5,322
Maintenance Cost Future – 300W units ($)	0	150	150	300	300	450	450	600	600	750	750	6,246

5.2 Benefits

5.2.1 Power Production and Losses

The Distribution Solar System Integration pilot project has been in service since February 2013. The pilot project has not been in operation for sufficient time to provide historical annual power production information, but a previous installation site on 10th Line in Halton Hills near Ashgrove (Ashgrove) has been in operation for several years. The rated power output per unit at the Ashgrove site is 200 W, while the units used in the pilot project have a rated output of 240 W.

The Ashgrove site is an ideal site for PV installations and the PSMs installed in the pilot project are not expected to produce as much energy per installed Watt of capacity. The power output from the four units at the Ashgrove site was used to estimate the power production from the PSMs in the pilot project. To forecast the annual output of the PSMs in the pilot project, the average measured energy output from the Ashgrove PSMs was scaled to match the average measured output of the pilot project PSMs between March and June 2013. The forecasted annual pilot project PSM energy output was found by scaling the annual Ashgrove output by this scaling factor. Therefore, the forecasted energy output of the PSMs in the pilot project was based on the Ashgrove data, but adjusted to match the actual pilot project energy output measured between March 2013 and June 2013.

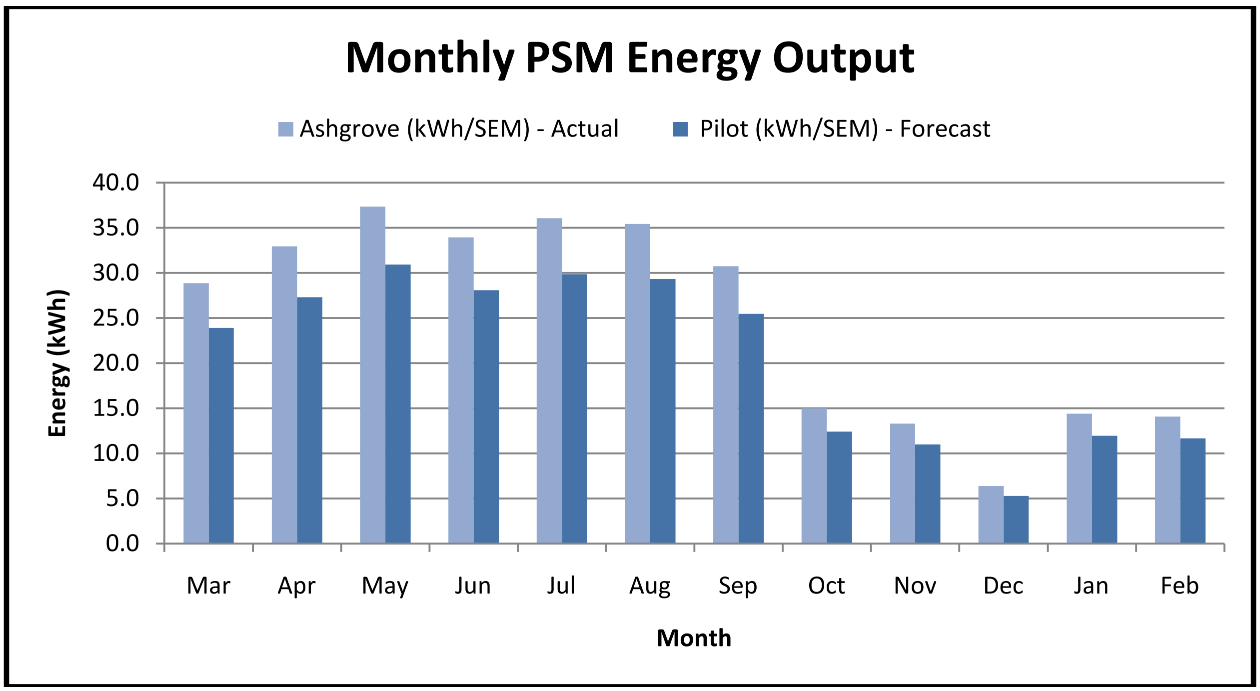


Figure 2: PSM monthly power output

Figure 2 shows the average measured monthly energy output of the PSM installations at the Ashgrove site from March 2012 to February 2013 and the forecasted monthly pilot project PSM energy output. Based on this prediction, the 187 PSMs in the pilot project are expected to produce approximately 46,214 kWh per year.

It is not uncommon to see a decrease in the power output of PV panels over time, however, and Petra projects that the productivity loss after 20 years will not exceed 15%. This decrease in productivity has been factored into the NPV calculation. According to a report by SANDIA National Laboratories, the mean annual decrease in the maximum power available from eleven different PV panels tested was 0.27% per year[3]. This annual decrease in energy output was used in the NPV calculations.

The power produced by the PSM installations will also have a beneficial impact on Halton Hills Hydro's losses. The power that is produced by the PV panels will be consumed locally and will therefore decrease the losses associated with transmitting this power through both the distribution and transmission systems.

Prior to the Distribution Solar System Integration Pilot Project, HHH's Total Loss Factor (TLF) was calculated to be 106.02%. This is comprised of HHH's Distribution Loss Factor (DLF) of 102.53% and an upstream Facilities Loss Factor (FLF) of 103.4%.

The impact of the Pilot Project PSM power production was calculated as follows. HHH's 5-year average DLF was calculated using the following equation:

$$DLF = \frac{W}{R} = \frac{490{,}073{,}766\ kWh}{477{,}985{,}841\ kWh} = 102.53\%$$

where W is the 5-year average net "wholesale" kWh delivered to the distributor and R is the 5-year average net "retail" kWh delivered by the distributor. Let E represent the annual kWh produced by the PSMs in the pilot project, then HHH's new DLF, considering the impact of the PSMs can be calculated to be:

$$DLF_{PSM} = W - DLF \cdot ER$$

because the energy produced by the PSMs will reduce both the net wholesale kWh delivered by the distributor and the losses on HHH's distribution system; therefore the difference in the net wholesale kWh delivered to the distributor is increased by the DLF. Solving for the new DLF_{PSM},

$$DLF_{PSM} = \frac{W}{R + E} = \frac{490{,}073{,}766\ kWh}{477{,}985{,}841\ kWh + 46{,}214\ kWh} = 102.52\%$$

Therefore the effect of the energy from the PSM pilot project being generated locally can be expected to decrease HHH's DLF by 0.01%. The savings associated with this loss reduction will be passed on to the customer. As an estimate for future PSM installations, the impact of 100 kW of PSMs (which would be expected to produce 102,972 kWh annually) on HHH's DLF would be a decrease of approximately 0.02%. It is also expected that PSM installations would have a different impact on losses for different utilities. For example, PSMs should reduce losses more for rural distributors than urban distributors. This is due to the reduced power flow along the lengthy feeders associated with rural utilities.

Considering the reduction of losses, the expected change in the average net wholesale kWh delivered to the distributor will be $E \cdot DLF_{PSM} = 46{,}214\ kWh\ \cdot 102.52\% = 47{,}378\ kWh$.

Because the PSMs only generate during daytime hours, which typically coincide with peak distribution system loading, the PSMs should reduce peak distribution system losses.

The PSMs reduce the net wholesale kWh delivered to HHH; therefore the rate paid to HHH is effectively the same rate as for energy delivered to the distributor. This rate is composed of the Hourly Ontario Energy Price (HOEP), the Global Adjustment (GA), the Transmission Network Charge, the Transmission

[3] Smith, R., Jordan, D., Kurtz, S, *Outdoor PV Module Degradation of Current-Voltage Parameters - Preprint*, 2012 World Renewable Energy Forum, 2012.

Connection Charge, the Wholesale Market Service Charge, the Low Voltage Charge, and the Rural and Remote Electricity Rate Protection. This rate is then multiplied by the FLF. The average hourly HOEP peak rate was used in the calculation because the PSMs only generate during daytime hours, which coincide with peak HOEP hours.

The rate for 2013 and future years was estimated by extrapolating the historical rates from 2008 to 2012; the average rate for 2012 was $0.0932/kWh and the trend shows an annual increase of $0.0035/kWh. The FLF is 3.4%, therefore the rate used in the NPV calculation was $0.0964/kWh in 2012 with an annual increase of $0.0036/kWh.

5.2.2 Smart Grid

The PSMs, in addition to the energy they produce, provide additional benefits that can be described as "smart grid" features. The PSMs measure and report system parameters, such as voltage and frequency, at regular intervals and are capable of raising alerts when these parameters fall outside of nominal ranges. The benefits associated with this smart grid functionality are described and their value is assessed in this section.

<u>Reliability & Fault Detection</u>

The PSMs monitor system voltage and frequency and can therefore report outages when configured to do so. HHH currently has them configured to raise an alert whenever the measured voltage is outside of the nominal range. Because many outages are only detected when customers report them, the automatic alert from the PSMs will allow HHH to detect and respond to outages more rapidly. This will reduce customer outage times and will have a positive impact on the utility's SAIDI and CAIDI statistics.

If it assumed that the alerts from the PSMs will provide HHH with notice of an outage 5 minutes earlier on average than the current reporting methods, the result would be a decrease in both of HHH's SAIDI and CAIDI statistics of 0.083. Considering the 2012 statistics, the resulting SAIDI and CAIDI statistics would be 1.45 hours and 0.72 hours, down from 1.53 hours and 0.80 hours respectively. No impact on the frequency of outages (SAIFI) is expected.

It is important to note, however, that the alerts from the PSMs are not currently actively communicated to utility personnel; the alerts are raised in the PSM's monitoring software program (IntelliView) and are only visible when someone logs into the system. Therefore, the positive impact of the PSM's smart grid functionality on reliability is not as significant as it could be if automated email or SMS alerts were to be incorporated into the system. It is recommended that HHH work with the equipment supplier to add this functionality to maximize the value of this system. However, it should also be noted that Halton Hills Hydro does not currently have a control room. This system could be integrated into a control room for ongoing monitoring.

<u>Power Quality Monitoring, and Troubleshooting</u>

The PSMs provide valuable data for diagnosing and troubleshooting power quality issues. As mentioned above, the PSMs measure the system voltage where they are connected. Using this information, HHH has found several locations along their feeders where the voltages were outside of the nominal range and the appropriate corrective action was taken. Correcting over/under-voltage conditions is generally expected to have a positive effect on utility and customer equipment. Without the data from the PSMs, it is likely that these over/under-voltage conditions would have gone unnoticed and would not have been corrected. Prior to the installation of the PSM units, over/under-voltages would only have been detected if the utility implemented a program to proactively measure voltages or if a customer measured their voltage and notified the utility that it was not at an acceptable level. Some over/under-voltages can stress utility and customer equipment and lead to increased failure rates.

Additionally, Petra has indicated that the next generation model of PSM will be capable of measuring system harmonics and flicker. Harmonic and flicker problems can be difficult to investigate and resolve and this capability will allow HHH to proactively address and resolve potential power quality problems. The model of PSM installed in the pilot project does not have the capability to measure harmonics or flicker.

Because the PSMs are single-phase devices, it is not possible for them to measure unbalance.

It is recommended that HHH require harmonic and flicker measurement capabilities for future PSM installations.

<u>Voltage Regulation</u>

The PSM system has the physical capability to perform active voltage regulation through dynamic VAR injection. This control mode would allow a utility to set a voltage set point and the PSMs would dynamically adjust their reactive power output to maintain the voltage at that set point. Although dynamic VAR injection is not yet available and the PSMs in the pilot project operate at a constant power factor (1.0 at full power output), future PSM models may be equipped with this functionality.

This control mode could provide a benefit to HHH, but it should be studied before implementation for several reasons. Firstly, active voltage regulation by distributed devices requires careful coordination to ensure that there are no conflicts with the utility's existing voltage regulating equipment. Secondly, the PSMs have a limited power output and any quantity of reactive power (VAR) produced would come at the expense of active power production (W). Since HHH receives financial compensation from the PSMs as a function of the active power produced (kWh), any reactive power production will decrease the savings from the active power production. Finally, due to the relatively low rated capacity of the PSMs (240 W – 320 W), the PSMs may not be physically capable of regulating the voltage. It is recommended that HHH study these issues before considering the implementation of active voltage regulation by the PSMs.

<u>Smart Grid Valuation</u>

Although there is clear value in the added smart grid functionality associated with the PSMs in the pilot project, and to a greater extent the next generation of PSMs, it is difficult to quantify this benefit in financial terms. Much of the information provided by the PSMs, such as system voltages and power quality measurements, provides a benefit to HHH and its customers by helping to diagnose and resolve problems that may have otherwise gone undetected and these benefits are difficult to quantify financially. Therefore, instead of attempting to quantify these benefits directly, the cost associated with installing an alternative smart grid system with similar functionality has been used.

The OptaNODE system, manufactured by Grid20/20, was selected as the alternative smart grid technology because it offers smart grid features comparable to those provided by the PSMs. The OptaNODE units measure system parameters, such as voltage, current, power, and energy and have built-in communications. A future version of the OptaNODE unit is expected to be capable of measure harmonics and flicker as well. Unlike the PSMs, the OptaNODE units do not produce energy.

According to the Grid20/20, the approximate cost for fewer than 1,000 OptaNODE units is roughly $600/unit. Therefore, the cost of installing 187 units, the number of PSMs installed in the pilot project, was estimated to be $112,200. It was also assumed that there would be ongoing maintenance costs associated with the OptaNODE units, estimated at $3,600 per year after twenty years. This is based on the following assumptions: the units have a 20-year warranty, 6 units would need to be replaced annually, and each replacement unit would cost $600. The cost for this alternative smart grid system was deducted from the installation and maintenance costs of the Distribution Solar System Integration pilot in the relevant NPV calculations.

It should be noted that the benefit of any smart grid system will be maximized when the utility achieves visibility of every circuit. After this has been achieved, there is little value in the installation of additional devices, as far as smart grid functionality is concerned. For a distributor, this maximum smart grid value will occur when a smart grid device is installed on each phase of every circuit in the system, where a circuit is defined as a section of line that is separated by a transformer or a section of line that can be sectionalized from the rest of the grid.

5.2.3 Renewable Energy

The PSMs provide a benefit in that the solar energy they produce is green and renewable. In addition to the obvious environmental benefits of renewable energy production, the PSMs also provide a benefit to HHH's reputation and the reputation of the communities within which it operates; this is because the PV panel installations are prominently mounted on utility poles and clearly visible to the public.

However, similarly to the smart grid benefits discussed in Section 5.2.2, the financial benefit of green/renewable energy production is difficult to quantify. HHH is not receiving any premium for the renewable energy produced by the panels, and there is therefore no direct financial benefit to HHH or its customers. However, there is clearly value in the renewable nature of the energy produced by the PSMs and this should be captured in the NPV calculations.

There is an energy provider that operates in Ontario (and other areas of Canada), Bullfrog Power[4], that sells electricity from renewable sources to its customers for a premium. This company has been operating successfully in Ontario since 2005 and, therefore, the premium they charge to customers for renewable electricity was used to represent a reasonable valuation for the renewable energy produced by the PSMs. The premium charged by Bullfrog Power is $0.03/kWh and this rate has been used in the relevant NPV calculations in Section 5.3.

It should also be noted that the installation of PSMs may be eligible for carbon credits. According to the United States Environmental Protection Agency, electricity generation in the US produces 1,222.29 lb/MWh of equivalent carbon emissions[5]. Using this number, it is estimated that the Distribution System Solar Integration pilot project would offset approximately 26 metric tons of equivalent carbon emissions annually. This is equivalent to 0.58 metric tons per installed kW. Carbon credits were not considered in this analysis, but should be investigated to determine if PSM installations are eligible.

[4] http://www.bullfrogpower.com/index.cfm, May 30, 2013.
[5] *eGRID2012 Version 1.0 Year 2009 Summary Tables*, EPA, April 2012
http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf

5.3 NPV Calculation

The 30-year cost/benefit Net Present Value (NPV) calculation was performed for the following eight cases:

A) Pilot Project - Actual: this case represents the actual NPV for the pilot project. The revenue from power production and loss reduction was estimated and neither the benefit of smart grid nor renewable energy was considered.

B) Pilot Project - Smart Grid: this case represents the NPV for the pilot project when the smart grid benefit is considered.

C) Pilot Project - Renewable: this case represents the NPV for the pilot project when the renewable energy benefit is considered.

D) Pilot Project - Smart Grid and Renewable: this case represents the NPV for the pilot project when both the smart grid and renewable energy benefits are considered.

E) Future PSMs: this case represents the NPV for future PSM installations, with the estimated future installation cost of $1,071 for a 300W PSM, or $3.57/W.

F) Future PSMs - Smart Grid: this case represents the NPV for future PSM installations when the smart grid benefit is considered.

G) Future PSMs - Renewable: this case represents the NPV for future PSM installations when the renewable energy benefit is considered.

H) Future PSMs - Smart Grid and Renewable: this case represents the NPV for future PSM installations when both the smart grid and renewable energy benefits are considered.

The following assumptions were used in the NPV calculations for all cases:

- The discount rate used was 6.09%[6]
- NPV is calculated in 2012 Canadian dollars.
- The installation costs are described in Section 5.1.1.
- The maintenance costs are described in Section 5.1.2.
- The energy production, losses, and revenue received for energy produced by the PSMs is described in Section 5.2.1.
- The added benefit of the smart grid functionality is described in Section 5.2.2.
- The added benefit of the renewable energy produced by the PSMs is described in Section 5.2.3.

[6] The Regulated Rate of Return from Halton Hills Hydro's 2012 COS Rate Application

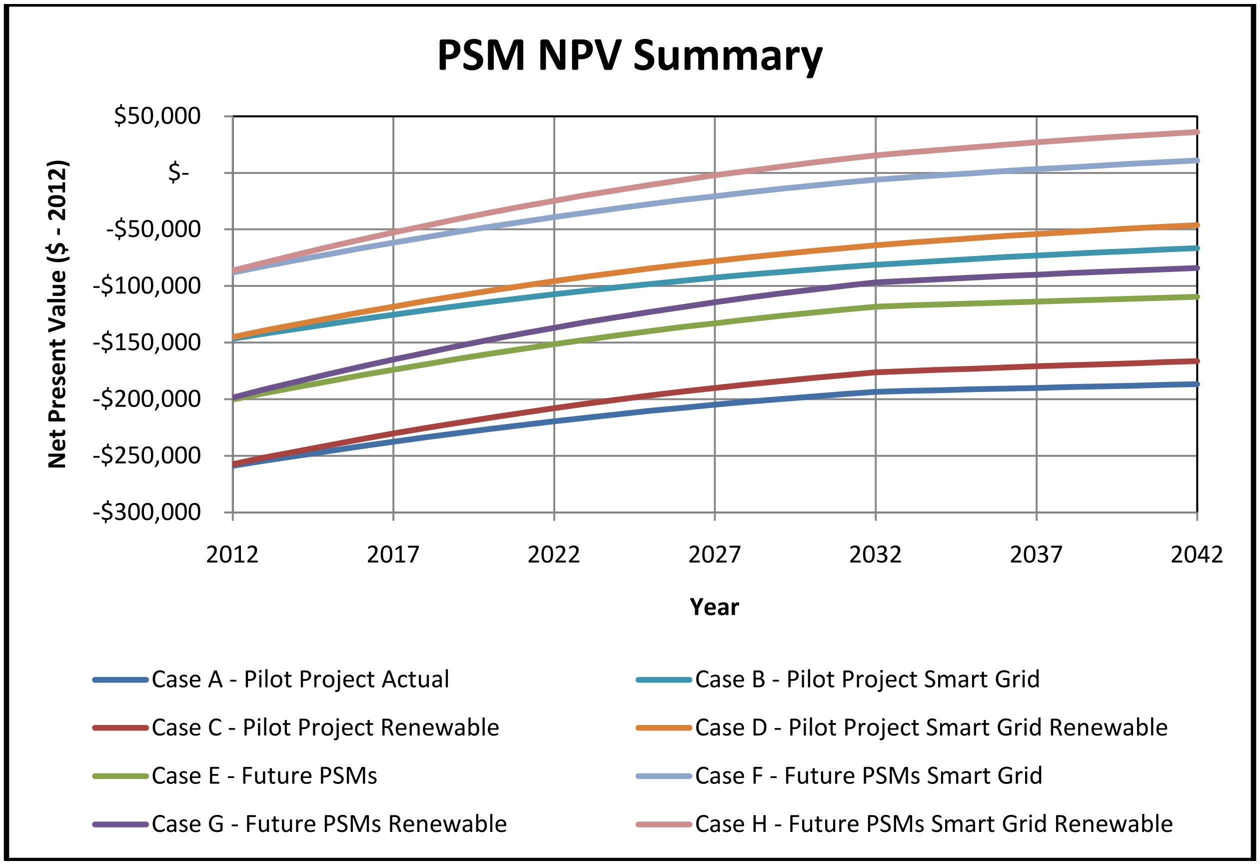


Figure 3: 30-year Cost/Benefit NPV Summary

Figure 3 shows the results of the NPV calculations for the eight cases. The results indicate that the Distribution Solar System Integration pilot project will not be revenue-positive, even when considering the added benefits of smart grid and renewable energy. Table 3 shows a summary of the 30-year NPV for the pilot project both with and without the benefits of smart grid and renewable energy.

Table 3: Pilot Project NPV Summary

Cost/Benefit Scenario	NPV (2012 $)
Smart Grid and Renewable Benefits	-$46,186
Renewable Benefits (no smart grid benefit)	-$166,474
Smart Grid Benefits (no renewable benefit)	-$66,474
Actual Benefits (no smart grid or renewable benefit)	-$186,762

However, due to the predicted increase in energy output and decrease in installation costs, future PSM installations are predicted to have a positive NPV. Table 4 shows a summary of the 30-year NPV for the future PSM installations, both with and without the benefits of smart grid and renewable energy.

Table 4: Future PSM NPV Summary

Cost/Benefit Scenario	NPV (2012 $)
Smart Grid and Renewable Benefits	$36,174
Renewable Benefits (no smart grid benefit)	-$84,114
Smart Grid Benefits (no renewable benefit)	$10,814
Actual Benefits (no smart grid or renewable benefit)	-$109,474

When the benefit of smart grid is considered, future PSM installations are expected to break even in 24 years and provide a modest positive value of approximately $11,000 over 30-years. When the added benefit of renewable energy is also considered, future PSM installations are expected to break even in approximately 16 years and a positive NPV of approximately $36,000 over 30 years is predicted.

It is important to note that the NPV analysis is dependent on the data used in the calculations and the results can change significantly when variables such as capital costs, maintenance, and energy prices are changed.

5.3.1 Break Even Cost Calculations

Additional NPV calculations were performed to find the necessary installation costs, in $/W, for a PSM installation to be revenue neutral over 30 years for four different scenarios:

1. Actual: the only financial benefit considered was the expected reduction in 5-year average net "wholesale" kWh delivered to the distributor, valued at $0.0964/kWh in 2012 and increasing by $0.0036/kWh annually.

2. Smart Grid: in addition to the financial benefit considered in 1, the benefit of the smart grid functionality was added. This was valued at $112,200 in 2012 with annual maintenance costs of $3,600 per year after year 20.

3. Renewable: in addition to the financial benefit considered in 1, the benefit of the renewable nature of the energy produced by the PSMs was added. This was valued at $0.03/kWh.

4. Smart Grid and Renewable: in addition to the financial benefit considered in 1, the benefits of smart grid and renewable energy were added. They were valued per 2 and 3 above.

These "break even" costs represent the maximum installation cost per Watt required for the PSMs to be financially profitable. Table 5 shows the calculated break even costs.

Table 5: Break Even Costs

Cost/Benefit Scenario	Cost
Smart Grid and Renewable Benefits	$4.17
Renewable Benefits (no smart grid benefit)	$2.17
Smart Grid Benefits (no renewable benefit)	$3.75
Actual Benefits (no smart grid or renewable benefit)	$1.75

Without considering the added benefits of renewable energy or smart grid functionality, the maximum installation cost per Watt required for the PSMs to be financially profitable was found to be $1.75/W. In contrast, when the benefits of both smart grid and renewable energy are considered, this cost was found to be $4.17/W.

6.0 SAFETY

The PSM installations are not expected to have a significant impact on safety, either positive or negative. The PSMs are unlikely to reduce safety hazards, nor should they pose any additional risk to utility staff or the general public because they are certified to UL1741/IEEE 1547.1 and have been inspected and approved by the Ontario Electrical Safety Authority (ESA). However, it is strongly recommended that all utility safe-work practices, including checking for voltage and the application of safety grounds, are followed at all times.

There currently is some concern in the utility industry around the anti-islanding protections associated with certified inverters. It is uncertain whether all inverter anti-islanding protections will be effective when other inverter and/or non-inverter generation is operating on the same circuit. Because of this, some utilities are currently limiting the distributed generator penetration. For example, Hydro One is currently limiting the penetration of MicroFIT generators to 7% and 10% of peak feeder loading on F- and M-class feeders respectively[7]. It is likely that future PSM installations will be restricted by this Hydro One limit.

It is recommended that Halton Hills Hydro confirm the effectiveness of the PSM anti-islanding protections for multiple PSM installations connected in close proximity to one another before installing large numbers of PSMs. It is also recommended that Halton Hills Hydro works with Hydro One to ensure that Hydro One is aware of the PSM installations.

[7] Wrathall, Cress, Tsimberg, *Technical Review of Hydro One's Anti-Islanding Criteria for MicroFIT PV Generators*, Kinectrics Inc K-418086-RA-001-R00, November 22, 2011

7.0 Conclusions

The following are the significant finding of this study:

1. The PSM measurements are sufficiently accurate for practical utility engineering applications, such as reliability assessment, voltage regulation analysis, losses studies, fault detection, and general troubleshooting.

2. The PSMs do not currently measure harmonics or flicker.

3. The benefits associated with the PSMs can be grouped into three categories: Power Production and Losses, Smart Grid, and Renewable Energy.

   a. Power Production and Losses - the PSMs installed in the pilot project have an estimated annual output of 46,214 kWh and will reduce Halton Hills Hydro's (HHH) Distribution Loss Factor by 0.01%, from 102.53% to 102.52%. The expected loss reduction would be approximately 0.02% per 100 kW of installed PSMs. This reduction in losses will benefit HHH's customers. Because PSM generation typically coincides with peak loading (daytime hours), a reduction in peak losses would be expected.

   b. Smart Grid - PSMs provide the following smart grid benefits:
      i. The measurements and alerts provided by the PSMs will allow HHH to detect and respond to outages faster, which will have a positive effect on HHH's reliability statistics.
      ii. The voltage measurements provided by the PSMs have allowed HHH to diagnose over- and under-voltage problems on their feeders. These problems would most likely have gone undetected had the PSMs not been installed. Additionally, future PSM models will have the capability to measure harmonics and flicker, providing HHH additional tools to detect and troubleshoot power quality problems.

   c. Renewable Energy – the PV solar power produced by the PSMs has a positive environmental benefit and, because the PSMs are highly visible, will add to Halton Hills Hydro's reputation as an environmentally conscious organization. The energy output from the Distribution System Solar Integration pilot project is estimated to offset approximately 26 metric tons of equivalent carbon emissions annually. This is equivalent to 0.58 metric tons per installed kW.

4. The Net Present Value (NPV) analysis resulted in the following conclusions:

   a. Although the pilot project will not provide a net positive value when all costs and benefits are considered, future PSM installations, because of decreasing equipment costs, are expected to provide a net positive value when the benefit of smart grid is considered. The 30-year NPV of the pilot project and future PSM installations, with and without the added benefit of smart grid and renewable energy, are summarized in Table 6. This table also shows the number of years required for the PSM installations to achieve neutral value for each scenario.

Table 6: Pilot Project and Future PSM 30-Year Cost/Benefit NPV Summary

Cost/Benefit Scenario	Pilot Project		Future PSMs	
	NPV (2012 $)	Years to Break Even	NPV (2012 $)	Years to Break Even
Smart Grid and Renewable Benefits	-$46,186	>30	$36,174	16
Renewable Benefits (no smart grid benefit)	-$166,474	>30	-$84,114	>30
Smart Grid Benefits (no renewable benefit)	-$66,474	>30	$10,814	24
Actual Benefits (no smart grid or renewable benefit)	-$186,762	>30	-$109,474	>30

b. The maximum total installation costs per Watt required for a PSM installation to achieve a neutral net present value after 30 years was calculated for each scenario. When the actual installation costs are less than these "break even" costs, PSM installations will provide a net positive value within a 30-year time period.
    i. When only the benefits associated with energy production and loss reduction are considered, the break even cost was calculated to be $1.75/W.
    ii. When the benefit of the smart grid functionality is also considered, the break even cost was $3.75/W.
    iii. Similarly, when the benefits of energy production and loss reduction are considered with the value of renewable energy, the break even cost was found to be $2.17/W.
    iv. Finally, when all benefits are considered together, the break even cost was $4.17/W.
    v. For comparison, the costs associated with the pilot project were $5.76/W and the expected cost for PSM installations in 2014 is $3.57/W.

c. The NPV analysis indicates that, of the three primary benefits associated with the PSMs (energy and loss reduction, smart grid, and renewable energy), the smart grid features provide the greatest benefit to HHH.

8.0 RECOMMENDATIONS

Based on the results of this study, Kinectrics recommends the following:

1. Provided the costs and power densities of future PSMs are less than \$3.75/W, as they are predicted to be, HHH may wish to consider expanding the PSM program up to the point where the smart grid benefits are maximized. The maximum smart grid benefit would be achieved by having one PSM connected to each phase of each circuit. The installation of more than one PSM unit on one phase of a given circuit will not provide additional smart grid benefits and therefore would not be cost effective.

2. HHH should install the new versions of the PSM, once available, to take advantage of the additional smart grid features, such as improved power quality monitoring and automated alerts. If technically possible and cost-effective, existing PSM units should also be upgraded with this functionality.

3. Should the total installation price for PSM installations fall below \$1.75/W, HHH should consider installing PSM units beyond the point where the maximum smart grid benefit is achieved. When the installation price is below this level, the PSMs will provide a direct financial benefit to HHH's customers.

4. It is recommended that Halton Hills Hydro confirm the effectiveness of the PSM anti-islanding protections for multiple PSM installations connected in close proximity to one another before installing large numbers of PSMs. It is also recommended that Halton Hills Hydro work with Hydro One to ensure that Hydro One is aware of the PSM installations.

KINECTRICS

Smart Energy Module Measurements rev. 1

For Halton Hills Hydro *April 24, 2013*

Kinectrics Project: K-418480

Overview

The following is a summary of the results of *Part A: Measurement Validation* for Kinectrics project K-418480, *Smart Energy Module Validation*. Measurements were recorded at the AC outputs of two Smart Energy Modules (SEMs) and the data were compared to the measurements reported by the SEMs through the IntelliView system. The two SEMs measured were SN236121109P012 and SN236121109P014, on poles 706 and 3362 respectively.

Measurements

Kinectrics' measurements were recorded using a calibrated Fluke 435 Power Quality Analyzer (Fluke). Measurements were recorded every second on two different days; the SEM at pole 706 was measured over a three-hour period on February 21, 2013 and the SEM at pole 3362 was measured over a six-hour period on April 17, 2013. The following quantities were measured: frequency, RMS voltage, RMS current, active power, reactive power, energy, voltage THD, current THD, and voltage flicker (P_{st} and P_{lt}).

Measurements from the SEMs were reported at approximately 15-minute intervals. The following quantities reported by the SEMs were available in the IntelliView System: frequency, RMS voltage, RMS current, active power, reactive power, and energy. SEM measurements for voltage THD, current THD, and flicker could not be found in the IntelliView system and were therefore not compared against the Fluke measurements.

Time-Synchronization

The measurement time stamps of the SEMs and the Fluke were not synchronized. Synchronization of the data was performed by maximizing the sum of the correlations of the voltage and frequency measurements between the SEMs and the Fluke.

Results

Table 7 shows a summary of the measurement comparison. It shows the average magnitudes and percentages of the errors between the SEM and Fluke measurements for each measured quantity.

Charts showing the measurement comparisons of each quantity for the two SEMs, including the accuracy range of the Fluke 435 Power Quality Analyzer, can be found in the Appendix.

Table 7: Measurement analysis summary

Smart Energy Module (SEM) Measurement Analysis					
Quantity	Unit	Pole 706 SEM		Pole 3362 SEM	
		Average Error Magnitude	Average % Error Magnitude	Average Error Magnitude	Average % Error Magnitude
Frequency	Hz	0.01	0.02%	0.01	0.02%
Voltage	V	0.13	0.11%	0.50	0.41%
Current	A	0.01	1.68%	0.01	0.89%
Active Power	W	2.50	7.04%	3.11	1.50%
Reactive Power	VAR	1.67	0.50%	8.12	36.33%
Energy	Wh	3.43	2.03%	4.90	1.45%

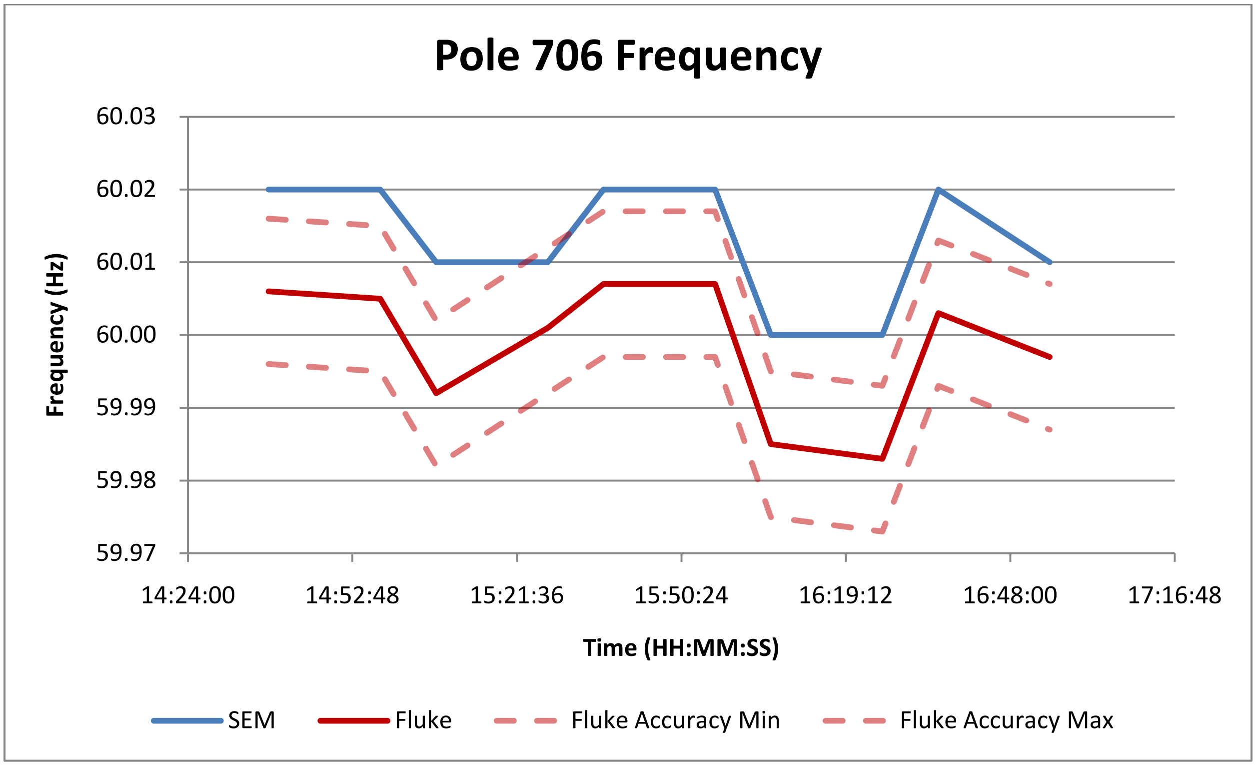
Conclusions

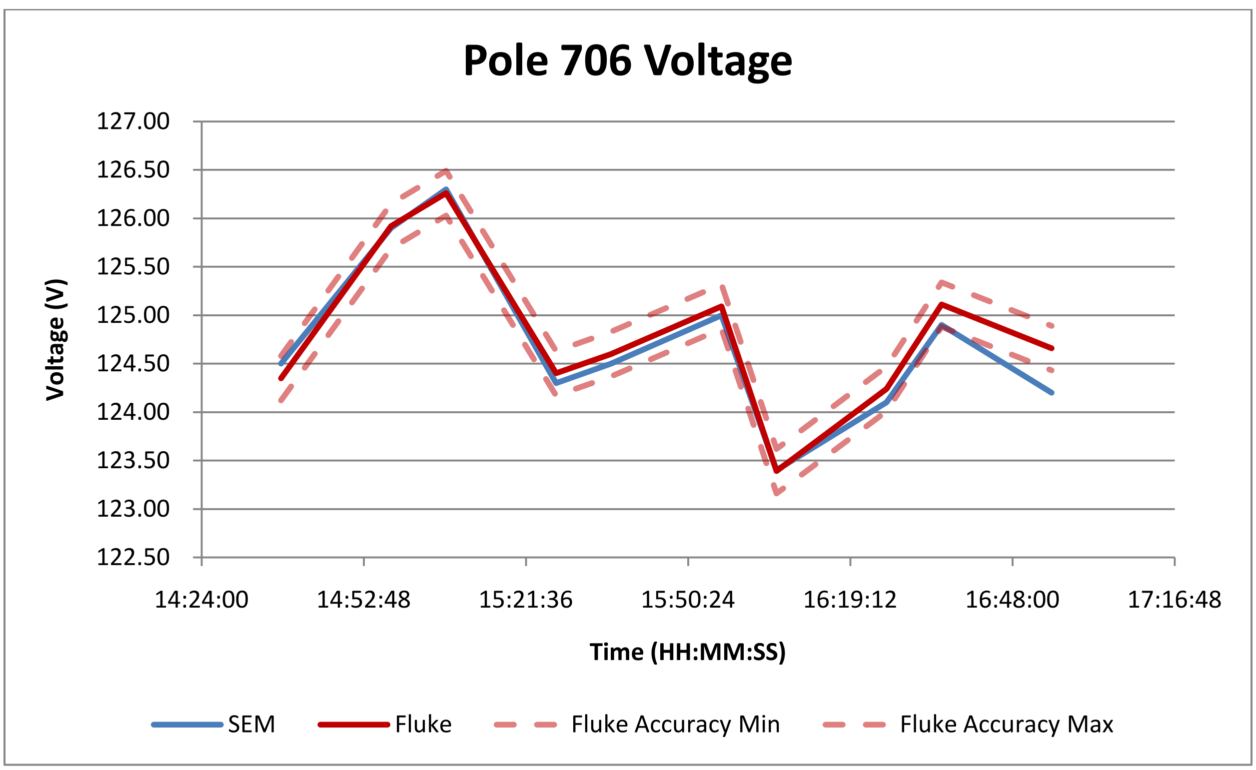
1. The measurements recorded by the SEMs are sufficiently accurate for practical applications, including: reliability assessment, voltage regulation analysis, losses studies, fault detection, and general troubleshooting.
2. The measurements recorded by the SEMs may not be sufficiently accurate to be used as a substitute for field or laboratory measurements with calibrated instruments. However, the practical applications for which the SEM measurements would typically be used by a utility do not generally require highly accurate measurements.
3. SEM harmonic and flicker measurements were not available in the IntelliView system and could not be compared with the Fluke measurements. The availability of harmonic and flicker measurements should be confirmed during Part B.

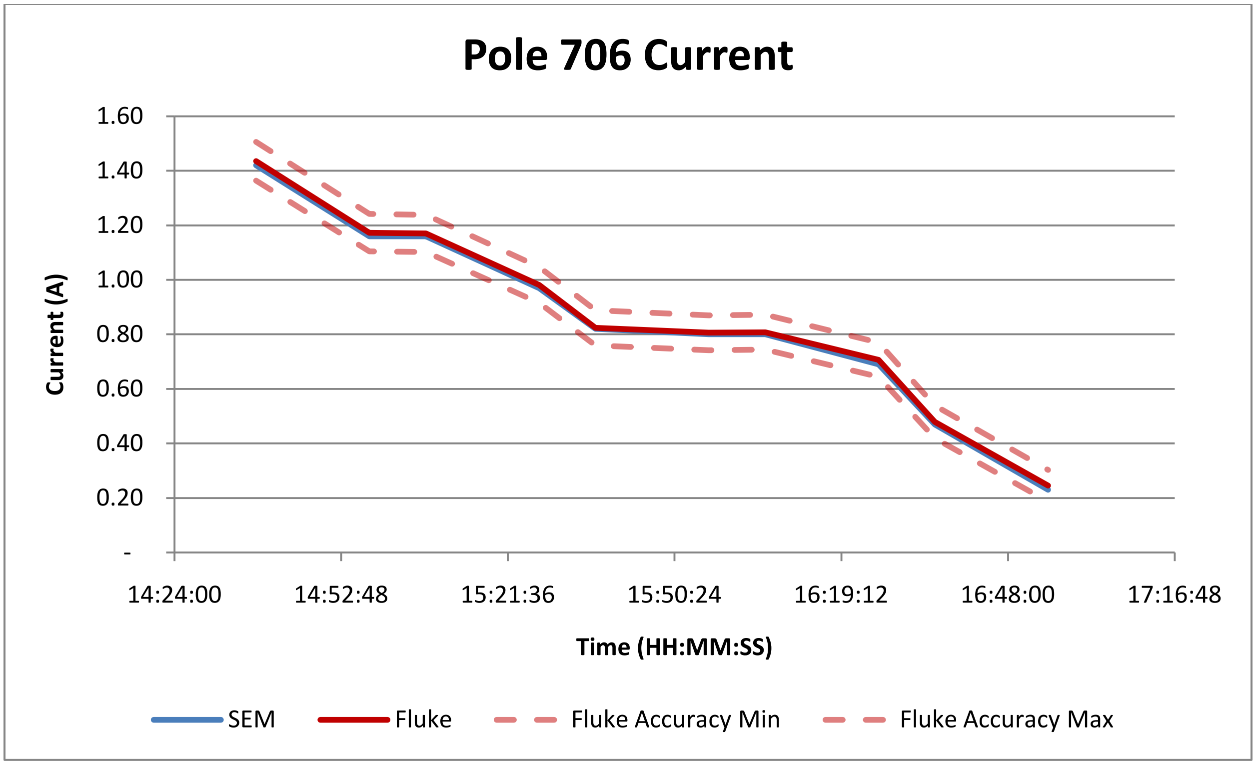
Recommendations

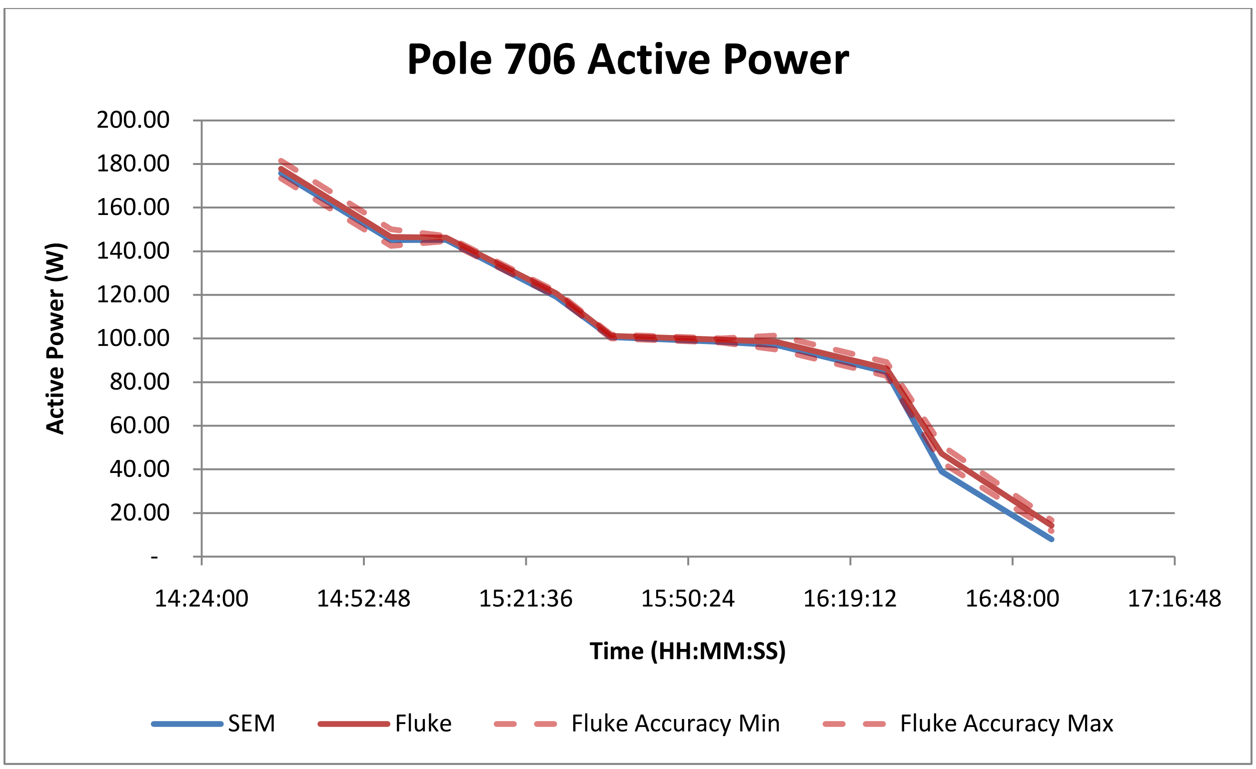
1. The measurement data recorded by the SEMs was found to be sufficiently accurate for practical applications, including Part B of this project. Therefore, it is recommended that Part B – Cost/Benefit Analysis proceed.
2. A SEM should be tested in a controlled laboratory environment to determine the accuracy of the active power, reactive power, and energy measurements under controlled conditions. Moreover, laboratory testing can also verify the SEM's various operating, protection, and maximum power point tracking (MPPT) functions, if required.
3. The availability of harmonic and flicker measurements should be confirmed during Part B.

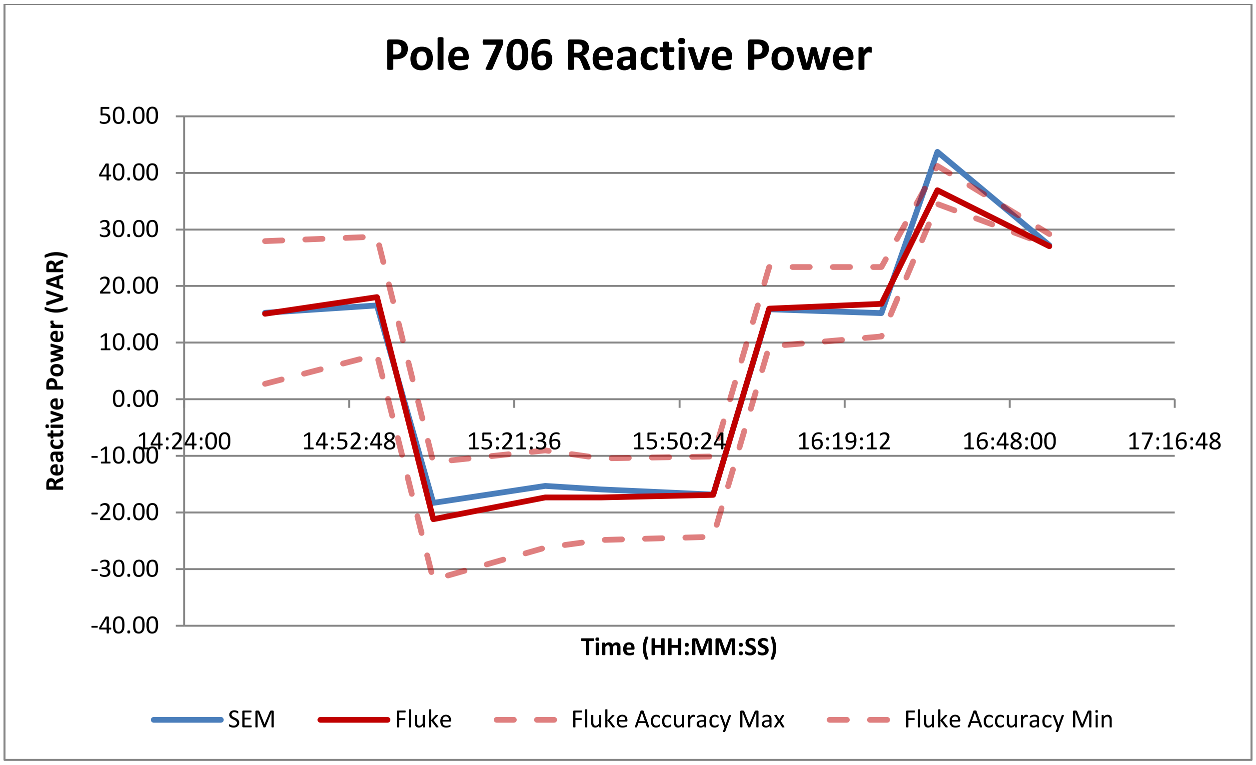
Appendix : Measurement Figures

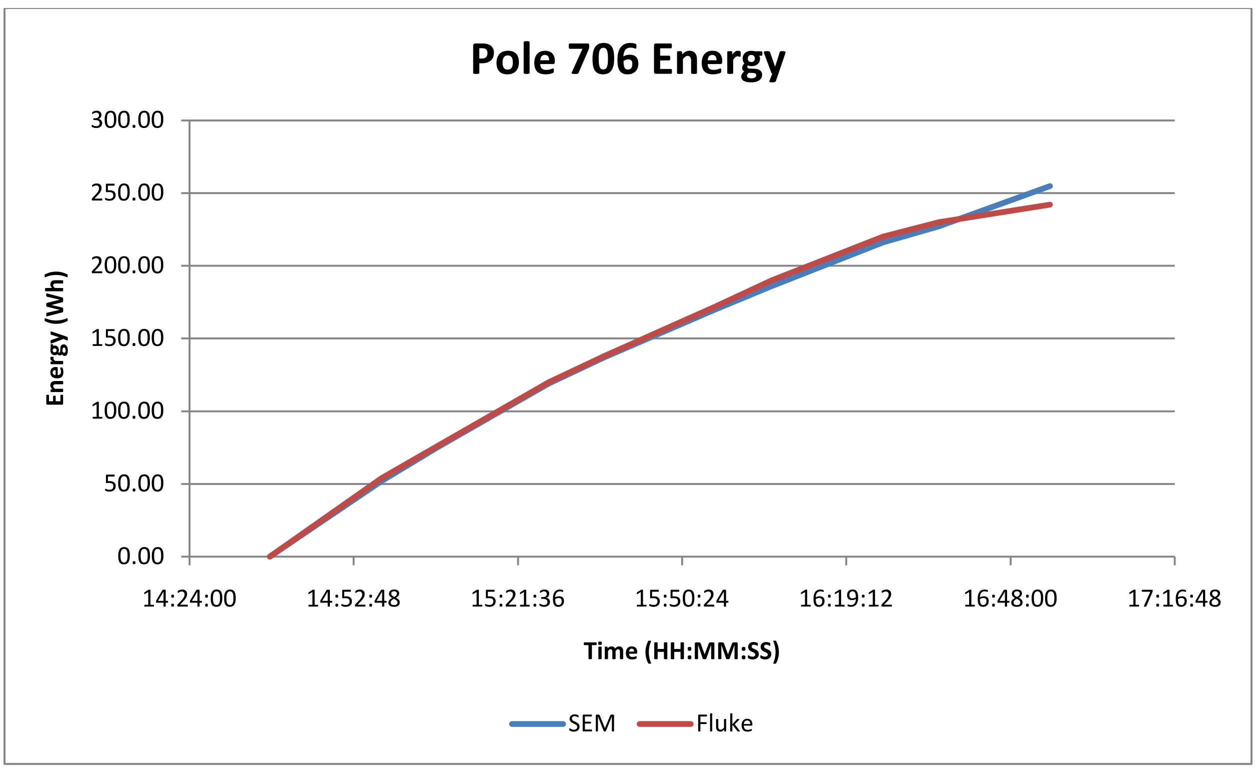


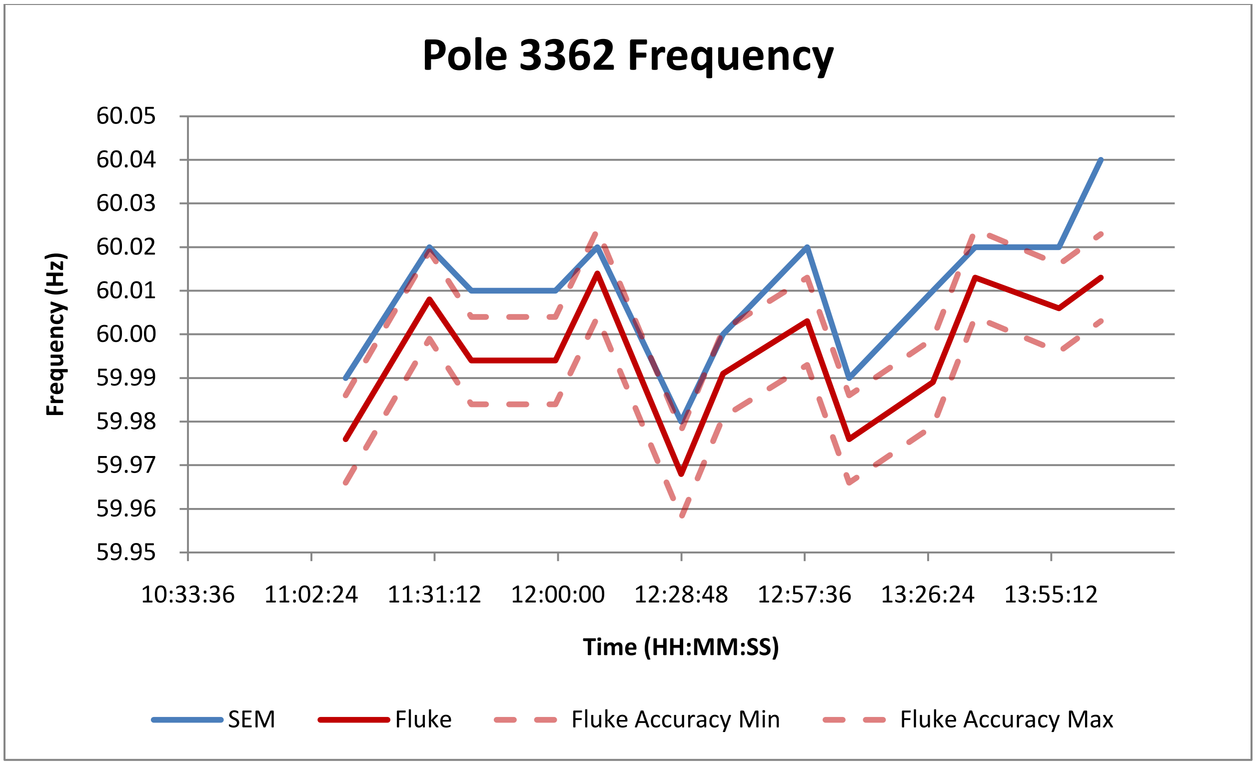



Pole 706 Current
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
-
Current (A)
14:24:00
14:52:48
15:21:36
15:50:24
16:19:12
16:48:00
17:16:48
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max

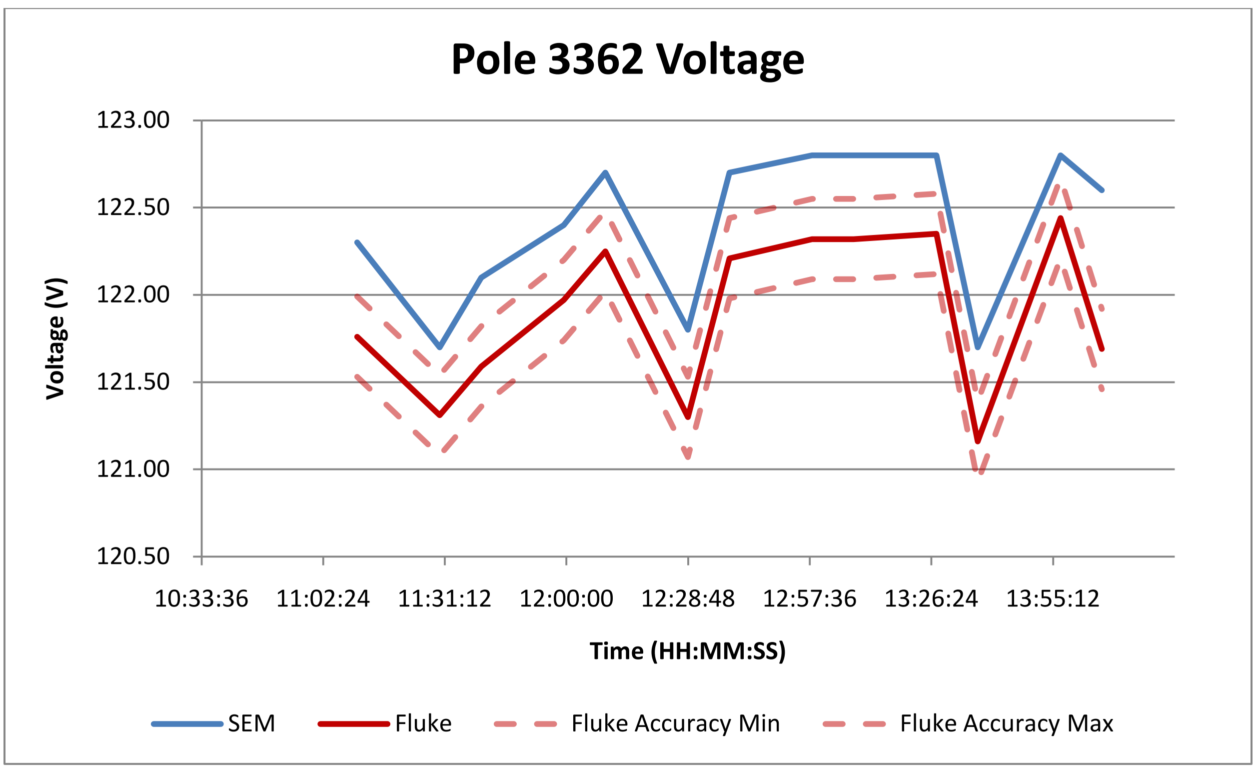

Pole 706 Active Power
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
-
Active Power (W)
14:24:00
14:52:48
15:21:36
15:50:24
16:19:12
16:48:00
17:16:48
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max


Pole 706 Reactive Power
50.00
40.00
30.00
20.00
10.00
0.00
-10.00
-20.00
-30.00
-40.00
Reactive Power (VAR)
14:24:00
14:52:48
15:21:36
15:50:24
16:19:12
16:48:00
17:16:48
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Max
Fluke Accuracy Min

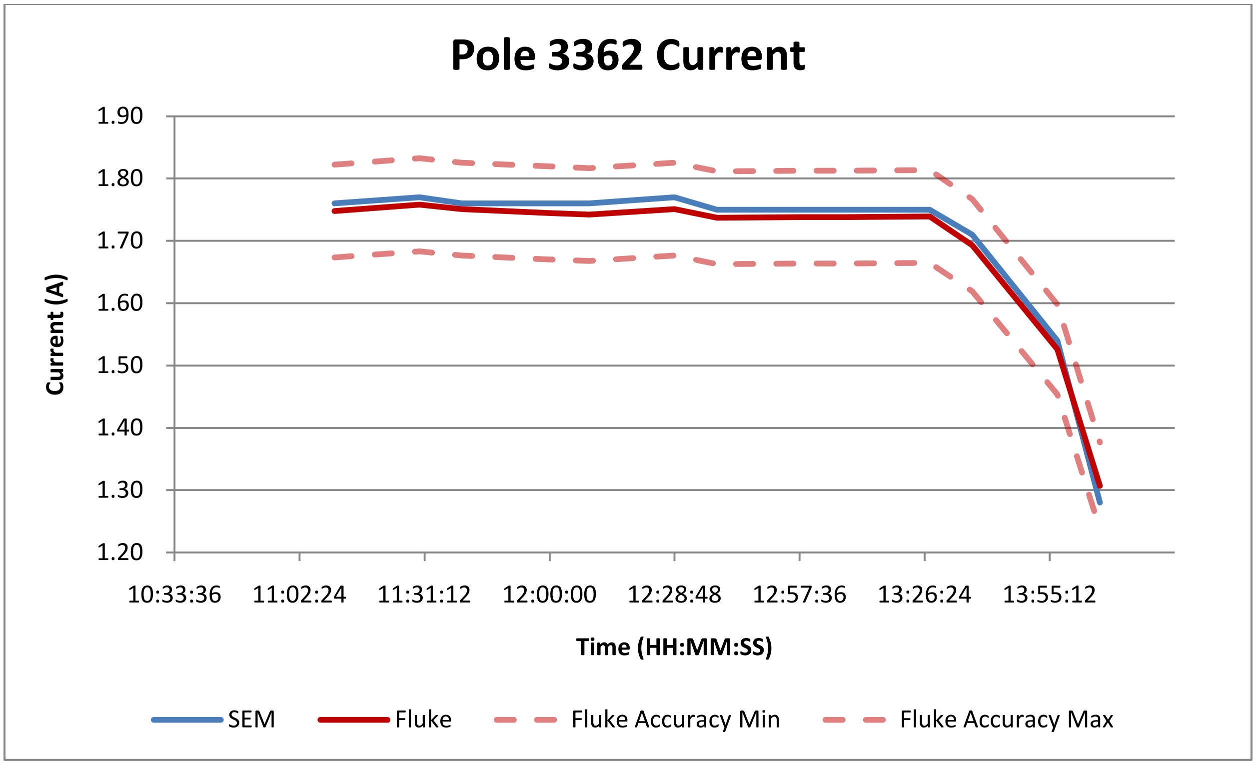

Pole 706 Energy
300.00
250.00
200.00
150.00
100.00
50.00
0.00
Energy (Wh)
14:24:00
14:52:48
15:21:36
15:50:24
16:19:12
16:48:00
17:16:48
Time (HH:MM:SS)
SEM
Fluke



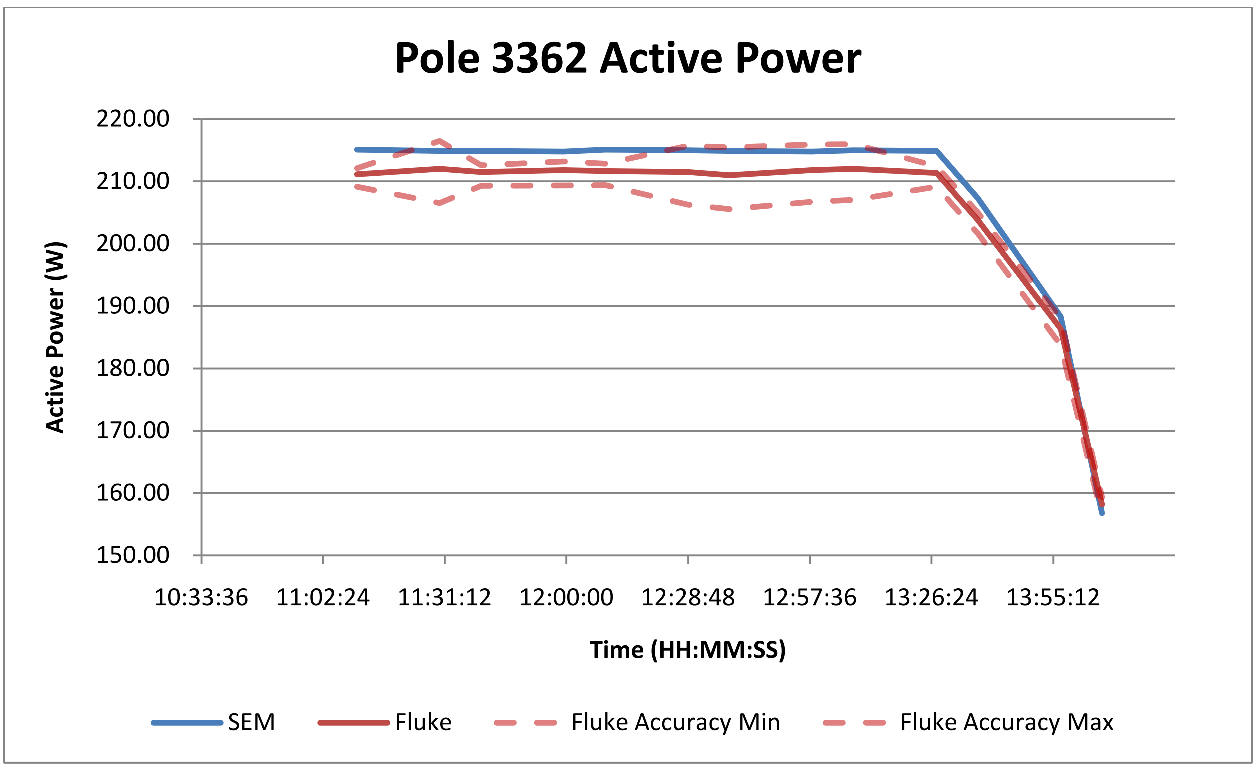
Pole 3362 Frequency
60.05
60.04
60.03
60.02
60.01
60.00
59.99
59.98
59.97
59.96
59.95
Frequency (Hz)
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max



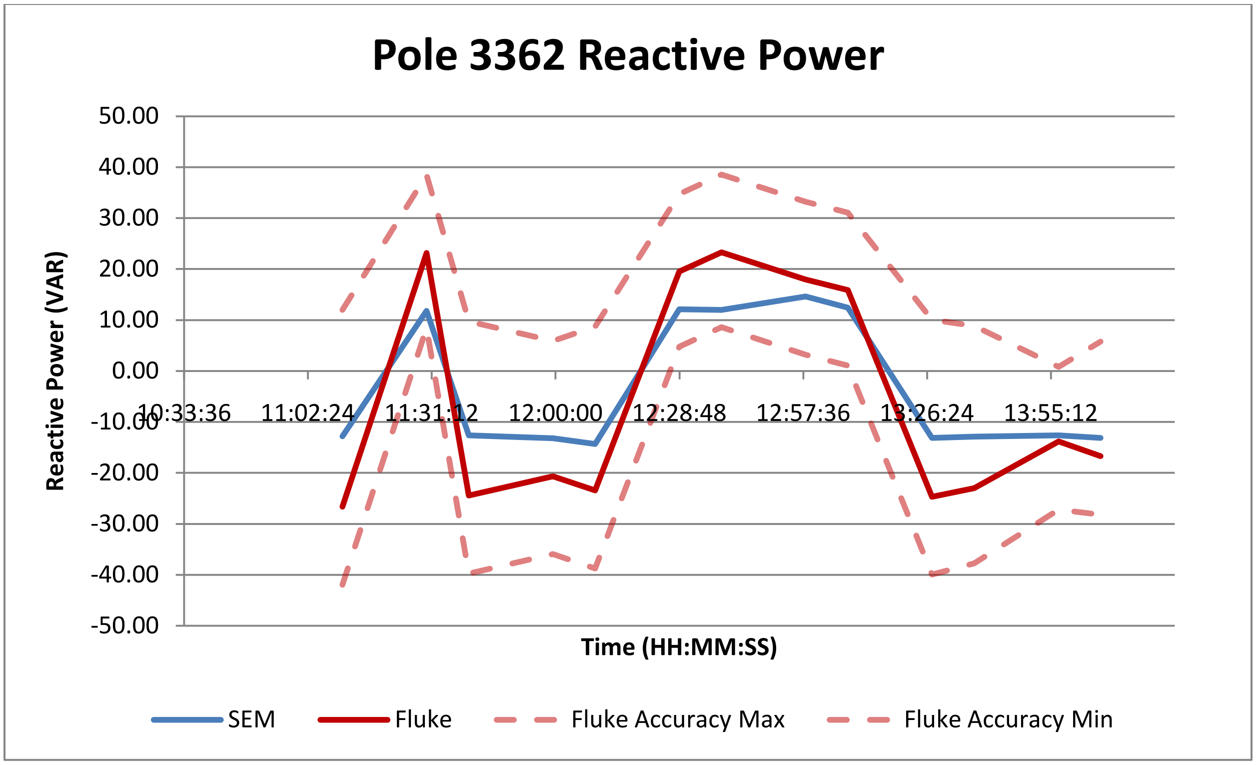
Pole 3362 Voltage
123.00
122.50
122.00
121.50
121.00
120.50
Voltage (V)
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max

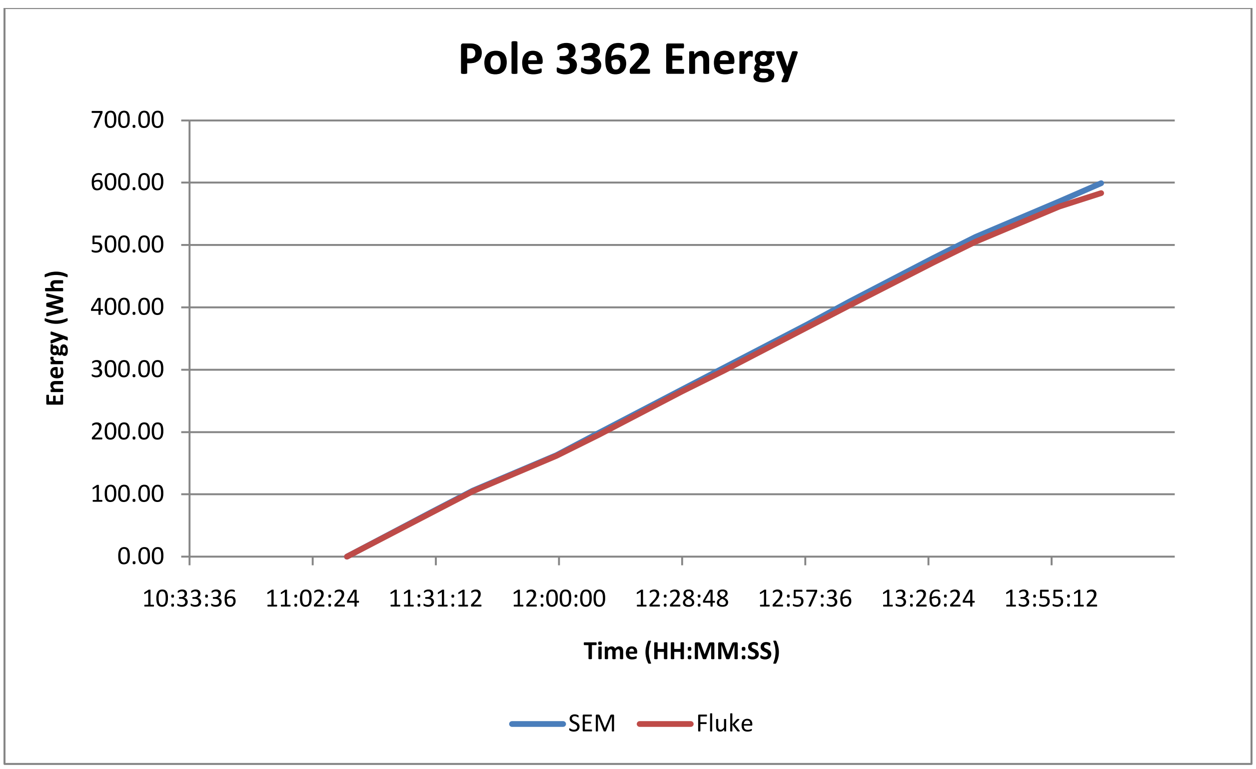


Pole 3362 Current
Current (A)
1.90
1.80
1.70
1.60
1.50
1.40
1.30
1.20
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max



Pole 3362 Active Power
Active Power (W)
220.00
210.00
200.00
190.00
180.00
170.00
160.00
150.00
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Min
Fluke Accuracy Max


Pole 3362 Reactive Power
50.00
40.00
30.00
20.00
10.00
0.00
-10.00
-20.00
-30.00
-40.00
-50.00
Reactive Power (VAR)
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke
Fluke Accuracy Max
Fluke Accuracy Min


Pole 3362 Energy
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
Energy (Wh)
10:33:36
11:02:24
11:31:12
12:00:00
12:28:48
12:57:36
13:26:24
13:55:12
Time (HH:MM:SS)
SEM
Fluke

Appendix 3 – C

Sample Letter to Customer 1

Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6J 5E3
Telephone: 905-825-9400
Fax: 905-825-5830
email: hydro@oakvillehydro.com
www.oakvillehydro.com

January 18, 2013

Dear Customer:

Oakville Hydro is committed to superior service to all customers. As part of our commitment we have an ongoing maintenance and capital projects plan that is intended to improve the safety and reliability of the electrical system in Oakville.

We are upgrading the electrical system in your neighbourhood. This project involves reconstruction of the existing overhead electrical distribution network located in the rear yards, and installation of new underground electrical distribution in the area east of Sixth Line on Napier Cres., Pallatine Dr., Newton Rd., Montclair Dr., Rayne Ave., Redbank Cres., Ridge Dr. and Sewell Dr.

The overhead pole line reconstruction will be completed by [redacted], specialized in overhead pole line construction. The underground work will be completed by [redacted], specialized in underground distribution system installation.

Before construction begins [redacted] will be surveying the current condition of the existing power lines located in the rear lot and adjacent areas that might be affected by the construction. As well we will be required to remove vegetation around existing poles to facilitate installation of new poles.

Any restoration that is necessary will be completed to an "as found" condition.
The electrical contractor will require access to your backyard in order to perform work on the rear lot overhead distribution network. We would appreciate if you would ensure that rear yard gates are not locked or inform us if you require to make arrangements for granting access to the your backyard.

Please be aware some trees near or touching our lines in the rear lots may have to be trimmed to provide a safe working environment for our contractors.

This project will commence the week of January 28, 2013 and should take approximately five to six months to complete, weather permitting. There will be brief power outages required in order to complete this work. If for any reason extended outages are required, you will be contacted in advance to schedule the times of the interruptions.

We would ask any residents with sprinkler systems installed in the Town Boulevard to please have the sprinkler heads staked out to avoid potential damage during construction. In the event your sprinkler system is damaged, repairs will be made by our contractor. Thank you in advance for your cooperation.

Yours truly,

[redacted]

[redacted]
Director, Engineering & Construction

Project Contacts

[redacted]
Supervisor, Planning & Design
905-825-9400, [redacted]

[redacted]
Supervisor Construction Management
905-825-9400 [redacted]

[redacted]
Line Supervisor
905-825-9400 [redacted]

Appendix 3 – D

Sample Letter to Customer 2

Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6J 5E3
Telephone: 905-825-9400
Fax: 905-825-5830
email: hydro@oakvillehydro.com
www.oakvillehydro.com

March 13, 2013

Dear Customer:

Oakville Hydro is committed to superior service to all customers. As part of our commitment we have an ongoing maintenance and capital projects plan that is intended to improve the safety and reliability of the electrical system in Oakville.

We are upgrading the electrical system in your neighbourhood. This project involves replacement of the existing pole line and underground distribution on Forest Glade, Kathleen Crescent, Grand Boulevard.

The construction is required to improve the reliability of supply to the local area. Any restoration that is necessary will be completed to an "as found" condition or better.

There will be brief power outages required in order to complete this work. If for any reason extended outages are required, you will be contacted in advance to schedule the times of the interruptions.

Please be aware some trees within the road allowance corridor that have the potential of being near or touching our lines may have to be trimmed to provide a safe working environment for our contractors.

Oakville Hydro approved electrical contractors will be reviewing existing electrical meterbases in the Forest Glade, Kathleen Crescent, Grand Boulevard areas in the next 2 to 3 weeks. As part of the underground secondary rebuild, we will be replacing meterbases (including down pipe) found in poor condition and/or unsuitable for new secondary connections.

The project will commence March 25, 2013 and take approximately seven months. We realize inconveniences can be caused by such projects and would like to thank you in advance for your co-operation and understanding. If you have any questions about the project, please contact [redacted], Supervisor Construction Management at 905-825-9400 [redacted] or Mr. Gary Ellis, Operations Line Supervisor at 905-825-9400, [redacted]

Yours truly,

[redacted]

[redacted] P.Eng., M.B.A.
Director, Engineering and Construction

Appendix 3 – E

Sample Email to Councillor

From: [redacted]
Sent: Friday, January 03, 2014 7:38 PM
To: [redacted]
Subject: Continuous power outages

Dear [redacted]

We truly appreciate the efforts and all the hard work of Oakville Hydro to get us all back on line so quickly during the recent ice storm outage.
However our area of Town (Westmount -- north west Oakville) experiences
frequent and many more outages than other areas of Oakville. Every summer
we experience power blips several times a season. Yesterday we lost power for 1/2 hour and again lost power this evening for 15 minutes. These
frequent disturbances play havoc with sensitive electronics, etc. When we
have called Hydro for an explanation, we have been told that our area is overloaded/stressed. If this is the case, why is this issue not being addressed and more building is now underway which will stress the systems even further?

The outages seem excessive and there must be an underlying issue. None of my coworkers who live in Oakville have experienced any of these outages, even during the ice storm.

We realize that some customers are still experiencing power loss from the storm, but we don't understand how this area, with underground wires, loses power so frequently, and how some houses have power and some don't on the same street.

We would greatly appreciate if you could look into this issue so it may be resolved. We would appreciate any help you could provide.

Thank you [redacted]

[redacted]

Sent from my iPad

Appendix 3 – F

Sample Customer Email 1

[redacted]

From: Hydro Mail
Sent: July 19, 2012 12:08 PM
To: [redacted]
Subject: FW: A huge thank you
Attachments: 2012-07-19 11.19.52.jpg

[redacted]

861 Redwood Square
Oakville, ON
L6J 5E3
905-825-9400

From: [redacted]
Sent: Thursday, July 19, 2012 11:48 AM
To: Hydro Mail
Subject: A huge thank you

Dear Oakville hydro,

My 2 1/2 year old son, Owen, loves trucks is a huge fan of the hydro trucks that have been working in our neighbourhood (near 8th line & Grand Blvd.) all summer. Every day the crews are out he wants to go supervise! The crews have always been very friendly and always had time to say hello to Owen. Today they presented him with his own orange hard hat that says "junior foreman." He absolutely loves it - they have made his whole summer!

I just wanted to let you know how happy your team has made my little guy, and send a huge thank you to all of the guys who have been so great to Owen. He talks about the "hydro guys" and "hydro trucks" nonstop now.

Best,
[redacted]

Appendix 3 – G

Sample Customer Email 2

[redacted]

From: [redacted]
Sent: December 12, 2011 1:43 PM
To: [redacted]
Cc: [redacted]
Subject: Sidewalk markings, [redacted]

Hi Bob,

[redacted] called of the above address, [redacted]. She is trying to sell her house and markings keep appearing on the sidewalk in front of her home and she wants to know what, who they are from. Is there any way you can find out for her and let her know.

Also, [redacted] she says there is a hydro light post in front of her house that has a lot of wires going from both sides and she is wondering what these are – she says she thinks they are making her sick? If you could have someone call her that would be great.

Thanks.

[redacted]
Town of Oakville | 905-338-4173 | f: 905-815-2001 | www.oakville.ca

4-Operational Effectiveness

Issue 4.1 *Does the applicant's distribution system plan appropriately support continuous improvement in productivity, the attainment of system reliability and quality objectives, and the level of associated revenue requirement requested by the applicant?*

4.1-Staff-18

Ref: 1) Exhibit 1/Tab1/Schedule 1/p. 15, and

2) Exhibit 2/Appendix A- Distribution System Plan/pp. 34–36, 70-75

System Service Investments

At Reference (1) Oakville Hydro states that in 2014 it plans to acquire an on-site emergency back-up transformer for Oakville Hydro's Glenorchy Municipal Transformer Station at a cost of $5.0 M and that "The on-site emergency back-up transformer will ensure long term system reliability for both Oakville and Milton customers if one of the existing transformers were to fail."

Reference (2) (page 35) states that investments in the System Service category are considered discretionary.

Reference (2) (page70) states that the proposed emergency back-up transformer could be made available to other transmitters or distributors in the same geographical area.

a) Please describe how the acquisition of the on-site emergency back-up transformer is expected affect the reliability performance of the Oakville Hydro distribution system in terms of impact on SAIDI, SAIFI and CAIDI.

RESPONSE:

As indicated in Exhibit 2, Appendix A – Distribution System Plan, p. 74-75, in the event of a substantial power failure at the Glenorchy Transformer Station, based on peak summer load levels experienced in July 2011, Oakville Hydro expects up to 29 MW of stranded load until Glenorchy Transformer Station can be put back into service. In response to a stranded load scenario, Oakville Hydro would need to initiate rolling blackouts that would significantly impact SAIDI, SAIFI and CAIDI. The on-site emergency back-up transformer would allow Oakville Hydro to put Glenorchy Transformer Station back into service within 10 days, as per best utility practice.

b) Please describe and provide the results of any additional analysis Oakville Hydro has carried out to determine the cost effectiveness of acquiring the on-site emergency back-up transformer.

RESPONSE:

As discussed in Exhibit 2, Appendix A – Distribution System Plan, p. 72-75, Oakville Hydro explored the possibilities of sharing existing back-up transformers with both Hydro One and PowerStream. Hydro One indicated that they are not interested in sharing their back-up transformers due to potential liability concerns. Although PowerStream is interested in sharing their back-up transformer, Oakville Hydro has determined, through a third party assessment, that sharing of PowerStream's back-up transformer would not allow Oakville Hydro to put Glenorchy Transformer Station back into service within the 10 day timeframe established as best utility practice. There have been discussions with PowerStream on a possible scenario whereby their on-site emergency back-up transformer could be considered as an option, but due to the practical difficulties of transport to the Glenorchy site, no further discussions on commercial terms, have ensued.

c) Oakville Hydro indicates that Hydro One often calls upon Oakville Hydro to perform short-term load transfers among its distribution stations to alleviate capacity constraints within the region. How often does this occur and is there a significant cost incurred by Oakville Hydro to perform these transfers? How is/could this arrangement inform the regional planning exercise?

RESPONSE:

Oakville Hydro performs an average of 20 load transfer calls per year. The costs are incurred annually are not material in nature however responding to Hydro One's requests involves time spent by the Control Room Operators and Powerline Technicians. Approximately one third of these transfers are accomplished using SCADA controlled switches without any field switching required. On an annual basis, an average of 350 MW is transferred for planned maintenance and 20 MW relate to unplanned transfers.

d) Please advise whether Oakville Hydro has entered into any agreements with other transmitters or distributors in the same geographical area to share the proposed emergency back-up transformer and describe any agreements reached.

RESPONSE:

Oakville Hydro has not entered into any agreements to share the proposed emergency back-up transformer, but is certainly willing to do so.

e) Has Oakville Hydro developed a plan or strategy to establish a stand-by fee and a monthly lease fee for Oakville's back-up transformer as was done by Powerstream as described on page 73? If so, please file this plan and any rationale for the fees established.

RESPONSE:

Oakville Hydro has not established a stand-by fee for the proposed emergency back-up transformer.

f) Please explain why information technology expenditures for 2014 are split into two categories of System Renewal and General Plant.

RESPONSE:

Oakville Hydro has split information technology expenditures into two categories: System Renewal and General Plant in Exhibit 2, Appendix A, Table 3, Material Capital

Expenditures, Page 36 as $452,000 categorized in System Renewal are for capital projects that are led by the Information Technology department but relate to System Renewal projects. The projects in the System Renewal category that are identified as IT projects are the SCADA enhancement project with a forecasted cost of $300,000 and the Power Systems Analysis Tool with a forecasted cost of $152,000. These assets are directly related to Oakville Hydro's distribution system and therefore more appropriately categorized as System Renewal assets.

The SCADA enhancements project is described in more detail Exhibit 2, Appendix A-Distribution System Plan, page 78.

The power system analysis tool will integrate smart meter consumption data from Oakville Hydro's Advanced Metering Infrastructure with it Geographical Information System ("GIS") network model to deliver analytical capabilities that are considered to be best practice in the industry but currently are not available within Oakville Hydro. This project is below Oakville Hydro's materiality level and therefore a detailed description of the project has not been included in the Distribution System Plan.

The remaining Information Technology related projects are grouped in General Plant category. Refer to 4.1-Staff-19 for further discussion on the General Plant category

4.1-Staff-19

Ref: Exhibit 2/Appendix A- Distribution System Plan/pp. 34–36, 70-75

System Service Investments

The table on page 36 indicates a 2014 expenditure of $452,000 for information technology. An additional expenditure of $1,897,210 for information technology is shown in General Plant for a total information technology expenditure of $2,349,210 in 2014.

Please explain why a 2014 expenditure of $2,349,210 is required to support Oakville Hydro's stated objective to optimize the performance of its assets at a reasonable cost with due regard for customer service expectations, system reliability, technology innovation and public and employee safety.

RESPONSE:

As discussed in response to 4.1-Staff-18 part f), $452,000 of the total $2,349,210 is related to System Renewal investments in Oakville Hydro's SCADA system and GIS.

The remaining 2014 expenditures of $1,897,210 2014 are required as it relates to a number of Information Technology related expenditures. The most significant capital item is the Indefeasible Right of Use for two fibre optic cables owned by a third party of $738,210. While this investment relates to an acquisition in 2010, it is being included in the 2014 Test year as an addition to rate base in accordance with Oakville Hydro's 2010 Settlement Agreement. This is described in detail in Exhibit 2, Tab 2, Schedule 5, Page 6-7.

The remaining $1,159,000 relates to the capital projects are described in Exhibit 2, Tab 5, Schedule 2, Page 74-76. These capital investments are required in order to maintain the integral systems that Oakville Hydro requires to support its day to day business and operations activities. The 2014 Test Year includes investments of:

- Customer Services Initiatives:

  Oakville Hydro has forecasted expenditures of $210,000 in the 2014 Test Year to provide its customers with improved communication, easier access to their account details and improved tools for communicating outage information. Improved customer communication is imperative and an area in which Oakville Hydro received constructive feedback from its customers regarding the need to keep them informed during and after the recent 2013 ice storm. In addition, meter reading hardware and software upgrade investments will serve to reduce billing errors and delayed bills, streamline the billing processes and ensuring accurate readings are being captured in the field. Essentially, the meter reading and billing processes will become increasingly reliable with the planned upgrades.

- Oakville Hydro has forecasted expenditures of $420,000 in the 2014 Test Year for infrastructure costs to maintain optimal performance on servers, desktops, data storage and provide Disaster Recovery for all systems/services relating to core Information Technology services

- Oakville Hydro has forecasted expenditures of $379,000 in the 2014 Test Year for application upgrades and modules to continue to provide ongoing development of assets management strategies, Health and Safety programs at Oakville Hydro, support for industry compliance and data management and analytics. In 2014 Oakville Hydro will also upgrade its Great Plains system. This system is the core financial, time track (Payroll), job control (Engineering), Procurement and warehouse management system for Oakville Hydro. The current version, which was upgraded in 2010, will not be supported after the end of 2014. Oakville Hydro also requires new modules to enable it to improve the workflow in the organization to support the functions of Oakville Hydro.

- Oakville Hydro has forecasted expenditures of $150,000 in the 2014 Test Year for a software enhancement, Conduit Manager, for its GIS that will allow accurate tracking of cables within Oakville Hydro's duct and manhole system. Accurate and easy to access records are essential for efficient operations and maintenance in these areas. The benefits of implementing this software include improved and more efficient access to records, more optimal cable routing for planned projects, improved network efficiency, improved accuracy of field information and elimination of duplicate records. These improvements will have a positive impact on customer service, system reliability, technology innovation and public and employee safety. Oakville Hydro considers this a reasonable cost as part of the evolution from paper documents to electronic records, and required to optimize the performance of distribution assets.

4.1-Staff-20

Ref: Exhibit 2/Appendix A- Distribution System Plan/Appendix 1 Asset Management Process

<u>Road Widening Projects</u>

Project Numbers: 15-E and 15-I are both road widening projects ($403,115) which both face the risk of delay due to municipal design planning. In Oakville Hydro's experience, how likely is it that these capital projects will be delayed due to municipal planning constraints? What has been the past experience in these cases?

RESPONSE:

Past experiences have shown that delays due to municipal planning constraints may not delay Oakville Hydro relocation work. Oakville Hydro works closely with road authorities to forecast upcoming projects to ensure relocation activities are completed in timelines requested by the road authority. Although there may be delays due to municipal design planning, it is not uncommon for Oakville Hydro's relocations to take place in advance of any municipal road construction due to conflicts with Oakville Hydro's physical plant and the road authorities' proposed works. The completion of relocation works well in advance of road construction may be required to ensure adequate timing for third parties to transfer their assets to the relocated plant.

In past experience, the road authority has executed Right of Entry agreements where ongoing land expropriations would otherwise delay Oakville Hydro's plant relocation. The Right of Entry agreement allowed Oakville Hydro to complete the necessary works ahead of the road construction.

Road authority requests to relocate plant, at times, may also come forward unexpectedly and without budgetary foresight. In these cases, the capital program is reviewed to determine if other projects need to be deferred, or additional capital funds secured.

4.1-Staff-21

Ref: 1) Exhibit 2/Appendix A- Distribution System Plan/Appendix 1 Asset Management Process

2) Exhibit 2/Tab5/Schedule 2/p. 6

<u>2014 Fleet Replacements</u>

Project Number: 14-62 indicates that Oakville Hydro plans to replace 6 existing vehicles with hybrid vehicles, as part of a $384,762 vehicle replacement program.

a) Why were hybrid vehicles chosen?

RESPONSE:

Hybrid vehicles were initially chosen for both their improved fuel economy and lessor environmental impact. After further review in late fall 2013, however, it has been determined that the return on investment and the current cost of these vehicles outweighs the benefits for hybrid capabilities. Therefore, Oakville Hydro proposes to purchase conventionally powered regular vehicles as replacements. The vehicle replacement program cost for the 2014 Test Year is now updated to $328,000, a reduction of $56,762 from its original submission.

b) What is the difference in life cycle costs between hybrid and conventionally powered vehicles? Please explain with specific reference to fuel, maintenance, capital and other cost differences

RESPONSE:

Please see Oakville Hydro's response to part a) of this interrogatory. Oakville Hydro is proposing to remove the incremental cost of hybrid vehicles in its 2014 Test Year.

c) Did any marketing or branding considerations factor into the proposal to adopt hybrid vehicles? If so, on what basis should this corporate value be recovered through rates?

RESPONSE:

Please see Oakville Hydro's response to part a) of this interrogatory. After further review it has been determined that the return on investment and the cost of these vehicles outweighs the benefits of hybrid capabilities.

d) What actions did Oakville Hydro take to establish whether its customers support the purchase of hybrid vehicles?

RESPONSE:

Oakville Hydro did not perform any actions to its customers to support the proposed purchase of hybrid vehicles. Please see Oakville Hydro's response to part a) of this interrogatory. Oakville Hydro is not proceeding with the purchase of hybrid vehicles.

e) At Reference 2), Appendix 2-AA shown on this page does not include any fleet replacement investments in 2014. Please explain.

RESPONSE:

In Appendix 2-AA, Oakville Hydro lists individual projects if they are over the materiality threshold of $180,000. The eight individual fleet replacement investments which are identified in Exhibit 2, Appendix A-Distribution System Plan, Page 76, have costs less than the materiality threshold and were therefore included under the miscellaneous line in Appendix 2-AA.

4.1-EP-9

Ref: Exhibit 2, Tab 5, Schedule 2

a) Does the distributor agree that system reliability has to be attained, or does it have to be maintained? Please explain fully.

RESPONSE:

Oakville Hydro agrees that system reliability must first be attained through prudent distribution asset replacements and subsequently system reliability must be maintained in order to provide its customers with the continued level of reliability and a minimized level of interruptions. It is Oakville Hydro's view that the reliability thresholds have been attained and now must be maintained. The maintenance of the distribution system includes continued reinvestment at a measured pace in order to avoid deterioration of the reliability.

The results of the Customer Satisfaction Survey discussed in Exhibit 1, Tab 2, Schedule 1, and the feedback that is provided directly to Oakville Hydro by its customers, demonstrate that reliability is important to Oakville Hydro's customers. Optimization of maintenance for Oakville Hydro's physical assets drives reliability, and provides a safe & controlled work environment with minimum risk to the health and safety of Oakville Hydro's customers, employees, public, and the environment.

Service (reliability) ties in to customer value as part of this value equation:

$$Value = \frac{Quality \times Service}{Cost \times Time \times Risk}$$

(Campbell & Reyes-Picknell, 2006)

Should service (reliability) decrease when cost, time and risk either remain constant or increase, then customer value decreases.

Works Cited

Campbell, J.D., & Reyes-Picknell, J.V. (2006). *Uptime, Strategies for Excellence in Maintenance Management, Second Edition*. New York: Productivity Press.

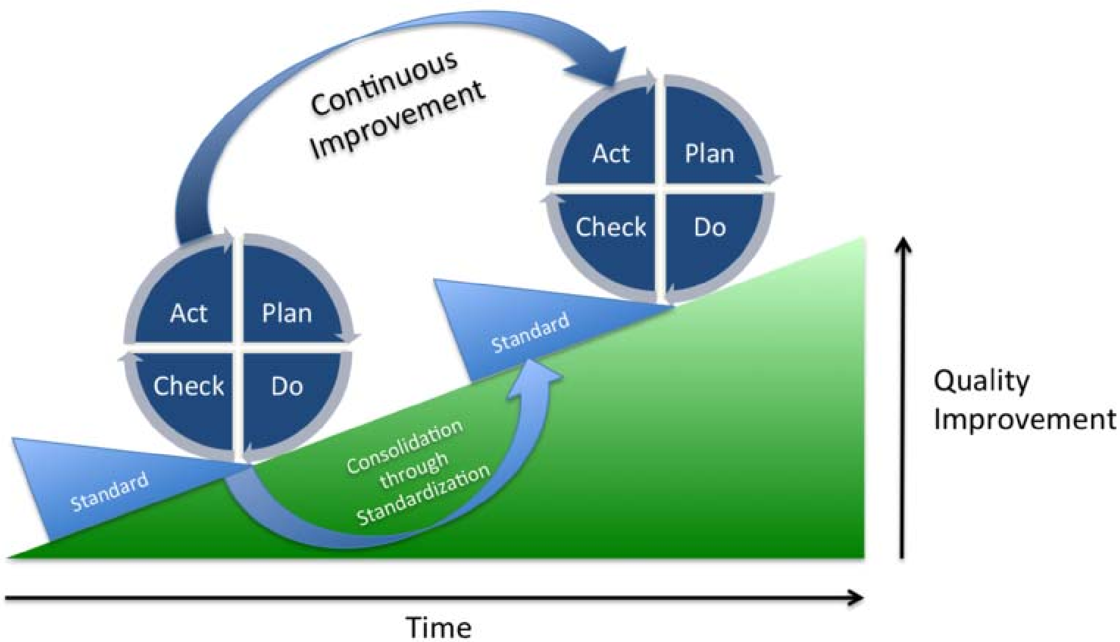
b) How has the distributor determined that its distribution system plan will result in continuous improvement in productivity? Please explain fully.

RESPONSE:

Using the PDCA (Plan, Doing, Check, Act) cycle illustrated below, the Distribution System Plan will result in continuous improvement in productivity. The "Plan" has already been set through use of the Distribution System Plan documentation. Oakville Hydro has been "Doing" work on both Capital and Maintenance by following the set plan. Oakville Hydro will be reviewing Key Performance Indicators (KPIs) in order to "Check" that what is being done is the same as what has been planned, and if any problems exist. Through results of the "Check" Oakville Hydro will "Act" and revisit and refine the "Plan". Each refinement of the plan will result in continuous improvement, not only in productivity, but also in:

- Greater safety and environmental integrity
- Improved operating performance
- Greater maintenance effectiveness
- Longer 'useful life' for key high cost assets
- Comprehensive database
- Greater motivation for individuals
- Better teamwork

By implementing this cycle, a new standard is set through each refinement.



(Vietze, 2013)

Works Cited

Campbell, J.D., & Reyes-Picknell, J.V. (2006), *Uptime, Strategies for Excellence in Maintenance Management, Second Edition.* New York: Productivity Press.

c) Does the distributor believe that its current level of system reliability and quality objectives need to be improved or that they are already high and need to be maintained?

RESPONSE:

There is always room for refinement of system reliability and quality objectives, however, Oakville Hydro believes that the service reliability and quality objectives are sufficiently high and need to be maintained. Refinements ensure that Oakville Hydro keeps pace with evolving customer service reliability expectations as well as ensuring that there is not a deteriorating situation developing. Oakville Hydro believes that it has put appropriate emphasis on technology and maintenance activities in order to deliver good service results to its customers. Opportunities to improve are always present and should be sought – where they add value to customers. Through the cycle process described in the answer to b) the net result should not only be continuous improvement in productivity, but a continuous improvement in system reliability and quality objectives.

d) What component or percentage of the associated revenue requirement does the distributor believe is directly related to the continuous improvement in productivity, the attainment of system reliability and quality objectives?

RESPONSE:

Oakville Hydro believes it is difficult to calculate a specific component or percentage of the associated revenue requirement is directly and specifically related to continuous improvement in productivity, separate from the attainment of system reliability and quality objectives. Oakville Hydro has not segregated its programs in this fashion. Oakville Hydro's programs such as the asset management team, routine patrolling of assets, enhanced technology all contribute to the continuous improvement in productivity and the attainment of system reliability and quality objectives.

4.1-SEC-8

Please explain how the Applicant has demonstrated that its distribution system plan will support continuous improvements in productivity?

RESPONSE:

Please see Oakville Hydro's response to Energy Probe interrogatory number 4.1-EP-9a.

4.1-SEC-9

Ref: Ex.2/5/2/p.6

Please provide the business case for the purchase of hybrid vehicles.

RESPONSE:

Please see Oakville Hydro's response to Board staff interrogatory number 4.1-Staff-21b.

4.1-VECC-7

Ref: E2/Appendix A

Please explain what metrics (reliability targets etc.) or other objectives that Oakville is using to assess the success of the Distribution System Plan? Specifically discuss the separate metrics used to judge; (1) the success of the plan itself (e.g. in achieving stated goals) and (2) the success of the plan's implementation.

RESPONSE:

The over-arching goal is to both control costs and maintain a reliable system in order to sustain customer satisfaction through this period. The implementation of the plan will be continually monitored against stated objectives of system reliability (SAIDI, SAIFI, CAIDI) and customer satisfaction- especially in the area relating to reliability. The implementation of the Distribution System Plan will be assessed against the outcome metrics on reliability and customer service indicators. It will be refined in accordance with these metrics and the evolving state of overall asset condition. Oakville Hydro believes it has designed a Distribution System Plan that addresses the upcoming 20 years of distribution system requirements. As customer needs and demands change and the actual reliability of the distribution system become known, the success of the plan will be measured by its ability to adapt to changes necessary to address these factors, with due regard to the impact on ratepayers while still maintaining the long term financial sustainability of the utility.

Issue 4.2 *Are the applicant's proposed OM&A expenses clearly driven by appropriate objectives and do they show continuous improvement in cost performance?*

4.2-Staff-22

Ref: Exhibit 4/Tab 1/Schedule 1

Update of 2013 and 2014 Operating Costs

Since October 1, 2013 when the current application was filed, and considering that the 2013 year is now complete, please file an update of 2013 OM&A costs, noting significant changes from the 2013 Bridge Year as filed and if any components of the OM&A costs for the test year will be updated.

RESPONSE:

Oakville Hydro's 2013 Actual (unaudited) OM&A costs are $18,118,740. This represents an increase of $194,335 as compared to the 2013 Bridge Year Forecast of $17,924,405. This increase in the actual as compared to the forecast can be explained by the incremental cost for the December ice storm, estimated to be $364,250, offset by lower than forecast locates expense of $180,000.

Although it is not material, Oakville Hydro is proposing to update its OM&A costs for the Test Year as detailed in the Table below:

Item	Amount	Description	Sub-Category	Interrogatory
Postage	$ 80,000	Result of recent postage rate changes	Billing and Collecting	7.1-EP-31e
Postage - Monthly Billing	60,000	Result of recent postage rate changes	Billing and Collecting	7.1-EP-31e
Property Taxes - Municipal Transformer Stations (Distribution & Transmission)	(45,818)	Adjustment	Operations & Maintenance	7.3-EP-37a
Key Account Manager	(22,931)	Based on updated information	Community Relations	4.2-Staff-24
Shared Services	(10,000)	Based on acquisition of affiliate	Administrative and General	4.2-EP-17d
Total	$ 61,251			

4.2-Staff-23

Ref: Exhibit 4/Tab 1/Schedule 2/p.1

Operational Effectiveness

At this reference Oakville Hydro indicates that it "…is continuously striving to improve its processes to achieve sustainable efficiencies."

As mentioned above, for 2014, Oakville Hydro's OM&A/customer is forecast to be $293.69, an increase of 6.1% from 2013 levels (on a New GAAP basis). For 2013, the OM&A/customer shows a similar 6.1% increase ($231.75/$218.50) (on an Old GAAP basis). In 2012, the increase was 5.8%.

Please reconcile the increases in OM&A cost per customer to continuously improving processes to achieve sustainable efficiencies.

RESPONSE:

Oakville Hydro reference to "its continuously striving to improve its process to achieve sustainable efficiencies" was made in the context that it has been able to maintain an inflationary factor (see response 3.1-Staff-16a) increase without any new initiatives while having a collective agreement of a 3% increase in unionized salaries and union progressions during the IRM period

(2010-2013.) Much of the increase in OM&A can be attributable to the increasing demands that are being met by the utility. For reference see 5.1-Energy Probe-26 and 5.1-VECC-22. In addition, a more detailed discussion is provided in 4.2-SEC-17.

4.2-Staff-24

Ref: Exhibit 4/Tab2/Schedule 2/pp. 7-8

Impact of Customer Preferences: Community Relations

Oakville Hydro shows that community relations expenses have grown significantly from 2010 to the test year: 18.1% in 2011, 83.3% in 2012, -2.6% in 2013 and 28.7% in the 2014 test year, for a total increase of 171% over that time period.

Please explain how this increase reflects customer preferences or needs which were identified through customer engagement.

RESPONSE:

The increase in this category of expenses is a result of the hiring of the Communications and Website Coordinator in 2011 and the return of 80% of the costs of the key account representative to the community relations category. That employee had diverted 50% of his responsibility to the OPA CDM programs, specifically for the Electricity Retrofit program and has been instrumental in progressing to meet Oakville Hydro's kW CDM targets. However, he is now expected to return and focus on serving Oakville Hydro's key account customers. This is referenced in Exhibit 4, Tab 2, Schedule 2, Page 7 of 9. Oakville Hydro has updated its evidence for the change of 100% of this person's time to only 80% of the person's time.

Oakville Hydro has not engaged customers directly as to the requirement for either of these positions, however, through various channels Oakville Hydro has received feedback on its website and the need to communicate with its customer through social media. The use of social media to communicate with customers was very important and well received during the recent December 2103 ice storm. Oakville Hydro's customers have requested improvements and updates to its website to enable them to understand their bills, apply for service and receive news about the industry.

There is interaction between commercial and industrial customers and Oakville Hydro's key account representative regarding support for the customer analysis of energy use, identification of areas for improvement to their operations and assisting them with understanding the ever changing electricity pricing and market rules.

Based on this, Oakville Hydro feels this increase reflects customer preferences or needs which were identified through customer engagement.

4.2-Staff-25

Ref: Exhibit 4/Tab2/Schedule 2/p. 9

Increase in Administration and General Costs

Oakville Hydro shows that Administration and General costs have increased by 36% from 2010 to the test year, with specific increases of 7.5% and 9.8% respectively for the bridge and test years. How do these increases reflect a focus on customer needs and operational effectiveness?

RESPONSE:

As illustrated in the table, Oakville Hydro has presented administrative recoveries as revenue offsets in its Application. Oakville Hydro administrative costs have increased a cumulative amount of 31% since 2010 as shown in the table below when one-time costs and revenue offsets are considered. This increase reflects operational effectiveness and customer needs as it primarily consists of the associated personnel and benefits costs required to secure experienced employees to service the customers adequately. These cumulative increases also contain the non-inflationary types of expenses such as OMERs costs which continue to rise at a rate greater than inflation, and costs associated with keeping competitive salaries and benefits for experienced employees.

Item	Description	2010	2011	2012	2013 Actual (unaudited)	2014 Test Year
Admin & General		3,887,171	4,744,456	4,461,324	4,830,193	5,268,840
Less: one time costs						(152,209)
Less: revenue offsets						
	data centre	(113,575)	(123,900)	(125,377)	(125,999)	(128,000)
	billing &vehicle insurance	(85,766)	(75,058)	(100,599)	(75,500)	(106,750)
	intercompany -occupancy	(179,705)	(111,200)	(83,216)	(86,600)	(127,900)
	Office space rental- Town of Oakville			(36,707)	(146,829)	(146,820)
		3,508,125	4,434,298	4,115,425	4,395,265	4,607,161
			26.40%		6.80%	4.82%
	Cumulative					31.33%

4.2-Staff-26

Ref: Exhibit 4/Tab2/Schedule 2/p. 5

Increase in Operations and Maintenance Costs

Oakville Hydro shows that non-normalized Operations and Maintenance costs have increased by 93% from 2010 to the test year. One of the reasons cited for this increase is the three-year effort to establish baseline information for the Asset Management Work plan. Now that this work is complete, why do costs continue to rise into the test year?

RESPONSE:

Oakville Hydro has established baseline data over the past three years. However, in order to ensure that asset replacement is being completed correctly an ongoing condition assessment program is required to support the capital replacement program. Asset conditions are continuously changing and there is a need to capture these changes to mitigate emergency expenditures that can result in lengthy outages and/or costly repairs. By undertaking an ongoing asset condition assessment as part of its regulated Preventative Maintenance Program as per the Distribution System Code Appendix C, Oakville Hydro is able to accomplish this task. As noted in Table 4-4 Ref: Exhibit 4/Tab2/Schedule 2/p. 5, the percentage change is decreasing from the initial investment as Oakville Hydro optimizes the data collection process and uses the collected data more effectively.

4.2-Staff-27

Ref: Exhibit 4/Tab3/Schedule 3/p. 2

Increase in 24/7 Control Room Operations and Load Dispatching Services

Oakville Hydro shows that costs in this area are forecast to increase by $293,755 due to the hiring of additional control room staff, but offset by an expected retirement and revenues from Halton Hills Hydro to provide control room services.

a) How much revenue is to be received from Halton Hills Hydro for control room services and what is the duration of this revenue?

RESPONSE:

Oakville Hydro will receive $120,000 from Halton Hills Hydro Inc. annually for a three-year term. This revenue was referenced in Exhibit 3, Tab 3, Schedule 1, Page 7 of 10 originally as $100,000 but will be updated in the "Revenue Offsets" RRWF to $120,000 based on the final signed agreement.

b) Please explain Oakville Hydro's training and skills continuity plan as it relates to retirement and replacement of staff in the control room, including discussion of costs, benefits and staffing risk. Has the expected retirement taken place?

RESPONSE:

The costs associated with Oakville Hydro's staffing plan for the control room for 2014 are described on Exhibit 4, Tab3, Schedule 3, Page 5 of 7.

At the end of 2013 Oakville Hydro had only four full time Operators, which is the minimum required for single Operator 24/7 coverage. With only four Operators, Oakville Hydro depends on overtime and backup operators from the Operations department for vacation and sick time coverage. However, with this model, Oakville Hydro is at an elevated staffing risk level and the continued operation of the control room would be in jeopardy if one of those four operators was away on an extended leave of absence for any reason. One of these Operators is expected to retire towards the end of 2014, but is still currently working as a full time Operator. Oakville Hydro had planned to hire one Operator in 2013, but this did not materialize until early 2014.

In 2015 Oakville Hydro plans to shift to a 'six Operator' model which provides staff sustainability for Oakville Hydro and also improved support for Halton Hills Hydro. To achieve this goal and manage through an expected retirement towards the end of 2014, Oakville Hydro plans for a second operator hire later in 2014, and one hire in 2015. This will deliver a sustainable 'Six Operator' model by the end of 2015.

4.2-Staff-28

Ref: Exhibit 4/Appendix A

Impacts of Change to Monthly Billing

Oakville Hydro has indicated that it intends to change the billing frequency for Residential and General Service <50kW customers from bimonthly to monthly in 2014.

Oakville Hydro has estimated that the cost of this change to be $380,000 and that this represents an incremental cost per bill of $0.53/bill.

a) Please provide the details behind the $380,000 calculation and the $0.53/bill calculation.

RESPONSE:

The details of the $380,000 are provided in Exhibit 4, Appendix A, Page 5. Oakville Hydro has calculated the amount of $0.53/bill as follows:

Description	Reference	Amount
Annually Incremental Monthly Billing Cost	(A)	$ 380,000
# of customers (moving to Monthly Billing)		
(as per Exhibit 4, Appendix A, Page 2)	(B)	59,944
Annual cost per customer	(A)/(B) = C	$ 6.34
Monthly monthly cost per customer	C /12	$ 0.53

These costs do not include the increased postage costs that were announced by Canada Post subsequent to the filing of Oakville Hydro's application.

b) What is Oakville Hydro's current (2013) cost per bill? Please provide the detailed cost components.

RESPONSE:

Oakville Hydro's current estimated cost per bill is 87 cents. The detailed cost components are provided in the following table.

Description	Amount
Postage	$ 0.66
Envelope	0.07
Paper	0.02
Salaries and benefits	0.07
Equipment Rental	0.15
Total	$ 0.97

These costs do not include the increased postage costs that were announced by Canada Post subsequent to the filing of Oakville Hydro's application.

c) What is the status of the discussions with the Region of Halton (as referred to on page 7) to move to monthly billing for water and waste-water? Will the Region of Halton also face additional costs due to the move to monthly billing?

RESPONSE:

Based on Oakville Hydro's last discussions with the Region of Halton, they have indicated that their preference would be for all distributors in the Region of Halton to bill on the same frequency, however this continues to be discussed. One distributor in Halton Region bills on monthly basis for electricity but includes bi-monthly billing for the water component of the bill. If Oakville Hydro structures its monthly billing process in the same manner then there would be not additional costs to the Region of Halton.

d) Please identify the percentage of Oakville Hydro customers on e-billing as of December 31, 2013.

RESPONSE:

Oakville Hydro currently has 65,436 customers. As of December 31, 2013, 7.45% (4,877) are on e-billing.

e) Please describe Oakville Hydro's efforts to promote e-billing to its customers and how the move to monthly billing may contribute to the success of those efforts.

RESPONSE:

Oakville Hydro promotes e-billing to customers in the following manner:

- Customers registering for online access are defaulted to e-billing
- Customer Service Representatives on the phones or in person
- Auto attendant messaging
- Website
- Bill inserts/messages
- Direct marketing – Oakville Hydro plans to email customers that have registered for online access and have not registered for e-billing in 2014.
- Community events

f) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

RESPONSE:

In addition to the items mentioned in response to part e) of this interrogatory, Oakville Hydro will undertake the following initiatives in order to manage the costs of monthly billing for all customers:

- Promote Pre-authorized Payment (PAP)
- Promote e-billing to all customers
- Continue to looks for ways to automate processes
- Increased promotion of CDM initiatives through increase frequency of monthly billing

g) As part of the decision making process, has the applicant determined the impact of the change to monthly billing on its working capital? If so, how is the working capital impacted by this change? If not, why not?

RESPONSE:

Oakville Hydro has not conducted a formal assessment of the impact of monthly billing. However, Oakville Hydro has conducted a high-level analysis to determine the impact of monthly billing on working capital versus the change in 2013 of the frequency of Oakville Hydro's payment to the IESO from a monthly to a weekly basis. Oakville Hydro's high-level analysis resulted in a working capital allowance in excess of the default 13% set by the Board.

4.2-Staff-29

Ref: Exhibit 4/Tab3/Schedule4/p.1

Compensation Strategy/Benchmarking

Oakville Hydro provides a summary of its Human Resources and Compensation strategy and how this contributes to the positions it has created. It also indicates that it has used various benchmarking sources but has not filed any studies with the application. Please provide an analysis of how Oakville Hydro has used compensation benchmarking, with a listing of the studies used, copies of the studies and how salaries and benefits were established for the purposes of the application.

RESPONSE:

Oakville Hydro has used various sources in the past for compensation benchmarking, including services with access to multiple databases and confidential industry specific surveys to assist in Oakville Hydro's assessments. In addition, Oakville Hydro has polled other electricity distributors on wages and benefits for employees. Oakville Hydro also uses specialized services for specific positions such as the Ontario Society of Professional Engineers and the Certified General Accountants of Ontario. Oakville Hydro has considered the 2011/2012 Management Salary Survey of Ontario's Local Distribution Companies prepared by the MEARIE Group and placed on the public record in London Hydro's rate proceeding (EB-2012-0146), although Oakville Hydro was not a participant in that survey.

Oakville Hydro compensation for Executive and Non-Union personnel was considered in a 2012 study prepared for Oakville Hydro Corporation (referred to here as "OHC") by PeopleFirst HR Services. That study considered compensation as it relates to both the regulated LDC (Oakville Hydro) and its competitive affiliates. Oakville Hydro is prepared to file a copy of the PeopleFirst material in confidence in accordance with the Board's *Practice Direction on Confidential Filings* (the "Practice Direction"), with certain exceptions in that certain information constitutes personal information and Oakville Hydro does not intend to disclose it in any event. The basis for the confidentiality request is as follows:

The public disclosure of the PeopleFirst material could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interests of Oakville Hydro, its affiliates, and the employees discussed in the study, in several ways:

- As an LDC, Oakville Hydro competes for employees with other LDCs and with private sector employers. Public disclosure of Oakville Hydro's compensation strategies could reasonably be expected to prejudice Oakville Hydro's competitive position in the labour market in that the disclosure would allow other employers to outbid Oakville Hydro for executive and non-union employees;

- As noted above, the study was performed for OHC, and addresses compensation issues related to both Oakville Hydro and its competitive affiliates. Salary strategies as they relate to the activities of the competitive affiliates of Oakville Hydro are commercially sensitive and their disclosure could reasonably be expected to prejudice those affiliates' competitive positions in two ways: (i) in the labour market in that the disclosure would allow other employers to outbid them for employees; and (ii) in their respective competitive markets as competitors would have access to sensitive employee cost information; and
- With respect to the employees themselves, disclosure of Oakville Hydro's compensation strategies and the salary ranges of members of the executive and other non-union employees could reasonably be expected to prejudice the employees' own competitive positions in the labour market in that the disclosure would allow other prospective employers to reduce compensation that might otherwise be offered to attract those individuals.

The Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in subsection 17(1) of the *Freedom of Information and Protection of Privacy Act* ("FIPPA"), and the Practice Direction notes (at Appendix B of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential.

Oakville Hydro has also redacted a limited amount of information from the PeopleFirst material that, in Oakville Hydro's submission, is not relevant to this proceeding or constitutes personal information. Information in the study related to the Vice President and General Manager of Renewable Generation and Energy Services has been redacted as that position is not an Oakville Hydro position, nor is there any allocation of the costs related to that position to Oakville Hydro, and that information is therefore not relevant to this proceeding.

Information in the study related to identifiable individuals' actual salaries and other compensation and how those may relate to the midpoints or other points in the ranges identified by PeopleFirst have also been redacted as this constitutes personal information, and in accordance with the Practice Direction, Oakville Hydro does not intend to disclose it in any manner, whether publicly or in confidence, notwithstanding that individuals may have executed the Board's form of Declaration and Undertaking with respect to confidentiality.

In light of the foregoing, Oakville Hydro requests that the PeopleFirst study be kept confidential, and that items identified as personal information and redacted from the study not be disclosed in any event, in accordance with section 4.3.1 of the Practice Direction and Rule 9A.02 of the Board's Rules of Practice and Procedure. Oakville Hydro is prepared to provide copies of the PeopleFirst Study (with the exception of personal information and information related to the position of Vice President and General Manager of Renewable Generation and Energy Services) to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Oakville Hydro's right to object to the OEB's acceptance of a Declaration and Undertaking from any person.

In keeping with the requirements of the Practice Direction, Oakville Hydro is filing a confidential, redacted version of the PeopleFirst study (with the personal information and information related to the position of Vice President and General Manager of Renewable Generation and Energy Services redacted). This material has been placed in a sealed envelope marked "Confidential". Separately from that, Oakville Hydro is filing with the Board a confidential, unredacted version of the PeopleFirst study that includes the personal information but not the information related to the position of Vice President and General Manager of Renewable Generation and Energy Services. This version has been placed in a sealed envelope marked "Confidential – Personal Information".

4.2-Staff-30

Ref: Exhibit 4/Tab3/Schedule4/pp. 18-19

Total Compensation

Oakville Hydro states that it sets compensation to attract, retain and incent current and future talent and that it feels that salary ranges and benefits appear to fall within market rates. Oakville Hydro also stated that it had negotiated a union agreement that raised unionised pay by 2.5% each year until 2017.

a) What facts led Oakville Hydro to think that its compensation fell within market rates?

RESPONSE:

As part of its preparation for a negotiation mandate, Oakville Hydro conducted a review of current collective agreements and recently settled agreements with other Ontario LDC's to determine if its wages were within market rates. As a result of the review of other collective agreements and recently settled agreements, Oakville Hydro's negotiated rate was at the lower, if not lowest, increase in the range. Through fair arm's length negotiation with the union and with the benchmarking information from other LDCs Oakville Hydro concluded that the compensation is within market rates.

b) With inflation expected to be 2% or less in the coming few years, please explain why annual 2.5% increases over 4 years is an appropriate wage increase? What inflation forecasts were available to Oakville Hydro at the time the new agreement was entered into?

RESPONSE:

At the time of negotiation, settlements for LDC's were between 2.8-3%. At 2.5%, Oakville Hydro has negotiated one of the lowest increases for the GTA market. Oakville Hydro's agreement allows for a balance between ensuring the union could recommend the settlement for ratification and remain within the fiscal restraints of the CPI, LDC sector trends and the competitive market positioning for resources.

Oakville Hydro uses the CPI, other collective agreement settlements and benchmark wage rates to determine an appropriate negotiated increase.

4.2-Staff-31

Ref: Exhibit 4/Tab3/Schedule4/p.25

Headcount and Compensation

Oakville Hydro has proposed a material 9.0% increase in headcount and 10.3% increase in employee compensation for the Test year relative to the 2012 actual levels.

Please provide specific information on why the proposed cost and headcount increases are necessary for Oakville Hydro to achieve the objectives that it has targeted in the capital and operating expenditure sections of its application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed headcount and compensation increases.

RESPONSE:

Additional resources were added or anticipated to accommodate change in business and regulatory need and retirements. Specific information on why the additions are needed is provided in Exhibit 4, Tab 3, Schedule 4, Pages 4 to 10, in the section entitled Incremental Hires. As part of the decision making process on increasing headcount, Oakville Hydro reviews the costs associated with outsourcing, increasing headcount or not providing the service to determine the best course of action.

4.2-EP-10

Ref: Exhibit 1, Tab 1, Schedule 1

a) What is the dollar impact of the union rate increase of 2.5% in July 2013, combined with the 1.5% increase effective July 1, 2014 on the 2014 unionized costs?

RESPONSE:

The dollar impact of the union rate increase of 2.5% in July 2013, combined with the 1.5% increase effective July 1, 2014, excluding individual progressions, on the unionized labour costs is approximately $ 73,988.

b) What is the dollar impact associated with the 2% increase in the test year for non-union employees?

The dollar impact associated with the 2% increase is $ 98,909.

c) What was the percentage and associated dollar increase in the bridge year for non-union employees?

In the bridge year, the budgeted increase was 2.1% (excluding progressions) and amounted to $ 84,072.

4.2-EP-11

Ref: Exhibit 4, Tab 1, Schedule 1, page 3

Please provide the operating, maintenance, meter reading and any other costs associated with the use of mechanical meters included in the 2010 Board approved OM&A costs that have been eliminated through the use of smart meters.

RESPONSE:

Oakville Hydro did not include any operations or maintenance cost related to the mechanical meters in 2010. However, Oakville Hydro included $132,000 of manual meter reading costs for part of the year for customers that had not had their smart meter installed.

4.2-EP-12

Ref: Exhibit 4, Tab 1, Schedule 2

a) Is the 1.5% increase shown for July 1, 2014 to December, 2014 on top of the 2.5% increase received for the January 1, 2014 through June 30, 2014 period shown on page 9?

RESPONSE:

The 1.5% increase shown for July 1, 2014 for July 1, 2014 through December 2014 is on top of the increase of 2.5% for the period July 1, 2013 through June 30, 2014. The annual impact of the cumulative increases for the calendar year 2014 is 2%, compared to the 2013 rates.

b) Based on the figures shown on page 9, is the average increase for unionized employees about 3.25%, based on a 2.5% increase for the first half of the year and 4% (2.5% + 1.5%) for the second half of the year? If no, please calculate the average increase for 2014 and show all calculations.

RESPONSE:

The average increase for the unionized group for the 2014 calendar year is 2.00%. Wages were increased by 2.5% for the 12-month period from July 1, 2013 to June 30, 2014. The annual impact for the 2013 increase for the period January 1, 2014 to June 30, 2014 is 1.25%. For the period of July 1, 2014 to December 31, 2014 the annual impact of the 2014 increase is .75%. This is illustrated in the following table:

Increase Effective Dates	Effective from prior year	Annual impact
July 1,2013 – December 31, 2013	2.50%	
January 1, 2014- June 30, 2014	0.00%	1.25%
July 1, 2014 – December 31, 2014	1.5%	0.75%
Total 2014 annual impact		2.00%

c) What is the increase in unionized employee wages and salaries for 2014 compared to 2013 in both dollar and percentage terms?

RESPONSE:

Based upon the existing union staff at December 31, 2013, the increase in unionized employee wage and salary for 2014 compared to 2013 is $ 97,716 or 3%. This amount includes those staff who will receive payroll progression payments in 2014

d) What is the increase in non-unionized employee wages and salaries for 2014 compared to 2013 in dollars based on the 2% increase used (page 11)?

RESPONSE:

Based upon existing non-union staff, the dollar increase from 2013 actual to 2014 budget based upon the 2% increase is $ 98,909.

4.2-EP-13

Ref: Exhibit 4, Tab 2,

a) Has Oakville Hydro obtained Board of Director approval for the 2014 forecasts included in this rate application (OM&A, capital expenditures, revenues, etc.)? If not, when is this approval expected?

RESPONSE:

On September 11, 2013, Oakville Hydro's Board of Directors approved a resolution which approved the 2014 forecasts included in this rate application. The final budget was approved on December 12, 2013.

b) Please provide the full cost (including benefits) of the three full time staff additions noted on page 2, along with the amounts that are recovered from affiliates or through related revenues.

RESPONSE:

The full annual wage and benefit cost of the three full time staff additions was $251,793. Oakville Hydro does not expect to recover an amount from affiliates for the monthly billing clerk, but Oakville Hydro expects to recover as much as $168,000 from its affiliates or related revenues

c) How long of an overlap will there be in the hiring of an additional control room operator for succession planning purposes?

RESPONSE:

If the successful candidate is already a trained Journeyperson Operator, then Oakville Hydro anticipates up to a two to four month period to familiarize the candidate with its control room standard operating procedures and the Oakville Hydro distribution system. However, if the successful candidate is not an experienced Operator, then there might be as much as a one year overlap required.

d) What is the 2014 cost forecast for the accounts receivable insurance on selected non-governmental general service customers noted on page 11?

RESPONSE:

The 2014 budget for accounts receivable credit insurance is $50,000.

e) Is the cost of the insurance noted above directly allocated to the general service rate classes? If not, why not?

RESPONSE:

Oakville Hydro has not allocated the accounts receivable credit insurance to the general service rate classes as the amount is immaterial.

4.2-EP-14

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please provide the smart meter related costs that were included in the deferral account by the year they were incurred in 2010, 2011 and 2012 (other years as well, if applicable).

RESPONSE:

The smart meter related costs that were included in the deferral account by the year that they were incurred are provided in the following table.

Smart Meter OM&A Costs		
Year		**OM&A**
2007	$	89,833
2008	$	88,000
2009	$	166,161
2010	$	378,048
2011	$	384,159
2012	$	-
Total	$	1,106,201

b) Is the $427,224 shown in Table 4-3 the costs incurred for smart meters only in 2012, or does it include the amounts cleared in the deferral account? If the latter, and if different from the response to part (a) please indicate the actual costs incurred in 2012, rather than the costs expensed in 2012.

RESPONSE:

The $427,224 shown in Table 4-3 includes only the costs incurred for smart meters in 2012. It does not include the amounts cleared in the deferral account. The revenues and OM&A costs that related to prior years were cleared to USoA account 6305 – Unusual Income in 2012. Only the costs that related to 2012 were recorded in expense accounts.

4.2-EP-15

Ref: Exhibit 4, tab 2, Schedule 2, pages 2-3

a) Please quantify the identified cost savings associated with the processing of invoices soon after account closure as a result of the proposed move to monthly billing. Please confirm these cost savings have been included as a reduction to the OM&A component of the revenue requirement for 2014.

RESPONSE:

Oakville Hydro anticipates that there will a reduction in bad debt write offs of $20,000. This is based on the premise that customers' final bills will be much more manageable (smaller bills due to shorter billing period) and that the collection cycle will occur more quickly and, as a result, bad debts will be reduced.

b) Please quantify the reduced costs associated with bad debts and doubtful accounts as a result of the proposed move to monthly billing. Please confirm these reduced costs have been included as a reduction to the OM&A component of the revenue requirement for 2014.

RESPONSE:

As discussed in Exhibit 4, Appendix A, Page 5, Oakville Hydro has included a reduction in bad debts of $20,000 as a result of its proposal to move to monthly billing in its 2014 Test Year. Oakville Hydro confirms these reduced costs have been included as a reduction to the OM&A component of the revenue requirement for 2014.

4.2-EP-16

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please update Tables 4-3 and Appendix 2-JA to reflect the most recent year-to-date figures available for 2013, along with an estimate of the remaining months in 2013.

RESPONSE:

Please find below an updated Table 4-3 and Appendix 2-JA with the Actual 2013 year (unaudited).

Item	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual (unaudited)	2014 Test Year (updated)
Recoverable OM&A costs (excluding property taxes)	$11,628,803	$11,017,743	$13,133,111	$14,006,880	$18,118,740	$19,276,251
Less:						
Changes in Capitalization Policies					3,094,778	3,027,884
Regulatory Initiatives (Smart Meters)				427,224	564,484	550,847
Municipal Transformer Station Operating Costs			30,930	164,981	247,040	256,135
Monthly Billing						440,000
Sub-Total	-	-	30,930	592,205	3,906,302	4,274,866
Normalized OM&A (excluding property taxes)	**$11,628,803**	**$11,017,743**	**$13,102,181**	**$13,414,675**	**$14,212,438**	**$15,001,385**
Annual Increases			19%	2%	6%	6%
$ increase (2014 Test Year versus 2012 Actual)						1,586,710
% increase (2014 Test Year versus 2012 Actual)						12%
% increase (2014 Test Year versus 2010 Board Approved)						29%

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013Actual (unaudited)	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$ 4,060,217	$ 3,645,295	$ 4,953,375	$ 4,755,638	$ 8,008,407	$ 8,207,743
Maintenance	2,074,335	1,922,776	1,982,894	2,552,677	2,935,062	2,854,124
SubTotal	**6,134,551**	**5,568,071**	**6,936,269**	**7,308,315**	**10,943,469**	**11,061,866**
%Change (year over year)			24.6%	5.4%	49.7%	1.1%
%Change (Test Year vs Last Rebasing Year - Actual)						98.7%
Billing and Collecting	$ 1,252,147	$ 1,463,012	$ 1,334,858	$ 2,021,868	$ 2,103,749	$ 2,708,644
Community Relations	89,686	99,489	117,528	215,373	241,329	246,901
Administrative and General	4,152,419	3,887,171	4,744,456	4,461,324	4,830,193	5,258,840
SubTotal	**5,494,252**	**5,449,672**	**6,196,843**	**6,698,565**	**7,175,271**	**8,214,385**
%Change (year over year)			13.7%	8.1%	7.1%	14.5%
%Change (Test Year vs Last Rebasing Year - Actual)						50.7%
Total	**$ 11,628,803**	**$ 11,017,743**	**$ 13,133,111**	**$ 14,006,880**	**$ 18,118,740**	**$ 19,276,251**
%Change (year over year)			19.2%	6.7%	29.4%	6.4%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013Actual (unaudited)	2014 Test Year
Operations	$ 4,060,217	$ 3,645,295	$ 4,953,375	$ 4,755,638	$ 8,008,407	$ 8,207,743
Maintenance	2,074,335	1,922,776	1,982,894	2,552,677	2,935,062	2,854,124
Billing and Collecting	1,252,147	1,463,012	1,334,858	2,021,868	2,103,749	2,708,644
Community Relations	89,686	99,489	117,528	215,373	241,329	246,901
Administrative and General	4,152,419	3,887,171	4,744,456	4,461,324	4,830,193	5,258,840
Total	**11,628,803**	**11,017,743**	**13,133,111**	**14,006,880**	**18,118,740**	**19,276,251**
%Change (year over year)			19.2%	6.7%	29.4%	6.4%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2010 BA – 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013Actual (unaudited)	Variance 2013 Bridge vs. 2012 Actuals	2014 Test Year	Variance 2014 Test vs. 2013 Bridge
Operations	$ 4,060,217	$ 3,645,295	$ 414,922	$ 4,953,375	$ 1,308,079	$ 4,755,638	-$ 197,736	$ 8,008,407	$ 3,252,768	$ 8,207,743	$ 199,336
Maintenance	2,074,335	1,922,776	151,559	1,982,894	60,118	2,552,677	569,783	2,935,062	382,385	2,854,124	- 80,938
Billing and Collecting	1,252,147	1,463,012	- 210,865	1,334,858	- 128,154	2,021,868	687,010	2,103,749	81,881	2,708,644	604,895
Community Relations	89,686	99,489	- 9,803	117,528	18,039	215,373	97,845	241,329	25,956	246,901	5,571
Administrative and General	4,152,419	3,887,171	265,248	4,744,456	857,285	4,461,324	- 283,132	4,830,193	368,869	5,258,840	428,647
Total OM&A Expenses	11,628,803	11,017,743	611,061	13,133,111	2,115,369	14,006,880	873,769	18,118,740	4,111,859	19,276,251	1,157,512
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	11,628,803	11,017,743	611,061	13,133,111	2,115,369	14,006,880	873,769	18,118,740	4,111,859	19,276,251	1,157,512
Variance from previous year				$ 2,115,369		$ 873,769		$ 4,111,859		$ 1,157,512	
Percent change (year over year)				19%		7%		29%		6%	
Percent Change: Test year vs. Most Current Actual						37.62%					
Simple average of % variance for all years						74.96%					15%
Compound Annual Growth Rate for all years											11.8%
Compound Growth Rate (2012 Actuals vs. 2010 Actuals)						8.33%					

b) Please provide a table in the same level of detail as in Appendix 2-JA that shows the most recent year-to-date actual expenditures in 2013 along with the figures for the corresponding period in 2012.

RESPONSE:

See response in a) which provides an annual comparative for 2013 and 2012.

4.2-EP-17

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please provide a breakdown of the Operations and Maintenance line items shown in Table 4-4 for each year shown (including 2010 Board approved) so as to separate out the costs associated with the mechanical meters that were replaced with smart meters beginning in 2010.

RESPONSE:

As documented in Oakville Hydro's Smart Meter Prudence Review (EB-2012-0193), Oakville Hydro began installation of residential smart meters in October 2009 and completed installation in August 2010. The installation of smart meters for the General Service < 50 kW rate class began in June 2010 and was completed in August 2011.

Oakville Hydro is unable to separate out the Operations and Maintenance costs related to mechanical meters as metering technicians work on all types of meters in any given year for residential, commercial or industrial customers. However, since the bulk of the mechanical meters were removed by August 2010 the Operations and Maintenance costs associated with mechanical meters should be relatively low for the years 2011 through to the 2014 Test Year.

b) Please provide a breakdown of the Billing line item shown in Table 4-5 for each year shown (including 2010 Board approved) so as to separate out the costs associated with the mechanical meters that were replaced with smart meters beginning in 2010.

RESPONSE:

In the Billing line item in Table 4-5, the costs associated with mechanical meters includes the manual meter reading costs incurred for residential and General Service < 50 kW customers being converted to smart meters. In Oakville Hydro's 2010 Board approved application; Oakville Hydro included a small amount of manual meter reading costs with the expectation that that the mechanical meters would be converted to smart meters in 2010 and therefore manual meter reads would no longer be required.

However, as documented in Oakville Hydro's Smart Meter Prudence Review (EB-2012-0193), the tuning of the smart meter network required an extensive effort and as a result Oakville Hydro continued to incur manual meter reading costs in 2010. By 2011, Oakville Hydro had stabilized its smart meter network and the number of meter reads was reduced the point where virtually no manual meter reads were required.

Billing Costs Associated with Mechanical Meters

Year	Amount
2010 Board Approved	$132,000
2010 Actual	$212,658
2011 Actual	$0
2012 Actual	$0

c) With respect to the key account representative that had allocated half of his time to the CDM program, please indicate where these costs were allocated prior to 2014.

RESPONSE:

Since the inception of the OPA programs in 2007, 50% of the costs associated with the key account representative were allocated to the Oakville Hydro's OM&A in the "Community Relations" category. The remaining 50% of the costs are not included in Oakville Hydro's OM&A costs. The costs are recorded in a chargeable work order in a balance sheet account which is fully funded through the OPA's PAB funding. This individual has worked primarily on the OPA funded Electricity Retrofit Incentive Program (ERII).

d) If the costs noted in part (c) were funded by the OPA, please confirm that the OPA funding for one half of this person's costs will cease at the beginning of 2014.

RESPONSE:

Oakville Hydro has re-evaluated the OPA's CDM programs, the availability of its existing resources and its progress towards the achievement of its 2014 CDM targets and concluded that this individual cannot completely redirect his activities as initially thought 100% to customer focus and engagement with Oakville Hydro's general service customers as this representative is currently involved in some ERII projects. Therefore, the key account representative will be attributing 20% of his time to the OPA CDM programs and 80% of his time will focus the remainder of his time on the engagement of Oakville Hydro's general service customers. Oakville Hydro will update its evidence for the change of 100% of his time to OM&A cost to only 80% of this time.

4.2-EP-18

Ref: Exhibit 4, Tab 2, Schedule 3, Appendix 2-JB

Tree trimming costs show a significant increase in 2012 in Appendix 2-JB. This increase is explained on page 10 of the evidence, as is the increase in 2014. However, if 2012 was an unusual year, please explain why there is no decrease shown for 2013.

RESPONSE:

Upon further examination, Oakville Hydro has determined that 2012 was not an unusual year at $284,000. Although there was a backlog of work to complete as stated on page 10 of the evidence, the workload for that year's cycle was normal. For 2013, the actual costs (unaudited) are $253,367. In 2011, Oakville Hydro invested $197,000 in tree trimming and vegetation management. This was unusually low due to constraints applicable to the third party contractor not able to allocate sufficient time and resources to the tree trimming that was necessary.

4.2-EP-19

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-3

If the municipal transformer station operating costs have been included in the deferral account which is to be cleared as part of this proceeding, why has Oakville Hydro included the costs in the recoverable OM&A costs to begin with?

RESPONSE:

As stated in the Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated July 10, 2010 (the "2010 "Filing Requirements"), "the Incremental Capital Module (ICM) is intended to address the treatment of new capital investment needs that arise during the IRM plan term…"

In accordance with the 2010 Filing Requirements Oakville Hydro sought approval for capital costs associated with the design and construction of the Glenorchy Municipal Transformer Station. The revenue requirement associated with these capital costs included the return on the rate base, depreciation and PILs. Oakville Hydro did not seek recovery of the OM&A costs associated with the maintenance and operation associated with the Glenorchy Municipal Transformer Station. In its reply to the written submissions of Board staff, SEC and VECC, Oakville Hydro noted that it would "incur additional OM&A costs associated with the MTS of $242,000 which it is not recovering"[1].

Therefore, it is appropriate to include the costs in the recoverable OM&A and to remove the costs from OM&A when normalizing OM&A costs in Table 4-3 – Normalized OM&A Costs.

4.2-EP-20

Ref: Exhibit 4, Tab 2, Schedule 4 &
Exhibit 2, Tab 2, Schedule 2

Please explain the $1 million difference in 2010 Board approved normalized OM&A between Table 4-9 and Table 4-3. If necessary, please provide a corrected table.

RESPONSE:

There is a typographical error in 2010 Board approved normalized OM&A in Table 4-9. Oakville Hydro has provided a corrected table below.

[1] EB-2010-0104, Oakville Hydro's Reply to the Written Submissions of Board Staff, SEC and VECC, February 2, 2011 page 10.

Corrected Table 4-9 – OM&A Cost per Customer and FTE – Normalized

Description	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Customers	64,575	62,674	63,614	64,106	64,763	65,427
Normalized OM&A (Table 4-3)	$ 11,628,803	$ 11,017,743	$ 13,102,181	$ 13,414,675	$ 14,154,325	$ 14,975,131
OM&A per customer-normalized	**$ 180.08**	**$ 175.79**	**$ 205.96**	**$ 209.26**	**$ 218.56**	**$ 228.88**
FTE	111	116	114	110	114	120
OM&A cost per FTE-normalized	**$ 104,763.99**	**$ 94,980.54**	**$ 114,479.52**	**$ 121,774.47**	**$ 124,455.51**	**$ 124,409.16**

4.2-EP-21

Ref: Exhibit 4, Tab 3, Schedule 1

Please provide an updated version of Appendix 2-JC that reflects the most recent year-to-date information available for 2013, along with an estimate for the remainder of the year.

RESPONSE:

The updated version of Appendix 2-JC is updated with 2013 Actuals (unaudited) and updated evidence for the 2014 Test Year outlined in 4.2-Staff-22.

Appendix 2-JC (updated)
OM&A Programs Table

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013Actual (unaudited)	2014 Test Year(Updated)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Customer Focus						
Operational Effectiveness & Communication		$ 388,322	$ 709,615	$ 664,625	$ 679,270	$ 712,894
Customer Service, Mailing Costs, Billing and Collections		1,878,302	1,885,546	2,015,387	2,042,435	2,061,244
Bad Debts		167,480	256,873	327,847	156,371	300,000
Monthly Billing (net of savings)		0	0	0		440,000
Service Locates		360,164	700,105	787,353	616,423	825,000
Sub-Total		**2,794,268**	**3,552,139**	**3,795,211**	**3,494,499**	**4,339,138**
Operational Effectiveness						
Municipal Transformer Station -operating and maintenance costs		0	30,930	164,981	247,040	256,135
Meters maintenance		418,193	433,614	506,003	557,532	657,073
Distribution sub-stations and protection and control		641,352	777,352	715,413	763,185	884,556
Asset management & maintenance department		77,924	195,334	201,194	232,816	212,534
Overhead lines		630,386	834,790	831,833	854,141	801,664
Underground Lines		940,883	1,265,267	1,253,666	1,211,326	1,019,702
24/7 Control room operations and load dispatch activities		700,000	720,854	678,378	810,952	972,133
Operations & engineering ,Inspection drafting & design construction services		1,752,114	1,714,874	1,617,157	1,677,111	1,725,959
Distribution Transformers		447,758	617,018	605,953	577,867	581,500
Tree trimming		234,103	197,433	284,764	253,367	365,000
Underground conduit		220,673	304,092	298,638	321,047	284,981
Poles Towers & Fixtures		212,049	292,206	286,966	273,690	266,188
Fleet costs		413,007	449,798	483,592	500,645	523,544
Health & Safety Costs		221,247	281,220	208,478	264,095	282,215
Executive, Financial , Legal, Professional and Insurance Services		2,943,993	3,178,340	3,147,648	3,157,726	3,320,959
Post employment costs		330,500	491,200	265,022	400,000	400,000
Procurement and Materials Management		616,528	642,279	619,490	559,244	553,856
Office building & security costs		874,122	939,378	824,325	838,287	857,796
IT, software, telecommunications		1,251,252	1,557,184	1,564,077	1,539,878	1,679,870
Internal Labour & Benefit Costs - attributed to capital work		(4,124,345)	(4,759,087)	(3,876,747)	(3,827,120)	(3,519,891)
Administrative services recovered from affiliates		(1,417,975)	(1,007,727)	(1,215,154)	(1,250,257)	(1,387,849)
Collection charges recovered from customers		(290,108)	(290,654)	(305,213)	(353,476)	(315,000)
Other- including storm costs		219,332	90,164	(66,297)	394,506	31,872
Sub-Total		**7,312,989**	**8,955,860**	**9,094,167**	**10,003,602**	**10,454,797**
Public and Regulatory Responsiveness						
Regulatory & Compliance		861,854	536,342	612,501	862,658	758,485
Metering Compliance		48,631	88,770	77,776	98,748	145,100
Smart Meter data management program				427,224	564,484	550,847
Capitalization Policy Change (Effective Jan 1 , 2013)				0	3,094,778	3,027,884
Sub-Total		**910,485**	**625,111**	**1,117,501**	**4,620,667**	**4,482,316**
TOTAL OM&A		**11,017,742**	**13,133,110**	**14,006,880**	**18,118,769**	**19,276,251**
Operational effectiveness						
Municipal Transformer Station- operating and maintenance costs		0	(30,930)	(164,981)	(247,040)	(256,135)
Monthly Billing		0	0	0	0	(440,000)
Public Policy						
Smart Meter data management program		0	0	(427,224)	(564,484)	(550,847)
Capitalization Policy Change (Effective Jan 1 , 2013)		0	0	0	(3,094,778)	(3,027,884)
Sub-Total		**0**	**(30,930)**	**(592,205)**	**(3,906,302)**	**(4,274,866)**
Normalized OM&A		**$11,017,742**	**$13,102,180**	**$13,414,675**	**$14,212,467**	**$15,001,385**

4.2-EP-22

Ref: Exhibit 4, Tab 3, Schedule 8

a) Based on the most recent information available, please provide the costs incurred to date for each of the legal and consulting line items shown in Appendix 2-M associated with the cost of service application.

RESPONSE:

As of December 31, 2013, Oakville Hydro has incurred a cumulative amount of $206,860 for legal and consulting services. Oakville Hydro incurred $24,877 in the 2011 year, $18,170 in 2012 year and $163,813 in the 2013 year.

b) If the consultant costs are associated with more than one consultant or report/service, please provide a breakdown of these costs and indicate what each cost is for.

RESPONSE:

In the table below Oakville Hydro detailed the breakdown of these costs. Oakville Hydro has grouped consultants that prepared only one report or service for Oakville Hydro's application. This is intended to protect any commercially sensitive information related to these consultants.

Name	Type of Service/Report	Cumulative Costs
Four consultants providing one service or report	• Corporate Cost allocation report by BDR North America • Indefeasible Right of Use Fair Market Valuation by TR Consulting • PILs model and tax write up review by Price Waterhouse • Cost of Service overview one day session by Paul Vlahos	$37,922
Two Temporary Contractors	• Assistance with drafting evidence and preparing multiple sections of the Application • Administrative assistance in formatting and organizing application	$110,493
Borden Ladner Gervais LLP	• Bruce Bacon for regulatory assistance, direction, consultation and review of application and James Sidlofsky legal assistance and review of application	$51,342
Other	• Estimated transcription costs for Issues Day and printing costs for copies of applications for OEB & Intervenors	$7,103
	TOTAL	**$206,860**

4.2-EP-23

Ref: Exhibit 4, Tab 3, Schedule 4

a) Are the premiums paid by the distributor to OMERS equal to the employee contributions to OMERS? If not, please provide a table, similar to Table 4-13 that shows the distributors contributions to OMERS in one line and the contribution of all employees in aggregate to OMERS in a separate line.

RESPONSE:

OMERS employer contributions are equal to the employee contribution.

b) Have there been any changes in post-retirement benefits since the 2010 cost of service application? If yes, please provide details, including any change in costs.

RESPONSE:

The post-retirement benefits have not changed since 2010, however, eligibility was reduced in August 2010 to limit benefits to age 65 only.

c) Have there been any changes in the benefits provided to employees since the 2010 cost of service application? If yes, please provide details, including any change in costs.

RESPONSE:

Please see response to part b) above.

4.2-EP-24

Ref: Exhibit 4, Tab 3, Schedule 4

a) Please provide the actual amount of bonus or incentive payments made in each of 2010 through 2012, along with the forecast for 2013 and 2014 included in Appendix 2-K.

RESPONSE:

The following is the total actual amount of bonus or incentive payment made in each year (payments in year are for incentive earned in prior year):

Payment Year	Incentive Year	Actual Payout
2010	2009	$ 387,456
2011	2010	542,064
2012	2011	414,728
2013	2012	433,788
2014	2013	448,400

b) Please provide the total potential amount of bonus or incentive payments that were available in each of 2010 through 2012, along with the forecast for 2013 and 2014.

RESPONSE:

See response below.

c) Based on the response to parts (a) and (b) above please provide a table that shows the ratio of actual to potential bonus or incentive payments for each of 2010 through 2014.

RESPONSE:

Incentive Payments	2010	2011	2012	2013	2014
Actual	$542,064	$414,728	$433,788	$448,400	$472,471
Potential	$722,263	$620,113	$919,050	$955,977	$983,595
Ratio	75%	67%	47%	47%	48%

4.2-EP-25

Ref: Exhibit 4, Tab 3, Schedule 8 &
Exhibit 4, Tab 2, Schedule 2

a) Please confirm that the $106,609 figure that represents one-fifth of the cost of preparing the cost of service application includes costs incurred in 2012 and 2013.

RESPONSE:

Oakville Hydro confirms that the $106,609 represents one-fifth of the cost of preparing the cost of service application which includes costs incurred in 2012 and 2013.

b) Are these amounts that are included in 2012 and 2013 also reflected in those years in Table 4-4 in Exhibit 4, Tab 2, Schedule 2?

RESPONSE:

In Exhibit 4, Tab 2, Schedule 2, Table 4-4 Oakville Hydro has not included $18,170 in 2012 Actual and $240,000 in the 2013 Bridge Year for the costs it incurred or anticipated to incur in those years for costs directly related to this Application. Oakville Hydro has included them in Exhibit 4, Tab 2, Schedule 2, Table 4-7.

c) If the response to part (b) is yes, please explain why this is not double counting these costs.

RESPONSE:

In Exhibit 4, Tab 2, Schedule 2, Table 4-7 Oakville Hydro is providing information related to its actual OM&A cost for 2012 and its forecasted costs for 2013 including those it incurred or expects to incur as a result of this Application. Oakville Hydro believes it is not double counting as Oakville Hydro incurred costs in 2012 and 2013 as discussed in response to part b) for which Oakville Hydro has not been able to recover. Therefore, in the 2014 Test Year Oakville Hydro is requesting to recover 1/5th of the cumulative costs associated with the preparation of this Application.

4.2-SEC-10

Please detail the objectives has the Applicant set for its OM&A activities.

RESPONSE:

Oakville Hydro's objectives for its OM&A activities are as follows:

- Look for opportunities for shared services with other local distributors to find economies of scale (such as Oakville Hydro shared services with Halton Hills Hydro Inc., and Milton Hydro)
- Enhance services to customers based on their preferences with minimal added cost
- Focus on paperless billing and increasing the number of customers on Pre-authorized Payment to reduce costs
- Mitigate unexpected cost increases
- Continue to tender services more frequently
- Re-evaluate labour positions as retirements arise
- Make use of technological advancements to reduce costs
- Empower employees to find innovative ways to perform tasks to achieve savings

4.2-SEC-11

Please revise the following tables to include 2013 year-end actuals and explain any material variances. (If 2013 actual data is not yet available, please provide the most recent year-to-date actuals available, along with a forecast for the remaining period in 2013):

a) Ex.4/1/1/p.4 Table 2

RESPONSE:

Item	2010 Board Approved (CGAAP)	2012 Actual (CGAAP) updated	2013 Actual (unaudited) (New CGAAP)	2014 Test Year (Updated) (New CGAAP)
OM&A	$11,628,803	$14,006,880	$18,118,740	$19,276,251
Amortization	9,807,682	11,720,662	8,831,962	8,611,141
Property Taxes	210,600	170,969	181,633	184,721
Payment in lieu of Taxes (PILs)	1,899,098	797,852	-198,883	176,472
Total Operating Costs	**23,546,183**	**26,696,363**	**26,933,452**	**28,248,585**
Operating Costs previously approved by OEB:				
Less: Smart Meter Operating Costs & Depreciation recovered through current approved rider (EB-2012-0193)		929,634	1,394,451	1,394,451
Less: Transformer Station depreciation costs approved through rate rider (EB-2010-0104)		525,319	525,319	525,319
Normalized Operating Costs	**$ 23,546,183**	**$ 25,241,410**	**$ 25,013,682**	**$ 26,328,815**
% increase (2014 Test Year versus 2012 Actual)				4%
% increase (2014 Test Year versus 2010 Board Approved)				12%

b) Appendix 2-JA

RESPONSE:

See response 4.2-EP-16

c) Appendix 2-JB

RESPONSE:

Appendix 2-JB (updated)
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actual Year (unaudited)	2014 Test Year (updated)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance	$ 10,224,013	$ 11,017,743	$ 13,133,111	$ 14,006,880	$ 18,118,740
Wages, Salaries, Progressions and Benefits	389,944	329,825	241,811	503,801	459,153
Post employment costs	225,574	160,700	(226,178)	134,978	0
Temporary Contractors	0	383,631	(378,089)		0
Customer Focus Drivers					
Service Locates	0	339,941	87,248	(170,930)	208,577
Monthly Billing	0	0	0		440,000
Bad debts	0	89,393	70,974	(171,476)	143,629
Operational Effectiveness Drivers					
Asset Management & Asset condition assessements	0	417,620	(125,885)		0
Administrative services recovered from affiliates	335,310	410,248	(207,427)		0
Maintenance - Vehicles and Corporate Office	0	112,787	0		0
New Municipal Transformer Station - operating & maintenance costs	0	0	134,051		0
Internal Labour & Benefit Costs - attributed to capital work	(694,258)		711,762		307,229
Tree Trimming	0	0	87,331		111,633
Public Policy Drivers					
Smart Meter -operating costs	0	0	427,224	137,260	0
Regulatory costs	85,692	0	0	212,242	(104,173)
Impact of change of capitalization policies	0	0	0	3,094,778	(66,894)
Late payment charge - one time payment	257,572	(257,572)	0		0
Other	193,895	128,796	50,946	6,949	22,616
Ice Storm costs				364,259	(364,259)
Closing Balance	$ 11,017,743	$ 13,133,111	$ 14,006,880	$ 18,118,740	$ 19,276,251

d) Appendix 2-JC

RESPONSE:

See response 4.2-EP-21.

Oakville Hydro has addressed the material variances in response to Board staff Interrogatory number 4.2-Staff-22.

4.2-SEC-12

Ref: Ex.4/1/2/p.9

Please provide a copy of the Applicant's current collective agreement with its union(s).

RESPONSE:

Oakville Hydro has provided a copy of its current collective agreement as Appendix 4-A.

4.2-SEC-13

Ref: Ex.4/2/2/p.3

What is the per customer cost of moving to monthly billing?

RESPONSE:

Oakville Hydro's cost per customer is estimated to be $0.53 per month for monthly billing, reference in Exhibit 4, Appendix A, Page 4.

4.2-SEC-14

Ref: Ex.4/2/2/p.3-4

Please explain the variance between the 2010 Board-approved OM&A expenses and actuals.

RESPONSE:

The variance between the 2010 Board-approved OM&A and the actuals of $611,060 is attributed to the lower post-employment expense, as well as the significant time allocated to capital for the construction of the Glenorchy Transformer station. Lastly, Oakville Hydro had an interim President & CEO until mid-April of 2010 which also caused some delay in anticipated spending.

4.2-SEC-15

Ref: Ex.4/2/3p.10

Please provide a copy of the Applicant's contract with its third party tree trimming service provider.

RESPONSE:

The tree trimming contract expired December 31, 2013 and no new contract has yet been finalized. Oakville Hydro is operating on a month to month basis until such time as the contract is finalized.

4.2-SEC-16

Ref: Ex.4/3/2/p.2

Please provide a breakdown of the OM&A costs for the Glenorchy Municipal TS.

RESPONSE:

The breakdown of the OM&A costs for the Glenorchy Municipal Transformer Station is provided in the following table.

Glenorchy Municipal TS Operating & Maintenance Costs		
Description	**2014 Test Year (updated)**	
Internal Labour & Benefits for maintenance of TS	$	77,265
Third party contracted annual maintenance work		62,000
Property Insurance		48,000
Property Taxes		20,997
UPS battery systems		18,023
Water, snow removal, security, ground maintenanc		29,850
	$	256,135

4.2-SEC-17

Ref: Ex.4/2/4/p.2

Please explain how the Applicant's change in OM&A cost per customer, OM&A cost per FTE, and customer per FTE, shows a continuous improvement in cost performance.

RESPONSE:

In Exhibit 4, Tab 2, Schedule 4, Page 1 of 2, Table 4-9 Oakville Hydro provides a normalized cost per customer and cost per FTE. This normalization shows Oakville Hydro's cost performance in the absence of significant new regulations or initiatives, but does not adjust for the less significant additional regulatory and requirements that are noted in the response to 5.1-EP-26 and 5.1-VECC-22. OM&A cost per customer continues to increase at 1.6% in 2012, 4.4% in the 2013 Bridge Year and 4.7% in the 2014 Test Year. The increase in OM&A costs per customer is as a result of an increased focus on the maintenance of distribution assets, the requirement to provide additional locates, the annual increase of 3% for unionized employees throughout Oakville Hydro's IRM period and inflation. Salaries and wages are a large component of Oakville Hydro's OM&A costs. Therefore, Oakville Hydro has had to achieve savings in other areas in order to improve upon its asset maintenance program and provide locate services to its customers.

The cost per FTE fluctuates from year-to-year as a result of staff changes during any given year, vacancies that persist until appropriate replacements are found and changes in responsibilities for existing and new staff members as discussed in Exhibit 4, Tab 3, Schedule 4, Page 9 of 25. However, the number of customers per FTE has increased only slightly from 2010 actuals.

As the improvement in efficiencies are developed, it is expected that the OM&A cost per customer will decline and the FTE per customer will begin to increase.

Description	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Metered Customers	64,575	62,674	63,614	64,106	64,763	65,427
FTE	111	116	114	110	114	120
Customer per FTE	582	540	558	583	568	545

4.2-SEC-18

Ref: Ex.4/3/3/p.2

Please provide the terms of the agreement with Halton Hills Hydro for the provision of 24hr control room services.

RESPONSE:

Oakville Hydro has provided a copy of the agreement with Halton Hills Hydro for the provision of 24-hour control room services as Appendix 4-B.

4.2-AMPCO-8

Ref: Exhibit 4, Tab 1, Schedule2, Page 2

Preamble: Oakville Hydro indicates in 2013 it will complete a meter to cash process review to examine its procedures and implement changes to realign staff and automate various billing and collections processes to minimize inaccuracies and improve operating efficiencies.

a) Please explain this process in more detail and provide an update on this work.

RESPONSE:

The primary goal of the "Meter to Cash" (M2C) mapping project is to identify gaps and opportunities in Oakville Hydro's current way of conducting business in order to streamline processes and procedures, and create an overall efficient and effective environment. In the first stage of the project, the key subject matter experts were engaged in a process mapping exercise to establish a record of the existing business processes. As these processes were mapped, a document was developed to track business process gaps and opportunities for improvement. The document then drove the identification of five key initiatives to drive business process improvement. In 2014, Oakville Hydro is moving forward on these key initiatives. As the business process improvements are implemented, it is expected that there will be improvements in the OM&A costs per customer.

b) Please provide a summary of any planned or implemented changes including realignment of staff.

RESPONSE:

Moving forward in 2014, Oakville Hydro will pursue the following five key initiatives as outcomes to the (M2C) project.

1. Assignment of final bill collection receivables to 3rd party Collection Agencies that have proven performance, automating active collection process by engaging Harris (Customer Information System) resources, and a regulatory audit to ensure compliance with respect to delinquent accounts.

2. Reduction in Truck Rolls – conversion of 25 commercial accounts, where interval data is downloaded via laptop by installing remote cellular communications, and provide more emphasis on contractor engagement on new construction as a contact point rather than asking Oakville Hydro's crews to visit the site to collect updates.

3. Process Automation and Process Management – fine tune Oakville Hydro's mobile work order system, improve web enablement and presentment processes; create detailed plans for Automation Platform development and development of on-line forms through integration with Harris.

4. Faster Meter to Cash Cycle – develop Automation Platform for file imports/exports; billing exceptions, variance analysis, and billing determinant reports; establish monthly billing; install wireless modems on commercial and industrial meters with known phone line issues; and improvement of Quad logic meter data collection.

5. Re-evaluate 3rd Party Contracts – Bill print and meter reading contracts to be reviewed for possible RFP/RFI opportunities

4.2-AMPCO-9

Ref: Exhibit 6, Tab 1, Schedule 2, Page 3, Revenue Deficiency Cost Drivers

Preamble: Oakville Hydro indicates $1.407 million of the $5.381 million revenue deficiency is due to incremental distribution system operation, maintenance and administration.

a) Please provide a breakdown and description of the costs that make up the OM&A component of the $1.407 million.

RESPONSE:

As discussed in Exhibit 6, Tab 1, Schedule 2, Oakville Hydro's revenue deficiency of $5.381M is comprised of three main factors:

1. North Oakville (Glenorchy) Municipal Transformer Station: $1.819M.
2. Smart meter implementation: $2.155M.
3. Incremental distribution system operation, maintenance and administration: $1.407M.

The incremental distribution system operation, maintenance and administration relate to the operation of the utility and not just to OM&A. A detailed breakdown of the costs that make up the component of $1.407 are provided in the following table.

Causes of Revenue Deficiency	Amount (000's)	
Glenorchy Municipal Transformer Station		$ 1,819
Smart Meters		2,155
Changes to Depreciation and Capitalization Policies	(485)	
OM&A	3,665	
Depreciation	1,279	
Return on Equity	(71)	
Interest	(1,790)	
Taxes Other than PILs	(95)	
PILs	(1,069)	
Revenue Offsets	(27)	1,407
Revenue Deficiency		$ 5,381

4.2-AMPCO-10

Ref: Exhibit 1, Tab 3, Schedule 3, Page 15

Preamble: Oakville Hydro provides a high-level organization chart.

a) Please provide an expanded organization chart that shows the next layer and reporting structure of Oakville Hydro's departments.

RESPONSE:

Oakville Hydro has provided an expanded Organization Chart as Appendix 4-C.

4.2-AMPCO-11

Ref: Exhibit 4, Tab 1, Schedule 2, Page 4

Preamble: The evidence indicates Oakville Hydro negotiated with the union to hire part-time customer service representatives, resulting in cost savings and additional flexibility.

a) Please confirm when these negotiations took place and the compare the number of part-time customer service representatives in the 2014 Test Year compared to prior years.

RESPONSE:

A Letter of Understanding was signed between the union and Oakville Hydro in May 2012. The agreement allowed Oakville Hydro to hire three part-time call centre agents, until the union and Oakville Hydro could negotiate the inclusion of part time people into the collective agreements on a basis acceptable to both parties. During Oakville Hydro's 2013 negotiations with the union the number of part time call-centre agents was increased to four effective July 1, 2013.

Prior to July 2012 there were no part-time call centre agents. For 2012 there were three call centre agents for six months, in 2013 there were three call centre agents for six months.

b) Please quantify the savings.

RESPONSE:

For 2013, the savings amounts to approximately $52,400 for the year. This is based on replacing two full-time customer service representatives on a 35 hour work week with three part-time call-centre agents working up to 24 hours per week.

4.2-AMPCO-12

Ref: Exhibit 4, Tab 1,Schedule 2, Page 5

Preamble: Oakville Hydro indicates it has searched for opportunities to minimize costs through collaboration with other distributors and has partnered with a number of other utilities in GridSmartCity with a focus on achieving increased purchasing power.

a) Please summarize Oakville Hydro's collaboration activities with other distributors and quantify any savings.

RESPONSE:

Oakville Hydro is in the early stages of engaging other distributors to work towards achieving increased purchasing power. Oakville Hydro is currently collaborating on working towards material standardization with several LDCs in close proximity to Oakville Hydro, and will not be able to pursue any purchasing collaboration until each participant has common standards.

Oakville Hydro is actively engaged with other LDCs as part of the GridSmartCity consortium in addition to the focus on material standardization and procurement. Of note is the Control Room Operations Shared Services agreement that was put in-place in 2013 between Oakville Hydro and Halton Hills Hydro to optimize the delivery of control room capabilities for both entities. In addition, Oakville Hydro, in conjunction with a third party industry-leading Occupational Health and Safety Management System provider, are working on the development of a 'regional' Health and Safety Services Model for Oakville Hydro, Halton Hills Hydro and Milton Hydro to provide enhanced Health and Safety services at an optimal cost for all parties.

b) Please summarize any shared procurement opportunities in 2014.

RESPONSE:

Oakville Hydro is not anticipating any shared procurement opportunities with other distributors in 2014. Oakville Hydro expects that its efforts in 2014 will be focused on material standardization to enable shared procurement in the future.

4.2-AMPCO-13

Ref: Exhibit 4, Tab 1, Schedule 2, Page 9

Preamble: Oakville Hydro indicates its management team has undergone many changes since its last Cost of Service application.

a) Please explain this statement more fully.

RESPONSE:

Since 2010 Oakville Hydro has experienced a number of losses in its senior executive and management teams. In 2010, the position of Chief Operating Officer was created. Later that year, the position of President and Chief Executive Officer became vacant. The position of President and Chief Executive Officer was filled temporarily until a suitable replacement could be found. In 2011, the position of CFO became vacant and the position was filled temporarily with an internal resource until a suitable replacement was found at the end of 2011. In addition, the position of Director of Operations became vacant in 2010 and the position was replaced with a Manager, Operations.

As identified in Exhibit 4, Tab 3, Schedule 4, Page 12, three vacant positions became vacant in Oakville Hydro's Information Technology department in 2010. Filling these positions proved to be a challenge and Oakville Hydro was required to fill those management positions with a number of temporary contractors until suitable replacements could be found.

As discussed in Exhibit 4, Tab 3, Schedule 4, Page 9, a new senior management role was created in 2011 after a review and realignment of business functions. Filling this position with a suitable candidate has proven to be challenging and a number of temporary candidates have been hired until such time as the position can be filled permanently.

4.2-AMPCO-14

Ref: Exhibit 4, Tab 1, Schedule 2, Page 11, Inflation Rates Used

Preamble: Oakville Hydro's 2014 Test year budget includes an inflationary index of 2% for non-union employees.

a) Please provide the rationale for using a 2% increase.

RESPONSE:

At the time of preparation of the 2014 budget, the "Consumer Price Index for Canada, all items CPI, not seasonally adjusted, historical data" as reported by Statistics Canada was sitting at 1.8% and had been increasing since the first of the year. Oakville Hydro was also engaged in union negotiations for a new contract, effective July 1, 2013. The prior contract was three year contract with increases of 3% per year. Oakville Hydro's position was that 3% per year was unrealistic and certainly not in keeping with the direction of the government in their dealing with public service employees. Oakville Hydro believed that 2% was a reasonable estimate for budgetary purposes.

4.2-AMPCO-15

Ref: Exhibit 4, Tab 2, Schedule 1, Budget Process

a) Page 2 - For 2014, please summarize the discretionary costs or cost areas that have been delayed to future years in order to contain costs.

RESPONSE:

During the budget process, Oakville Hydro reviews the following types of discretionary expenses that could be delayed or for which an alternative approach would be less costly:

- Delay hiring for succession planning
- Contractors – is need short term? How critical? Do we have internal resources with appropriate skill set that could be diverted to perform the task?
- Conferences – who goes, how often
- Memberships – which ones are beneficial and bring additional value to the business
- Training – are there opportunities to offer in-house and have more employees attend for a lower cost
- Office / Computer supplies
- Deferral of facility maintenance projects – can they be deferred
- Vehicle maintenance vs. replacement
- Courier

In addition, Oakville Hydro has deferred a number of initiatives until 2015:

- Change Management Program
- Electric Vehicle Pilot and Charging Stations
- Utility Leading Practices (in 2014 Oakville Hydro will gather benchmarking to support this initiative).

b) Page 2 - For 2014, please summarize any delays in hiring for succession planning.

RESPONSE:

Succession planning is an ongoing concern with an aging workforce. Oakville Hydro has been fortunate in its planning to accommodate younger employees in its growth, thereby providing some training and transfer of knowledge. Management looks at all potential upcoming retirements and reviews contingency plans that could be put in place if there was to be an unexpected loss of one or more key employees. Where possible and the risks can be mitigated a delay in the hiring of a potential successor to key roles will be made.

Examples include:

- Executive management: Review and discussion with the Board of Directors on the three executives and contingencies that would be exercised if an unexpected change occurred.
- VP, Directors and managers: Review at the management level to consider the risks to the business if there was an unexpected change, including succession and cross training.
- High Potential and Key employees: Discussion and review of cross training of skill sets and reduced dependency on specific roles.

c) Page 2 – Please confirm the percentage of costs partially recovered for the Accountant and Control Room Operator.

RESPONSE:

Oakville Hydro expects to recover up to 75% of the cost of the accountant and control room operator.

d) Page 4 - Please provide the total number of executives, management, union and non-union FTEs included in Engineering and Operations.

RESPONSE:

Engineering & Operations: This includes all departments that report to the COO, including control room, protection and control, asset management, material management and health and safety.

Executive	1
Management	14
Union	42
Non-union	2
Total	**59**

e) Page 10 - Please provide the total number of executives, management, union and non-union FTEs included in Customer Service and Organizational Effectiveness.

RESPONSE:

Customer Service & Organizational Effectiveness (includes customer service, billing, collecting, metering, human resources and communications departments

Management	4
Union	22
Non-union	4
Total	**30**

f) Page 12 – Please provide a summary of telephone inquiries per year for the years 2008 to 2013.

RESPONSE:

Oakville Hydro has provided a summary of the telephone in inquiries for the years 2008 to 2013 in the tables below.

2008

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	4019	3366	3510	3906	4183	4523	5000	4267	4325	4126	3541	3081	47,847
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	3455	2935	2953	3252	3647	3641	3568	3175	3606	3336	2915	2455	38,938
(3) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	85.97%	87.20%	84.13%	83.26%	87.19%	80.50%	71.36%	74.41%	83.38%	80.85%	82.32%	79.68%	81.38%

2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	3650	3264	4179	3999	3977	4764	4990	4651	4959	4855	3966	2282	49,536
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	2875	2696	3343	3199	3102	3478	3044	2969	3244	3790	3539	1738	37,017
(3) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	78.77%	82.60%	80.00%	79.99%	78.00%	73.01%	61.00%	63.84%	65.42%	78.06%	89.23%	76.16%	74.73%

2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	3262	3909	4901	4833	4885	5815	5102	5402	5528	6143	5738	3456	58,974
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	2408	3496	4259	4350	4410	5457	4748	5103	4592	4061	4894	3068	50,846
(3) ABANDONED CALLS- abandoned after 30 seconds	92	46	62	39	37	9	19	19	121	322	72	11	849
(4) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	73.82%	89.43%	86.90%	90.01%	90.28%	93.84%	93.06%	94.47%	83.07%	66.11%	85.29%	88.77%	86.22%
(5) PERCENT ABANDONED AFTER 30 SECONDS [(3)/((1)+(3))	2.74%	2.78%	1.25%	0.80%	0.75%	0.15%	0.37%	0.35%	2.14%	4.98%	1.24%	0.32%	1.42%

2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	4801	3964	5046	4333	4658	6857	5867	5841	5344	5853	5168	3489	61,221
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	4179	3359	4344	3505	3965	5634	4986	4559	4229	4341	4381	2994	50,476
(3) ABANDONED CALLS- abandoned after 30 seconds	48	39	58	100	100	83	80	111	109	177	46	43	994
(4) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	87.04%	84.74%	86.09%	80.89%	85.12%	82.16%	84.98%	78.05%	79.14%	74.17%	84.77%	85.81%	82.45%
(5) PERCENT ABANDONED AFTER 30 SECONDS [(3)/((1)+(3))	0.99%	0.97%	1.14%	2.26%	2.10%	1.20%	1.35%	1.86%	2.00%	2.94%	0.88%	1.22%	1.60%

2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	4795	4128	4416	4135	4982	5121	5137	5301	4777	5525	5065	3006	56,388
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	4238	3718	3907	3659	4326	4437	4155	3777	3821	4450	4077	2659	47,224
(3) ABANDONED CALLS- abandoned after 30 seconds	58	28	52	23	52	52	75	200	97	129	109	5	880
(4) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	88.38%	90.07%	88.47%	88.49%	86.83%	86.64%	80.88%	71.25%	79.99%	80.54%	80.49%	88.46%	83.75%
(5) PERCENT ABANDONED AFTER 30 SECONDS [(3)/((1)+(3))	1.20%	0.67%	1.16%	0.55%	1.03%	1.01%	1.44%	3.64%	1.99%	2.28%	2.11%	0.17%	1.54%

2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	ANNUAL TOTAL
(1) # OF GENERAL INQUIRY TELEPHONE CALLS ANSWERED	4445	3930	4214	4407	5081	5165	5850	5117	4528	4237	3873	2763	53,610
(2) # OF THESE CALLS ANSWERED WITHIN 30 SECONDS	3677	3247	3247	3463	4162	4198	4876	4354	3958	3780	3365	2414	44,741
(3) ABANDONED CALLS- abandoned after 30 seconds	65	70	130	120	89	74	154	55	40	35	31	21	884
(4) % OF THESE CALLS ANSWERED WITHIN MINIMUM STANDARD [((2) * 100)/(1)]	82.72%	82.62%	77.05%	78.58%	81.91%	81.28%	83.35%	85.09%	87.41%	89.21%	86.88%	87.37%	83.46%
(5) PERCENT ABANDONED AFTER 30 SECONDS [(3)/((1)+(3))]	1.44%	1.75%	2.99%	2.65%	1.72%	1.41%	2.56%	1.06%	0.88%	0.82%	0.79%	0.75%	1.62%

g) Page 14 - Please provide the total number of executives, management, union and non-union FTEs included in Corporate Services and Regulatory Affairs.

RESPONSE:

Corporate Services & Regulatory Affairs (includes finance, information technology, purchasing, building services and regulatory affairs departments)

Executive	**1**
Management	6
Union	2
Non-union	13
Total	**22**

4.2-AMPCO-16

Ref: Exhibit 4, Tab 3, Schedule 3, Variance Analysis, Page 1

a) In 2014 Oakville Hydro plans to conduct a safety audit of substation sound grids (one substation annually). Is this a new activity for 2014? Please provide the annual cost of this safety audit.

RESPONSE:

The substation ground grid safety audit began in 2012 with the audit of one substation. It continued in 2013 and will be an annual audit until all of our substations have been completed. The approximate cost per year will be $25,000 for completion of this work.

4.2-AMPCO-17

Ref: Exhibit 4, Tab 3, Schedule 4

a) Appendix 2-K - Please confirm the number of vice-presidents, directors, managers and supervisor FTEs for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual and 2014 Test Year.

RESPONSE:

The number of vice-presidents, directors, managers and supervisors are provided in the table below:

Category	Board Approved 2010	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year
Executive	3.00	2.75	2.97	3.00	3.00	3.00
Vice Presidents			0.58	1.00	1.00	1.00
Directors	6.00	5.04	5.90	8.01	7.79	7.65
Managers	5.00	7.00	5.79	4.88	4.50	5.00
Supervisors	11.00	9.25	10.53	11.88	12.00	12.00
Total	25.00	24.04	25.77	28.77	28.29	28.65

b) Appendix 2-K - Please provide the number of existing vacancies.

RESPONSE:

Oakville Hydro has the following vacancies:

- Control Room Apprentice
- Three Powerline Technicians
- Stock keeper helper
- Billing Clerk (for monthly billing)

c) Appendix 2-K - Please confirm the number of part-time FTEs for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual and 2014 Test Year.

RESPONSE:

The following chart provides the number of part time FTE's for each of the years:

Category	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year
Part Time FTE's	n/a	14.11	11.71	4.37	6.50	3.02

d) Please update Table 4-13 to include 2013 Actuals.

RESPONSE:

Oakville Hydro has updated Table 4-13 to include 2013 Actuals (unaudited). Effective 2013, Sandpiper Energy Solutions Inc. and El-Con Construction Inc. created their own separate payrolls for their non-management staff. Therefore, there is a drop in the benefit costs and statutory expenses.

Item	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year
Benefit Cost		$ 542,096	$ 576,132	$ 560,691	$ 553,695	$ 536,070
Statutory		917,589	851,672	900,748	789,306	972,538
OMERS		753,174	888,357	1,011,784	1,209,924	1,214,019
Payroll Benefits Recovered from Affiliates		(459,169)	(440,635)	(483,831)	(279,058)	(384,625)
Total	$ 1,861,902	$ 1,753,690	$ 1,875,526	$ 1,989,392	$ 2,273,867	$ 2,338,002

4.2-AMPCO-18

Ref: Exhibit 4, Tab 3, Schedule 5

e) Page 6 – Please summarize the detailed analysis of other vehicle maintenance service providers in the area compared to using the Town of Oakville.

RESPONSE:

Oakville Hydro used a third party contractor who did an external survey of five area maintenance facilities that would be able to handle Oakville Hydro's fleet and obtained their standard hourly rates for repairs. The hourly rates for each of the vendors surveyed were in excess of the rates proposed to be charged by the Town. The Oakville Hydro fleet consists of several different manufacturer vehicles and also includes pneumatic devices. Of the five area businesses contacted, two handle light cars and trucks, two handle heavy duty trucks and one handles heavy duty transmissions. Of the area facilities contacted some would have to outsource repairs as they did not have in house expertise to handle items (i.e. – pneumatics). In addition to the hourly costs charged by the Town being comparable to other pricing, a further significant advantage is the timing of the service that the Town provides. Maintenance and repair work is performed during evening and/or night shifts when the majority of the equipment is not being used. This significantly reduces the down-time for equipment during normal working hours when the equipment is needed. This service was not available from other service providers.

f) Page 6 – Please provide the results of the independent assessment of the space at 861 Redwood Square to demonstrate that the lease renewal was within current market prices.

RESPONSE:

Oakville Hydro engaged Colliers International to provide an independent assessment of the space in its building and a comparison to facilities in the area that were available for rent. Their analysis was based upon 7,000 square feet of available space, which would have required Oakville Hydro to reorganize its Customer Service and Billing areas. Their recommendation was a listing price to keep gross rent under $ 20.00 or $ 11,600 per month. The current lease is for 5,758 square feet, with a monthly rent of $12,236.

4.2-AMPCO-19

Ref: Exhibit 4, Tab 3, Schedule 6

a) Page 5 – Please provide the Non-Affiliate Purchased Products or Services for 2013.

RESPONSE:

The table below provides the Non-Affiliate Purchased Products or Services for 2013.

2013 Non-Affiliate Purchased Services

Vendor Name	Product and Service	Methodology of Selection
K-Line Maintenance & Construction	Commercial Transformer & Switchgear Vault Washing ,Overhead line maintenance	Alliance
Util-Assist	Consulting Services	Sole source, specialized knowledge
Westburne Electrical Inc.	Lugs, sleeves, terminator- cold shrink, cabling grounding connectors	Competitive Bid
HD Supply Power Solutions	Miscellaneous line inventory	Competitive Bid
G&W Canada Inc.	Switchgear	Sole source
SOFTCHOICE INC.	Phone upgrade (original installer), Infrastructure, firewall, etc.	Competitive Bid
Guelph Utility Pole Company	Wood poles	sole source
Olameter Inc.	Meter reading services	Competitive Bid
Harris Computer Systems	Billing software, upgrade, maintenance & support	Sole source, specialized knowledge
Posi-Plus Technologies Inc.	Aerial devices for vehicles	Competitive Bid
ABB Inc.	Distribution / Power Transformers	Competitive Bid
Noramco WIre & Cable Co.	Wire and cable	Competitive Bid
Sensus	AMI System / Smartmeters	Competitive Bid
Canada Post Corporation	Postage	Sole source
EPTCON Limited	Construction Services	Competitive Bid
Siemens Canada Limited	Switchgear	Competitive Bid
KTI Limited	Smart meter provider	Competitive Bid
Dell Computer Inc.	Server farm, Storage Area Network (SAN)	Competitive Bid
BDO Canada LLP	Information Systems Consulting Services	Sole source, specialized knowledge
Pioneer Transformers Ltd.	Transformers	Competitive Bid
Anixter Canada Inc.	Wire and cable	Competitive Bid

4.2-VECC-8

Ref: E4/T2/S1/p.11

Please provide the following statistics for 2010 through 2013:

a) CPI

b) GDP-IPI

c) Oakville Hydro's IRM Stretch Factor

d) Oakville Hydro's IRM Productivity Factor.

RESPONSE:

The statistics for 2010 to 2013 are provided in the table below.

Statistic	2010	2011	2012	2013
CPI	2.5%	3.1%	1.4%	1.0%
GDP-IPI	1.3%	1.3%	2.0%	1.6%
Stretch Factor	NA	0.4%	0.4%	0.4%
Productivity Factor	NA	1.0%	1.0%	1.0%

4.2-VECC-9

Ref: E4/Appendix 2-JC

Please file the Detailed OM&A for 2010 through 2014 in the USoA format showing accounts 5005 through 6205 and including the 2013 actual year-end (unaudited).

RESPONSE:

In accordance with Chapter 2 of the Board's Filing Guidelines, page 26-27, in which the Board has indicated that it is moving away from significant attention to discreet elements of the input to OM&A. Instead, Oakville Hydro provided all its OM&A expenses in program tables which have been updated 2013 Actuals (unaudited) in 4.2-EP-21 and also provided in 4.2-Staff- 24, 25 and 26.

4.2-VECC-10

Ref: E4/T2/S2/pg.6

Smart Meter Incremental Costs (the purpose of this interrogatory is to understand the elements which have caused billing and collection to increase from 2010 to 2014.

a) Please compare the cost components of Billing and Collection accounts 5305, 5310, 5315, 5320,5325, 5335, 5340 for 2010 for Board approved 2010, 2010 actuals and 2014 forecast.

RESPONSE:

The smart meter incremental costs have been segregated in the Exhibit 4, Tab 3, Schedule 1, Appendix 2-JC "OM&A Programs Table". The OM&A programs table has been updated with 2013 (unaudited) actuals in response to interrogatory 4.2-EP-21. Oakville Hydro has included $550,847 in its 2014 Test Year. The smart meter incremental costs are also described in Exhibit 4, Tab 3, Schedule 3, Page 7 of 7.

Billing and collections costs have increased additionally for the proposal to move to monthly billing for which the components are identified in Exhibit 4, Appendix A.

b) Please compare and contrast the components of actuals 5315 Billing for 2010 actuals as compared to 2014 forecast costs.

RESPONSE:

Please see response 4.2-VECC-9.

4.2-VEC-11

Ref: E4/T2/S2/pg.3

Please provide a breakdown of the incremental OM&A costs associated with the maintenance of the Glenorchy Municipal Transformer Station.

RESPONSE:

Please see Oakville Hydro's response to SEC interrogatory number 4.2-SEC-17.

4.2-VECC-12

Ref: E4/T2

Please provide all training, conference and travel costs for each year 2010 through 2014.

RESPONSE:

The training, conference and travel costs for each year 2010 through 2014 are provided in the following table.

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Budget
Conferences	20,902	47,397	37,939	48,586	56,730
Training	94,592	72,168	72,438	101,956	104,950
Travel (incl. mileage & allowances)	43,026	41,157	31,275	41,166	40,615

4.2-VECC-13

Ref: E4/T3/S6

For each year in the period 2010 through 2014 please provide the amounts for:

a) EDA Fees;

RESPONSE:

The EDA Fees for 2010 – 2014 are shown below.

Category	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Budget
EDA Fees	$ 62,700	$ 64,700	$ 68,200	$ 74,600	$ 80,000
MEARIE Insurance – Gross,	357,647	421,039	377,291	416,908	504,244
Recovered from Affiliates	-24,542	-27,480	-29,000	-35,380	-156,281
EDI Insurance Expense	333,105	393,559	348,291	381,528	347,963

b) MEARIE insurance premiums;

RESPONSE:

The MEARIE insurance premiums shown for 2010 – 2014 are for the total corporation which are then allocated across the affiliates.

Please see Oakville Hydro’s response to part a) of this interrogatory.

c) MEARIE Actuarial Services.

RESPONSE:

In 2010 Oakville Hydro issued an RFP for Actuarial Services and MEARIE was not the successful bidder. Oakville Hydro paid MEARIE $10,678 in 2010, but it was for 2009 services which had been accrued at $10,000 in 2009.

4.2-VECC-14

Ref: E4/Appendix A, pg.5 7

Monthly Billing Report & Appendix 2

Util-Assist: Billing Frequency Report

a) Please explain how the savings in moving to monthly billing were estimated.

RESPONSE:

Oakville Hydro estimated it savings in moving to monthly billing by taking 10% of its average actual 2010-2012 write-offs.

b) The study does not identify any savings related to lower working capital requirements arising from the more frequent billing (i.e. increased cash flow). Please explain why this was not included in the study.

RESPONSE:

Please see Oakville Hydro's response to Energy Probes interrogatory number 7.1-EP-31.

c) The associated Util-assist Report states "In addition to the benefits associated with improved cash flow which can be easily quantified through analysis of the impact of changing the frequency of invoicing, there are some "anecdotal" improvements to the cash flow which are well understood but perhaps difficult to quantify". It then goes on to describe a number of cost saving measures. Please explain how these measures were imputed in the cost saving analysis of the study on moving to monthly billing.

RESPONSE:

The anecdotal improvement identified in the Util-assist report include: lower customer bills; reduced collections; reductions in bad debt; reductions in payment arrangements; reduction in customer calls; easier data verification process; reduction in unbilled revenue; improved proration process; and more certainty around specific service charges.

Most of the anecdotal improvements identified by Util-assist relate to the reduction in bad debt. As discussed in response Energy Probe's interrogatory number 4.2-EP-15 part a), Oakville Hydro anticipates that there will a reduction in bad debt write offs of $20,000. This is based on the premise that customer's bill will be much more manageable (smaller bills due to shorter billing period) and that the collection cycle will occur more quickly and, as a result, bad debts will be reduced.

The other anecdotal improvements could include reduction in customer calls, easier data verification process and reduction in unbilled revenue are difficult to quantify.

Reduced doubtful debts would likely reduce the need for payment arrangements and by association the number of calls to follow-up with the customers.

Improved verification of data as there is a smaller period of billing that needs to be analysed and verified as well as the reduced "high bill" calls

These anecdotal savings are unknown and very difficult to quantify. The additional volume of billing may result in an increase in calls which would have the opposite effect than expected from moving to monthly billing.

4.2-VECC-15

Ref: E4/T2/S2/pg.6 & S3/pg.7

From Appendix J-C Oakville Hydro's Bad debt costs for the years 2010 through 2013 are shown as:

2010	2011	2012	2013	2014
167,480	256,873	327,847	300,001	300,000

a) What steps has Oakville taken since 2010 to reduce these costs?

RESPONSE:

Oakville Hydro has increased its focus on the collection process through its Meter-to-Cash review in 2012. As a result of this review Oakville Hydro has made changes to its collection process including the outsourcing collection activities to a third party professional collection agency and through analysis of the data on a timelier basis. In addition, Oakville Hydro continues to build relationships with its customers and provides them with payment options.

b) Please explain why, if Oakville is moving to monthly billing and has identified 20k in bad debt reductions as a result (E4/Appendix A, pg.5), it still expects to have bad debt costs at the second highest level in 5 years?

RESPONSE:

Oakville Hydro's estimated 2014 Test Year Bad Debts is actually $280,000 rather than $300,000. In Appendix 2-JC, the $20,000 bad debt saving is grouped in "Monthly Billing (net of savings)". At this time, Oakville Hydro has received public information that at least two major customers will be closing in the 2014 Test Year which may result in a bad debt expense. These customers are referenced Exhibit 2, Appendix A, Page 7.

c) Please describe the methodology for estimating the 2014 bad debt amount.

RESPONSE:

The methodology used for estimating the 2014 Bad debt amount is based on the average of the last years actual results (2011 and 2012 years) adjusted by an inflationary factor.

d) Please provide the actual 2013 bad debt amount.

RESPONSE:

The 2013 Bad debt expense (unaudited) is $156,371. This consists of actual write-offs of customer accounts of $220,583 and an overprovision of the allowance of doubtful accounts from the previous year.

4.2-VECC-16

Ref: E4/T2/S2/pg.8

Please provide a breakdown of the 2010 community relations expenses and compare and contrast these to the 2014 proposed expenses.

RESPONSE:

Description	Amount
2010 Actual	$99,489
2014 LEAP contribution	47,000
Communication and Website Co-ordinator and the Key account representative allocated at 80% for customer focus (rather than 50% of time in the 2010 Cost of Service application)	100,411
2014 Test Year	$246,900

4.2-VECC-17

Ref: E4/T2/S3/pg.4 / T3/S4/pg.19

Please provide the average annual wage/salary increase (without progression and benefits) for each year 2012 through 2016 for:

a) Management and Executive

b) Non-Union

c) Union

Description	2012	2013	2014	2015	2016
Executive/management	2.10%	2.10%	2.00%	No Information	No Information
Non-Union	2.10%	2.10%	2.00%	No Information	No Information
Union	3%	2.75%	2.00%	2.50%	3.00%

We cannot provide average wage and salary increases for our Management and Non-union groups for 2015 and 2016 as these are determined by factors not known at this time (i.e. CPI, market). The union increases are provided based on the current collective agreement effective July 1, 2013 to June 30, 2017.

4.2-VECC-18

Ref: E4/T2/S4 & Appendix 2-L

Why does the "normalized" OM&A per customer in Table 4-9 differ from the amount in Appendix 2-L for the 2010 Board approved year?

RESPONSE:

Table 4-9 has a typographical error of $1,000,000 in the 2010 Board Approved year. The OM&A should have been $11,628,803 not $10,628,803 and the OM&A per customer should have been $180.08 not $164.60.

4.2-VECC-19

Ref: E4/T3/S4/pg.25

Oakville Hydro's FTE count has increase from 111 Board approved in 2010 to 120 or 9 incremental FTEs (positions). Please allocate these 9 positions into one of the following categories:

a) Primarily driven by smart meter/TOU requirements

RESPONSE:

- Advanced Metering Infrastructure and Metering Coordinator

b) Primarily driven by incremental regulatory or government requirements;

RESPONSE:

- Regulatory Analyst

c) Customer growth driven;

RESPONSE:

- Billing Clerk

d) Enhanced services (Transformer station related, new billing cycle, Web presentation etc.); or

RESPONSE:

- Control Room Operator
- Control Room Operator Apprentice
- Engineer in Training

e) Enhanced maintenance programs.

RESPONSE:

- Line Supervisor
- Asset Management Supervisor
- Asset Management Technician

For each category please provide an estimate of the annual compensation increase related to the category.

RESPONSE:

As each of the categories has three or fewer employees, Oakville Hydro has estimated annual compensation increase related to the all of the categories for the 2014 Test Year to be approximately $903,200.

4.2-VECC-20

Ref: E4/T2/S4 & Appendix 2-L

Please breakdown Oakville Hydro's "normalized" OM&A per customer increase from 2010 ($164 per customer) to 2014 ($228 per customer) into the following components:

a) % due to increase in capital programs/maintenance
b) % due to incremental regulatory/government responsibilities
c) % due to inflation
d) % due to enhanced services

Please provide an explanation of how the percentage was calculated.

RESPONSE:

In response 4.2-VECC-18, Oakville Hydro provided the corrected 2010 cost per customer of $180.08, therefore Oakville Hydro has used this amount in formulating its response to this interrogatory. Oakville Hydro has made an attempt (although difficult to accurately segregate on a year over year basis) to the best of its abilities to provide percentage for the categories above based on a review of its programs in Appendix 2-JC.

The percentages are as follows:

- 12% due to increase in capital programs/maintenance
- 5% due to incremental regulatory/government responsibilities
- 5% due to inflation (includes item increases that exceed inflation ie. OMERs contributions)
- 7% due to enhanced services

4.2-VECC-21

Ref: E4/T3/S

With respect to Appendix 2-M

a) Please confirm that the regulatory costs associated with this application are $533,047.

RESPONSE:

Oakville Hydro confirms that the regulatory costs associated with this application are $533,047.

b) Please provide the actual regulatory costs to-date. Include separately any amounts unbilled but estimated based on work completed.

RESPONSE:

Please see the table below. The unbilled but estimated based on work complete are the intervenor and OEB cost awards outlined below and a $5,000 unbilled amount for the transcription costs (included in Consultants and legal) for Issues Day at the OEB.

Description	Costs
Consultants and Legal (from 4.2-EP-22)	$206,870
Regulatory staff incremental salaries (reduced work week staff member working on full time basis for Application)	23,488
Intervenor and OEB Cost awards for Application (estimate to Dec 31, 2013)	65,000
TOTAL	**$295,348**

c) Please explain the $43,047 in historical costs and identify the year of this spending.

RESPONSE:

Oakville Hydro incurred $24,877 in 2011 for the third party reports in Exhibit 2, Appendix C and Exhibit 4, Appendix C, and incurred $18,170 in 2012 for contractor assistance for this rate application.

Issue 4.3 *Are the applicant's proposed operating and capital expenditures appropriately paced and prioritized to result in reasonable rates for customers, or is any additional rate mitigation required?*

4.3-Staff-32

Ref: Exhibit 2/Tab 5/Schedule 2/p. 6 Appendix 2-AA

Miscellaneous Capital

The Appendix 2-AA Capital Projects shows Miscellaneous Capital for the 2014 Test Year to be $2,289,049. This is more than double the levels of previous years. Please provide a breakdown of the capital expenditures included in this total for 2014 and discuss their relative priority to other elements in the miscellaneous category as well as to other projects in the plan.

RESPONSE:

The relative priority for projects in the Miscellaneous Capital is generally:

1) System Access projects ($123,994) considered mandatory.

2) System Renewal projects ($1,265,970) – incudes individual projects that are under the materiality threshold. Although under the materiality threshold, they are scrutinized and optimized in the same manner as any other System Renewal projects, but frequently driven by system failures, near failures or the asset condition assessments.

3) Systems Service and General Plant projects comprise the balance of the Miscellaneous Capital category, of which each individual category/project is under the materiality threshold. These projects are scrutinized and prioritized based upon specific

needs/requirements, current costs to maintain, operational impact and regular appropriate asset condition assessments.

The breakdown of the 2014 Miscellaneous Capital expenditure is provided below:

2014 Miscellaneous Capital Expenditures Summary

Description	2014
System Access	
ROAD WIDENING - NO OH CONTROL	
North Service Road East Widening	$123,994
System Renewal	
LOAD TRANSFER AND SYSTEM SECURITY	
27.6kV Sub Switchgear Replacement	$124,758
4kV Air insulated switchgear replacements	$41,604
Switch Replacement Budget - Emergency	$148,841
O/H REBUILDS	
Budget Estimate Capital Projects Engineering	$24,962
SUBSTATIONS	
MS 27.6kV Switchgear Replacement Program	$86,785
SUPERVISORY	
Smart Grid Dtechs	$126,073
U/G REBUILDS	
Emergency Underground Replacement	$121,021
Replace U/G Assets on Copeland Ct	$152,471
Replace U/G Assets on Maurice Dr	$69,375
Replace U/G Assets on Warren Dr	$124,475
Replace U/G Assets on Weldon Avenue	$137,136
Replace U/G assets on Wood Pl	$108,469
System Service	
IT CAPITAL	
Power System Analysis	$152,000
O/H REBUILDS	
Harvester Solar Pilot Project	$100,000
SUPERVISORY	
Install Remote Fault Indicators	$36,899
Administration - IT	
Administration - Building	
Miscellaneous Leasehold Improvements	$8,199
Parking Lot Replacement	$40,083
Redwood Carpeting - Main Floor	$29,151
Substation Security Installations	$54,658
MAJOR TOOLS AND SAFETY EQUIPMENT	
Tools - Line	$53,333
Tools - Meter	$11,429
Tools - P&C	$28,571
VEHICLES	
Vehicles	$384,762
Grand Total	**2,289,049**

4.3-Staff-33

Ref: Exhibit 2/Appendix A- Distribution System Plan/Appendix 1 Asset Management Process

Distribution Meters

Under Project Number 14-61, Distribution Meters, Oakville Hydro intends to spend $481,706 in 2014 on meter replacements. In addition, Oakville Hydro also indicates that the meters will be equipped with ‘zigbee’ to facilitate ‘real-time’ data access and ‘behind the meter’ services.

a) Considering that Oakville Hydro has just replaced the bulk of distribution meters with new TOU metering, why is such an extensive meter replacement program needed in 2014?

RESPONSE:

Project 14-61 description should have read “$481,706 for new meter installations”. These costs are primarily for installation of new meters on new residential and commercial services and a new Tower Gateway Base station to support smart meter data collection. Oakville Hydro is not planning an extensive meter replacement program in the 2014 Test Year.

b) What is the incremental cost of including ‘zigbee’ capabilities in these meters?

RESPONSE:

The incremental cost of Zigbee capability in these meters is approximately $15,000.

4.3-Staff-34

Ref: Exhibit 2/Tab5/Schedule 2/p.3 Table 2-31

Pacing and Distribution Rate Impacts

When considering Table 2-31, it appears that the applicant’s annual capital spending since the last COS year (2010) has generally been higher (even when normalized) than the approved amount for 2010 and on a non-normalized basis, much higher in specific years.

a) In its annual capital planning and implementation for the years 2011 to 2014 did Oakville Hydro take into account the cumulative impact of its capital expenditures on rates in 2014?

RESPONSE:

Capital spending in the period 2011 – 2014, as noted, has been impacted by several additional system access projects, as well as mandatory road widening projects, not originally anticipated in its COS year (2010), and by their nature outside of Oakville Hydro's control. In each of these years, Oakville Hydro prioritized its capital investments, with the intent in mind to minimize the changes from its initial forecasts. In setting its five year capital program (2014 - 2018), Oakville Hydro's goal was to lower its annual capital investment pace, keeping in mind the requirements driven by asset renewal and mandatory requirements.

b) Did any changes ensue from these considerations?

RESPONSE:

Oakville Hydro consciously reduced its capital investment pace in the period 2014 - 2018, aware of the impacts on customer rates but mindful of the distribution system needs and external requirements. In 2014, the on-site, emergency backup transformer at Glenorchy Municipal Transformer Station is the only significant investment that needed to be added that had an impact on this strategy.

4.3-SEC-19

Ref: Ex.2/5/2/p.63

Please provide an update on the in-service status of all 2013 capital projects.

RESPONSE:

Oakville Hydro has updated its 2013 and 2014 continuity schedules to reflect the 2013 projects that closed to rate base in 2013 and the 2013 projects that will close to rate base in 2014. Please refer to 7.1-EP-29 for the updated continuity schedules.

4.3-SEC-20

Ref: Ex.2/5/2p.68

With regards to the 'air-insulted switchgear' project, what is the full cost of this multi-year program? Please provide a breakdown by year.

RESPONSE:

As discussed in page 43 of Appendix 1 of Oakville Hydro's Oakville Hydro's Distribution System Plan in the section entitled "Asset Management Objectives", this multi-year program, which was initiated about 8 years ago, coincides with the proactive asset replacement of Pad Mounted Air Insulated Switchgear (AIS). Three AIS will be replaced with Gas Insulated Switchgear (GIS) each year on the 27.6kV distribution grid as part of the proactive replacement program. Compared to the 27.6kV grid, the AIS installed in the lower voltage grids (13.8kV and 4.16kV) have not experienced the same failure levels due to salt spray, and will be replaced "Like for Like" within this program. The information shown on page 43 is a combination of both replacements.

The proposed cost annual to replace pad mounted AIS with GIS is as follows:

Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Units	3	3	3	3	3	3	3	3	3	3
Cost*	$379	$387	$395	$403	$411	$419	$427	$436	$444	$453

Year	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Units	3	3	4	4	4	4	4	4	4	4
Cost*	$462	$472	$641	$654	$667	$681	$694	$708	$722	$737

*In Thousands

4.3-SEC-21

Ref: Ex.2/Appendix/p.31

Please explain why the Applicant believes its proposed Test Year capital expenditures are appropriately paced to result in reasonable rates, considering there is a significant increase in spending in the Test Year compared to the bridge year and a significant decrease in 2015-2018.

RESPONSE:

See Response 4.3-Staff-34.

4.3-SEC-22

Please revise the following tables to include 2013 year-end actuals and explain any material variances. (If 2013 actual data is not yet available, please provide the most recent year-to-date actuals available, along with a forecast for the remaining period in 2013):

a) Appendix 2-AA

RESPONSE:

Table 2–AA has revised to include the 2013 year-end actuals (unaudited). The material variances are explained in the following paragraphs.

System Renewal - Replace/Rebuild Rear Lot Distribution

This was a very large project with an estimated projected completion time of approximately six months including the coordination of resources of two major contractors.

Variances in costs are explained by several factors:

Additional costs were required for legal costs, easement confirmation, field surveying and staking out of the existing easements for construction purposes. Additional costs, more than previously anticipated, were required for line clearing (vegetation). Difficult access to rear yards increased the actual costs of this work. Throughout the duration of the project, weather conditions at times affected the productivity of work (snow and lots of rain and muddy conditions in the backyards slowed down pole installations).

Due to the fact that the existing poles were found shorter than records indicated (existing poles were owned by Bell, Oakville Hydro was a tenant), working clearance was insufficient and adjustments to the new installation (bus attachment heights) were required. This required additional tree trimming to be completed in order to maintain the line clearance, and safe working clearances. This required additional time for our overhead contractor to work under these conditions.

There were several design changes required during construction due to customer input, field obstructions and the proximity of other utilities. Significant additional cost for the underground work was due to the unforeseen conditions for directional boring for underground secondary bus installation to the rear lot poles. Multiple site excavations were required due to other utilities being within 1 metre of proposed installations, with limited clearance. Many obstructions were encountered including current landscaping, customer fencing and other building additions over existing easements. Extensive use of costly hydro vacuuming techniques was required to deal with these issues, to complete the project safely.

System Renewal - Holten Heights Secondary Rebuild

This project includes two sections of the distribution system located at Grand Blvd and Forest Glade, and includes reconstruction of the overhead distribution system as well as reconstruction of the secondary distribution system in 7 distinct districts. In 2013, the rebuild of the overhead system was completed and two of the seven secondary districts. The remaining work has been deferred for construction in 2014 due to underground resource availability. Underground resources were deployed to emergency replacements and additional capital work that was required to be completed in 2013.

System Renewal - Replace Underground Assets on McCraney St

This project was an emergency rebuild initiated in late fall 2012, due to multiple failures of primary cables in the McCraney Area. The multiple failures and instability that resulted increased concerns that a safe and reliable system could not be maintained in this area. Design and planning was completed in 2012 with the intention to complete the work late in 2012. The project commenced in 2012, and was completed in 2013.

System Renewal - Replace Underground Assets on Speers Rd (Kerr to Cross)

The underground primary cables and transformers in this area are approximately 40 years old and represent one of the oldest underground cable systems in Oakville Hydro's distribution territory. The phasing out of vault style transformers and NX fuses is Oakville Hydro's plan over time due to operational, access, and safety concerns.

The construction of this project has been deferred to 2014 due to other priorities in 2013 (emergency replacements) as well as planning and design complexities. Various alternative designs are being explored as a solution for this project, including the use of cable injection to extend the life of the cable, at a cost savings as compared to replacement. Various high voltage switching options are also being considered to improve safety, operations and maintenance.

General Plant - Hybrid Aerial Device

The vehicle delivery has been delayed because of the manufacturer’s work schedule.

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2013 Actual	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP	MCGAAP	MCGAAP
System Access	**4,139,081**	**5,746,031**	**3,306,569**	**29,059,361**	**2,978,136**	**3,793,912**	**3,642,004**	**2,197,868**
27.6 kV Additions								
27.6kV Additions TBD	0	0	0	0	0	0		420,973
Additional CCT	394,758	524,026	418,821	0	0	0		0
Glenorchy Feeders	0	0	0	3,555,771	348,925	0		0
Glenorchy North Oakville TS	0	0	50,000	22,860,578	159,348	61,115		0
Hospital Feeder Construction	0	0	0	0	0	807,547	866,495	0
Milton Feeder Construction from Glenorchy	0	0	0	0	0	464,620	548,747	0
Winston Churchill Blvd.	0	290,464	12,075	0	213,732	0		0
Sub-Total	**394,758**	**814,489**	**480,896**	**26,416,349**	**722,005**	**1,333,282**	**1,415,242**	**420,973**
Meters								
Multi-Residential to Individual Metering	0	815,150	378,596	0	0	0		0
Distribution Meters	528,632	771,085	235,431	213,136	673,701	362,879	373,110	481,706
Wholesale Metering	0	0	257,900	0	0	0		0
Sub-Total	**528,632**	**1,586,235**	**871,927**	**213,136**	**673,701**	**362,879**	**373,110**	**481,706**
New Development and Services								
Sub-Total	**2,800,568**	**2,924,906**	**1,346,001**	**1,558,676**	**1,043,129**	**1,102,130**	**948,200**	**1,016,068**
Road Widening - no OH Control								
Bronte Rd/QEW Relocations	51,272	266,413	0	9,965	0	0		0
Dundas St Widening, Old Bronte Rd. to Proudfoot Trail	0	0	0	0	0	455,300	433,880	0
Dundas St Widening, Stages 2 & 3	0	0	0	314,089	247,424	2,002	5,436	0
Neyagawa Rd Widening, Dundas St. to Burnhamthorpe Rd	0	0	0	0	0	538,319	466,136	0
Rebuild for Road Widening - Miscellaneous	138,260	135,840	607,745	547,146	3,039	0		279,121
Region Bridge Construction - Dundas/16 Mile	225,590	18,148	0	0	0	0		0
Road Widening - 9th Line	0	0	0	0	288,837	0		0
Sub-Total	**415,122**	**420,401**	**607,745**	**871,200**	**539,300**	**995,621**	**905,452**	**279,121**
System Renewal	**8,001,659**	**12,528,628**	**10,672,496**	**6,303,077**	**7,277,448**	**4,875,942**	**5,720,375**	**4,713,776**
Load Transfer and System Security								
27.6Kv Air Insulated Switchgear Upgrade	0	0	0	0	280,842	323,671	305,276	379,340
Transformer Top Replacements	240,458	96,058	225,268	95,973	155,797	0		0
Gang-Operated Switch Replacement	0	0	0	0	0	0		267,139
Underslung Switch Replacement	0	0	0	0	417,440	-52,313	8,196	66,974
Sub-Total	**240,458**	**96,058**	**225,268**	**95,973**	**854,080**	**271,358**	**313,472**	**713,452**
O/H Rebuilds								
600 Amp, 13.8kV Switch Replacement	0	0	36,944	183,206	0	0		0
Concrete Poles	0	0	0	617,409	42,664	0		0
Pole Replacements	1,083,322	1,544,348	824,830	767,177	387,696	117,422	187,263	68,744
Rebuild 4.16kV System	0	0	610,751	468,900	0	0		0
Rebuild 4kV System	547,480	2,461,988	1,531,971	382,340	485,531	0		0
Rebuild Overhead Distribution System - Various Area	1,290,315	10,647	343,561	338,682	255,135	151,977	132,009	566,189
Reinsulation	422,727	523,814	469,501	302,568	0	0		0
Replace O/H Assets on Robinson Street	0	0	0	0	0	0		458,981
Replace/Rebuild Rear Lot Distribution	1,243,098	3,275,048	1,086,708	498,909	1,276,059	1,558,346	2,324,088	0
Sub-Total	**4,586,943**	**7,815,845**	**4,904,266**	**3,559,192**	**2,447,085**	**1,827,745**	**2,643,360**	**1,093,914**
Substations								
Arkendo MS - Construct New Substation	0	2,010,806	628	0	0	0		0
Margaret MS - Replace Transformer	0	278,445	0	0	0	0		0
MS Low Voltage Breaker Replacement Program	0	0	0	0	0	287,126	372,180	547,715
Munns MS Breaker and Switchgear Replacement	0	0	0	0	591,398	-5,876		0
Power Transformer Replacement Program	0	0	0	0	0	257,334	186,553	268,190
Substation Air Breaker Retrofits	0	0	407,411	0	0	0		0
Substation Equipment Refurbishment/Upgrades	243,825	69,349	212,387	172,254	52,220	165,931		114,073
Substation Oil Breaker Retrofits	0	679,383	352,639	0	0	0		0
Sunset MS - Replace Transformer	0	0	0	304,713	0	0		0
Sub-Total	**243,825**	**3,037,983**	**973,067**	**476,967**	**643,618**	**704,515**	**558,733**	**929,978**
Supervisory								
Replace/Upgrade Line Switch RTUs	110,587	163,002	191,482	117,629	269,235	105,869	108,977	105,815
Sub-Total	**110,587**	**163,002**	**191,482**	**117,629**	**269,235**	**105,869**	**108,977**	**105,815**
Transformer Replacements and Voltage Conversion								
Allan MS - Eliminate Station	0	0	0	237,298	22,442	105,132	92,783	0
Delta Transformer Replacements	0	0	0	0	197,865	96,304	45,632	172,171
Howard Ave / Park Ave	0	0	238,587	0	0	0		0
Live Front Padmount Transformer Replacements	0	0	0	0	0	0		275,730
South of Lakeshore Rd	818,885	0	0	0	0	0		0
Unallocated Transformers (Spare)	-47,415	-150,862	598,177	0	277,018	0		0
Underground/Overhead Transformers (2013 Project)	246,942	226,555	334,898	80,602	476,538	136,759	280,614	118,430
Underground/Overhead Transformers (2012 Project)							48,336	
Woodhaven Park Area Rearlot Zone 2	0	0	424,435	0	0	0		0
Sub-Total	**1,018,411**	**75,693**	**1,596,097**	**317,900**	**973,862**	**338,196**	**467,365**	**566,332**

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2013 Actual	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MCGAAP**	**MCGAAP**	**MCGAAP**
Rebuild Underground Distribution System								
Holten Heights Area Secondary Rebuild (2013 Project)	0	0	0	562,928	944,742	626,940	346,958	0
Holten Heights Area Secondary Rebuild (2012 Project)							6,474	
Emergency Underground Replacement								
McCraney Area - Primary Rebuild	0	0	470,370	0	0	0		0
Replace Underground Assets on McCraney (2012 Project)							494,477	
Rebuild Underground Distribution System - Misc	309,734	382,302	127,782	835	184,431	3,764		0
Replace Poletrans on Shanley Ter and Patricia Dr	814,758	0	1,241,094	122,336	738,691	274,159	380,113	292,164
Replace Poletrans on Falgarwood Dr						164,530	294,210	
Replace U/G Assets on Colchester, Oakhill, Dolphin and Albion	0	0	0	0	0	0		385,205
Replace U/G Assets on Speers Rd (Kerr to Cross)	0	0	0	0	0	411,117		0
Replace U/G Assets on Willowbrook Dr and Wendy Ln	0	0	0	0	0	0		184,665
Retrofit PMH Switchgear	382,286	438,621	844,647	548,250	31,678	0		0
Splice Replacement Program	0	249,901	0	0	0	0		0
Spring Garden Drive Primary Rebuild	0	0	0	203,417	0	0		0
Switchgear Refurbishment Program	294,656	269,222	98,424	0	0	0		0
Transformer Bushing Insert/Elbow Replacements	0	0	0	297,650	190,027	147,747	106,234	126,011
Vault Transformer Removals	0	0	0	0	0	0		316,241
Sub-Total	**1,801,434**	**1,340,046**	**2,782,317**	**1,735,416**	**2,089,569**	**1,628,258**	**1,628,467**	**1,304,285**
System Service	**41,151**	**1,214,229**	**670,956**	**791,555**	**11,217,808**	**40,000**	**24,699**	**5,300,000**
27.6kV Additions								
Remote Controlled Switch Installations	39,176	91,298	265,218	576,784	322,926	0		0
Switching Improvements - Winston Park	1,976	0	405,739	24,576	0	0		0
Sub-Total	**41,151**	**91,298**	**670,956**	**601,360**	**322,926**	**0**	**0**	**0**
IT Capital								
Field Communications	0	0	0	135,924	190,630	0		0
SCADA and OMS	0	815,417	0	0	585,298	40,000	24,699	300,000
Sub-Total	**0**	**815,417**	**0**	**135,924**	**775,928**	**40,000**	**24,699**	**300,000**
AMI - Smart Metering Rollout								
Sub-Total	**0**	**0**	**0**	**54,271**	**10,118,954**	**0**		**0**
Substations								
Spare Substation Transformer	0	307,514	0	0	0	0		0
Sub-Total	**0**	**307,514**	**0**	**0**	**0**	**0**	**0**	**0**
Emergency Back-up Transformer for Glenorchy MTS								
Sub-Total	**0**	**0**	**0**	**0**	**0**	**0**		**5,000,000**
General Plant	**1,573,504**	**1,724,946**	**903,344**	**2,734,558**	**1,549,972**	**1,906,172**	**1,356,778**	**2,106,734**
Administration - IT								
Asset Management	0	0	0	0	262,610	110,000	62,725	100,000
Blink IRU	0	0	0	0	0	0		738,210
Customer Service	76,539	8,761	0	0	67,014	110,000		210,000
ERP	745,265	124,110	149,382	194,074	78,195	342,500	175,228	203,000
GIS	70,927	0	126,728	728,642	188,862	260,858	95,574	150,000
Infrastructure	149,185	254,878	554,294	382,619	215,256	515,549	612,366	420,000
Organizational Effectiveness	0	0	0	188,220	0	40,570	216,927	76,000
Sub-Total	**1,041,915**	**387,749**	**830,404**	**1,493,556**	**811,937**	**1,379,477**	**1,162,820**	**1,897,210**
Administration - Building								
HVAC Replacement	0	0	72,940	92,180	0	0		209,524
Peak Demand Reduction	0	899,982	0	0	0	0		0
Re-Roofing, renovations and furniture	0	0	0	851,368	0	0		0
Sub-Total	**0**	**899,982**	**72,940**	**943,548**	**0**	**0**	**0**	**209,524**
Vehicles								
Replace 38ft Single Bucket Hybrid	0	0	0	0	0	187,648	193,958	0
Replace Derrick Digger(s)	370,619	0	0	297,454	0	0		0
Replace Double Bucket Truck (s)	0	437,215	0	0	449,337	0		0
Replace Single Bucket Truck (s)	160,970	0	0	0	288,697	0		0
Hybrid Aerial Device	0	0	0	0	0	339,048		0
Sub-Total	**531,589**	**437,215**	**0**	**297,454**	**738,034**	**526,695**	**193,958**	**0**
Miscellaneous	1,575,580	1,553,366	1,061,946	1,157,890	973,109	1,078,722	985,134	2,289,049
Total	**15,330,975**	**22,767,200**	**16,615,311**	**40,046,440**	**23,996,472**	**11,694,747**	**11,728,990**	**16,607,427**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*								
Total	**15,330,975**	**22,767,200**	**16,615,311**	**40,046,440**	**23,996,472**	**11,694,747**	**11,728,990**	**16,607,427**

b) Appendix 2-AB

RESPONSE:

Oakville Hydro has revised the Appendix 2-AB to include 2013 year-end actuals (unaudited) and corrected the typographical error Oakville Hydro had made in the 2013 plan.

The following is the explanations of the material variances.

Oakville Hydro had overspent $911K under System Renewal category primarily due to the projects mentioned in answer (a) above. The explanations of the material variances for these projects, please refer to the answer (a) above.

Oakville Hydro had underspend $548K under General Plant due to the following two projects:

- The delivery of Hybrid Aerial Device ($339K) has delayed because of the manufacturer's work schedule.
- Oakville Hydro has deferred some small IT projects ($217K) that planned in 2013.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		$ 5,782	--		$ 3,307	--		$ 29,215	--		$ 3,090	--	$ 3,822	$ 3,670	-4.0%	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal		13,001	--		11,146	--		6,939	--		7,571	--	5,535	6,446	16.5%	5,980	5,436	5,505	5,599	5,599
System Service		1,449	--		916	--		838	--		11,351	--	201	25	-87.7%	5,589	559	581	605	629
General Plant		2,535	--		1,247	--		3,055	--		1,984	--	2,137	1,588	-25.7%	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,695	11,729	0.3%	16,607	10,251	11,401	10,752	10,931
System O&M	n/a	$ 5,852	--	$ 6,135	$ 5,568	-9.2%	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,794	$ 10,943	1.4%	$11,108	n/a	n/a	n/a	n/a

We correct this number

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	-	$ 4,967	--	2,372	$ 3,307	39.4%	-	$ 6,354	--	-	$ 2,931	--	$ 3,822	$ 3,670	-4.0%	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal	-	13,001	--	8,662	11,146	28.7%	-	6,939	--	-	7,571	--	5,535	6,446	16.5%	5,980	5,436	5,505	5,599	5,599
System Service	-	1,449	--	781	916	17.2%	-	783	--	-	1,232	--	201	25	-87.7%	589	559	581	605	629
General Plant	-	1,635	--	2,906	1,247	-57.1%	-	3,055	--	-	1,984	--	2,137	1,588	-25.7%	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,695	11,729	0.3%	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-		5,000	-	-	-	-
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-		-	-	-	-	-
New Customer Information System	-	-		-	-		-	-		-	-		-	-		-	-	486	-	-
Remaining 3rd Tranche CDM Activities	-	1,715		-	-		-	-		-	-		-	-		-	-	-	-	-
3rd Party IRU	-	-		-	-		-	-		-	-		-	-		738	-	-	-	-
TOTAL EXPENDITURE	$ 18,232	$ 22,767	24.9%	$ 14,721	$ 16,615	12.9%	$ 29,024	$ 40,046	38.0%	$ 13,562	$ 23,996	76.9%	$ 11,695	$ 11,729	0.3%	$16,607	$10,251	$11,401	$10,752	$ 10,931

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 5

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. histrical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

c) Appendix 2-BA

RESPONSE:

Oakville Hydro updated Appendix 2-BA to reflect 2013 actuals (unaudited). The material capital variances in accounts 1830 and 1835 are due to the Replace/Rebuild Rear Lot Distribution project discussed in response to part a) of this interrogatory. There is a material capital variance in account 1855 as the expenses for Oakville Hydro's "New Services" projects were fully funded through capital contributions therefore the expenses were recorded in account 1855 and the capital contributions were recorded in account 1995. The material capital variance in account 1930 – Vehicles is as a result of the delay in the acquisition of the Hybrid Aerial Device discussed in response to part a) of this interrogatory.

Appendix 2-BA (Excluding WIP)

Fixed Asset Continuity Schedule - CGAAP

Year **2013** **OLD CGAAP**

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$5,286,592	$45,060	$0	$5,331,652	($4,395,627)	($300,589)	$0	($4,696,216)	$635,435
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	1,722,054	0	0	1,722,054	0	0	0	0	1,722,054
47	1808	Buildings	829,700	0	0	829,700	-265,544	-101,230	0	-366,775	462,925
13	1810	Leasehold Improvements	3,505,475	20,756	0	3,526,231	-1,190,359	-351,586	0	-1,541,945	1,984,286
47	1815	Transformer Station Equipment >50 kV	21,602,201	40,982	0	21,643,184	-647,283	-137,448	0	-784,732	20,858,452
47	1820	Distribution Station Equipment <50 kV	7,310,742	587,835	0	7,898,578	-2,558,874	-543,535	0	-3,102,409	4,796,169
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	22,547,385	2,414,045	0	24,961,430	-5,959,170	-900,996	0	-6,860,166	18,101,264
47	1835	Overhead Conductors & Devices	31,791,864	1,873,789	0	33,665,652	-12,148,124	-1,326,179	0	-13,474,302	20,191,350
47	1840	Underground Conduit	60,446,766	3,488,226	0	63,934,992	-26,455,432	-2,651,053	0	-29,106,485	34,828,507
47	1845	Underground Conductors & Devices	46,080,876	4,149,767	0	50,230,643	-17,990,209	-2,004,107	0	-19,994,315	30,236,327
47	1850	Line Transformers	44,916,673	1,698,078	0	46,614,752	-20,215,405	-1,930,295	0	-22,145,701	24,469,051
47	1855	Services (Overhead & Underground)	9,684,898	1,411,111	0	11,096,009	-1,480,039	-415,618	0	-1,895,658	9,200,352
47	1860	Meters	1,901,542	488,444	0	2,389,986	-319,510	96,631	0	-222,879	2,167,107
47	1860	Meters (Smart Meters)	11,033,523		0	11,033,523	-1,858,374	-441,339	0	-2,299,713	8,733,810
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	872,187	40,257	0	912,444	-750,494	-25,878	0	-776,372	136,073
8	1915	Office Furniture & Equipment (5 years)	0		0	0	0		0	0	0
10	1920	Computer Equipment - Hardware	0		0	0	0		0	0	0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0		0	0	0		0	0	0
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	7,371,011	1,226,436	0	8,597,447	-5,994,187	-1,039,424	0	-7,033,612	1,563,836
10	1930	Transportation Equipment	4,488,353	259,738	-222,595	4,525,496	-2,439,959	-545,784	220,600	-2,765,142	1,760,354
8	1935	Stores Equipment	166,334	0	0	166,334	-150,679	-2,133	0	-152,812	13,521
8	1940	Tools, Shop & Garage Equipment	1,279,206	63,999	0	1,343,205	-866,772	-96,021	0	-962,793	380,412
8	1945	Measurement & Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	8,098	0	0	8,098	-3,248	-810	0	-4,058	4,040
47	1970	Load Management Controls Customer Premises	171,648	0	0	171,648	-171,648	0	0	-171,648	0
47	1975	Load Management Controls Utility Premises	49,876	0	0	49,876	-49,876	0	0	-49,876	0
47	1980	System Supervisor Equipment	4,486,620	270,400	0	4,757,019	-2,381,175	-283,366	0	-2,664,541	2,092,478
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	-41,494,285	-3,902,433	0	-45,396,718	9,836,144	1,737,820	0	11,573,964	-33,822,753
	2005	Property Under Capital Lease	11,689,385	0	0	11,689,385	-7,579,335	-246,286	0	-7,825,621	3,863,763
						0				0	0
		Sub-Total	**$257,748,723**	**$14,176,491**	**($222,595)**	**$271,702,619**	**($106,035,180)**	**($11,509,227)**	**$220,600**	**($117,323,806)**	**$154,378,813**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				0				0	0
		Total PP&E	**$257,748,723**	**$14,176,491**	**($222,595)**	**$271,702,619**	**($106,035,180)**	**($11,509,227)**	**$220,600**	**($117,323,806)**	**$154,378,813**

4.3-AMPCO-20

Ref: Exhibit 2, Tab 1, Schedule 2, Page 1

Preamble: In 2010, Oakville Hydro capitalized $16,615,311 or $1,894,084 more than planned.

a) Please identify the additional expenditures that were discretionary in nature.

RESPONSE:

Please see Oakville Hydro's response to Energy Probe interrogatory number 1.1-EP-1

4.3-AMPCO-21

Ref: Exhibit 2, Tab 5, Schedule 2, Page 7, Table 2-32

a) Please update Table 2-32 to include 2013 actual capital additions.

RESPONSE:

Oakville Hydro has updated Table 2-32 to include 2013 actual (unaudited) capital additions. Please see the table below for details.

Table 2-32: Capital Additions by Major Project by Year

Major Project	2010 Board-Approved	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	2013 Actuals New CGAAP	2014 Test Year New CGAAP
27.6kV Additions	$400,000	$480,896	$26,416,349	$722,005	$1,879,441	$1,333,282	$1,615,242	$420,973
Distribution Meters / Wholesale Meter Upgrades	732,398	871,927	213,136	673,701	479,202	362,879	374,919	481,706
New Development / Services	1,075,016	1,346,001	1,558,676	1,043,129	1,412,561	1,102,130	3,950,285	1,016,068
Road Widening (Dependent on Road Work - No Hydro Control)	165,000	607,745	1,026,475	651,136	1,543,453	1,023,557	1,085,820	403,115
System Access	**2,372,414**	**3,306,569**	**29,214,636**	**3,089,972**	**5,314,658**	**3,821,848**	**7,026,266**	**2,321,862**
Alterations and Improvements for Load Transfer and System Security	292,959	344,096	219,750	888,426	572,150	471,194	500,693	1,028,655
Rebuild Overhead Distribution System	4,843,049	5,037,728	3,825,171	2,454,789	2,466,663	1,874,389	2,643,360	1,118,877
Rebuild Underground Distribution System	1,409,133	2,871,729	1,804,143	2,245,090	2,299,891	1,714,853	1,833,261	2,017,232
Substations	732,398	1,104,439	476,967	643,618	930,273	782,606	679,369	1,016,763
Supervisory Control and Communications	244,133	191,859	117,629	272,846	144,088	105,869	112,626	231,887
Transformer Replacements and Voltage Conversion	1,139,908	1,596,097	495,203	1,066,708	821,381	585,917	675,612	566,332
System Renewal	**8,661,580**	**11,145,948**	**6,938,864**	**7,571,478**	**7,234,446**	**5,534,829**	**6,444,921**	**5,979,745**
27.6kV Additions	732,398	796,263	601,360	322,926				
Administration - IT			135,924	775,928	45,000	45,000	24,699	452,000
Distribution Meters / Wholesale Meter Upgrades			98,360	10,118,954	77,000	77,000		
Rebuild Overhead Distribution System								100,000
Substations		67,485						
Supervisory Control and Communications	48,827	51,988	1,899	94,880	108,214	79,443		36,899
On-Site Emergency Back-up Transformer								5,000,000
System Service	**781,224**	**915,736**	**837,543**	**11,312,688**	**230,214**	**201,443**	**24,699**	**5,588,899**
Administration - Buildings	314,443	247,516	1,080,051	261,256	72,500	66,046	61,012	341,615
Administration - IT	2,132,597	830,404	1,493,556	811,937	1,403,474	1,379,477	1,207,880	1,897,210
Major Tools and Safety Equipment	126,949	129,233	13,684	109,329	115,439	107,902	87,147	93,333
Fleet	332,020	39,905	468,107	839,811	638,008	583,203	232,281	384,762
General Plant	**2,906,009**	**1,247,058**	**3,055,398**	**2,022,334**	**2,229,421**	**2,136,627**	**1,588,321**	**2,716,920**
Grand Total	**$14,721,227**	**$16,615,311**	**$40,046,440**	**$23,996,472**	**$15,008,738**	**$11,694,747**	**$15,084,207**	**$16,607,427**
Increase/(Decrease) vs Prior Year		**$1,894,084**	**$23,431,129**	**-$16,049,968**	**-$8,987,735**	**-$3,313,991**	**$3,389,460**	**$1,523,220**

4.3-AMPCO-22

Ref: Exhibit 2, Tab 5, Schedule 2

a) Page 7 – In 2010, please confirm the need to add a transformer replacement and voltage conversion in the Woodhaven Park for $422,435.

RESPONSE:

Oakville Hydro also added a transformer replacement and voltage conversion project to the 2010 capital program. Although this project had not been budgeted, conditions were such that the replacement was required in 2010. The project was associated with other work that was carried out in 2009. This portion of the larger project was deferred from 2009 to 2010 due to project scheduling and scope changes required due to field conditions.

b) Page 9 – In 2011, please explain the need for the higher spending of $601,914 on the continued conversion of GIS.

RESPONSE:

The GIS conversion project was a multi-phased project that took several years to complete. Oakville Hydro did not incur additional spending on this project in 2011. The increased capital additions in 2011 was due to previously budgeted work that was deferred from 2010 and closed to rate base in 2011. The total spending on the GIS conversion project was lower than planned, however, due to the nature of the project, it was not complete and closed to rate base until 2011.

Appendix 4 – A

Collective Agreement

This Agreement made this First day of July, 2013

BETWEEN

OAKVILLE HYDRO ELECTRICITY
DISTRIBUTION INC.

hereinafter referred to as "OHEDI"

and

LOCAL 636 OF THE INTERNATIONAL
BROTHERHOOD OF ELECTRICAL WORKERS

hereinafter referred to as "the Union"

THIS AGREEMENT WITNESSETH:

This Agreement made this First day of July, 2013

BETWEEN

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

hereinafter referred to as "OHEDI"

and

LOCAL 636 OF THE INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

hereinafter referred to as "the Union"

THIS AGREEMENT WITNESSETH:

ARTICLE 1.

RECOGNITION

1.01 OHEDI recognizes the Union as the exclusive bargaining agency for negotiating working conditions, hours of work and wages for, and this Agreement applies to, employees in the bargaining unit defined as "all employees of OHEDI engaged in production, supply and distribution of electrical energy, all office employees, in the Municipality of the Town of Oakville save and except all Management, Professional and Supervisory staff and students. Office employees are hereafter referred to as "salaried employees", all other employees are hereafter referred to as "hourly rated employees". Words importing the masculine gender shall include the feminine.

1.02 The Union and OHEDI recognize that they have a duty to the public to maintain the continuous operation of both plant and services and therefore both undertake to assist each other in the discharge of that obligation.

1.03 OHEDI agrees that it will not contract work out which will result directly in lay-off or demotion of any employees regularly employed in the bargaining unit. OHEDI further agrees that any Management, Professional and Supervisory member of staff, with the exception of students, who is excluded from the bargaining unit shall not normally perform any work covered by the classification in this Agreement except in the case of emergency, instruction, or temporary work overload.

1.04 OHEDI and the Union shall both participate in a joint Union - Management Productivity Committee. This Committee shall consist of four Union delegates, three Management delegates, plus the President/CEO as Chair. These delegates will work conscientiously and innovatively to a program of increasing the productivity of OHEDI's forces.

1.05 OHEDI will recognize a negotiating committee of not more than four (4) employees to represent the Union in meetings with OHEDI in negotiation of this Agreement. OHEDI will pay the employees for any normal working time lost at such meetings, up to four (4) days maximum per employee. The Union negotiating committee shall be accompanied by the local Union Business Representative and/or a representative of the International Brotherhood of Electrical Workers at any negotiation meeting.

ARTICLE 2.

RESPONSIBILITIES

2.01 It is understood and agreed that because OHEDI is engaged in the operation of giving service to its customers, OHEDI may fully and freely temporarily move its employees from one job classification to another job classification to cope with and meet the demands of its customers in an emergency. Such temporary movement of employees shall be made without change in the rates of pay applicable to such employees so moved.

2.02 The management and operation of OHEDI's plant and services, the direction, supervision and control of all operations and all working forces, except as specifically set forth otherwise in this Agreement, shall remain vested in OHEDI.

2.03 OHEDI agrees that these functions will be exercised in a manner consistent with the terms of this Agreement and a claim that these functions have not been so exercised may be the subject of a grievance.

2.04 An employee who claims that he has been unjustly disciplined or discharged may file a grievance at Stage 2 of the Grievance Procedure.

2.05 In view of the orderly procedure hereafter established by this Agreement for the settling of disputes and handling of grievances, the Union agrees that during the life of this Agreement there will be no strike, slow down, stoppage of work or production, and OHEDI agrees that there will be no lockout of its employees to the date of termination hereof.

2.06 OHEDI will not interfere with the right of the employees to join the Union or engage in Union activities, and the Union agrees that such activities will not be carried on in OHEDI's plant or property or on OHEDI's time or in such a manner as to interfere with the efficient operation of OHEDI, except as hereinafter provided. OHEDI will not discriminate against, interfere with, restrain or coerce any employee (including temporary employees) because of membership in or activities on behalf of the Union. Union Stewards, with the approval of their immediate supervisor, shall be permitted during their regular working hours, without loss of time or pay, to investigate a grievance in their respective jurisdiction, provided the Steward first obtains the approval of his immediate supervisor which shall not be unreasonably withheld and the Steward reports back on completion of his investigation.

2.07 Union officers may request leave of absence for time off to attend Union functions. OHEDI agrees that leave of absence for such purpose, not to exceed twenty (20) days in total per year, shall not be unreasonably withheld.

ARTICLE 3.

UNION SECURITY

3.01 OHEDI agrees to deduct an amount equivalent to the regular monthly Union dues as certified in writing by the Business Manager/Financial Secretary, including any changes, from the pay as per Section 47 of the Labour Relations Act of Ontario. An employee shall, upon commencement of employment, sign a written authorization for the deduction of an amount equivalent to the regular Union dues as certified by the Union. With respect to new employees, an additional amount shall be deducted equivalent to the Union initiation fee. The amounts so deducted shall be forwarded to the Business Manager/Financial Secretary so that they are received by the Union no later than the tenth (10th) day of the month following the month in respect of which the dues are deducted. They shall be accompanied by an alphabetical listing of the names of each employee and their current address on behalf of whom the deductions were made, the amount deducted on behalf of each employee, and information upon which such deductions were calculated. Also included will be a list of names and addresses of employees who have left the employment of OHEDI, since the last payment. This section shall include temporary employees, if they work five (5) or more days in a calendar month. In consideration of this deduction and forwarding service by OHEDI, the Union agrees to indemnify and save OHEDI harmless against any claim or liability arising out of or resulting from the collection and forwarding of these regular monthly dues.

ARTICLE 4.

GRIEVANCE PROCEDURE

4.01

a) OHEDI will recognize a Grievance Committee of up to three (3) members selected by the Union from the employees, plus the Unit Chairperson. In addition the Local Union Business Representative of the International Brotherhood of Electrical Workers may be a member. The Union will present OHEDI a list of the Committee members indicating the Chairperson.

b) For the purposes of this Agreement any matter relating to the interpretation, application or administration of this Agreement, including any question as to whether a matter is arbitrable or where an allegation is made that this Agreement has been violated by either party, shall be considered a fit matter for a grievance. Both OHEDI and the Union shall also have the right to expect fair treatment, each from the other, and an allegation that unfair treatment has been received shall also be considered grievable, and grievances shall be dealt with as specified below. The time limits for the processing of a grievance will be observed strictly by the parties, except in the case of mutual agreement to alter the time limits. All grievances referred to in this procedure will include a statement of the following, except as hereinafter provided:

   i the grievance,
   ii the part of the Agreement that is involved,
   iii the redress sought.

4.02 **Stage 1**:

Grievances will first be presented to the Supervisor immediately concerned. Grievances must be presented in writing within ten (10) working days of the occurrence which has given rise to the grievance, or of the time when the employee shall have been aware of the grievance. The griever has the right to the presence of a Union Steward or the Unit Chairperson at this stage.

Within four working days of the presentation of the grievance, the supervisor will discuss the matter with the aggrieved employee. The supervisor will render a decision within two working days of the discussion and, failing satisfactory settlement, the aggrieved employee will be allowed four working days of the decision in which to provide written notice to the Department Head of a desire to proceed to Stage 2.

Stage 2:

Within four working days of the receipt by the Department Head of the written notice, the Department Head will discuss the matter with the aggrieved employee and will render a decision within four working days of the discussion and, failing satisfactory settlement, the Grievance Committee will be allowed four working days in which to provide written notice to the President / CEO of a desire to proceed to Stage 3. At this Stage 2, a Steward or Grievance Committee member may be present.

Stage 3:

Within four working days of the receipt by the President / CEO of the written notice the President / CEO will discuss the matter with the Grievance Committee at which time the griever may be in attendance, and render a decision within five working days of the discussion. Failing satisfactory settlement, the Union will be allowed twenty working days of the decision to present written notice to the President / CEO of a desire to submit the matter to arbitration pursuant to Article V.

4.03 If OHEDI or the Union has any dispute or grievance concerning the interpretation or violation of this Agreement, it may submit the same in writing to the Grievance Committee or the President / CEO of OHEDI, as the case may be, at Stage 3 within ten full working days of the occurrence which has given rise to the dispute or grievance and if a satisfactory settlement is not made the matter may be referred to arbitration as provided in Article V.

4.04 No written entry of reprimand shall be entered into an employee's personal file, nor any disciplinary action taken, unless a prior discussion has been held with that employee at which time he shall have the right to be accompanied by the Union Steward.

Employees are able to view their personnel files, in accordance with the Freedom of Information and Protection of Privacy Act.

4.05 The Union shall be advised in writing of any written reprimand entered into an employee's file, or any disciplinary action taken.

4.06 All steps of the grievance procedure, including any meetings with a grievance mediation officer shall be held during regular hours of work with no loss of regular wages.

4.07 Written and verbal warnings will be removed and not referenced after twelve (12) months provided the employee's record has remained discipline free for twelve (12) months. Suspensions of one (1) day will be removed and not referenced from the employee's record after eighteen (18) months. Suspensions of greater than one (1) day will be removed and not referenced after twenty-four (24) months provided the employee's record has remained discipline free for twenty-four (24) months. The foregoing does not apply to any form of discipline related to health and safety (including Bill 168).

ARTICLE 5.

ARBITRATION

5.01

a) Except by mutual agreement, no matter which has not been properly carried through all previous steps of the grievance procedure may be submitted to arbitration, provided a demand in writing, listing the names of three (3) potential arbitrators, therefore is presented by either OHEDI or the Union, not later than twenty working days after the decision is rendered at Stage 3.

b) Within five (5) days thereafter, the party receiving the request will advise the other party of their concurrence with one of the submissions or failing agreement, further submit the names of three (3) other potential arbitrators.

c) If the parties are unable to come to an agreement on the selection of a single arbitrator, the party submitting the grievance to arbitration shall then make application to the Ontario Labour Relations Board and request that the Minister of Labour appoint a sole arbitrator.

5.02 A Single Arbitrator shall not have the power to add to or to subtract from, or change the provisions of the Collective Agreement, or to deal with any matter not covered by this Agreement.

5.03 The Union and OHEDI shall each pay one-half of the remuneration and expenses of the Single Arbitrator, and each shall bear the expenses for their own appointees to the Board and any other expenses incurred in presenting their case.

5.04 The legal decision of the Single Arbitrator appointed shall be accepted as final and binding on the parties of this Agreement and on any employee or employees affected.

5.05 Notwithstanding the above, the Union and the Company may mutually agree to reach settlement to a grievance through the services of a Grievance Settlement Officer or other mutually agreeable third party facilitator, including a Mediator/Arbitrator. The parties shall jointly bear the expenses of the Grievance Settlement Officer or other agreed to third party facilitator.

ARTICLE 6.

SENIORITY

6.01 "Seniority" is defined as the length of continuous service with OHEDI. The purpose of seniority is to provide a basis or policy of rights of preference as to lay-off, rehiring, promotion or transfer within the bargaining unit, leave of absence granted by OHEDI and vacation entitlement, covered by this Agreement.

6.02

a) Vacancies occurring in positions up to and including the first level of supervision beyond the bargaining unit and in all newly created positions falling within the bargaining unit shall be advertised to all employees not less than five working days before the deadline for applications. The Employer will periodically update the Union on the status or plans (and potential timing) for declaring a vacancy that is to be posted.

b) When the successful applicant has been selected the name of the successful applicant will be posted on the bulletin boards and a copy of this notice, together with a list of employees who applied for the job, shall be forwarded to the Unit Chairperson.

c) Newly hired employees or employees who have been transferred or promoted shall not be eligible for any other job opening unless such employee has completed six months in their present position.

d) In promotions, transfers and the filling of new positions, the following factors shall be of major importance:

   i seniority;
   ii qualifications, working knowledge, skill, demonstrated initiative and the ability to perform the work required in the day-to-day execution of the job concerned;
   iii potential for future promotion, if applicable;
   iv an established record of being fit for work.

   Where factors (ii), (iii) and (iv) are relatively equal in the judgment of the Management, which judgment shall not be exercised in an arbitrary or discriminatory manner, factor (i) shall govern.

e) Where deemed advisable by Management, a trial period of three months may be arranged. If not satisfactory, the employee shall revert to his former classification and rate of pay.

6.03 An approved seniority list will become part of this Agreement and will be maintained by OHEDI. Seniority shall date from the time the employee last entered the employ of OHEDI. The Union may obtain a copy of the list from OHEDI upon request.

6.04 It is understood and agreed that in the event of a lay-off, senior employees shall be entitled to transfer in lieu of lay-off to other jobs held by less senior employees, provided that:

a) they have the physical capacity;

b) they have the qualifications or are able to acquire the qualifications with a training period of twelve weeks [which OHEDI will not unreasonably refuse] to perform the job efficiently.

   The employee concerned shall apply in writing for such transfer and shall receive the rate applicable to the job to which he is transferred.

6.05 An employee may at OHEDI's option lose his seniority status, have his name removed from the seniority list and cease to be an employee of OHEDI if any of the following conditions occur:

a) if he quits his employment voluntarily or is discharged for cause; or

b) if he fails to report to work after a lay-off within five working days after recall. OHEDI shall notify such employee of his recall by telephone and by registered letter sent to him at his last address as shown in OHEDI's records, in which last mentioned event he shall be deemed to have been recalled when he would be expected to have received such registered letter in the ordinary course of the mail; or

c) if he fails to report to work after an absence without permission for a period exceeding three full working days; or

d) on the expiration of twelve months following a lay-off during which period the employee has not been recalled; or

e) if he fails to return to work having been cleared to do so under the regulations of the Workplace Safety and Insurance Act; or

f) if he remains away from work due to illness or disability, longer than a period equal to two months for each completed year of service to a maximum of twenty-four months after becoming eligible for the Long Term Disability plan in effect or OMERS Disability Pension; or

g) if he accepts employment elsewhere or engages in self-employment while on leave of absence, sick leave or in receipt of Workers' Compensation, Long Term Disability benefits or OMERS Disability Pension.

6.06

a) The Union shall be advised of relevant data on new employees below the supervisory level.

b) The first five months of employment shall for each new employee be considered a probationary period. An employee on probation shall not be entitled to any of the seniority rights granted by this Agreement, nor shall he or the Union be entitled to process a grievance with respect to discharge or lay-off. After such five months period his seniority shall date from the time he was hired.

c) A regular employee is an employee who has successfully completed the probationary period.

d) A new employee, whether temporary or probationary, shall be entitled to statutory holiday pay on a prorated basis as per the Employment Standards Act with part-time employees receiving a proration as per the Employment Standards Act, and shall be subject to any Union Security clause.

6.07

a) It is understood and agreed that OHEDI's work load is subject to seasonal variations and short-term peaks resulting from temporary increases in work in a specific area.

b) Where OHEDI deems it necessary to hire temporary help to cope with short-term work load fluctuations during the life of this Agreement, they will present in writing, in advance, to the Union:

   i the nature of the specific job;

   ii the expected duration of the job which is not to exceed eight months; except in the case of pregnancy and parental leave which shall not exceed fifty-two weeks;

   iii the classification and rate of pay of the person expected to fill the job.

   It is agreed that the temporary employee's period of engagement shall terminate in reasonable accord with the expected duration originally stated. This Article does not apply to contract employees.

c) Temporary employees will not be entitled to any seniority rights or pension benefits hereunder. They shall be entitled to Employer's Health Tax and, effective the first calendar month after completing five months, to drug coverage.

d) Rates and progressions as contained in Schedule "A" of this Agreement, shall apply.

6.08

a) Except as defined elsewhere in this Agreement, an employee shall not lose his seniority because of absence due to illness or injury provided the employee reasonably satisfies OHEDI of such illness or injury. If he is physically unable to do the same work or work similar to that which he was doing prior to his illness or injury, OHEDI shall endeavour to transfer him to suitable work, provided the employee is willing to accept such work at the salary then currently applicable thereto. Any employee whom OHEDI deems is no longer able to perform his regular duties, either permanently or temporarily, may be employed at the discretion of OHEDI in any work which OHEDI is satisfied he can do and is available.

b) If the applicable salary or wage rate of the new work is below that of the employee's original salary or wage rate, then the employee shall revert to the new salary or wage rate over a period of time according to the following formula:

   i To the base rate of his new classification will be added an additional 1.5 percent of the differential between the base rate for the new job and the base rate for the employee's former job for each year by which his continuous service exceeds ten years at the time of transfer. This determines the rate to which the employee's pay will be reduced.

   ii The reduction in rate will take place in six equal steps. The first step shall occur three months after he has been transferred to the new job. The subsequent steps shall occur at three-month intervals until the rate determined has been reached.

ARTICLE 7.

LEAVE OF ABSENCE and SICK BENEFITS

7.01 Work and other operating conditions permitting, request to his immediate supervisor for any leave of absence [not otherwise provided for], will be given consideration. Such leaves of absence are to be without pay and will be deemed temporary leaves of absence. Application to his immediate supervisor for temporary leave of absence shall be made in writing giving reasons and length of time for such leave.

7.02

a) OHEDI sick leave plan was created to provide income maintenance and thereby reduce the financial hardship that bona fide illness can cause so far as inability to work and subsequent loss of normal wages are concerned.

b) Personal illness leave of absence is applicable only to those days where an individual is scheduled to work with the following exception. Should an employee because of serious injury or serious illness be hospitalized or be under a doctor's care while on a vacation of five (5) days or more, the employee will notify his supervisor at once. The employee may request to be placed on sick leave.

c) Monthly accumulation of sick leave will accrue provided the employee has worked at least fifteen of the working days in the month excluding bereavement leave, vacation and paid holidays.

d) All employees shall be allowed personal illness leave of absence at their regular rates of pay as follows: after six months, one and one-half days per month personal illness leave of absence at the regular rates of pay shall be credited each employee up to a maximum of one hundred and twenty-five days with pay, provided however, that after completing six months of continuous employment with OHEDI each employee will be credited with nine days with pay. It is also agreed and understood that any personal illness leaves of absence taken while the maximum is being accumulated shall be deducted from the amount accumulated at the time the personal illness leave of absence is taken. Once the maximum one hundred and twenty-five days is reached, personal illness leaves of absence taken by the employee will be deducted, but the employee shall commence accumulating again up to the maximum as hereinbefore provided and so on from time to time. For Power Line Technician/Operators, 1-1/2 days per month sick leave credit is considered equivalent to one 12 hour shift.

e) It is further agreed that each employee shall, as soon as possible, notify his supervisor, prior to commencement of his normal working hours or shift, of his impending absence. In the case of absence due to illness, the employee will keep his supervisor informed of his progress, and of the date of his probable return to work.

f) It is further agreed that any personal illness leaves of absence allowed under the provisions of this Article shall only be allowed if the illness is verified by a medical doctor's official certificate if required by Management, the cost of which will be borne by the employee.

g) It is further agreed that in cases where the employee's absence is occasioned by illness or injury compensable under the Workplace Safety and Insurance Act, OHEDI will pay the difference between the compensation received and the employee's take home pay at the regular rate of pay applicable at the time of illness or injury was sustained, but no employee is to receive additional monies including tax adjustment as a result of being absent on Worker's Compensation. This period shall be up to a maximum of sixty days and may be extended on special consideration by OHEDI. Thereafter, the employee must resort to his personal illness leave of absence credits in which case OHEDI shall only be obliged to make up the difference between the compensation received by the employee and the regular rates of pay applicable to the employee concerned at the time of illness or injury was occasioned and only for the period of days equal to the employee's personal illness leave of absence credit.

However, in the event that legislative requirements reduce the amount payable to those employees eligible for Worker's Compensation assistance below the present ninety percent (90%), the employer's make up allowance shall provide a benefit equal to ninety-five percent (95%) of the employee's take home pay.

7.03

a) Bereavement leave is applicable only to those days where an individual is scheduled to work. Absence from work of an employee shall be granted as bereavement leave as follows:
   i Death of the employee's spouse and/or child(ren) shall entitle a regular or probationary employee to five (5) days' leave of absence with pay
   ii Death of the employees immediate family (defined to mean, mother, father, sister, brother, mother-in-law, father-in –law, step-parent or step-children shall entitle a regular or probationary employee to three (3) days' leave of absence with pay
   iii Death of a brother-in-law, sister-in-law, grandparent or grandchild, a regular or probationary employee shall be entitled to one (1) day's leave of absence with pay.

   For the purposes of this article a day shall be considered all of an employee's schedule work day or shift

b) In addition to the above bereavement leaves, a regular or probationary employee shall be entitled to two floating bereavement days per calendar year with pay

7.04 For the duration of this Agreement OHEDI agrees to pay the insurance premiums for the following benefits for all regular employees covered by this Agreement, effective the first calendar month following attainment of regular status:

- Employer's Health Tax;
- Semi-private hospital room;
- Prescription Drug Plan with $11.99 dispensing fee cap; and excludes Over the Counter Drugs; Mandatory Generic Drug Substitution with Doctor Override (Effective July 1, 2013)
- Great West Life Deluxe Dental Plan, or equivalent, as may be selected through another carrier by OHEDI. Includes recall oral exams once every 9 months and Orthodontic Services of $2250 limit on the lifetime of each individual, at the 2013 ODA Fees. Effective January 1, 2014 – 2014 ODA fees; Effective January 1, 2015 – 2015 ODA fees; Effective January 1, 2016 – 2016 ODA fees; Effective January 1, 2017 – 2017 ODA fees.
- Great West Life Vision Care Plan, or equivalent, as may be selected through another carrier by OHEDI as follows:
  Effective July 1, 2014 - $350/24 month period
  Laser Surgery is included in the maximum per 24 months
  Eye examination –Effective July 1, 2013 - $90/24 month period
- Great West Life Extended Health Plan, or equivalent, as may be selected

through another carrier by OHEDI. Includes four services -Physiotherapist, Registered Massage Therapist, Speech Therapist and Chiropractor with a combined maximum limit of $1000/covered per person per calendar year.

- Orthotic coverage of $350/24 month period.

7.05 For the duration of this Agreement OHEDI agrees to provide a Long Term Disability Plan which will pay to any regular employee, who has exhausted his personal illness leave of absence credit, 65% of his basic regular wages at time of disability, until he returns to work or reaches age 65, whichever comes first. For the duration of this Agreement OHEDI agrees to continue the Long Term Disability Plan which is presently carried by the Municipal Electric Association for all regular employees.

7.06 A regular employee who has exhausted his sick bank, continues to be absent due to illness and is receiving LTD benefits, or OMERS benefits, will continue to receive the following benefits for a period equal to two months for each completed year of service to a maximum of twenty-four months:

- Employer's Health Tax
- Semi-private hospital room
- O.M.E.R.S. [as outlined in Article XVI]
- Dental Plan
- Drug Plan
- Vision Care Plan
- Extended Health Plan

7.07

a) An employee who has exhausted his sick bank and continues to be absent due to illness or disability will not be entitled to:
   - further sick credits;
   - statutory holiday pay;
   - vacation pay credits accruing during such period.

b) An employee who has exhausted his sick bank and continues to be absent due to illness or disability and is **not receiving** LTD or WSIB may continue to participate in the Employer benefit plans, providing he pays both the Employee and Employer benefit plan premiums in advance, as long as the insurer will accept the payments.

7.08 A requested leave of absence in excess of thirty (30) working days without pay and without loss of seniority may be granted to an employee by OHEDI. Thereafter, an employee will not accumulate sick leave credits, vacation credits or receive statutory holiday pay. For leaves of absence beyond the thirty (30) working days, the employee may continue to participate in the Employer benefits plan, provided he pays both the Employee and Employer benefit plan premiums in advance, as long as the insurer will accept the payments.

7.09

a) A request for pregnancy leave and/or parental leave must be presented in writing to the Department Head as early as possible. Such notice shall not be less than two (2) weeks prior to the proposed starting date of the leave indicating the duration of such leave and shall be granted in accordance with the Pregnancy and Parental Leaves provision of the Employment

Standards Act.

b) An employee shall continue to receive the following benefits during pregnancy/parental or Emergency Medical Leave approved in excess of the Employment Standards Act of Ontario:

- Employer's Health Tax
- Semi-private hospital room
- O.M.E.R.S.
- Dental Plan
- Drug Plan
- Vision Care Plan
- Life Insurance
- L.T.D. Insurance
- Extended Health Plan
- Vacation credits and sick leave credits.

7.10 It is recognized and agreed that the employee's share of any rebate received from a premium reduction under the Employment Insurance Act will be deemed to have been applied against other benefits.

7.11

a) In the event that the *Employment Standards Act, 2000* is amended (as contemplated by Bill 56) to allow for family medical leave, then OHEDI and the Union will comply with that amendment while it is in force.

b) After lieu time has been exhausted, an employee may use upon request and approval, up to 24 hours per calendar year, from their sick bank for emergencies involving a dependent child, parent or spouse, in increments of no less than one (1) hour.

7.12 If an employee takes family medical leave during his probation, his probationary period will be extended for the period of absence.

7.13 Article 7.08 will be applied where family leave is taken.

ARTICLE 8.

VACATIONS WITH PAY

8.01

a) OHEDI may determine the time at which any employee takes the vacation (in increments of not less than half a day) to which he is entitled in any year and employees must submit their vacation requests before February 15th, for any year and the vacation schedule for any year shall be posted by OHEDI and requested vacation periods confirmed in such time as to be completed by March 15th of that year. Employees submit vacation requests for the balance of the calendar year as well as the time period from January 1 to the first Saturday in April. Senior employees shall be entitled to preference as to time of vacation provided their vacation requirements are received by February 15th of the year.

b) Annual vacation credits accrue, and should be taken during the calendar year, but no later than the first Saturday in April of the following year.

c) An employee upon retirement effective after June 30th shall be entitled to his full annual vacation. An employee effective before June 30th shall be entitled to his pro-rated annual vacation.

8.02 During the calendar year in which employment commences an employee shall be entitled to one day of vacation with pay for each month of service completed, to a maximum of ten days.

8.03 An employee shall be entitled to two weeks' [80 hours for hourly rated employees and 70 hours for salaried employees] vacation with pay in the calendar year in which he completes one year of service, or 4% of his previous year's gross wages as shown on the employee's T4 Statement of Remuneration Paid, whichever is the greater.

8.04 An employee shall be entitled to three weeks' [120 hours for hourly rated employees and 105 hours for salaried employees] vacation with pay in the calendar year in which he completes three years of service.

8.05 An employee shall be entitled to four weeks' [160 hours for hourly rated employees and 140 hours for salaried employees] vacation with pay in the calendar year in which he completes nine years of service.

8.06 An employee shall be entitled to five weeks' [200 hours for hourly rated employees and 175 hours for salaried employees] vacation with pay in the calendar year in which he completes sixteen years service plus one additional day's vacation with pay commencing in his twenty-third year of service to a maximum of five additional days giving 6 weeks [30 days] in his twenty-seventh year of service.

Where an employee is entitled to five weeks or more vacation, the fifth week or more may be paid in cash in lieu of time off, provided such has been mutually agreed upon by the employee and OHEDI.

8.07

a) An employee who, in any calendar year, terminates his services with OHEDI or is absent from work on an extended leave of absence shall be paid for the annual vacation indicated above, prorated by the number of months' service completed during that calendar year.

b) An employee upon retirement effective after June 30th shall be entitled to his full annual vacation. An employee upon retirement effective before June 30th shall be entitled to his pro-rated annual vacation.

8.08 **Trouble Group**:

a) Power Line Technician/Operators shall be paid double time for the regularly scheduled last 4 hours of their shift which falls in the week that they work 48 hours, if this 4 hour period falls during their vacation.

b) A vacation day shall be considered 12 hours or equivalent to 1-1/2 eight-hour days.

ARTICLE 9.

PAID HOLIDAYS

9.01 All employees, including shift workers, shall be granted the following holidays with pay:

a) New Year's Day;
b) Family Day;
c) Good Friday;
d) Easter Monday;
e) Victoria Day;
f) Canada Day;
g) Civic Holiday;
h) Labour Day;
i) Thanksgiving Day;
j) half-day Christmas Eve;
k) Christmas Day;
l) Boxing Day;
m) half-day New Year's Eve

provided the employee has worked his last complete regularly scheduled shift immediately preceding the holiday and his complete regularly scheduled shift immediately succeeding the holiday, unless justifiably absent. If the paid holiday is observed by OHEDI as a holiday on an alternate day, the alternate day shall be treated as a paid holiday for the purposes of this Agreement in lieu of the day on which the holiday actually falls.

9.02 If a paid holiday falls within an employee's vacation he shall be entitled to an extra day's vacation or if, because of work requirements, he is required to be at work and does not receive the extra day's vacation, he shall be entitled to an extra day's pay in lieu thereof.

9.03

a) If an employee is required to work on a paid holiday he shall be paid the normal holiday pay as well as double time for all hours worked.

b) Should the employee request, and his immediate supervisor agree, he may be given an alternate day off with pay in lieu of the holiday pay referred to above.

9.04 **Trouble Group**:

Power Line Technician/Operators shall be paid 8 hours holiday pay for each full paid holiday and 4 hours holiday pay for each half-holiday, as per conditions in the Collective Agreement. Payment for Power Line Technician/Operators working the holiday will be at Power Line Technician/Operators double time rates for a half-day or full day, as applicable. Overtime rates will apply to the Power Line Technician/Operators for Paid Holidays on the actual dates they fall.

ARTICLE 10.

WAGES AND HOURS OF WORK

10.01 Job classifications and the wage rates applicable thereto shall be as set out in Schedule "A" attached hereto and forming part hereof. Any new classifications or job rates established by OHEDI during this Agreement shall be notified to the Union forthwith and the Union shall be entitled to discuss them, in an attempt to resolve the issues, with OHEDI within thirty days of notification. If so discussed and agreed upon they shall be incorporated in and become part of this Agreement. If not so agreed upon, they shall be instituted as proposed by OHEDI and shall be subject to negotiation at the next negotiations for a renewal of the Agreement.

10.02

a) The regular and normal work week for the Line Group, Stockkeeper, Metering, Protection & Control Group, Meter Reading Section, Inspectors, and Engineering Technologists (40 hours) but excluding shift workers, shall consist of forty hours, eight hours per day, 8:00 a.m. to 4:30 p.m. Monday to Friday inclusive, with one half hour off for lunch.

b) The regular and normal work week for salaried employees, other than the one classification as outlined in Section 2, shall consist of thirty-five hours, seven hours per day, 8:30 a.m. to 4:30 p.m. Monday to Friday inclusive, with one hour off for lunch. Exceptions to starting times may be arranged to provide for switchboard coverage from 8:00 a.m. to 5:00 p.m.

This in no way limits OHEDI from:

i establishing other shifts;
ii establishing an alternative work week from 7:00 a.m. until 6:00 p.m. that shall consist of thirty-five hours, seven hours per day, Monday to Friday inclusive, with one hour off for lunch;

as it may deem necessary for the operations of its business.

ARTICLE 11.

OVERTIME

11.01

a) It is understood and agreed that employees can be required to work at other than their regular hours and in addition to their regular hours beyond the limits of hours of work described in Section 17 of the Employment Standards Act.

b) All time worked in excess of the working schedule, except for shift workers, shall be paid for at overtime rates of double time after the completion of their regular hours and for all hours worked on a Saturday, Sunday or on a paid holiday.

c) Should the employee request and his immediate supervisor agree, he may be given time off in lieu of the overtime pay referred to herein, on the basis of hour and a half for hour worked in increments of not less than half a day. The employee may elect to receive a split of lieu time or overtime pay if the overtime hours worked exceeds two (2) hours.

11.02

a) For hourly rated shift workers, all time worked in excess of their working schedule shall be paid for at overtime rates of double time and for such hours worked on their scheduled days off, or on a paid holiday. In the case of the Power Line Technician/Operator Shift, scheduled days off will be as laid down in the Trouble Shift Schedule forming part of this Agreement.

b) When a shift worker is called in ahead of his regular shift hours he shall be paid overtime rates at double time for all hours worked before the commencement of his regular shift. Power Line Technician/Operators shall be paid double time for the regularly scheduled last 4 hours of their shift which falls in the week they work 48 hours.

11.03 If an employee has:

a) worked overtime at overtime rates preceding his regular shift and has then worked into and completed his regular shift at regular rates, and then continued to work overtime beyond his regular shift at overtime rates; or

b) completed his regular shift at regular rates and then continued to work overtime at overtime rates;

he shall continue to be paid overtime for all hours worked thereafter in excess of his regular shift until he has been relieved and given at least four hours' rest prior to being put back on his regular shift at regular rates.

11.04 If an employee is required to work overtime immediately following a regular day shift for a period in excess of one hour, and it is not practicable for him to notify his family, Management will endeavour to notify his family.

11.05

a) Should an employee be required to work continuously for a minimum of sixteen hours, he is entitled upon completion, to an eight hour rest period which will be paid at straight time for any or all of those eight hours which fall on hours which he would normally be working.

b) Employees called in to work 12:00 midnight to 8:00 A.M. shall have the following rest time:

i none if call-out occurred on a Saturday, Sunday or Statutory Holiday
ii less than 3 hours – no sleep time entitlement
iii 3 hours to less than 5.5 hours - entitlement to 4 hours of sleep time commencing at the start of the regular shift at straight time rates, or, subject to any safety concerns, the employee shall have the option to take the rest period in the final 4 hours of the regular shift.
iv 5.5 hours or more – day off with pay at straight time rates
v In the case of a Level 2 emergency or higher as defined in the Electricity Distribution Inc. Emergency Operation Plan, employees may be required to work a minimum of 16 hours without a rest period.

Clarification: Hours worked are hours worked between 12:00 midnight and 8:00 am only.

Exemption: Article 11.05 b) does not apply to Power Line Technician/Operators.

During summer hours, call-out work is deemed to occur before the start of the scheduled flextime shift.

c) Employees shall not be paid less than their normal hours of pay in a week as a result of the Employer sending the employee home because of legislative/regulatory rest requirements.

11.06 Employees may be required from time to time to engage in training sessions. OHEDI agrees to reimburse such employees for those sessions at normal rates of pay for standard daily or weekly hours only. Mileage for travel shall be paid in accordance with OHEDI's laid down policy.

11.07 Any planned overtime cancelled due to inclement weather, after the employee has reported to work, to be paid at a minimum of one hour at double time rates.

11.08 Pre-scheduled overtime will normally be offered to those who are qualified and normally perform the work, in a rotation system, excluding work in progress. A list updated as required will be posted in each department. This does not change the practice or use of contractors.

ARTICLE 12.

POWER LINE TECHNICIAN/OPERATOR SHIFT, STAND-BY PAY, and MINIMUM CALL-OUT PAY

12.01 A Trouble Group may be maintained consisting of four Journey Power Line Technicians or other personnel considered by the Management to be qualified. The hours of work will be on a shift basis, seven days per week, in accordance with a 12 hour Trouble Shift Schedule determined by the Employer following input from the Control Room Operators..

Shift premium will be applicable to shifts worked after 4:00 p.m. or before 8:00 a.m. No shift bonus shall be paid for any hours to which an overtime premium applies.

12.02 **Stand-by**:

If employees are required to be on stand-by, they shall receive the following:

a) For a week day - $35.00 Effective July 1, 2015 - $40.00
b) For a Saturday - $55.00
c) For a Sunday - $55.00
d) For a Paid Holiday - $55.00
e) For a half-day Paid Holiday$40.00 [to 8:00 a.m. the following day]

Overtime work actually performed will be paid for at the appropriate rates as provided elsewhere in this Agreement.

12.03 **Minimum Call-Out Pay**:

Any employee called out from his home to perform work shall receive the overtime pay for the work actually performed plus an allowance of fifteen minutes travel time to work and fifteen minutes travel time to return home at applicable overtime rates, or, a minimum of two hours pay at applicable overtime rates, whichever is the greater, except that -

a) any call-out within one hour of the regular starting time shall be paid for at applicable overtime rates,

b) any call answered within two hours of the time of previous call-out, the time shall be considered continuous.

ARTICLE 13.

TEMPORARY RELIEF

13.01 The parties agree that OHEDI may from time to time fully and freely move employees for the purpose of temporary relief. Such temporary movements will be in the best interest of productivity and efficiency as deemed by OHEDI but being mindful of seniority where applicable.

13.02

a) It is understood and agreed that if an hourly rated employee is requested to perform the work of an employee within the bargaining unit calling for a higher rate of pay, such temporary relief shall be paid at the higher rate of pay for the number of hours actually worked in that classification, but not exceeding the level in the higher classification than they currently receive in their own classification.

b) When an hourly rated employee is requested by Management to perform the work of a supervisor, his rate shall be increased by the same percentage as a Sub-Foreperson's rate exceeds that of Power Line Technician.

c) It is understood and agreed that if a salaried employee is requested to perform the work of a salaried employee in the bargaining unit in a higher classification, and if such temporary relief is for a period of a full half-day or more, the relieving employee shall receive the rate of pay applicable to the classification of the relieved employee and at the level that they currently receive in their own classification for the number of hours actually worked.

d) When a salaried employee is requested by Management to perform the work of a Supervisor for a period of duration in excess of one working day, his rate shall be increased by the same percentage as a Sub-Foreperson's rate exceeds that of a Power Line Technician.

e) It is understood and agreed that if a salaried employee is requested to perform the work of an hourly rated employee within the bargaining unit calling for a higher rate of pay, such temporary relief shall be paid at the higher rate of pay for the number of hours actually worked in that classification but not exceeding the level in the higher classification than they currently receive in their own classification.

13.03

a) A Lead Power Line Technician, Lead Protection and Control Technician, and Lead Meter Technician will be paid the Sub-Foreperson rate if he is placed in charge of two or more men, excluding students, Utility Person and line apprentices who have not completed their second year of apprenticeship.

b) An employee receiving Group 11 Sub-Foreperson rate shall also receive an additional $.15 cents per hour premium.

c) When two Power Line Technicians are working call-out and a Lead Power Line Technician is not present, the senior Power Line Technician shall be paid Lead Power Line Technician rate.

13.04 **Metering, Protection & Control Group**:

Where two Meter Technicians or two Protection & Control Technicians are working together away from the Operations Centre and a Lead Meter Technician or Lead Protection & Control Technician is not present, one Meter Technician or Protection & Control Technician shall be placed in charge and shall be paid the Lead Hand rate.

13.05 **Trouble Group:**

For the purposes of temporary relief for the 12 hour Power Line Technician/Operator Shift Schedule, payment terms for other than Power Line Technician/Operators shall be as follows:

Specific situations are set out below.

a) Except when undergoing training, the base rate shall be the Power Line Technician/Operator rate plus shift differential, when applicable.

b) When relief is required for any number of shifts, Monday to Friday without 7 days' notice, the employee will be expected to only work for 12 hours per day, unless already at work, to a maximum of 32 hours in a 48 hour period. E.g. not at work -pay 8 hours Power Line Technician/Operator rate and 4 hours Power Line Technician/Operator double time rate. E.g. already at work - pay 4 hours regular rate, 4 hours Power Line Technician/Operator rate and 8 hours Power Line Technician/Operator double time rate

An employee who works a regular 8 hour work day and is assigned and works a Trouble relief shift before the start of their next regular work day, will be paid at the appropriate overtime rate until the beginning of their next regular work day.

c) When relief is required for Saturday or Sunday, the employee will be expected to work 12 hours per shift at Power Line Technician/Operator double time rates.

d) When scheduled relief is required for the Monday to Friday two-day block, subject to 7 days' minimum notice, the employee shall only work as a Power Line Technician/Operator for the two days. He will be expected to work 24 hours, consisting of: E.g. 16 hours Power Line Technician/Operator rate and 8 hours Power Line Technician/Operator double time rate.

e) When scheduled relief is required, subject to 7 days' minimum notice, for the three-day block, the employee shall only work as a Power Line Technician/Operator for the three days. He will be expected to work 36 hours consisting of: E.g. 8 hours Power Line Technician/Operator rate and 28 hours Power Line Technician/Operator double time rate.

f) It is understood and agreed that, for extended temporary relief on the Trouble Shift, the employee working the Trouble Shift for the first block of shifts, either 2 or 3 days, shall be paid in accordance with the temporary relief payment terms as per d) or e) above. An employee working in this situation will be given a minimum of 40 hours work in the first week. Scheduling of any extra hours will be at the supervisor's discretion. The employee shall also average a minimum of 80 hours in a two-week period.

ARTICLE 14.

SAFETY EQUIPMENT

14.01 OHEDI will supply reasonably sufficient first-aid equipment which shall be kept at reasonable points reasonably accessible to all employees.

14.02

a) OHEDI shall supply to all hourly rated employees, without expense to the employees but on charge to the employees, FR clothing at the required Arc Flash rating, including rainwear. OHEDI shall supply, without expense to all employees who require them, spurs, belts, and tinted or clear safety glasses in accordance with EUSA requirements, when required, as well as the necessary equipment for the covering of live apparatus, on the strict understanding that each employee shall make the best use of such equipment for his own safety and the protection of others, at all times.

Prescription Safety Glasses:

b) OHEDI will provide tinted or clear prescription safety glasses in accordance with EUSA requirements for those probationary or regular employees who require them, from their normal supplier of safety glasses. The employee will provide OHEDI with his prescription. Alternately, OHEDI will pay $ 175.00 toward tinted or clear prescription safety glasses purchased from the employee's own Optometrist, upon receipt of purchase; a maximum of once a year. An employee is also entitled to replace glasses damaged at work to a maximum cost of $125.00 once per year. Safety glasses must meet OHEDI's standard.

c) OHEDI also agrees to supply annually, without expense to the hourly rated employees, provided they require them, eight pairs of gloves [summer] and four pairs of gloves [winter], provided that the old gloves are turned in before receiving new ones. Each employee shall report any defects in safety equipment to his immediate Supervisor. It is agreed that an average of one hour with pay every month will be allowed as best arranged by the officers of OHEDI, in which the hourly rated employees will practice first-aid resuscitation and accident prevention methods.

d) All work will be done in accordance with the Electrical Utilities Safety Association Rule Book.

14.03

a) OHEDI will issue the following:

1. All new Inspectors, Engineering Technologists, Power Line Technicians, Power Line Technician/Operators, Meter Technicians, P & C Technicians, Cable Locators, Utility – outside, Stockkeepers, Labourers, Water Heater Servicepersons, Meter

Reader Servicepersons, Building Serviceperson shall receive orange FR clothing as follows: 7 shirts and 7 pair of pants.

All new Inspectors, Engineering Technologists, Power Line Technicians, Power Line Technician/Operators, P & C Technicians, Cable Locators, Utility – outside, Labourers and Stockkeeper, Meter Reader Servicepersons, Water Heater Servicepersons and Meter Technician will also receive orange FR wear not exceeding:

- 2 summer jackets and 2 summer overalls and
- 2 parkas and 2 insulated overalls or
- 2 insulated jackets and 2 insulated overalls or
- 2 insulated coveralls
- 2 hooded fleece sweaters

OHEDI will replace any of the above clothing upon receipt of the worn duplicate items.

2. This clothing shall be kept in good order and appearance and shall be worn in accordance with Corporation standards. The clothing shall be in accordance with CSA standards

3. OHEDI shall reimburse via paycheque each probationary and regular employee, who is required to wear safety boots, up to $190.00 per Collective Agreement year:

   - Effective July 1, 2014 - $200.00 per year
   - Effective July 1, 2015 - $205.00 per year

   and to those employees required to wear safety shoes, up to $100.00 (increased to $110 effective July 1,2016) per Collective Agreement year. Employees may accumulate this allowance up to $795.00 and $410.00 respectively during the term of this Agreement. Receipts are required for payment. Employees may accumulate unused amounts which must be used before expiry of the agreement.

4. Employees in all departments shall supply their own hand tools, according to established practice, and shall be of Corporation approved design for safety. OHEDI will replace personal tools when lost, worn out or damaged, on OHEDI work, where the employee shows that he has taken reasonable care and responsibility.

b) Requests for replacement of worn out clothing shall be made through the Designated Management Representative. Issue of new clothing will be as required by wear to the existing issue and worn clothing must be returned to the Designated Management Representative prior to issue of replacement.

c) It is agreed that all personal clothing, tools and gear provided by OHEDI, either as described herein or elsewhere, are for use on Corporation business and shall not be otherwise used.

ARTICLE 15.

MISCELLANEOUS PROVISIONS

15.01 OHEDI shall have the right to require of any employee that he shall, upon employment, submit to a physical examination by a competent physician selected by OHEDI at the expense of OHEDI; provided further that under certain circumstances, such as before returning to work after any injury, leave of absence, serious or extended illness, frequent absences and similar conditions, OHEDI at its own expense may require a physical examination of any employee, which shall be made by a competent physician chosen by OHEDI.

15.02 OHEDI will permit the Union to use the bulletin boards provided by OHEDI for the Union for the posting, by the properly authorized officials of the local Union, of notices of Union business having the official seal or letterhead of the Union, giving pertinent facts concerning meetings and business of the local Union. There shall be no distribution or posting by the Union of pamphlets, advertising matter, cards, notices or any kind of literature upon OHEDI property, except as herein provided.

15.03

a) OHEDI will pay the cost of applicable license renewals for all employees required to drive regularly during working hours on Corporation business. Employees shall obtain, and keep current, appropriate driving licenses as are deemed necessary by OHEDI to perform their various duties.

b) All medicals for A-Z licenses when required by the Ministry of Transportation will be reimbursed up to $125.00 by OHEDI when proof of the request and the medical is presented to OHEDI.

15.04 There will be a 10- minute break [combined rest period and coffee break] in mid-morning and mid-afternoon.

15.05 If there is inclement or below -18 Celsius weather the employees will be permitted to work indoors, provided that the permission of the immediate Supervisor shall be obtained and no time shall be lost by regular or probationary employees while off the job in such circumstances. It is understood and agreed that this shall not apply to emergency work.

15.06

a) Hourly rated employees will be required to carry their lunches, and lunch periods should normally be taken at the nearest suitable facility.

b) All employees shall be entitled to a hot meal at a restaurant or a meal allowance, not to exceed in value $9.00 for breakfast or lunch or, $12.00 for dinner, at OHEDI's expense. Meal allowance is increased to $13.00 effective July 1, 2014:

i if they work five continuous hours without a meal period; or
ii if they are not taken to a suitable facility for lunch; or
iii if they are called out and report to work between the hours of 8:00 a.m. to 9:00 a.m., 12:00 noon to 1:00 p.m. and 5:00 p.m. to 6:00 p.m., on Saturdays, Sundays or paid Holidays or work through these periods; or
iv if any employee is called out and reports to work between the hours of 7:00 a.m. and 8:00 a.m. or between 5:30 p.m. and 6:30 p.m. Monday through Friday, or work through these periods.

Meal allowances will not be paid when planned overtime has been arranged during regular hours on the preceding work-day.

Under (iii) and (iv) above, only one meal will be paid for during any eight-hour period for hourly-rated employees and seven hour period for salaried employees.

15.07 This section shall apply to emergency overtime work:

a) If an employee is taking a meal which is being paid for under the terms of this clause by OHEDI, and will not be working following completion of the meal, then the time spent taking the meal will not be paid.

b) If an employee is taking a meal which is being paid for under the terms of this clause by OHEDI, and will be required to continue working after completion of the meal, then the time taken for the meal will be paid time.

15.08 **Jury Duty and Crown Witness**:

a) An employee who is summoned and reports for jury duty shall be granted leave of absence with pay for any time lost from his normal work-week provided:

   i. he has notified the head of his department immediately upon receiving such jury duty summons; and
   ii. he shall have deposited with the Director of Finance the full amount of compensation received for such jury duty less any allowed travelling expense.

   Whenever an employee, who has been granted leave of absence pursuant to this Article, is released from jury duty in the forenoon of any day he shall, as a condition of receiving full pay for that day, return to work at the commencement of his afternoon scheduled hours of work.

b) Any employee who is subpoenaed by the Crown to appear in court as a witness shall be paid at regular rates for the time lost from his normal work week which he would otherwise have worked provided he pays to the Director of Finance any fees he may have received as such witness less any allowed travelling expense.

15.09

a) Continuing employment of certified tradesmen is conditional upon their certification being kept current. For appointments made after July 1, 1987 continuing employment of tradesmen who do not possess a Journeyman Certificate will be conditional on their obtaining such certification. Continuing employment of apprentices hired to complete their certification is conditional upon their continuing successful progress and final certification.

b) Should OHEDI request an employee to attend a training course on his own time, or an employee requests and receives approval from his supervisor to attend such a course, OHEDI will reimburse the employee up to 100% of the tuition fee if the employee successfully completes the course with a passing grade.

15.10 Employees covered by this Agreement shall be paid on every second Thursday by electronic deposit to their bank account.

ARTICLE 16.

PENSIONS AND INSURANCE

16.01 OHEDI will maintain the Canada Pension; OMERS. F.A.E. Plan now in effect; will provide all regular employees with an OMERS. Supplementary Pension, Type 1, 1-3/4% past service; and Group Life Insurance Basic Plan with Canada Life or equivalent as may be selected through another carrier by OHEDI.

16.02 Benefits for Retirees

a) When an employee qualifies and takes early retirement under the OMERS 90 plan he shall be eligible to remain in the following Ontario Provincial benefit plans:

- Employer's Health Tax
- Semi-private hospital room
- $0.35 deductible Prescription Drug Plan [Effective July 1, 1999]
- Great West Life Deluxe Dental Plan, or equivalent Plan, as may be selected through another carrier by OHEDI. Includes recall oral exams once every 6 months and Orthodontic Services of $ 1500 limit on the lifetime of each individual, at the 2001 ODA Fees [effective date of ratification] and effective July 1, 2002 - at the 2002 ODA Fees.
- Great West Life Vision Care Plan, or equivalent as may be selected through another carrier by OHEDI. [$225/24 month period]

b) OHEDI shall pay 100% of the premium costs. The coverage shall be based upon one year's coverage for every 12-1/2 days to the credit of the employee's personal illness leave of absence at the time of retirement. Should the average of the employee's personal illness leave of absence for the previous five years be higher than the number of days remaining at retirement, this number shall be used for calculation of the period of time the benefit will be available to the retiree. Should an early retiree have insufficient personal illness leave of absence credits to entitle him to 100% paid coverage to age sixty-five, he may continue in the various benefit plans by paying 100% of the premium costs.

c) When an employee who has taken early retirement attains age sixty-five, or an employee who retires from OHEDI at age sixty-five, OHEDI shall pay 100% of the premium costs for the benefits outlined above which are not paid by the Province of Ontario.

d) Upon the death of a retired employee the coverage shall be provided to the surviving spouse under the same conditions, provided the spouse is not receiving benefit coverage from elsewhere and provided this spouse was designated by the employee at the time of his retirement. "Spouse" shall mean, "the legally married spouse of the Employee," or "a person of either sex with whom the Employee has continuously cohabitated for a period of at least one year in or analogous to a common-law relationship". "Common-law" means a person of the same or opposite sex who resides with the Employee under a mutual agreement that the relationship is permanent and exclusive of all other relationships.

e) The above coverages will not be reduced and/or altered for any employee who retires or who is currently retired from OHEDI during the life of the Agreement, except through collective bargaining negotiations.

f) Employees hired after July 1, 2007, who have completed 20 years of service and otherwise qualify under this Article, will be eligible for the Retiree Group Benefits outlined above except where 16.02 (g) below is applicable.

g) In respect of employees who retire after July 31, 2007, the following revisions to benefits will apply to Article 16.02 (a)

- Revise $0.35 deductible Prescription Drug Plan to $2.00
- Revise recall oral exams to once every 9 months

h) Effective on the first of the month following ratification (August 1, 2010), there shall be no post age 65 retiree benefit coverage for new employees hired after that date.

ARTICLE 17

DURATION of AGREEMENT

17.01 This Agreement shall be in full force and effect from July 1, 2013 until June 30, 2017 and shall continue in force from year to year thereafter unless in any year thereafter, not more than ninety days and not less than sixty days before the date of its termination, either party shall furnish the other with written notice of termination of or proposed revision of this Agreement, in which latter case the party submitting notice of proposed revision of this Agreement shall set out the revisions which it proposes.

FOR OHEDI

[redacted]

for

[redacted]

[redacted]

[redacted]

[redacted]

FOR THE UNION

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE: Christmas Shutdown

In the event the Company closes its operation between Christmas and New Year's Day, employees will have the option to use lieu time, vacation time or unpaid personal time.
For days closed between Christmas and New Year's Day that are not statutory holidays, employees on call who are scheduled for a normal shift (or normal work day) will attend work for that shift and will receive normal wages for that shift. After that shift they will be entitled to the on-call rate if applicable plus applicable overtime.

Dated this 2ND day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

Re: Job Evaluation Process

Newly created bargaining unit positions shall be subject to the Joint Job Evaluation Committee process, using the current evaluation tool and process for determining placement in the wage grid.

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE:Out-of Province/Country Emergency Work

The parties agree to have a discussion on the first year of the collective agreement regarding out of province/country emergency work.

Dated this 2ND day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE:GIS Technician

In The Employer agrees to a joint job evaluation review of the role to determine an appropriate pay grade

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE: Post-Retirement Benefits

The parties agree to meet and discuss setting up a voluntary option for employees who have employer paid post-retirement benefits (PRB) coverage, to instead, elect to receive a payout in lieu of PRB.

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE: Part-time Call Centre Agents

This letter of understanding addresses the addition of part-time Call Centre Agents in the Customer Service Department, who will be required to be on-call. They shall be recognized as bargaining unit employees and have access to the Grievance/Arbitration procedure in the Collective Agreement and will be subject to the following-terms and conditions as follows:

1. Effective July 1, 2013 all employees in the new classification of Part Time Call Centre Agent shall be paid an hourly wage of $15.00 per hour. The number of part-time employees hired shall be limited to a maximum of four (4) employees. The hourly wage rate will be increased during the term of the contract by the same percentage increases as negotiated for the general rates of pay.

9. Effective July 1, 2013 all employees in the new classification of Part Time Call Centre Agent shall work between 10-24 hours a week, depending on work load, vacation and other factors. Part-time Call Centre Agents shall be able to work up to a maximum of 35 hours per week during peak business loads; however this shall not exceed a total of 16 weeks for each call center agent in a calendar year. If there is a need to exceed the 16 weeks, it will be discussed and mutually agreed to by both parties. The objective of increased part-time call centre hours is both to cope with higher workload and unscheduled absences but also to provide greater flexibility in scheduling vacation including increasing the number of Customer Service staff who can be off on vacation in July and August. For clarification, the employer will from time to time decide which weeks of the calendar year will be utilized as a week in which one, two, three or four of the part time employees will be scheduled up to 35 hours.

9. In lieu of benefits, employees in this classification will be paid, as part of their wage rate, an additional $1.00 per hours worked.

9. As a part-time employee, Call Centre Agents have the option to participate in the Ontario Municipal Employees Retirement Systems (OMERS). In order to be eligible to participate in OMERS they must meet conditions that are specified by OMERS. This information will be provided upon hire or as requested.

9. Overtime hours will be offered to full-time employees first. If part-time employees are eligible for over-time work, payment will be in accordance with the Employment Standards Act.

9. Vacation pay and Statutory Holiday pay will be in accordance with the Employment Standards Act.

7. As a part time employee, union dues will be deducted from each paycheque in accordance with Article 3.01.

8. Seniority shall be calculated on a pro-rata basis and at no time shall surpass a full-time employee.
9. This letter of understanding expires on June 30, 2017 and is subject to renegotiation.

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE: Lieu Time

This Letter of Understanding replaces the Letter of Understanding dated July 10, 1987.
Employees will be allowed to bank lieu-time at a rate of time and one half up to a maximum of two (2) weeks based on the regular work week.

Any outstanding balance of banked time will be paid out effective the first pay period after the Saturday in April.

Periods of time worked shall be in increments of on hour or more.

At the end of each calendar year any outstanding time worked, which at the rate of time and one-half results in hours earned which are less than an increment of half a day, will be paid to the employee at the rate of time and one-half.

In all cases, the Supervisor's agreement is required as outlined in Article XI, Section 1, Paragraph 3.IN WITNESS WHEREOF the parties hereto have executed this Agreement under the hand of their proper officers.

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

LETTER OT UNDERSTANDING
between
Oakville Hydro Electrical Distribution Inc.
(hereinafter designated as "OHEDI")
-and-
Local Union 636,
International Brotherhood of Electrical Workers
(hereinafter designated as the "Union")

RE: Control Room Shift Schedule

The current 12 hour shift schedule based on four (4) Control Room Operators will remain until the complement or structure is changed.

Dated this 2nd day of December, 2013.

FOR MANAGEMENT:

[redacted]

FOR THE UNION:

[redacted]

Salary Grid

SCHEDULE A

Hourly Rates

July 1, 2013 to June 30 2014

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	15.83	17.05	19.49	21.91	23.13	24.35
Group 2	17.05	18.36	20.98	23.61	24.92	26.36
Group 3	17.97	19.35	22.12	24.88	26.26	27.64
Group 4	18.67	20.10	22.97	25.84	27.28	28.71
Group 5	19.72	21.24	24.27	27.31	28.82	30.34
Group 6	21.94	23.63	27.00	30.38	32.06	33.75
Group 7	22.91	24.67	28.20	31.72	33.49	35.25
Group 8	24.66	26.56	30.35	34.14	36.04	37.94
Group 9	21.38	22.76	25.26	29.15	33.04	38.87
Group 10	26.97	29.05	33.19	37.34	39.42	41.49
Group 11	27.36	29.46	33.67	37.87	39.99	42.09
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2014 to Dec 31, 2014

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	16.06	17.30	19.78	22.24	23.48	24.72
Group 2	17.30	18.63	21.30	23.96	25.29	26.76
Group 3	18.24	19.64	22.45	25.25	26.65	28.06
Group 4	18.95	20.40	23.31	26.23	27.68	29.14
Group 5	20.02	21.56	24.64	27.72	29.26	30.80
Group 6	22.26	23.98	27.40	30.84	32.54	34.26
Group 7	23.25	25.04	28.62	32.20	33.99	35.78
Group 8	25.03	26.96	30.81	34.65	36.58	38.50
Group 9	21.70	23.10	25.64	29.59	33.53	39.45
Group 10	27.37	29.48	33.69	37.90	40.01	42.11
Group 11	27.77	29.90	34.18	38.44	40.59	42.72
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Jan 1, 2015 to June 30, 2015

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	16.22	17.47	19.98	22.47	23.72	24.97
Group 2	17.47	18.82	21.51	24.20	25.54	27.03
Group 3	18.42	19.84	22.68	25.50	26.92	28.34
Group 4	19.13	20.61	23.55	26.49	27.96	29.43
Group 5	20.22	21.77	24.88	27.99	29.55	31.10

Group 6	22.49	24.22	27.68	31.15	32.87	34.60
Group 7	23.48	25.29	28.91	32.52	34.33	36.14
Group 8	25.28	27.23	31.11	35.00	36.95	38.89
Group 9	21.92	23.33	25.90	29.88	33.87	39.85
Group 10	27.65	29.78	34.02	38.28	40.41	42.54
Group 11	28.05	30.20	34.52	38.83	40.99	43.14
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2015 to Dec 31, 2015

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	16.47	17.74	20.27	22.80	24.07	25.34
Group 2	17.74	19.10	21.83	24.56	25.93	27.43
Group 3	18.70	20.14	23.02	25.88	27.32	28.76
Group 4	19.42	20.91	23.90	26.89	28.38	29.87
Group 5	20.52	22.10	25.26	28.41	29.99	31.57
Group 6	22.82	24.58	28.09	31.61	33.36	35.12
Group 7	23.84	25.67	29.34	33.01	34.84	36.68
Group 8	25.66	27.63	31.58	35.53	37.50	39.47
Group 9	22.24	23.68	26.29	30.33	34.38	40.44
Group 10	28.06	30.23	34.53	38.85	41.02	43.17
Group 11	28.47	30.65	35.04	39.41	41.61	43.79
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Jan 1, 2016 to June 30, 2016

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	16.63	17.91	20.48	23.03	24.31	25.59
Group 2	17.91	19.29	22.05	24.81	26.19	27.71
Group 3	18.88	20.34	23.25	26.14	27.60	29.05
Group 4	19.62	21.12	24.14	27.16	28.66	30.17
Group 5	20.73	22.32	25.51	28.70	30.29	31.89
Group 6	23.05	24.83	28.37	31.93	33.69	35.47
Group 7	24.08	25.93	29.63	33.34	35.19	37.05
Group 8	25.92	27.91	31.90	35.88	37.87	39.87
Group 9	22.47	23.92	26.55	30.64	34.72	40.85
Group 10	28.34	30.53	34.88	39.24	41.43	43.61
Group 11	28.75	30.96	35.39	39.80	42.02	44.23
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2016 to June 30, 2017

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	17.05	18.36	20.99	23.61	24.92	26.23

Group 2	18.36	19.78	22.60	25.43	26.84	28.40
Group 3	19.36	20.85	23.83	26.80	28.29	29.78
Group 4	20.11	21.65	24.74	27.84	29.38	30.93
Group 5	21.24	22.88	26.15	29.41	31.05	32.68
Group 6	23.63	25.45	29.08	32.73	34.54	36.36
Group 7	24.68	26.58	30.37	34.17	36.07	37.97
Group 8	26.57	28.61	32.69	36.78	38.82	40.86
Group 9	23.03	24.52	27.21	31.40	35.59	41.87
Group 10	29.05	31.29	35.75	40.22	42.47	44.70
Group 11	29.47	31.73	36.27	40.80	43.07	45.34
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Weekly 35 hours

July 1, 2013 to June 30 2014

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	553.91	596.60	681.98	767.01	809.70	852.39
Group 2	596.60	642.52	734.36	826.20	872.12	918.04
Group 3	628.89	677.32	774.18	870.69	919.12	967.55
Group 4	653.28	703.51	803.96	904.41	954.63	1,004.86
Group 5	690.24	743.33	849.52	955.71	1,008.81	1,061.90
Group 6	767.73	826.92	944.95	1,063.34	1,122.17	1,181.36
Group 7	801.81	863.51	986.92	1,110.33	1,172.04	1,233.74
Group 8	863.15	929.52	1,062.26	1,195.00	1,261.37	1,327.73
Group 9	748.21	816.23	884.25	1,020.29	1,156.32	1,360.38
Group 10	943.87	1,016.70	1,161.63	1,306.93	1,379.75	1,452.22
Group 11	957.50	1,031.05	1,178.49	1,325.58	1,399.48	1,473.03
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2014 to Dec 31, 2014

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	562.22	605.55	692.21	778.51	821.84	865.18
Group 2	605.55	652.16	745.38	838.59	885.20	931.81
Group 3	638.32	687.48	785.80	883.75	932.90	982.06
Group 4	663.08	714.06	816.02	917.97	968.95	1,019.93
Group 5	700.59	754.48	862.26	970.05	1,023.94	1,077.83
Group 6	779.24	839.32	959.12	1,079.29	1,139.00	1,199.08
Group 7	813.83	876.46	1,001.73	1,126.99	1,189.62	1,252.25
Group 8	876.10	943.46	1,078.19	1,212.92	1,280.29	1,347.65
Group 9	759.43	828.47	897.51	1,035.59	1,173.67	1,380.79
Group 10	958.03	1,031.95	1,179.06	1,326.53	1,400.45	1,474.00
Group 11	971.87	1,046.51	1,196.17	1,345.46	1,420.48	1,495.12
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%

Other	65%	70%	80%	90%	95%	100%

Jan 1, 2015 to June 30, 2015

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	567.84	611.61	699.14	786.30	830.06	873.83
Group 2	611.61	658.68	752.83	846.98	894.06	941.13
Group 3	644.71	694.35	793.65	892.58	942.23	991.88
Group 4	669.71	721.20	824.18	927.15	978.64	1,030.13
Group 5	707.59	762.02	870.89	979.75	1,034.18	1,088.61
Group 6	787.03	847.72	968.71	1,090.08	1,150.39	1,211.08
Group 7	821.97	885.23	1,011.74	1,138.26	1,201.51	1,264.77
Group 8	884.86	952.90	1,088.97	1,225.05	1,293.09	1,361.13
Group 9	767.03	836.76	906.49	1,045.95	1,185.40	1,394.59
Group 10	967.61	1,042.27	1,190.85	1,339.80	1,414.45	1,488.74
Group 11	981.58	1,056.98	1,208.13	1,358.92	1,434.68	1,510.07
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2015 to Dec 31, 2015

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	576.36	620.78	709.62	798.09	842.51	886.94
Group 2	620.78	668.56	764.12	859.68	907.47	955.25
Group 3	654.38	704.77	805.56	905.97	956.37	1,006.76
Group 4	679.76	732.02	836.54	941.06	993.32	1,045.58
Group 5	718.21	773.46	883.95	994.44	1,049.69	1,104.94
Group 6	798.84	860.43	983.24	1,106.43	1,167.65	1,229.24
Group 7	834.30	898.51	1,026.92	1,155.33	1,219.54	1,283.74
Group 8	898.13	967.19	1,105.31	1,243.43	1,312.48	1,381.54
Group 9	778.53	849.31	920.08	1,061.63	1,203.19	1,415.51
Group 10	982.12	1,057.90	1,208.71	1,359.89	1,435.67	1,511.07
Group 11	996.31	1,072.83	1,226.25	1,379.30	1,456.20	1,532.73
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Jan 1, 2016 to June 30, 2016

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	582.12	626.99	716.72	806.07	850.94	895.80
Group 2	626.99	675.25	771.76	868.28	916.54	964.80
Group 3	660.92	711.82	813.61	915.03	965.93	1,016.83
Group 4	686.56	739.34	844.91	950.47	1,003.26	1,056.04
Group 5	725.39	781.19	892.79	1,004.39	1,060.19	1,115.99
Group 6	806.83	869.04	993.08	1,117.49	1,179.32	1,241.53
Group 7	842.64	907.49	1,037.19	1,166.88	1,231.73	1,296.58
Group 8	907.12	976.86	1,116.36	1,255.86	1,325.61	1,395.36
Group 9	786.32	857.80	929.28	1,072.25	1,215.22	1,429.67

Group 10	991.94	1,068.48	1,220.80	1,373.49	1,450.03	1,526.19
Group 11	1,006.27	1,083.56	1,238.52	1,393.10	1,470.76	1,548.05
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2016 to June 30, 2017

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	596.68	642.66	734.64	826.22	872.21	918.20
Group 2	642.66	692.13	791.06	889.99	939.45	988.92
Group 3	677.44	729.61	833.95	937.91	990.08	1,042.25
Group 4	703.72	757.82	866.03	974.23	1,028.34	1,082.44
Group 5	743.53	800.72	915.11	1,029.50	1,086.69	1,143.88
Group 6	827.00	890.76	1,017.90	1,145.43	1,208.81	1,272.57
Group 7	863.71	930.18	1,063.12	1,196.06	1,262.52	1,328.99
Group 8	929.79	1,001.29	1,144.27	1,287.26	1,358.75	1,430.24
Group 9	805.98	879.25	952.52	1,099.06	1,245.60	1,465.41
Group 10	1,016.74	1,095.19	1,251.32	1,407.83	1,486.28	1,564.34
Group 11	1,031.43	1,110.65	1,269.48	1,427.92	1,507.53	1,586.75
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Weekly 40 hours
July 1, 2013 to June 30, 2014

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	633.04	681.83	779.41	876.58	925.37	974.16
Group 2	681.83	734.31	839.27	944.23	996.71	1,049.19
Group 3	718.73	774.08	884.78	995.07	1,050.42	1,105.77
Group 4	746.61	804.01	918.81	1,033.61	1,091.01	1,148.41
Group 5	788.84	849.52	970.88	1,092.24	1,152.92	1,213.60
Group 6	877.40	945.05	1,079.94	1,215.24	1,282.48	1,350.13
Group 7	916.35	986.87	1,127.91	1,268.95	1,339.47	1,409.99
Group 8	986.46	1,062.31	1,214.01	1,365.71	1,441.56	1,517.41
Group 9	855.10	932.83	1,010.57	1,166.04	1,321.51	1,554.72
Group 10	1,078.71	1,161.94	1,327.58	1,493.63	1,576.86	1,659.68
Group 11	1,094.29	1,178.34	1,346.85	1,514.95	1,599.41	1,683.46
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2014 to Dec 31, 2014

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate
Group 1	642.54	692.06	791.10	889.73	939.25	988.77
Group 2	692.06	745.32	851.86	958.39	1,011.66	1,064.93
Group 3	729.51	785.69	898.05	1,010.00	1,066.18	1,122.36
Group 4	757.81	816.07	932.59	1,049.11	1,107.38	1,165.64

Group 5	800.67	862.26	985.44	1,108.62	1,170.21	1,231.80
Group 6	890.56	959.23	1,096.14	1,233.47	1,301.72	1,370.38
Group 7	930.10	1,001.67	1,144.83	1,287.98	1,359.56	1,431.14
Group 8	1,001.26	1,078.24	1,232.22	1,386.20	1,463.18	1,540.17
Group 9	867.92	946.82	1,025.73	1,183.53	1,341.33	1,578.04
Group 10	1,094.89	1,179.37	1,347.49	1,516.03	1,600.51	1,684.58
Group 11	1,110.70	1,196.02	1,367.05	1,537.67	1,623.40	1,708.71
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Jan 1, 2015 to June 30, 2015

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	648.96	698.98	799.01	898.63	948.64	998.66
Group 2	698.98	752.78	860.38	967.98	1,021.78	1,075.58
Group 3	736.81	793.55	907.03	1,020.10	1,076.84	1,133.58
Group 4	765.39	824.23	941.92	1,059.61	1,118.45	1,177.29
Group 5	808.68	870.89	995.30	1,119.71	1,181.92	1,244.12
Group 6	899.47	968.82	1,107.10	1,245.80	1,314.73	1,384.09
Group 7	939.40	1,011.69	1,156.28	1,300.86	1,373.16	1,445.45
Group 8	1,011.27	1,089.03	1,244.54	1,400.06	1,477.82	1,555.57
Group 9	876.60	956.29	1,035.98	1,195.37	1,354.75	1,593.82
Group 10	1,105.84	1,191.16	1,360.97	1,531.19	1,616.52	1,701.42
Group 11	1,121.81	1,207.98	1,380.72	1,553.05	1,639.64	1,725.80
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2015 to Dec 31, 2015

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	658.70	709.46	811.00	912.11	962.87	1,013.64
Group 2	709.46	764.07	873.28	982.50	1,037.10	1,091.71
Group 3	747.86	805.45	920.64	1,035.40	1,092.99	1,150.58
Group 4	776.87	836.59	956.05	1,075.50	1,135.23	1,194.95
Group 5	820.81	883.95	1,010.23	1,136.51	1,199.64	1,262.78
Group 6	912.96	983.35	1,123.71	1,264.49	1,334.46	1,404.85
Group 7	953.49	1,026.87	1,173.62	1,320.38	1,393.76	1,467.13
Group 8	1,026.44	1,105.36	1,263.21	1,421.06	1,499.98	1,578.91
Group 9	889.75	970.64	1,051.52	1,213.30	1,375.07	1,617.73
Group 10	1,122.43	1,209.03	1,381.38	1,554.16	1,640.77	1,726.94
Group 11	1,138.64	1,226.09	1,401.43	1,576.35	1,664.23	1,751.69
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Jan 1, 2016 to June 30, 2016

	Step 1	Step 2	Step 3	Step 4	Step 5	Job Rate

Group 1	665.28	716.56	819.11	921.23	972.50	1,023.78
Group 2	716.56	771.71	882.02	992.32	1,047.47	1,102.63
Group 3	755.34	813.51	929.84	1,045.75	1,103.92	1,162.09
Group 4	784.64	844.96	965.61	1,086.25	1,146.58	1,206.90
Group 5	829.02	892.79	1,020.33	1,147.87	1,211.64	1,275.41
Group 6	922.09	993.18	1,134.94	1,277.14	1,347.80	1,418.90
Group 7	963.02	1,037.13	1,185.36	1,333.58	1,407.69	1,481.80
Group 8	1,036.70	1,116.42	1,275.84	1,435.27	1,514.98	1,594.70
Group 9	898.65	980.34	1,062.04	1,225.43	1,388.82	1,633.91
Group 10	1,133.65	1,221.12	1,395.20	1,569.70	1,657.17	1,744.21
Group 11	1,150.02	1,238.36	1,415.45	1,592.11	1,680.87	1,769.20
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

July 1, 2016 to June 30, 2017

	Step 1	**Step 2**	**Step 3**	**Step 4**	**Step 5**	**Job Rate**
Group 1	681.91	734.47	839.59	944.26	996.81	1,049.37
Group 2	734.47	791.00	904.07	1,017.13	1,073.66	1,130.19
Group 3	774.22	833.84	953.09	1,071.90	1,131.52	1,191.14
Group 4	804.25	866.08	989.75	1,113.41	1,175.24	1,237.07
Group 5	849.74	915.11	1,045.84	1,176.57	1,241.93	1,307.30
Group 6	945.14	1,018.01	1,163.32	1,309.06	1,381.49	1,454.37
Group 7	987.10	1,063.06	1,214.99	1,366.92	1,442.88	1,518.85
Group 8	1,062.62	1,144.33	1,307.74	1,471.15	1,552.86	1,634.56
Group 9*	921.11	1,004.85	1,088.59	1,256.07	1,423.54	1,674.75
Group 10	1,161.99	1,251.65	1,430.08	1,608.95	1,698.60	1,787.82
Group 11	1,178.78	1,269.31	1,450.83	1,631.91	1,722.89	1,813.43
NOTE: Progressions						
Trade*	55%	65%	70%	80%	90%	100%
Other	65%	70%	80%	90%	95%	100%

Shift Premium

<u>Effective July 1, 2013</u>
$.85/hour on 4:00pm to midnight shift
$1.15/hour on midnight to 8:00am shift

<u>Effective July 1, 2015</u>
$1.00/hour on 4:00pm to midnight shift
$1.25/hour on midnight to 8:00am shift

GROUP CLASSIFICATION AND PAY METHOD

	Paid Hourly	Salaried 35 Hr. Wk.	Salaried 40 Hr. Wk.
GROUP 1			
Office Services clerk		*	
GROUP 2			
Cashier		*	
Computer Operator		*	
Microfilming clerk		*	
Purchasing clerk		*	
Switchboard Operator		*	
Utility person	*		
GROUP 3			
Billing clerk		*	
Engineering clerk		*	
Customer Service Representative		*	
Labourer	*		
Meter reader	*		
Operations clerk			*
Payments clerk		*	
GROUP 4			
Accounts Payable clerk		*	
Adjustments clerk		*	
APP clerk		*	
Inventory clerk		*	
Utility person	*		

	Paid Hourly	Salaried 35 Hr. Wk.	Salaried 40 Hr. Wk.
GROUP 5			
Billing clerk		*	
Collections clerk		*	
Energy Services clerk		*	
Engineering clerk		*	
Final Bills clerk		*	
Meter Reader serviceperson	*		
Operations clerk			*
Permits clerk		*	
Stockkeeper	*		
Water Heater serviceperson	*		
GROUP 6			
Accounting clerk		*	
Cable locator	*		
Payroll clerk		*	
Technical Support Analyst		*	
GROUP 7			
Buyer		*	
Building Serviceperson	*		
Draftsperson		*	
Engineering Assistant		*	*
Lead Water Heater Serviceperson	Paid job rate.		
Meter Reader Sub-Foreperson	Paid job rate.		
GROUP 8			
Energy Services Representative		*	
Inspector	*		
Mechanic "A" License	Paid job rate.		
Help Desk/ Network Administrator		*	

	Paid Hourly	Salaried 35 Hr. Wk.	Salaried 40 Hr. Wk.
GROUP 9			
Power Line Technician	*		
Meter Technician	*		
P&C Technician	*		
GROUP 10			
Lead Power Line Technician	Paid job rate.		
Lead Meter Technician	Paid job rate.		
Lead P&C Technician	Paid job rate.		
Mechanic Sub-Foreperson	Paid job rate.		
GROUP 11			
Snr. Energy Services Representative		*	*
Engineering Technologist		*	*
Power Line Technician/ Operator	Paid job rate.		
Line Sub-Foreperson	Paid job rate.		
Meter Technician Sub-Foreperson	Paid job rate.		
P&C Sub-Foreperson	Paid job rate.		

Shift Premium

Effective July 1, 2013

$.85/hour on 4:00pm to midnight shift
$1.15/hour on midnight to 8:00am shift

Effective July 1, 2015

$1.00/hour on 4:00pm to midnight shift
$1.25/hour on midnight to 8:00am shift

Appendix 4 – B

Halton Hills Hydro Inc.

CONTROL ROOM SERVICES AGREEMENT

THIS AGREEMENT made effective the 23rd day of September, 2013,

BETWEEN:

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC., an Ontario corporation having offices within the Town of Oakville, in the Province of Ontario (hereinafter referred to as "**Oakville Hydro**")

– and –

HALTON HILLS HYDRO INC., an Ontario corporation having offices within the Town of Halton Hills Hydro, in the Province of Ontario (hereinafter referred to as "**Halton Hills Hydro**")

WHEREAS Halton Hills Hydro is engaged in the business of the local distribution of electricity within the municipality of Halton Hills and for such purposes has recently determined that its ability to serve its customers would be significantly enhanced if it had access to an electricity distribution system control room to enable it to more effectively manage its electricity distribution system generally; and

WHEREAS Oakville Hydro is engaged in the business of the local distribution of electricity in Oakville (adjacent to the municipality of Halton Hills) and for such purposes has personnel, premises, and a Control Room, which Control Room has available capacity which could be deployed as is and/or could be augmented to also provide Control Room services to Halton Hills Hydro; and

WHEREAS Oakville Hydro and Halton Hills Hydro have agreed on the basis upon which the Control Room services of Oakville Hydro may be made available to Halton Hills Hydro, and

WHEREAS Oakville Hydro and Halton Hills Hydro wish to enter into this agreement to record their mutual understandings.

NOW THEREFORE, in consideration of the premises and the covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is acknowledged by each party to this Agreement, the parties covenant and agree as follows:

ARTICLE 1 – DEFINITIONS

1.1 Words and Phrases Defined

In this Agreement, unless the subject matter or context is inconsistent therewith, the words and phrases set forth below shall have the meanings attributed below:

"**Agreement**" means this Agreement and includes all schedules to this Agreement and, further, includes all amendments and supplements as may be made from time to time.

"**Business Day**" means a day that is not a Saturday, Sunday or a public or bank holiday in the Province of Ontario;

"**Control**" shall have the meaning given thereto for the purposes of the Ontario *Business Corporations Act.*;

"**Control Room**" means the Oakville Hydro electricity system control room and any complimentary, substituted or auxiliary control room facilities operated by Oakville Hydro from time to time;

"**Default**" shall have the meaning provided therefor in Section 17.1.

"**Dispute Resolution Provisions**" means the provisions of Article 20.

"**Force Majeure**" means in relation to the performance of any obligation under this Agreement, any cause, condition or event of any nature whatsoever which is beyond the reasonable control of the party responsible for such obligation which prevents in whole or in part the performance by either party of its respective obligations including without limitation, acts of war, revolution, riot, sabotage, vandalism, earthquakes, storms, flooding, lightning and other acts of God, local or national emergencies, strikes, lockouts, work slowdowns and all other labour disputes, whether lawful or unlawful.

"**Information**" means: (i) all business, financial and technical information and data, whether oral or written, in whatever media or form, which is disclosed, directly or indirectly, by either party hereto to the other party hereto whether before, on or after the date hereof including, without limiting the generality of the foregoing, any other information or data relating to, comprising, describing or incorporating a party's current or proposed products, services, prices, suppliers, customers, dealers, agents, employees, businesses, business opportunities, addresses, locations, systems, specifications, drawings, sketches, designs, ideas, creations, inventions, formulas, improvements, models, samples, processes, codes, equipment, methods, techniques, experiments, demonstrations, prototypes, procedures, design methodology, evaluation methodology and criteria, trade secrets, business operations, reports, plans, forecasts, costs, salaries, sales, income, profit, profitability, pricing, business information, financial information and situation, business or marketing plans, distribution and other business strategies, current or historical data, test data, research, technology, computer systems, computer programs, source, object and any other codes, routines and other software and documentation, scientific, computer or technical information and network architecture maps, specifications and service; (ii) any information marked "private", "restricted", "confidential", "proprietary" (or otherwise marked or described so as to indicate confidentiality) or which, by the nature of the circumstances surrounding the disclosure thereof, ought in good faith be treated as confidential, in all cases in its original form or whether it is converted to different forms or combined with additional information, and including any information relating to third parties contained therein; and (iii) any notes, memoranda, summaries, analyses, compilations or any other writings relating howsoever to any of the foregoing prepared relative thereto by the receiving party or on its behalf.

"**Notice**" is defined in Section 17.1.

"**Person**" means an individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted.

"**Personal Information**" means information about an identifiable individual including, without limitation, a person's name, address, phone number, fax number, e-mail address, social insurance number or other government-issued identifier, credit card information and IP addresses, in any media or format including computerized or electronic records as well as paper-based files, used or collected from consumers, utility customers, employees of either Oakville Hydro or Halton Hills Hydro or any other person or individual (collectively, "Individuals").

"**Prescribed Rate**" means the rate of interest allowed, from time to time, to Oakville Hydro on its debt for the purposes of calculating the electricity distribution rates for Oakville Hydro pursuant to Performance Based Regulation of hydro utilities by the Ontario Energy Board.

"**Service Personnel**" means the operations staff of Oakville Hydro responsible for the operation of the Control Room and related electricity distribution functions as identified by Oakville Hydro from time to time.

"**Term**" means the period of time that this Agreement is in effect pursuant to the provisions of Article 8.

1.2 Derivations

Where a word or phrase is defined for the purposes of this Agreement, a derivative of that word or phrase shall have a corresponding meaning.

1.3 Extended Meanings

In this Agreement words importing the singular number only include the plural and *vice versa*, words importing any gender include all genders and words importing persons include all Persons.

1.4 Accounting Terms

All accounting terms not otherwise defined in this Agreement shall have the meanings assigned to them in accordance with Canadian generally accepted accounting principles and, alternatively where appropriate, the International Financial Reporting Standards ("IFRS") except where inappropriate in the context in which such accounting term is used in this Agreement.

1.5 Industry Terms

Unless expressly defined herein, words having well known technical or trade meanings within the electricity distribution and related industries shall be so construed.

ARTICLE 2: INTERPRETATION

2.1 Interpretation of Agreement and Schedules

The body of this Agreement and all the Schedules to this Agreement constitute the entire agreement between the parties and, accordingly, the body of this Agreement and all such Schedules shall be interpreted and enforced as though the provisions of such Schedules were set forth in the body of this Agreement prior to the execution page hereof and without giving paramountcy to the provisions of the body of this Agreement or any of the Schedules to this Agreement over the provisions of the other.

2.2 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario and shall be treated in all respects as an Ontario contract.

2.3 Legislation, Regulations and Rules

Any reference in this Agreement to all or any part of any statute, regulation or rule shall, unless otherwise expressly stated herein, be a reference to the statute, regulation or rule, or part thereof, as amended from time to time.

2.4 Article, Section, Subsection and Item References

The division of this Agreement into Articles, Sections and Subsections are for convenience of reference only and shall not affect or be considered to affect the construction or interpretation of the provisions of this Agreement. References in this Agreement or in a Schedule to this Agreement to an Article, Section or Subsection shall mean a reference to an Article, Section or Subsection within the body of this Agreement. References herein to an Item without identifying the Section in which the Item is contained shall mean a reference to the Item in the same Section where the reference is made.

2.5 Headings

The headings of Articles, Sections and Subsections herein and in the Schedules to this Agreement are inserted for convenience of reference only and shall not affect or be considered to affect the construction or interpretation of the provisions of this Agreement.

2.6 "Hereof" Etc.

The terms "hereof", "hereunder", "herein", "hereto" and similar expressions refer to this Agreement in its entirety and not to any particular Article, Section, Subsection or other portion of this Agreement.

2.7 Currency of Contract

All references in this Agreement to money shall denote the lawful currency of Canada, except as may be otherwise expressly stated.

2.8 Accounting Principles

Wherever in this Agreement reference is made to a calculation to be made or an action to be taken in accordance with generally accepted accounting principles, such reference will be deemed to be to the generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants, or any successor institute, applicable as at the date on which such calculation or action is made or taken or required to be made or taken in accordance with generally accepted accounting principles.

2.9 Waiver of Contra-Proferentem Rule

Each party to this Agreement acknowledges and agrees that it has participated in the drafting of this Agreement and, accordingly, this Agreement shall not be interpreted either more or less favorably in favor of any party to this Agreement by virtue of the fact that one party or its counsel has been principally responsible for the drafting of all or a portion of this Agreement.

ARTICLE 3 –CONTROL ROOM

3.1 Supply

Oakville Hydro shall, throughout the Term of this Agreement, supply the services of the Control Room to Halton Hills Hydro to provide to Halton Hills Hydro the same services as the Control Room provides to Oakville Hydro. For clarity, a non-exhaustive list of examples of the services to be provided under this paragraph may be set out in Schedule 3.1 to this Agreement and such list may be amended from time to time.

The fees to be paid by Halton Hills Hydro to Oakville Hydro for the services of the Control Room will be set out in Schedule 3.1, as amended from time to time by agreement of the parties, and unless otherwise provided in Schedule 3.1 those fees will be due and payable on the anniversary date of this Agreement being the twenty-third (23) day of September in each year.

3.2 Conflicts of Interest and Release of Service Personnel by Halton Hills Hydro

Halton Hills Hydro acknowledges that the Service Personnel are employees of Oakville Hydro and that certain Halton Hills employees may, from time to time, be placed on secondment to Oakville Hydro from Halton Hills Hydro for the purpose of working in the Control Room under the direction and control of Oakville Hydro.

The parties acknowledge that the Service Personnel and the seconded Halton Hills employees may perceive, from time to time, that they may have a conflict of interest with respect to matters which may involve business relations between Oakville Hydro and Halton Hills Hydro.

Halton Hills Hydro agrees that, insofar as this Agreement is concerned, any duties of care, allegiance, fidelity or employment obligation that those Service Personnel or seconded employees may owe, or believe they owe, to Oakville Hydro in connection with their work regarding the Control Room is paramount to any duty of care, allegiance, fidelity or employment obligation that they may owe or believe they owe to Halton Hills Hydro.

Accordingly, in each event of an unresolved conflict of interest in the obligations that any Service Personnel (or seconded Halton Hills employee) owes to Oakville Hydro and the obligations they may owe, or believe that they may owe, to Halton Hills Hydro as a Control Room operator, they may be excused by Oakville Hydro from performing such obligations and the particular event shall be referred by Oakville Hydro to officers or employees of Oakville Hydro and officers or employees of Halton Hills Hydro respectively, who do not have such a conflict, for resolution or, failing resolution at that level, to the Board of Directors of the two corporations, for discussion and resolution.

Further, Halton Hills Hydro hereby releases and forever discharges Oakville Hydro, all Service Personnel and any seconded Halton Hills employee acting as a Control Room operator from any and all liability or damages that may arise from or be associated with the operation of the Control Room other than liability or damages caused by their respective gross negligence or wilful misconduct.

3.3 Indemnity and Release

Halton Hills Hydro hereby indemnifies and holds harmless Oakville Hydro and each of the Service Personnel from and against all losses, claims and liability whatsoever that may arise howsoever from or may be associated with the performance by any Service Personnel of their responsibilities with respect to the Control Room except such thereof as results from the gross negligence or wilful misconduct of Service Personnel, or any of them.

Oakville Hydro hereby indemnifies and holds harmless Halton Hills Hydro and the Halton Hills Hydro employees on secondment from Halton Hills Hydro to Oakville Hydro as Control Room operators from and against all losses, claims and liability whatsoever that may arise howsoever from or may be associated with the performance by any seconded Halton Hills employee of their responsibilities to Oakville Hydro except such thereof as results from the gross negligence or wilful misconduct of such Halton Hills employees, or any of them.

3.4 Not Employees

The Service Personnel are not, and shall in no event be considered to be, employees of Halton Hills Hydro for the purposes of this Agreement. In no event shall Halton Hills Hydro become obligated howsoever to pay, or make any contribution to Oakville Hydro in respect of, the salaries, wages, benefits or other compensation payable by Oakville Hydro to the Service Personnel. Halton Hills Hydro will pay the employment and benefits compensation and pension contributions owing to any Halton Hills Hydro employee seconded to the Control Room. In no event shall the use by Halton Hills Hydro of the services of the Control Room become the basis for any labour union or similar organization to become the bargaining agent for any employees of Halton Hills Hydro.

ARTICLE 4 - TAXES

4.1 Taxes

The amounts stated in this Agreement to be payable by Halton Hills Hydro to Oakville Hydro pursuant to this Agreement do not include any taxes. Halton Hills Hydro shall be responsible for the payment of (and shall pay or reimburse Oakville Hydro if such tax is paid by Oakville Hydro) all Goods and Services taxes, Harmonized Sales Tax, Provincial Sales Tax and other taxes of a similar nature applicable to, or arising from the price or value, purchase or sale or the provision or use of any of the personnel, services, equipment and materials provided by Oakville Hydro to Halton Hills Hydro pursuant to this Agreement, regardless of the period or entity actually taxed.

ARTICLE 5 – PROVISION OF INSURANCE COVERAGE

5.1 Coverage upon Request

Upon request by Halton Hills Hydro to Oakville Hydro, subject to Oakville Hydro being reasonably able to do so and conditional upon Halton Hills Hydro paying any incremental cost to Oakville Hydro for so doing, Oakville Hydro shall add Halton Hills Hydro as an insured under the insurance policies of Oakville Hydro so as to make Halton Hills Hydro insured under such insurance policies.

ARTICLE 6 – PAYMENTS, INTEREST, ADJUSTMENTS AND SET OFF

6.1 Payments

All amounts payable by a party hereto pursuant to this Agreement shall be paid forthwith upon demand by the party owing the payment.

6.2 Interest

All amounts not paid by a party hereto after demand for the payment thereof shall bear interest until paid at the prescribed rate established under the Income Tax Act, Canada and all such interest payable by a party hereto shall be paid at the same time as the amount to which such interest relates is paid.

6.3 Adjustments

Upon the request of either party, the parties shall negotiate in good faith any change to this Agreement reasonably sought by a party, without any obligation upon the parties to agree to any change to this Agreement and, subject to express provision otherwise made elsewhere in this Agreement, the Dispute Resolution Provisions shall not apply to such negotiations.

6.4 Set-Off

A party obliged to make a payment to the other party may set off against the amount otherwise payable any amount to which the first party is then entitled to receive from the other party and to remit to the other party the amount by which the amount owed by the first party to the other party exceeds the amount owed to it by the other party, if any, provided the first party informs the other party of it having so done prior to the date upon which the other party is obliged to remit to the first party the amount which the first party has set off against the amount otherwise payable by the first party to the other party.

ARTICLE 7 - STANDARDS

7.1 Standards of Performance

Except as specifically set forth herein, for the purpose of this Agreement the standards and practices of performance within the electricity transmission, distribution and generation industry in the Province of Ontario shall be the measure of the performance of a party hereto.

ARTICLE 8 - TERM

8.1 Original Term

Subject to Sections 8.2 and 8.3, the term of this Agreement shall begin on the date of this Agreement and will terminate at the end of the day on September 30, 2015, such period being referred to as the "Original Term".

8.2 Extension of Original Term

Unless either party gives the other party written notice of termination of this Agreement at least ninety (90) days prior to the end of the Original Term or of any extension term, as the case may be, this Agreement shall automatically be renewed at the end of the Original Term or of any such extension term, as the case may be, for a one (1) year period upon the same terms and conditions in effect under this Agreement at the end of the Original Term or the end of the extension term, as the case may be.

8.3 Termination by Agreement

This Agreement may be terminated at any time by the agreement of both parties, a matter not to be determined pursuant to the Dispute Resolution Provisions.

ARTICLE 9 – TERMINATION

9.1 Expiry of Term

Upon expiration or termination of this Agreement the rights granted by each party to the other party shall immediately terminate and neither party shall have any further obligations to the other except:

(i) to finally settle accounts between the parties regarding the activities of the parties during the Term of this Agreement;

(ii) regarding those matters that this Agreement provides will be done upon termination of this Agreement; and

(iii) as expressly otherwise provided in this Agreement.

9.2 Removal

Promptly upon termination of this Agreement for any reason, each party shall, at its sole cost and expense, remove all of its equipment, facilities and other associated property from the property and facilities of the other party under the supervision of such other party should such other party desire. Should a party fail to effect such removal within thirty (30) days following termination of this Agreement, the equipment, facilities and other associated property of the party shall be deemed abandoned and may be removed by the other party at the expense of the party whose property is removed.

9.3 Effect of Termination

Notwithstanding the foregoing or any other provision of this Agreement, no termination or expiration of this Agreement shall effect the rights or obligations of any party:

(i) with respect to any prior breach or any then existing defaults of the obligation to make any payment hereunder attributable to the period prior to the date of termination or expiration; or

(ii) with respect to those provisions of this Agreement which survive the expiry of the Term of the Agreement by virtue of the express provisions of this Agreement or necessary implication based upon the terms of this Agreement or the course of dealing between the parties to the Agreement.

ARTICLE 10 – FORCE MAJEURE

10.1 Generally

Neither party shall be liable to the other party for any default in performance or compliance with provisions of this Agreement if such default is due to any circumstance beyond the reasonable control of the affected party including, without limitation of the foregoing, any act of God, fire, flood, lack of or delay in transportation, the adoption or amendment of government codes, ordinances, laws, rules, regulations or restrictions that materially impair the affected parties performance hereunder, war or civil disorder, strikes, law, codes or other labour disputes. Notwithstanding anything in the preceding sentence of this Section, none of the foregoing shall excuse any default in payment of any amount payable pursuant to this Agreement.

ARTICLE 11 – DEFAULT

11.1 Events of Default

A party shall be in default under this Agreement (a "Default") if:

(i) it fails to pay any amount which is due and unpaid within thirty (30) days of receipt from the party to which the amount is due of a written notice (a "Payment Notice") that the amount is due and unpaid; or

(ii) the other party gives it written notice that it has given it three (3) or more Payment Notices in any given twelve (12) month period;

(iii) in the case of any other material breach of this Agreement, it fails to cure such breach within thirty (30) days after notice specifying such breach, provided that if the breach is of a nature that cannot be cured within thirty (30) days, a default shall not have occurred so long as the breaching party has commenced to cure the breach within said time period and thereafter diligently pursues such cure to completion;

(iv) it becomes insolvent or bankrupt or any bankruptcy, reorganization, debt arrangement or other proceeding under any bankruptcy or insolvency law or any dissolution or liquidation proceeding being instituted by or against it; or

(v) the private or, court appointment of a receiver or receiver and manager or officer with similar powers over any part of its property.

11.2 Remedies

In the event of a Default by a party, the non-defaulting party may avail itself of one or more of the following remedies:

(i) take such action or actions as it determines reasonable or necessary, in its sole discretion, to correct the default; or

(ii) pursue any remedies it may have under applicable law or principles of equity, including specific performance; or

(iii) terminate this Agreement upon thirty (30) days prior written notice to the defaulting party.

Except as set forth to the contrary herein, any right or remedy of a party hereto shall be cumulative and without prejudice to any other right or remedy, whether contained herein or not.

ARTICLE 12 – TRANSFER

12.1 Prohibition

This Agreement may not be assigned, in whole or in part, by either party without the prior written consent of the other party. Each party shall have the right to arbitrarily withhold, delay or condition such consent.

12.2 Exception re: Security

Notwithstanding any other provision of this Agreement, a party may assign this Agreement as collateral security to a lender.

12.3 Change in Control

In the event of a change in control of a party, the other party shall have the right to terminate this Agreement by giving Notice of termination to the party who has had a change in Control within 1 year after such change of control and such Notice shall provide for a six (6) month notice of termination.

ARTICLE 13 - INSURANCE

13.1 Maintenance

During the term of this Agreement and at its sole expense, each party shall maintain commercial general liability insurance which shall have a minimum limit of liability of five million dollars ($5,000,000.00) per occurrence and shall include premises and operations liability, contractor's contingency liability with respect to the operations of subcontractors, completed operations liability and contractual liability and shall name the other party as co-insured.

ARTICLE 14 – DISPUTE RESOLUTION PROVISIONS

14.1 Generally

Should any dispute or disagreement of any kind arise at any time with respect to the interpretation or application of this Agreement or the carrying out by a party of its obligations hereunder, the parties agree that good faith negotiations shall take place between them with the objective of resolving such dispute or disagreement, and the dispute or disagreement shall thereafter be referred to the Chief Executive Officers of the parties who shall attempt in good faith to resolve such dispute or disagreement. If within the next following thirty (30) day period, the dispute or disagreement has not been resolved to the satisfaction of the parties, any party to whose satisfaction such dispute or disagreement has not been resolved (the "Aggrieved Party") may refer the dispute or disagreement to binding arbitration pursuant to the *Arbitration Act*, 1991 (Ontario) in accordance with this Section by notice in writing to the other party. Within ten (10) days of giving of such notice of arbitration, the parties shall jointly select a single arbitrator who shall be independent of and acceptable to the parties. In the event that the parties hereto are unable to agree upon a suitable arbitrator within such ten (10) day period, the arbitrator shall be selected by a Justice of the Ontario Superior Court of Justice upon application by any party to this Agreement.

14.2 Fees and Expenses

The fees and expenses of the arbitrator shall be split equally between the parties to the dispute.

14.3 Procedures

The arbitrator shall fix the appropriate procedures for the arbitration which may include an oral hearing. Unless the parties wish to mutually set the points at issue, the arbitrator shall order the parties to file statements pursuant to S. 25 of the Arbitration Act, 1991. The arbitrator may order interest on any award and the arbitrator may award costs to either party. In the absence of any such award of costs, each of the parties shall bear its own costs of any arbitration pursuant to this Section. The arbitrator shall be strictly bound by legal principles and the nature of this Agreement in rendering his decision.

14.4 Private Arbitration

The arbitration shall be completely private (subject to the regulatory requirements of any party or its Affiliates as a public company or regulated company) and shall take place in Toronto, Ontario unless the parties agree otherwise.

14.5 Arbitration Binding

The Parties agree that good faith negotiations and arbitration shall all be without recourse to the Courts and that the award of the arbitrator or arbitrators shall be final and binding, except that:

(i) either party may appeal an arbitration award to the Courts of the Province of Ontario on a question of law; and

(ii) either party may apply to a court of competent jurisdiction for an interim measure of protection.

ARTICLE 15 – INTELLECTUAL PROPERTY

15.1 No transfer of Rights

Except as otherwise expressly provided herein, this Agreement does not convey to a party any right, title, estate or interest whatsoever in or to any of the copyrights, patent rights and other intellectual property rights of the other party hereto including without limitation any rights regarding either party's SCADA system, distribution system maps and drawings or other intellectual property rights used to operate any electrical system, grid, computer system or equipment; provided that Halton Hills Hydro hereby assigns to Oakville Hydro for the Term of this Agreement and any renewals a non-transferrable licence to use any and all intellectual property rights owned or licenced by Halton Hills Hydro which may be necessary, desirable or necessary to enable Oakville Hydro to operate the Control Room for the benefit of Halton Hills Hydro, all as appropriate in support of the parties mutual co-operation and the spirit of this Agreement.

15.2 Jointly Developed Rights

The parties shall own jointly and equally any copyrights, patent rights and other intellectual property rights that are developed by the parties pursuant to this Agreement. Should a party wish to sell any or all of its interest in any jointly owned copyrights, patent rights and other intellectual property rights then the other party shall have a Right of First Offer with respect to the interests wished to be sold, the terms of which shall be settled by arbitration pursuant to the Dispute Resolution Provisions in the event that such terms cannot be agreed by the parties.

15.3 Logos

Neither party shall use the name, logo, trade dress, trade marks or other distinguishing characteristics of the other party: (i) without the prior written consent of that other party; and (ii) in the event that a party consents to such use by the other party, that other party most not undertake such use in a manner which might reasonably be construed as misleading to consumers as to the distinction between Oakville Hydro and Halton Hills Hydro.

ARTICLE 16 - NON-DISCLOSURE AND PERSONAL INFORMATION

16.1 Obligations Arising From Disclosure

During the course of the relationship established between the parties pursuant to this Agreement, each party may disclose to the other party or permit the other party access to certain Information, either directly or indirectly. Alternatively, a party may learn of Information independent of any disclosure by the other party. Each disclosure of Information will be made or permitted upon the basis of, and all Information of the other party otherwise learned by a party is received on the basis of, the confidential relationship established between the parties by this Agreement and upon each party's agreement that, unless otherwise specifically authorized in writing by the other, it will:

(i) use the Information solely for the purpose for which it was disclosed;

(ii) take all reasonable care and precautions, at least as great as the care and precautions that it takes to protect its own confidential or proprietary information, to keep the Information confidential;

(iii) not disclose, or allow the disclosure of, any Information before or after the termination of this Agreement, except as permitted by this Agreement;

(iv) restrict disclosure of the Information only to its employees or other personnel, advisors, consultants and agents (collectively, "Representatives") with a need to know the Information and who are bound to maintain the Information confidential;

(v) notify each Representative that receives any Information of the requirements of this Agreement and of the restrictions on use and disclosure of Information imposed by this Agreement;

(vi) insure that no Representative breaches or causes or allows to be breached any of the receiving party's obligations hereunder and direct each Representative to abide by the terms of this Agreement;

(vii) not use, or allow to be used, howsoever any Information to compete with or in a manner detrimental or adverse to the commercial interests of the disclosing party;

(viii) except in connection with the purpose for which Information is disclosed, not copy or duplicate such Information or knowingly allow anyone else to copy or duplicate such Information; and

(ix) promptly return to the disclosing party, upon its request made before or after termination of this Agreement, or certify as destroyed, the Information in whatever form and regardless of whether such Information was made or compiled by the receiving party or furnished by the disclosing party, together with all copies thereof, howsoever made.

16.2 <u>Exceptions</u>

The obligations under this Agreement shall not apply to any Information that the receiving party can demonstrate to the disclosing party's reasonable satisfaction:

(i) became public and generally known through no act or omission of the receiving party or its Representatives;

(ii) was disclosed on a non-confidential basis in good faith to the receiving party by a third party which the receiving party had reasonable grounds to believe had legitimate possession thereof and the right to make such disclosure;

(iii) was in legitimate possession of the receiving party prior to its disclosure by the disclosing party to the receiving party;

(iv) that the receiving party is required by law, judicial or arbitration process to disclose, provided that, prior to disclosing any Information, the receiving party shall promptly notify the disclosing party of such requirement to disclose and take such steps as are reasonably necessary, and cooperate with the disclosing party, to lawfully limit such disclosure and to maintain the confidentiality of the Information in the hands of the receiving party, including obtaining appropriate protective orders; or

(v) is approved in writing by the disclosing party for release or other use by the receiving party according to the terms set out in such written approval.

The burden of demonstrating the applicability of any exception in this Section shall be upon the party seeking to rely upon any such exception.

16.3 Discretionary Disclosure

Each party acknowledges that, notwithstanding the execution of this Agreement, each party maintains the sole and absolute discretion to determine what, if any, Information it will release to the other party. The receiving party acknowledges that the Information disclosed in any manner whatsoever is proprietary to the disclosing party.

16.4 Privacy and Security of Personal Information

Both parties, their employees, agents, subcontractors and any authorized third parties shall comply with all applicable municipal, provincial, and federal laws and regulations governing the privacy and security of Personal Information including, without limitation, the Municipal Freedom of Information and Protection of Privacy Act, Ontario.

16.5 No Warranty

Each party warrants that it has all requisite authorization to enter into this Agreement and that it has the right to disclose any Information disclosed to the other party. Each party acknowledges and understands that the other party makes no other representation or warranty in relation to any Information disclosed including, without limiting the generality of the foregoing, as to its adequacy, accuracy, or suitability for any purpose and, except as expressly agreed in writing, shall not be liable for any loss or damage arising from the use of the Information howsoever caused.

16.6 Intellectual Property

Each party acknowledges and agrees that all Information shall be owned solely by the disclosing party. Each party further agrees that nothing contained in this Agreement shall be construed as granting any rights, by licence or otherwise, under any intellectual property rights in, or concerning any of, the disclosing party's Information.

16.7 Indemnity

The receiving party shall indemnify and save harmless the disclosing party from and against all losses, liabilities, damages, costs and expenses (including reasonable legal fees and disbursements) suffered or incurred by the disclosing party as a result of a breach of a term of this Agreement by the receiving party or its Representatives.

16.8 Equitable Remedies

In the event of a breach or threatened breach of any term of this Agreement, the receiving party agrees that the harm suffered or that may be suffered by the disclosing party would not be compensable by monetary damages alone and, accordingly, that the disclosing party shall, in addition to other available legal or equitable remedies, be entitled to the issuance of immediate injunctive relief, specific performance and any other remedies in law or equity for such breach or threatened breach of the receiving party's obligations hereunder. The receiving party shall reimburse the disclosing party for all reasonable costs and expenses, including reasonable legal fees and disbursements, incurred by the disclosing party in attempting to enforce the obligations under this Agreement of the receiving party or its Representatives.

16.9 Independent Activities

Each party, as a disclosing party, understands that the receiving party may currently or in the future be developing information internally, or receiving information from a third party that may be similar to the disclosing party's Information. Accordingly, nothing in this Agreement shall be construed as a representation or warranty that the receiving party will not develop products or services, or have products or services developed for it, or enter into any arrangement that, without violation of any of the provisions of this Agreement, compete with the products or services which are contemplated by, or which are the subject of, the disclosing party's Information or the purpose for which Information was disclosed.

16.10 No Implied Obligations

Neither this Agreement, nor the disclosure or receipt of any Information, shall imply or confirm any intention to enter into any contract or other business relationship, or to purchase any product or service, by either of the parties or any commitment by either of the parties with respect to the present or future development, production or distribution of any product or service.

16.11 Termination and Survival

In the event that this Agreement is terminated, this Agreement shall not apply to any Information disclosed after such termination but, notwithstanding the termination of this Agreement, shall continue to apply to any and all Information disclosed prior to the termination of this Agreement.

ARTICLE 17 – NOTICES

17.1 Addresses

All notices and other communications from one party hereto to another (a "Notice") that are required or permitted under this Agreement shall be in writing and shall be delivered by hand or by courier, transmitted by facsimile, sent by mail or sent by e-mail to the party hereto to whom it is to be given at the address for such party below:

(i) to Oakville Hydro:

Postal Address: P.O. Box 1900, 861 Redwood Square
Oakville, Ontario L6J 5E3

Attention: Mr. Michael Brown
Vice President- Engineering and Operations
& Chief Operating Officer

Fax Number: (905) 285-4440

E-mail Address: mbrown@oakvillehydro.com

(ii) to Halton Hills Hydro:

Postal Address: 43 Alice Street
Acton, Ontario L7J 2A9

Attention: Mr. Arthur A. Skidmore
President and Chief Executive Officer

Fax Number: (519) 853-5592

E-mail Address: askidmore@haltonhillshydro.com

17.2 **Time of Receipt**

A Notice will be received for the purposes of this Agreement when actually received by intended recipient thereof. Notices shall be deemed to have been received in the following circumstances:

(i) when transmitted by facsimile or e-mail transmission, at 10:00 in the forenoon (local time of the recipient) on the next Business Day following the day upon which the Notice is transmitted, provided that another copy of the Notice is received or deemed received by the recipient by delivery, courier or post within ten days of the date of deemed receipt of the Notice by facsimile or e-mail transmission; and

(ii) by mail, on the tenth day (days upon which there is an interruption of postal service in Canada or the United States of America excepted) following the day on which the Notice was mailed.

17.3 **Change of Address**

A party hereto may change its address for the purposes of Section 23.1 by giving notice to the other party hereto and in such event all notices thereafter given to that party shall be to such changed address.

ARTICLE 18 – GENERAL

18.1 **Prior Agreements**

This Agreement supersedes and terminates all prior agreements, understandings or writings between the parties hereto and their predecessors, whether written or oral and whether legally enforceable or not, in connection with the matters dealt with in this Agreement.

18.2 **Inurement**

This Agreement shall be binding upon and shall inure to the benefit of the parties hereto and their respective successors, assigns and, as provided for herein, receivers, receiver-managers and trustees.

18.3 **Relationship of Parties**

The relationship between the parties hereto shall not be that of partners, agents, or joint venturers for one another, and nothing contained in this Agreement shall be deemed to constitute a partnership or agency agreement between them for any purposes, including, but not limited, to federal or provincial income tax purposes. The parties hereto, in performing any of their obligations hereunder, shall be independent contractors or independent parties and shall discharge their contractual obligations at their own risk subject, however, to the terms and conditions of this Agreement.

18.4 Waiver in Writing

No waiver by a party hereto of any provision, or the breach of any provision, of this Agreement shall be effective unless it is contained in a written instrument signed by authorized officers or representatives of the party hereto. Such written waiver shall affect only the matter specifically identified in the instrument granting the waiver and shall not extend to any other matter, provision or breach.

18.5 Delay Not Waiver

The failure of a party hereto to give notice to any other party hereto or to take any other steps in exercising any right, or in respect of the breach or nonfulfillment of any provision of this Agreement, shall not operate as a waiver of that right, breach or provision nor shall any single or partial exercise of any right preclude any other or future exercise of that right or the exercise of any other right, whether in law or in equity or otherwise.

18.6 Acceptance of Payment Not Waiver

Acceptance of payment by a party hereto after the breach or nonfulfillment of any provision of this Agreement by another party shall not constitute a waiver of the provisions of this Agreement, other than any breach cured by such payment.

18.7 Amendments

This Agreement may only be amended by a written agreement executed on behalf of both parties hereto by their duly authorized representatives in such regards.

18.8 Time of the Essence

Time shall be of the essence of this Agreement.

18.9 Further Assurances

Each of the parties hereto shall at its own cost and expense, from time to time and without further consideration, execute or cause to be executed all documents and shall take or refrain from taking all actions which are reasonably necessary or reasonably desirable to give effect to the provisions of this Agreement.

18.10 Severability

In the event that any provision of this Agreement shall be adjudged to be invalid for any reason whatsoever, such invalidity shall not affect the operation of any other provision of this Agreement and such invalid provision shall be deemed to have been deleted from this Agreement.

18.11 Use of Name

Each party hereto agrees that it will not use, suffer or permit to be used, directly or indirectly, the name of any other party hereto for any purpose whatsoever without, in each instance, first obtaining the written consent of such other party.

18.12 Waiver of Relief

The parties acknowledge that any default, forfeiture or assignment provisions contained in this Agreement are, in view of the risks inherent in the business to be conducted by the parties, reasonable and equitable. Each party waives any and all rights which it may have at law or in equity against default, forfeiture or penalty if such provisions herein are invoked.

18.13 No Third Party Beneficiaries

Nothing in this Agreement shall entitle any Person other than the parties and their respective successors to any claim, cause of action, remedy or right of any kind in respect of this Agreement or the subject matter of this Agreement.

18.14 Attornment

Each party irrevocably submits to and accepts the jurisdiction of the courts of the Province of Ontario, Canada and all courts of appeal therefrom as regards any legal proceedings relative to this Agreement. Each party irrevocably waives, to the fullest extent that it may effectively do so, the defense of an inconvenient forum to the maintenance in the courts of the Province of Ontario and all courts of appeal therefrom as regards any legal proceedings relative to this Agreement. Each of the parties hereto agrees that a final judgment of the courts of the Province of Ontario, Canada or any court of appeal therefrom and in respect of which all appeal periods have expired without appeal shall be conclusive and may be enforced in other jurisdictions by legal proceedings on the judgment or in any other manner provided by law.

18.15 Good Faith

Each of the parties hereto shall have a duty to act in good faith in the performance and enforcement of this Agreement. All actions, activities, consents, approvals and other undertakings of the parties hereto shall be performed in a reasonable and timely manner.

18.16 Language of Agreement

The parties to this Agreement have expressly agreed that this Agreement be drawn in the English language. Les parties aux presentes ont expressement convenu que le present contrat soit redige en anglais.

18.17 Entire Agreement

This instrument (including all Schedules hereto, if any) states and comprises the entire agreement between the parties hereto relative to the subject matter hereof. There is no representation, warranty or collateral agreement relating to this transaction except as expressly set forth herein.

18.18 Counterparts and Facsimile Execution

This Agreement and any amendment, supplement, restatement or termination of any provision of this Agreement may be executed and delivered in any number of counterparts, each of which when executed and delivered is an original but all of which taken together constitute one and the same instrument.
This Agreement may be executed by facsimile and the facsimile execution pages will be binding upon the executing Party to the same extent as the original executed pages. The executing Party covenants to provide originals of the facsimile execution pages for insertion into the original Agreement in place of the facsimile pages.

IN WITNESS WHEREOF the parties have executed and delivered this Agreement effective as of the date first above written.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

By: ______________________
Name: Michael Brown
Title: Vice President, Engineering & Operations and Chief Operating Officer

HALTON HILLS HYDRO INC.

By: ______________________
Name: Arthur A. Skidmore
Title: President and Chief Executive Officer

Schedule 3.1
Control Room Services
and
Fees to be paid to OHEDI for Control Room Services

SHARED SERVICES PROPOSAL

A non-exhaustive list of examples of the Control Room services to be provided under this Agreement is attached in the form of the Control Room Shared Services Proposal for Halton Hills Hydro from Oakville Hydro dated September 17, 2013 which is attached at the end of this schedule.

FEES:

- Annual Fee for the year beginning October 1, 2013 will be $120,000 to be paid quarterly in advance
- Annual Fee for the year beginning October 1, 2014 will be $123,000 to be paid quarterly in advance
- Annual Fee for the year beginning October 1, 2015 will be $126,075 to be paid quarterly in advance
- In the absence of any contrary agreement by the parties, the Annual Fee after 2015 will increase by 2.5% per year for each of the 5 years immediately following September 30, 2016

ADDITIONAL FEES AND COSTS WHICH MAY BECOME NECESSARY IN THE FUTURE:

- Costs that the parties may agree to share for system enhancements designed to augment Control Room services to the benefit of Halton Hills Hydro while increasing the Control Room operating costs.
- Costs that the parties agree to share for one time or future costs necessary to advance system integration between Halton Hills Hydro and Oakville Hydro.

Control Room Shared Services Proposal for Halton Hills Hydro

September 20th, 2013

Control Room Operations

As requested by Halton Hills Hydro, this document represents a shared services proposal by Oakville Hydro for Control Room Operations.

Halton Hills Hydro stands to benefit from Oakville Hydro's existing capabilities and for Control Room Operation such as:

- ✓ 24/7/365 active system monitoring
- ✓ Access to advanced systems currently in operation within the control room and ongoing system enhancements
- ✓ Trained and experienced Operator staff seasoned in coordinating both planned and unplanned outages, and accustomed to working with both Hydro One and the IESO
- ✓ Outage management reporting both during and after the system outage event

Oakville Hydro will benefit from the relationship through the ability to train and maintain the necessary resources and continue system investments in support of Oakville Hydro's infrastructure and by default provide additional benefit for Halton Hills. Oakville Hydro is committed to continuously improve LDC efficiencies, both locally and where possible for other LDCs

Looking forward to working with Halton Hills Hydro.
Please contact me with any questions and/or comments.

Mike Brown, P. Eng.
Vice President – Engineering and Operations,
Chief Operating Officer
Oakville Hydro
861 Redwood Square
Oakville, ON L6K 0C7
Ph: 905.825.4469
Cell: 416-949-5561

Oakville Hydro Control Room background

Oakville Hydro has a state of the art control room actively managed on a 24/7/365 basis using a Survalent SCADA system to coordinate over 120 remotely operable circuit switches, 19 Municipal Substations each with full control over breakers, and the new Glenorchy Municipal Transformer Station.

Oakville Hydro has redundancy built into both the SCADA system and the physical control room. The SCADA is equipped with three main servers to establish a tri-redundant architecture with multiple location capability in the unlikely event of a hardware failure. For disaster recovery purposes, there is a backup control room set up in the Glenorchy Municipal Transformer Station in which the Control Room Operator can relocate and maintain full system capability.

There are 4 trained control room operators with one direct supervisor, 2 certified backup operators in the Operations group, and the associated support of the Engineering department of Oakville Hydro.

Investments in excess of $950,000.00 have been made for the control room over the last five years including room layout, SCADA system, Operator workstations and video wall.

Utility Work Protection Code – Roles & Responsibilities

- **Controlling Authority** – Halton Hills Hydro will authorize Oakville Hydro as the Controlling Authority. This will enable Oakville Hydro to issue supporting guarantees on behalf of Halton Hills Hydro, as well as operate Halton Hills Hydro equipment after hours in line with established procedures.
- **Issuing Authority** – Halton Hills Hydro will authorize Oakville Hydro as their issuing authority. Oakville Hydro will ensure that the condition requested by the Halton Hills Hydro applicant has been established. Oakville Hydro is then responsible for making effective and terminating the PC2 Work Permit or Supporting Guarantee and keeping a written log of all such events.
- **Establishing Authority** – this authority will be shared between Oakville Hydro and Halton Hills Hydro. Oakville Hydro will be the authority to prepare the conditions for a Work Permit or Supporting Guarantee by filling out the "PC2" and "PC17A" forms. Halton Hills Hydro will then check and establish the conditions for said Work Permit or Supporting Guarantee.

Assumptions

a) Halton Hills Hydro will be contacting the Oakville Hydro Control Room Operator via phone, IP radio, or email.
b) The Oakville Hydro Control Room will have an up to date physical paper copy of the Halton Hills distribution system maps as a starting point for operating purposes, with updates issued via email.
c) Oakville Hydro will engage Planview Utility Services on building a GIS data export tool that will allow the Halton Hills Hydro GIS data to be imported into the Oakville Hydro SCADA for use in the control room. It is expected that this will work will cost less than $9,000, and Oakville Hydro will invoice Halton Hills Hydro directly once the work is complete.
d) Alarm enunciation from the Halton Hills Hydro SCADA directly to the Oakville Hydro Operator via email will be established by Halton Hills Hydro initially, to be replaced by an ICCP link to the Oakville Hydro SCADA at a later date.

Oakville Hydro Service Model Scope

Monitoring

- Monitor SCADA
  - Alarms
  - Tagging
  - Current & Voltage Levels
  - Switch & Breaker Positions
  - Communication Issues
- Load monitoring and coordination with Halton Hills Hydro based on pre-defined load levels.

Communication & Reporting

- Integration into existing Emergency Power Outage Procedure including communication activities.
- Use Great Plains to track Halton Hills Hydro outage information in place of the existing Field Interruption Reports currently used by Halton Hills Hydro.
  - Daily reporting directly to specific Halton Hills Hydro employees with regards to emergency work & outstanding issues.
  - Weekly interruption report with outage summaries (cause, duration, affected area, etc).
  - Monthly performance report with SAIDI, SAIFI, CAIDI, MAIFI, worst feeder, etc.

Work Protection & Switching Activities

- Oakville Hydro will receive work protection requests via PC1 forms that have been signed, scanned and emailed/faxed by Halton Hills Hydro.
- Fill out the required PC2 and PC17A forms signed as "prepared by" Oakville Hydro, then scan and email/fax back to Halton Hills Hydro.
- Halton Hills Hydro to review and sign both forms as "checked by" Halton Hills Hydro, then scan and email/fax back to Oakville Hydro.
- Halton Hills Hydro to coordinate PC17A switching activities with Oakville Hydro.
- Once Oakville Hydro has the completed PC17A form, PC2 form will be signed as "issued by" Oakville Hydro, issue work protection and supporting guarantee as required.
- Record and track work permit holders.
- Retention & filing of all documents
- Switching Activities
  - Issue and Log remote hold offs when requested (both in field & Hydro One)
  - Perform remote switching (when enabled).
  - Keep a current record of system configuration when field changes are made.
  - Communicate with other Utilities as required.

Trouble Calls

- Receive trouble calls originating from the Halton Hills Hydro service area
- Dispatch & coordinate crews during storms, emergency events and power outages
- Update Halton Hills Hydro in real time on outage status
- Monitor vehicle GPS locations utilizing the web based application

Future Development Opportunities

- ICCP link – implementation plans and costs estimate required.
- Developing the Halton Hills Hydro SCADA content in the Oakville Hydro SCADA – scope and costs estimate required.
- Halton Hills Hydro vehicle GPS data integration into Oakville Hydro SCADA.

Timeline to Implement

Once the shared services terms have been finalized and an agreement is put in place, it is estimated that it will take approximately 4 weeks to achieve basic level control room operations services to Halton Hills Hydro. In these 4 weeks the major milestones will include:

- Establishing the VPN SCADA connection
- Physical copy of the Halton Hills Hydro maps in place in the Oakville Hydro Control Room
- Training for the Oakville Hydro Operators on the Halton Hills Hydro maps, distribution system and operating procedures
- Develop and implement a change management plan for Halton Hills Line and Supervisory staff including on site meetings to explain revised operating procedures.

This will enable us to begin issuing work protection, dispatching crews, and tracking trouble calls.

Appendix: Operations Policies and Procedures

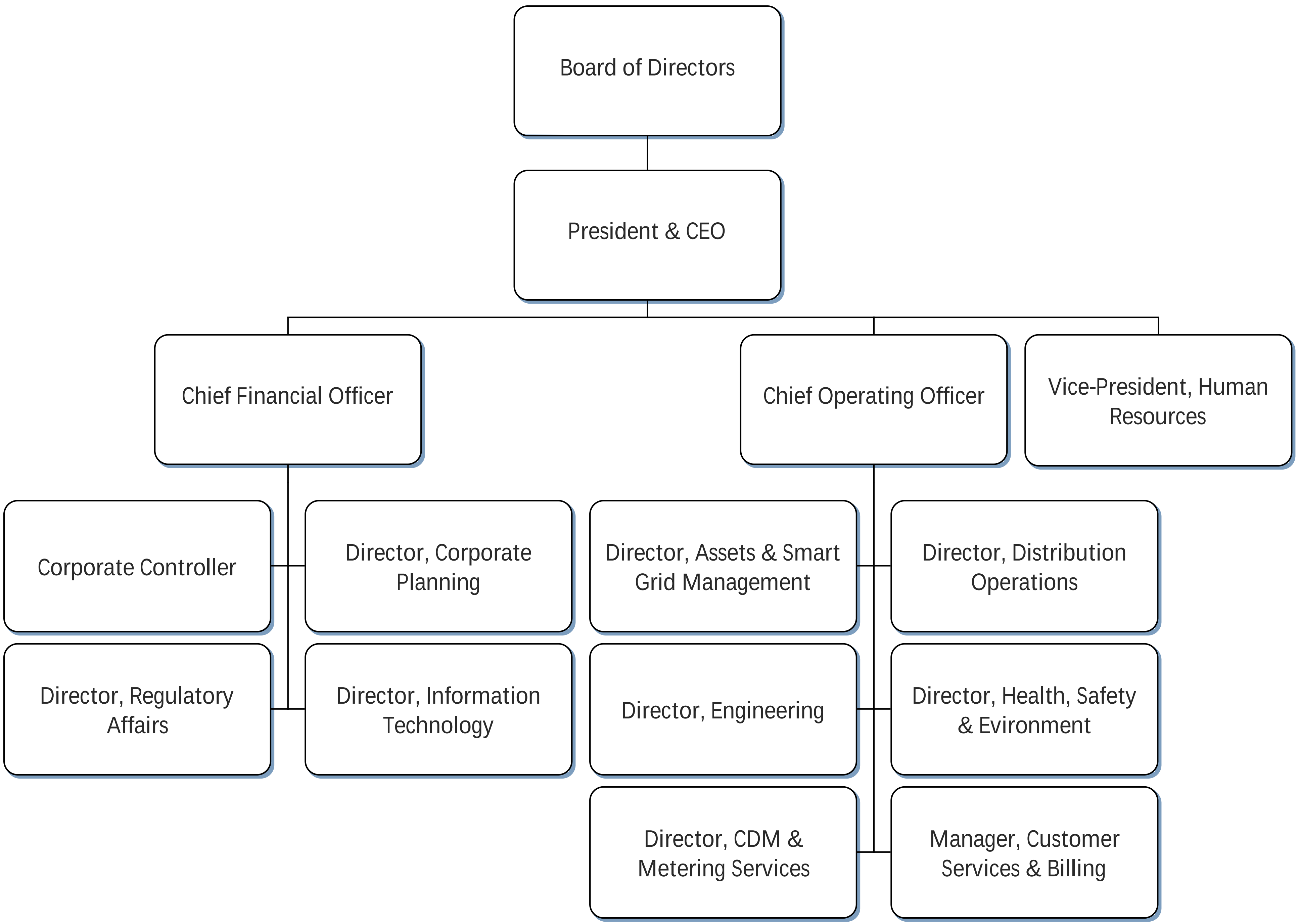
The following is a list of operating directives that all Operators have been trained on:

- OD-0 List of Glenorchy MTS 1 Directives
- OD-1 Bermondsey Station Operating Guidelines
- OD-2 Mayday Procedure
- OD-3 Action Following Feeder Breaker Trip Operations
- OD-4 Breaker Auto-Reclose Feature Blocking Local and Remote
- OD-5 Security Procedure
- OD-6 Loss of Transfer Trip
- OD-7 Loss of SF6 Gas in Gas Insulated Switchgear
- OD-8 Feeder Grounding Procedure
- OD-9 Bus Grounding Procedure
- OD-10 Transformer Grounding Procedure
- OD-11 Restoration after Circuit Breaker Failure
- OD-12 Station Inspections
- OD-13 Load Shedding
- OD-14 Blocking Gas Trip Relays on Oil Filled Transformers
- OD-15 Low Oil & Gas Accumulation Alarms
- OD-16 Restoration after Differential or Gas Trip
- OD-17 List of Contacts for Glenorchy MTS 1
- OD-18 Transformer Operating Ratings
- OD-19 Placement of a Transformer in/out of Service
- OD-20 Transfer Feeder Bus Supply
- OD-21 Parallel between Glenorchy MTS 1 and Neighbouring Stations
- OD-22 Guidelines for Contacting IESO and HONI

Appendix 4 – C

Organizational Chart

Oakville Hydro Electricity Distribution Inc.



5-Public Policy Responsiveness

Issue 5.1 *Do the applicant's proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations?*

5.1-Staff-35

Ref: 1) Exhibit 2/Appendix A- Appendix 5/pp. 16–19
2) Exhibit 2/Appendix A- Appendix 5/p. 42
3) Exhibit 2/Tab 5/Schedule 2/p. 71

Smart Grid

Appendix 5 provides a description of Oakville Hydro's Smart Grid Strategy, including key drivers, benefits and capabilities assessments (present and future) for each of five categories. Page 19 of Appendix 5 shows a high level 10-year roadmap for grid transformation and smart grid leading to initiatives for electric vehicles, system-wide self-healing grid and community energy storage.

At Page 3 of Appendix 5 Oakville Hydro states that the timing of smart grid investments will be somewhat dependent on upgrades to Oakville Hydro's distribution system facilities through expansion or renewal as well as the rate of customers' adoption of renewable generation and consumer technologies.

a) As noted in the Board's Supplementary Report on Smart Grid, February 11, 2013 (EB-2011-0004), did Oakville Hydro communicate with other distributors in Ontario regarding any Pilot projects in progress that may be similar to what it plans to launch, so duplications can be averted? If so, please provide description of such projects.

RESPONSE:

In Exhibit 2, Appendix A, Appendix 5 on pages 16 and 17, Oakville Hydro outlines plans for the dTechs Power Loss Monitoring-Meter Suite, Demand Response Transformers, and

Energy Storage as pilot projects under the Ontario Smart Grid Fund. Oakville Hydro depends on the Ontario Smart Grid Fund screening and approval process to ensure that these pilot projects are unique without duplication at other distributors in Ontario.

b) If Oakville Hydro did not communicate with other distributors in Ontario as outlined in a) above, please indicate what steps would Oakville Hydro take to address potential duplication of Pilot projects.

RESPONSE:

Please see Oakville Hydro's response to Question (a) above.

c) Oakville Hydro is only engaging in Smart Grid Pilot Projects as they are awarded as part of the Ontario Smart Grid Fund framework through the formal application process. It appears that besides dTech Meter Suite program, that Oakville Hydro is not planning any Smart Grid investments in the test year. When does Oakville Hydro expect that initial material Smart Grid investments will be made and what are the expected initiatives and expenditures in the first several years?

RESPONSE:

In addition to the dTech Meter Suite program, Oakville Hydro has also participated in the Ontario Smart Grid Fund through submissions for Demand Response Transformers and Energy Storage. For the Energy Storage, the amount of the Smart Grid investment in 2014 will be covered entirely by the Lead applicant with no capital costs incurred in the 2014 Test Year. For demand response transformers, Oakville Hydro plans to allocate the capital budget for padmounted transformer asset replacements in 2014. Oakville Hydro's Asset Management program has identified a number of padmounted transformers to be replaced in 2014 and an associated capital budget has been allocated for those replacements. If the Demand Response Transformer application to the Smart Grid Fund is successful, then the additional funding will be used to upgrade these replacement transformers to demand response transformers, and deployed in the field as per the Asset Management program with no incremental capital cost in the 2014 Test Year.

The 2014 capital program includes $126,073 for the dTechs MeterSuite project, which is included as part of the Miscellaneous category as indicated in Exhibit 2,Tab 5, Schedule 2,Appendix 2-AA- Capital Project Table, Page 6 of 76. This budget is intended to cover the Oakville Hydro portion for deployment of the 225 dTechs NGX meters, geospatial integration, mapping, project management, and internal resources for this project.

This project has experienced some delays from what originally was forecasted in 2012, and Oakville Hydro assumes that the new units will be deployed for installation in the Oakville Hydro's distribution system by July 2014.

d) At Reference 2) Oakville Hydro discusses the Smart Grid pilot project involving the dTech Meter Suite and mentions that 225 units were to be deployed in 2013 to cover 25% of the Oakville Hydro customer base. Were these meters deployed? Please clarify the 25% of the customer base reference and provide more information on this pilot in terms of costs, results and prospect of future implementation.

RESPONSE:

For the reasons discussed in this response, the meters are not yet deployed but the units are expected to be deployed in the field between May and July 2014. Oakville Hydro has been engaged for over two years in an Ontario Smart Grid Fund demonstration pilot project in collaboration with dTechs for distribution system power loss monitoring and theft detection. The initial pilot project included 10 units installed in the field for the purpose of monitoring and testing and produced varying degrees of success. Throughout the pilot project, several areas were studied and improved. The key areas for further development prior to a larger scale deployment were communications, energy harvesting and accurate voltage measurement.

Through the pilot project the key communications issues were discovered and corrected. To test the voltage measurement and energy harvesting, two units were installed in November 2013, one on the underground system and one on the overhead system. Preliminary results from the field test, have shown that the accuracy of voltage sensing for the overhead unit is acceptable as well as the energy harvesting ability on both the underground and overhead units. An updated unit should be available for field-testing in March 2014, at which time will be deployed for further testing. The underground voltage measurement accuracy is more difficult to achieve due to the shielded underground primary cables. Development is underway to use the elbow voltage test point for the voltage reference.

It is anticipated that if the testing results are satisfactory, full manufacturing of all units will be initiated, with units expected to be deployed in the field between May and July 2014. With this deployment, approximately 25% of Oakville Hydro customers will be monitored “downstream” from the dTech systems. Once all units are active in the Oakville Hydro distribution system, their functionality will be closely monitored for one year in order to determine if full implementation across Oakville Hydro’s distribution system will be considered. Also, after the one year test, further analysis and decisions will be required to assess integration of dTechs’ meters data with the OMS system, and use of the units for power outage information as well. The outcomes of this Smart Grid funded project will be made available to other LDCs.

5.1-Energy Probe-26

Ref: Current Application

a) Please provide a list of the obligations mandated by government in 2010 through to the current time.

RESPONSE:

There have been many changes introduced by governments since Oakville Hydro’s last cost of service application in 2010.

1. Municipal Freedom of Information and Protection of Privacy Act

2. Encryption of Smart Meters

3. *Green Energy Act, 2009*

4. Minister's Directive – Conservation and Demand Management

5. Mandated Time-of-Use Pricing

6. Customer Service Rules

7. Low-income Energy Assistance Program

8. Workplace Harassment – Bill 168

9. Harmonized Sales Tax

10. Ontario Clean Energy Benefit

11. Measurement Canada – Legal Units of Measure and Meter Readings

12. Ontario One Call Act

13. Accessibility for Ontarians with Disabilities Act

14. Anti-spam Legislation

15. Ontario Energy Board – Changes in Accounting Policies

16. Measurement Canada – SE-04 – Installation Requirements for Multiple Customer Metering Systems

b) For each of the obligations noted in (a) above, please explain how the distributor has met those obligations.

RESPONSE:

1. *Municipal Freedom of Information and Protection of Privacy Act* ("MFIPPA")

While Oakville Hydro's obligations under FIPPA have not changed since its last cost of service application, the need to protect the personal information of its customers has increased as a result of changes to technology and a higher level of customer awareness.

Oakville Hydro has received queries from both its own customers who are concerned about the protection of their privacy and from the Information and Privacy Commission.

There are real costs associated with a data breach. The Ponemon Institute's reported that in 2013 the average cost of a U.S. data breach was $194 per compromised record. In 2010, Oakville Hydro engaged Acumen Engineering Solutions Inc. (AESI), a third party consultant, to assist in the overall assessment of risk at Oakville Hydro. This mandate also included the development of an effective Enterprise Risk Management (ERM) program and framework for the Corporation. The risk of unauthorized access to the personal information of Oakville Hydro's customers was identified as being one of the top risks for Oakville Hydro. Oakville Hydro manages this risk by increasing the level of awareness of the need to protect personal information across the organization, conducting privacy impact assessments for projects that involve the collection and/or use of personal information and by ensuring that there are appropriate levels of security in place.

2. Encryption of Smart Meters

As discussed in Oakville Hydro's Smart Meter Prudence Review[1], challenges related to the security and privacy of smart meter data began to emerge while Oakville Hydro was deploying its smart meters. After a customer in Oakville Hydro's service area filed a complaint with the Information and Privacy Commissioner ("IPC") of Ontario a formal investigation was launched. As a result of the investigation, Oakville Hydro was required to change its internal business process with respect to privacy and security, improve components of its Customer Information System and implement the encryption of smart meter data flowing from the meter to the collectors. Oakville Hydro implemented all of the changes recommended by the IPC and became the first utility in North America to implement smart meter encryption.

3. Green Energy Act

[1] Smart Meter Prudence Review, EB-2012-0193, Page 9.

On September 9, 2009, the *Green Energy and Green Economy Act, 2009* (the "GEA") was proclaimed into force. The GEA amended *the Ontario Energy Board Act, 1998* the ("OEB Act") and the *Electricity Act 1998* (Electricity Act) to address renewable generation connections and smart grid development. The GEA amended section 70 of the OEB Act to include the following provisions that create deemed licence conditions for all licensed electricity distributors and transmitters:

- The licensee is required to provide, in accordance with such rules as may be prescribed by regulation and in the manner mandated by the market rules or by the Board, priority connection access to its transmission system or distribution system for renewable energy generation facilities that meet the requirements prescribed by regulation made under subsection 26 (1.1) of the Electricity Act, 1998.

- The licensee is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for,

    i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and

    ii. the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

- The licensee is required, in accordance with a plan referred to in paragraph 2 that has been approved by the Board or in such other manner and at such other times as mandated by the Board or prescribed by regulation,

    i. to expand or reinforce its transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and

    ii. to make investments for the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

Renewable Energy

As discussed in Oakville Hydro's Distribution System Plan – Appendix 4, Renewable Energy Generation Plan, Oakville Hydro's distribution system is a robust, integrated network throughout the Town of Oakville. Adequate planning and proactive infrastructure projects have made the distribution network well equipped to handle forecasted renewable generation except for areas supplied by two Hydro One owned transmission stations which have capacity restrictions due to short circuit levels. Oakville Hydro is working with Hydro One to alleviate these restrictions but would have to accept higher short circuit limits than set out in the Transmission System Code. Even if this restriction is lifted, Oakville Hydro estimates that it has the capacity to connect renewable generation projects through the 2014 to 2018 period.

Smart Grid

As discussed on page 39 of Oakville Hydro's Distribution System Plan, Oakville Hydro's Smart Grid Strategy is to grow and develop its distribution grid using a combination of good utility practice coupled with emerging technologies and systems. Oakville Hydro aligns its smart grid projects with it investment objectives by integrating them into its capital project portfolio to be evaluated and prioritized according to its asset management strategy.

4. Minister's Directive – Conservation and Demand Management

On March 31, 2010, the Minister of Energy issued a directive to the Board to amend the licences of all electricity distributors to add a condition requiring the distributor to achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of Conservation and Demand Management ("CDM") Programs. On November 12, 2010 the Board amended Oakville Hydro's licence to require that it achieve 2014 Net Peak Demand Savings of 20.7MW and 2011 to 2014 cumulative energy savings of 74.06 GWh.

As of December 31, 2012, Oakville Hydro has achieved 16.9 per cent of its Net Peak Demand Savings and 60.9 per cent of its Cumulative Net Energy Savings. In addition, Oakville Hydro has complied with the reporting requirements set out in the Board's *Guidelines for Electricity Distributor Conservation and Demand Management* and for the administration of the Board's Lost Revenue Adjustment Mechanism.

5. Mandated Time-of-Use Pricing

On August 4, 2010, the Board issued its determination under Section 1.2.1 of the Standard Supply Service Code to mandate time-of-use pricing for regulated price plan consumers (EB-2010-0218). In its determination, the Board assigned Oakville a mandatory time-of-use date of July 11, 2011. The Board's determination also required that distributors file a monthly report with regard to their progress.

In its determination, the Board acknowledged that distributors may encounter extraordinary and unanticipated circumstances during the implementation of time-of-use pricing and requested that any distributor encountering such circumstances bring these matters to the Board's attention.

During testing, Oakville Hydro discovered a technical problem with the meters that it had installed for its General Service < 50 kW customers and residential customers that resided in apartment buildings that were suite metered. The technical problem affected approximately 4,600 customers. On June 17, 2011, Oakville Hydro applied to the Board for an extension to its mandated time-of-use date for these customers. In its decision and order, the Board found the delay that Oakville Hydro encountered for these customers to be extraordinary and unanticipated. The Board amended Oakville Hydro's licence to include an exemption from the requirement to apply time-of-use pricing by its mandated date for those customers.

Oakville Hydro has continued to report on its progress and has converted over 99 per cent of its eligible Regulated Price Plan customers to time-of-use pricing. Communication issues that were preventing the remaining 490 customers from the conversion to time-of-use pricing have been resolved and all eligible regulated price plan customers will be on time-of-use billing.

6. Customer Service Rules

On July 2, 2008, the Board initiated a consultation process to examine issues associated with low-income energy consumers in relation to their use of natural gas and electricity. However, in a letter dated September 8, 2009, the Minister of Energy advised that it initiated its own low-income program and requested that the Board not proceed to implement new support programs in advance of a ministerial direction.

On July 10, 2010, the Minister of Energy confirmed that the Board should resume its work in relation to low-income energy customers. On July 22, 2010, the Board informed distributors that the Board would be considering policies in the areas of emergency financial assistance and customer service rules. As a result of the Minister's letter, the Board issued customer service rules to be applied to all residential customers.

The new rules affected the following areas:

- Disconnection for Non-Payment
- Security Deposits
- Bill Issuance and Payment
- Allocation of Payments between Electricity and Non-electricity Charges
- Correction of Billing Errors
- Equal Payment Plans
- Arrears Management Programs

Oakville Hydro discontinued its practice of obtaining security deposits from residential consumers as a result of the new customer services rules. Oakville Hydro has implemented the rest of the Board's customer service rules through a combination of system changes and manual processes which have increased administrative requirements.

7. Low-income Energy Assistance Program

Emergency Financial Assistance

On October 20, 2010, the Board advised that it had determined that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000, was a reasonable commitment by all distributors to emergency financial assistance. The LEAP amount was to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes. However, Oakville Hydro has not been eligible for recovery of its 2010, 2011, 2012 and 2013 cumulative contributions of $160,000.

On February 4, 2011, the Board issued a letter describing the information to be filed by electricity distributors in relation to LEAP emergency financial assistance. On December 21, 2011, the Board issued a letter advising electricity distributors of the changes that were being made to the content of the LEAP emergency financial assistance reporting requirements. Oakville Hydro and its LEAP partners have complied with these reporting requirements.

Oakville Hydro's LEAP Program has been very successful. As at December 31, 2013 99.7 per cent of the cumulative contributions have been disbursed to provide funding for emergency financial assistance to eligible low-income customers and to defray the costs of the distributor's social agency partner to deliver and administer the program.

Low-income Customer Service Rules

On March 30, 2011, The Board issued the final low-income customer service rules to supplement the customer service rules applicable to all residential electricity customers issued on July 2, 2010. In addition, some changes were made to the July 2, 2010 customer service rules.

The amendments to the Distribution System Code, Retail Settlement Code and the Standard Service Supply Code set out the definition of a low-income customer and provide customer service rules in the following areas:

- Correction of Billing Errors

- Equal Billing and Equal Payment Plan Options
- Disconnection for Non-Payment
- Security Deposits
- Low-Income Customer Arrears Payment Agreements

In addition, on March 19, 2012 the Board issued amendments to the reporting requirements to require electricity distributors to record and file information regarding the implementation of the customer service-related amendments. Oakville Hydro has implemented the changes for low-income consumers and has upgraded is Customer Information System to enable it to begin reporting on its residential and low-income programs.

8. Workplace Harassment – Bill 168

In December 2009, Bill 168 – Violence and Harassment in the Workplace, received Royal Assent. This bill amended the *Occupational Health and Safety Act* to set out roles and responsibilities for workplace parties with respect to workplace violence and workplace harassment, including developing and implementing policies and programs.

In accordance with the amendments to the *Occupational Health and Safety Act*, Oakville Hydro developed and implemented policies and procedures to address workplace violence and provided training to all employees on violence and harassment in the workplace. Oakville Hydro reviews the policies and procedures annually and investigates any complaints with regard to workplace safety.

9. Harmonized Sales Tax

On 1 July 2010, the Harmonized Sales Tax (“HST”) was implemented in Ontario. The HST replaced the separate Goods and Services Tax and the Provincial Sales Tax charged on goods and services in Ontario. The implementation of the HST required changes to Oakville Hydro’s Enterprise Resource Planning system and additional training for staff across the organization.

10. Ontario Clean Energy Benefit

In 2010, the Ministry of Energy introduced the *Ontario Clean Energy Benefit Act* (the "OCEB Act"). The OCEB Act required that distributors provide a 10 per cent rebate on applicable electricity charges and taxes beginning on January 1, 2011 and continuing to December 31, 2015.

Oakville Hydro made the necessary investment in its Customer Information System and began apply the OCEB rebate to eligible customers effective January 1, 2011. Oakville Hydro submits a claim to the Independent Electricity Systems Operator monthly to recover the rebate and reports monthly to the Minster of Energy regarding the amount of the rebate, the applicable kWh and the forecasted rebate for the following three months.

Effective September 1, 2012, the Minister of Energy determined that the 10 per cent rebate would be applied to the first 3,000-kilowatt hours of electricity consumed per month and the necessary changes to the customer information system were made.

11. Measurement Canada – Legal Units of Measure and Meter Readings

In December 2011, Measurement Canada sent a letter to Oakville Hydro, and other electricity distributors, to remind them of their obligations to under the *Electricity and Gas Inspection Act* regarding the issue of recognized legal units of measure and the need to establish supplied quantities on the basis of approved and verified meter readings. At that time, a working group had already been convened to discuss the option for presenting line losses on electricity bills to meet the requirements of the *Electricity and Gas Inspection Act*. In addition, the Independent Electricity Systems Operator and the Ministry of Energy worked together to implement a technical solution to permit electricity distributors to display meter reading on the customer's bill.

Oakville Hydro invested in the necessary changes to implement a solution for the display of meter readings on customer's bills in July 2012.

On June 27, 2013, the Board notified distributors that changes to Ontario Regulation 275/04 – Information on Invoices to Low-Volume Consumers of Energy would come in to force on July 1, 2013 that would require that distributors show the costs associated with distribution losses on the delivery line on the bill. Oakville Hydro implemented this change effective July 1, 2013.

12. Ontario One Call Act

The *Ontario Underground Infrastructure Notification System Act, 2012*, received Royal Assent on June 19, 2012. The Act established Ontario One Call Ltd. as a not-for-profit call centre whose objectives are:

- To operate a call system to receive excavator requests for the location of underground infrastructure within Ontario.
- To identify for excavators whether underground infrastructure is located in the vicinity of a proposed excavation or dig site.
- To notify a member of the Corporation of proposed excavations or digs that may affect the underground infrastructure of the member.
- To raise public awareness of the Corporation and the need for safe digging.

Oakville Hydro became a member of Ontario One Call on a voluntary basis in December 2011. The Act now requires that Ontario municipalities, Hydro One Inc., Ontario Power Generation Inc., gas distributor and transmitters, electricity distributors, and any entity that owns or operates underground infrastructure become members. Participation in this system has resulted in a significant increase in the number of calls that require locate services to be performed.

13. *Accessibility for Ontarians with Disabilities Act*

The government enacted the Accessibility for Ontarians with Disabilities Act in 2005. This act sets out the framework for the development of mandatory standards on accessibility in all areas of daily life. Effective January 1, 2012, the rules associated with providing accessible customer service came into effect for all Ontario businesses and organizations with one or more employee. In accordance with the requirements, Oakville Hydro developed and implemented a policy and procedures on the Customer Service Standard and trained its employees on the policy and procedure.

Oakville Hydro has also started to implement the Integrated Service Accessibility Requirements that will come into effect this year. The Integrated Service Accessibility Requirements set out the requirements for the following:

- training requirements for employees
- standards communication and information
- accessibility standards for employees

14. Anti-spam Legislation

Canada's Anti-Spam Legislation ("CASL") establishes rules for sending commercial electronic messages (“CEMs”) as well as the installation of computer programs, and prohibits the unauthorized alteration of transmission data. The rules that apply to CEMs come into force July 1, 2014. CASL applies to most forms of electronic messaging, including email, SMS text messages, and certain forms of messages sent via social networking. A CEM cannot be sent unless the recipient has consented to receiving it (some exceptions apply). Consent can be express or implied (some exemptions apply). CASL also specifies the information that is to be included in every CEM.

The Canadian Radio-television and Communications Commission (“CRTC”) enforces the CASL. The CRTC has the ability to impose administrative monetary penalties for violations of CASL of up to $10 million per violation. CASL also includes a private right of action, which comes into effect July 1, 2017 that allows a person affected by a violation of CASL and related amendments to PIPEDA and the Competition Act to sue for actual and/or statutory damages.

Oakville Hydro is planning to prepare for the new anti-spam legislation by evaluating all means of communication through CEMs to ensure that it is obtaining the proper consent to send the CEMs and that the CEMs contain the required information.

15. Ontario Energy Board – Changes in Accounting Policies

On July 17, 2012, the Ontario Energy Board issued a letter requiring all distributors to implement changes to depreciation and capitalization policies effective January 1, 2013. Oakville Hydro has implemented these changes in accordance with the Board's letter.

16. Measurement Canada – SE-04 – Installation Requirements for Multiple Customer Metering Systems

Measurement Canada Specifications SE-04 requires that all condominium suite meter systems be inspected under SE-04 within 1 year of the meters being installed by a certified service provider. Oakville Hydro has developed a plan in conjunction with Measurement Canada to complete the inspections by the end of 2015.

5.1-SEC-23

Ref: Ex.5/2/3/p.3

Please provide a breakdown of the regulatory cost driver for 2013.

RESPONSE:

The regulatory cost driver consists primarily of costs associated with this Cost of Service application that will be incurred in 2013. $240,000 is attributed to consultant costs and legal costs which are referenced in Exhibit 4, Tab 3, Schedule 3, Page 3 of 3.

5.1-VECC-22

Ref: E4/T1/S2/pg.10

Please provide Oakville's estimate of the cost in 2014 of meeting all new government and OEB obligations established since 2010. Please categorize by requirement.

RESPONSE:

In response to Energy Probe interrogatory number 5.1-EP-26 Oakville Hydro provided a list of the obligations mandated by government since 2010. Where possible the cost of meeting those obligations is provided below, however, for many of these costs it is not feasible to separately track staff time and separately report each expenditure within OM&A. Furthermore, wherever possible, current internal resources are used to meet these additional obligations, which result in additional strain on resources and ultimately an increase in FTE. The change in FTE may not be attributable to a specific single new legislation or regulation.

Oakville Hydro estimates that the implementation of these changes or additional legislation and regulations could have as much as $200,000 to $300,000 (excluding the mandated Time of use pricing for which costs are specifically identified below as 5, LEAP costs identified below as 7, and the Ontario One Call Act costs identified below as 12), cumulative effect through added employee workloads resulting in indirect additions to the FTE needs, outsourcing tasks that may have been performed internally, or specific costs associated with these would have otherwise be

1. Municipal Freedom of Information and Protection of Privacy Act

2. As discussed in Exhibit 4, Tab 3, Schedule 8, Oakville Hydro's regulatory department assumed responsibility for ensuring compliance with the *Municipal Freedom of Information and Protection of Privacy Act* in 2010. While Oakville Hydro's obligations under the Municipal Freedom of Information and Protection of Privacy Act ("MFIPPA") have not changed since its last cost of service application, the need to protect the personal information of its customers has increased as a result of changes to technology and a higher level of customer awareness. This, along with other compliance obligations noted below, has resulted in an increase in staff in the Regulatory Affairs department, which is described in Exhibit 4, Tab 3, Schedule 4, Page 8 of 25 for a regulatory analyst. Encryption of Smart Meters

3. As discussed in Oakville Hydro's response to 5.1-EP-26, Oakville Hydro implemented a number of changes recommended by the Information and Privacy Commissioner of Ontario and became the first utility in North America to implement smart meter encryption. Despite the challenges associated with this initiative, Oakville Hydro did

not incur any significant identifiable incremental costs for the encryption of smart meters, but does incur some additional staff time. *Green Energy Act*

As discussed in Exhibit 4, Tab 1, Schedule 2, Page 6, Oakville Hydro has not incurred significant identifiable incremental costs for the connection of renewable energy. Although Oakville Hydro did not incurred significant identifiable incremental costs for the connection of renewable generation it has devoted existing resources and added to their responsibilities to the administration of the FIT and microFIT programs. The personnel to whom additional responsibilities were assigned included the regulatory analyst, the engineering department, metering and billing department.

4. Minister’s Directive – Conservation and Demand Management

The Conservation and Demand Management program is funded through the OPA. However, as noted in item 1, Oakville Hydro’s Regulatory Affairs department has increased by one employee as a result of increased reporting requirements, as well as additional management time for oversight and follow-up.

5. Mandated Time-of-Use Pricing

As shown in Exhibit 4, Tab 3, Schedule 1, Appendix 2-JC, Oakville Hydro has incurred costs of $427,224 and $560,973 in 2012 and the 2013 Bridge Year respectively for smart meters and time-of-use billing. Oakville Hydro has estimated that it will incur costs of $550,847 for smart meters and time-of-use billing in the 2014 Test Year.

6. Customer Service Rules

Oakville Hydro has not incurred any significant identifiable incremental costs associated with the implementation of the Board’s customer service rules. However, existing resources have been dedicated to the administration and reporting requirements associated with the new rules.

7. Low-income Energy Assistance Program ("LEAP")

Oakville Hydro has incurred costs of $160,000 since 2010 for the Low-income Energy Assistance Program. In addition, the regulatory analyst and existing resources in the customer service have been assigned additional tasks related to the administration and reporting requirements associated with the Low-income Energy Assistance Program.

8. Workplace Harassment – Bill 16

Oakville Hydro incurred costs of $3,200 to have a third party provide training on workplace harassment to its employees, and there is the ongoing maintenance costs to ensure that the ongoing training, monitoring and if necessary enforcement and reporting are complied with.

9. Harmonized Sales Tax

Oakville Hydro has not incurred any incremental costs associated with the implementation of the harmonized sales tax. However, existing resources were dedicated to the implementation of the harmonized sales tax in 2010 and have been involved in government audits on the ongoing operation of the tax and the transition from GST to HST.

10. Ontario Clean Energy Benefit

Oakville Hydro has incurred additional costs to update the customer information system as well as the associated ongoing maintenance and monitoring to ensure that the benefit is appropriately and correctly administered. In addition, existing internal resources have been used to address the follow-up government audits and to process payments and reporting applicable to the program.

11. Measurement Canada – Legal Units of Measure and Meter Readings

Oakville Hydro has not incurred any incremental costs associated with the implementation of Measurement Canada's bill print requirements, with the exception of the costs associated with the upgrade to the customer information systems and the testing and approval of the information provided on the customer statements.

12. Ontario One Call Act

As shown in Exhibit 4, Tab 3, Schedule 1, Appendix 2-JC, Oakville Hydro has incurred costs of $360,164, $700,105 and $787,353 in 2010, 2011 and 2012 respectively for service locates. Oakville Hydro has estimated that it will incur costs of $825,000 for service locates in the 2014 Test Year.

13. *Accessibility for Ontarians with Disabilities Act*

Oakville Hydro has not incurred significant identifiable incremental costs associated with the implementation of Accessibility for Ontarians with Disabilities Act. Oakville Hydro continues to use its existing resources in this regard. There are ongoing costs to ensure ongoing training and compliance with the Act.

14. Anti-spam Legislation

Oakville Hydro has not incurred any significant identifiable incremental costs associated with the implementation of Anti-spam legislation, however, there are the ongoing costs to ensure that Oakville Hydro will be in compliance when the legislation is active and costs to change behaviours and processes to satisfy the legislation when it is in force.

15. Ontario Energy Board – Changes in Accounting Policies

Oakville Hydro has incurred initial assessment costs regarding this obligation as part of the IFRS deferral account. However, for the ongoing changes in accounting policies there are no significant identifiable incremental costs anticipated beyond 2014 when the system changes, testing, and analysis to ensure correct accounting for the changes and IFRS in 2015. As noted an additional resources in the finance area, a new accountant, which is described in Exhibit 4,Tab3, Schedule 4, Page 7 of 25 has already been identified.

16. Measurement Canada – S-E-4 – Installation Requirements for Multiple Customer Metering Systems

As discussed in Exhibit 4, Tab 3, Schedule 7, Measurement Canada Standards require that all newly installed suite meters be inspected and certified to Measurement Canada's SE-04 specification within one year of installation. Oakville Hydro currently completes the SE-04 inspections as the final step in commissioning a building with individual metered suites ("IMS"). However, there are a number of installations that were not inspected in accordance with the SE-04 standards and Oakville Hydro has, in conjunction with Measurement Canada, developed a schedule to complete the required inspections by the end of 2015, as provided in Table 4-23. Oakville Hydro will incur costs of $49,000 in 2014 and 2015 to complete these inspections. Once these inspections are complete, Oakville Hydro expects that the annual ongoing costs of the inspections will be $15,000.

6-Financial Performance

Issue 6.1 *Do the applicant's proposed rates allow it to meet its obligations to its customers while maintaining its financial viability?*

6.1-HVAC-2

Ref: Ex. 1/3/3, p. 22

Please provide a copy of the most recent Board self-assessment.

RESPONSE:

The Board of Directors' self-assessment was conducted in December 2013 through an anonymous on-line survey. Oakville Hydro has included a copy of the survey questions as Appendix 6-A.

6.1-HVAC-3

Ref: Ex. 1, App. D

Please provide a copy of the most recent "annual Board Work Plan".

RESPONSE:

The most recent Annual Board Work Plan is in Appendix 6-B.

6.1-HVAC-4

Ref: Ex. 1, App. D, p. 4

Please provide a copy of any document that imposes "limits on the business activities" of the utility pursuant to section 5.1(f) of the Mandate.

RESPONSE:

The Board of Directors discuss the risks and opportunities at quarterly Board meetings. Oakville Hydro and its affiliates risks and opportunities are being discussed as part of the parent Corporation's (Oakville Hydro Corporation) Enterprise Risk Management ('ERM') framework. The ERM is reviewed and updated on a quarterly basis.

Oakville Hydro, its affiliates and the Parent Corporation are guided by a Shareholder Direction and Unanimous Shareholder Declaration ('Shareholder Direction').

According to Section 3 of the Shareholder Declaration, the Corporation may engage in any business activities which are permitted by any laws applicable to Corporation including the Electricity Act, 1998.

In performing a business activity, the Corporation and its affiliates shall conform to all requirements of the Ontario Energy Board, the Ontario Independent Electricity System Operator and all other applicable regulatory or governmental authorities. In addition, according to Section 10 of the Shareholder Declaration from Town of Oakville, it requires the Shareholder's (Town of Oakville) approval on certain matters. A copy of the Shareholder Declaration is attached (Appendix 6-C). Oakville Hydro is not aware of any specific documents from the Corporation's Board of Directors that impose 'limits on the business activities' of the Corporation, outside of operating within the guidelines of the Shareholder Direction.

6.1-HVAC-5

Ref: Ex. 1, App. D, p. 6

Please provide a list of the last five matters referred to the Board of the utility by the parent company pursuant to section 5.5 of the Mandate.

RESPONSE:

According to section, 5.5 of the Mandate the Board will consider any other matter referred to the Board of Directors by Oakville Hydro Corporation.

On a regular basis at Board of Directors meetings, Oakville Hydro Corporation, being the sole, shareholder of the Oakville Hydro, reviews the business of Oakville Hydro and provides matters for consideration.

The following are the matters referred to the Board of Directors of Oakville Hydro by the parent company (Oakville Hydro Corporation).

- 2014 Budget
- Review of People policies
- LDC Landscape and Consolidation discussion
- Succession planning
- HR Strategy and Total Rewards Review

6.1-HVAC-6

Ref: Ex. 1, App. C

With respect to the consolidated audited financial statements of Oakville Hydro Corporation:

a) Please file the 2013 consolidated financial statements of Oakville Hydro Corporation as soon as they are available.

RESPONSE:

Oakville Hydro confirms that it will provide the 2013 consolidated audited financial statements of Oakville Hydro Corporation as soon as they are available.

b) P. 3. Please explain the main reasons why the percentage of revenues from unregulated activities increased from 17.0% to 20.3% from 2011 to 2012. Please advise whether this is a long-term trend, and whether this is part of the Corporation's strategic plan.

RESPONSE:

The main reason for an increased percentage in revenues is a direct correlation to the increased number of affiliates that Oakville Hydro Corporation has under its umbrella currently versus in its 2010 Cost of service corporate structure. The Corporate Entities Chart is displayed in Exhibit 1, Tab 3, Schedule 3, Page 16 of 51.

Oakville Hydro Corporation evaluates opportunities that present themselves and if that analysis shows that the opportunity remains within the bounds of its mandate and strategic plan as approved by the Board of Directors, and will benefit Oakville Hydro Corporation and its shareholder, then it may consider pursuing that opportunity.

c) P. 3. Please disaggregate the figures for Amortization for each year between the regulated utility and each of the other entities consolidated in these statements (including subsidiaries of subsidiaries).

RESPONSE:

Oakville Hydro believes this interrogatory and level of detail has no relevance to Oakville Hydro's rate application before the Board. The 2014 Test Year Amortization is the amount Oakville Hydro is requesting as part of its 2014 Revenue Requirement. Oakville Hydro will provide the requested information as follows:

Amortization	**2012**	**2011**
Oakville Hydro Electricity Distribution Inc.	$ 13,352	$ 10,220
Oakville Hydro Energy Services Inc. (Consolidated)	1,135	491
El-Con Construction Inc.	262	262

d) P. 17. Please advise the total of all amounts paid by the Applicant to the EDA and to MEARIE in each of 2011 through 2013, and forecast for 2014. With respect to the 2013 and 2014 amounts, please advise how much of those amounts were or will be allocated to each of the affiliates, if anything.

RESPONSE:

See interrogatory response 4.2-VECC-13 (a) and (b).

e) P. 21. Please advise the total of all expenses incurred by the Applicant to date with respect to the transition to IFRS. Please advise how much of those amounts was or will be allocated to each of the affiliates, if anything.

RESPONSE:

To date Oakville Hydro has incurred $889,425 (excluding interest) with respect to the transition to IFRS. There have been no costs allocated to the affiliates as they have minimal depreciation, capitalization issues or other changes required with the IFRS transition.

Issue 6.2 *Has the applicant adequately demonstrated that the savings resulting from its operational effectiveness initiatives are sustainable?*

6.2-Energy Probe-27

Ref: Exhibits 1, 2 & 4

a) Please describe, with references to the evidence, the operational effectiveness initiatives that the distributor has or is planning to undertake.

RESPONSE:

a) Oakville Hydro has undertaken many operational effectiveness initiatives since its last Cost of service application.

Asset Management and Condition assessments - Oakville Hydro has enhanced and documented its asset management strategy through implementation of PAS 55 style structure for asset management oversight. Oakville Hydro has an Asset management team of two individuals both trained Maintenance Management Professionals (MMP). Oakville Hydro has established scheduling processes to track compliance to plans including long term planning cycles and extensive use of standard job plans. In addition, Oakville Hydro has initiated inventory improvement plans and measured inventory performance. Oakville Hydro has established a Preventative Maintenance program that includes some Condition Based Maintenance (CBM). Downtime analysis is performed and recommendations for improvement are implemented. Maintenance processes are reviewed to drive efficiency and effectiveness.

Revenue Offsets

1. Shared Services with Halton Hills Hydro – Oakville Hydro entered into an agreement in September 2013 with Halton Hills Hydro to provide 24/7 control room services to Halton Hills' service territory. This initiative enables Oakville Hydro to make more efficient use of its existing control room resources. This initiative is referenced in Exhibit 3, Tab 3, Schedule 1, Page 1 of 10. The estimated revenues of $100,000 associated with this agreement are included in Appendix 2-H – Other Operating Revenue under Account 4220-Other Electric Revenues in Exhibit 3, Tab 3, Schedule 1, Page 7 of 10. Subsequent to Oakville Hydro's submission of its Application, the agreement between Oakville Hydro and Halton Hills Hydro was reached and the annual amount that was agreed upon was $120, 000. Oakville Hydro will update its forecasted Other Revenues to include the additional $20,000 in the Revenue Requirement Work Form filed in

response to the interrogatories of Board staff and intervenors. This is a long-term arrangement that is sustainable into the foreseeable future.

2. Office Space –Sublease – Oakville Hydro was successful in subleasing a portion of its space in its corporate office to the Town of Oakville effective late 2012. This sublease offsets the building operating and maintenance costs of Oakville Hydro's corporate office. The estimated revenues of $146,820 associated with this agreement are included in Appendix 2-H – Other Operating Revenue under Account 4390- Miscellaneous Non- operating revenues in Exhibit 3, Tab 3, Schedule 1, Page 8 of 10, and directly reduce the expenses that Oakville Hydro incurs annually. This is sustainable for the duration of the agreement (two years) with the Town of Oakville and any extensions thereafter.

OM&A

1. Board of Directors Costs – In 2011, Oakville Hydro reduced the number of members of its Board of Directors from thirteen to nine. Of the remaining nine directors, six are paid and three are unpaid. As a result, the costs associated with the Board of Directors has been reduced and Oakville Hydro has been able to realize cost savings in this area. This is referenced in Exhibit 4, Tab 3, Schedule 5, Page 15 of 15 and is sustainable as a permanent reduction to costs.

2. Unionized employee wage costs - In 2013, Oakville Hydro successfully negotiated a four-year employment contract with its unionized employees at lower increases than the distributors in the surrounding areas. This is referenced in Exhibit 4, Tab 3, Schedule 4, Page 19 of 25. Oakville Hydro notes that in Niagara- on- the- Lake Hydro Inc.'s responses to VECC interrogatories in its 2014 Cost of Service application (EB-2013-055) at Page 21 of 81, Niagara-on-the-Lake that the negotiated collective agreement was 2.8% annually which is higher than that of Oakville Hydro's negotiated collective agreement.

3. Part Time Call Centre Agents - Oakville Hydro achieved savings in wages and benefits, along with increased its staffing flexibility by replacing full time customer service representatives with part time staff. This is referenced in Exhibit 4, Tab 3, Schedule 4, Page 9 of 25. With this being a negotiated item in the collective agreement with the union, it will be sustainable and allows flexibility to the staffing demands for servicing customers.

4. Post-Employment Costs - Health and benefits costs continued to rise, however, Oakville Hydro is able to contain these costs and decrease its liability in this area by eliminating all post-employment benefits for all non-unionized employees hired after August 17, 2009. This is referenced in Exhibit 4, Tab 3, Schedule 4. In addition, it restricted post-employment benefits to age 65 for unionized employees hired after August 10, 2010. This is referenced in Exhibit 4, Tab 3, Schedule 4 page 22 of 25. These are negotiated changes that were maintained during the 2013 negotiations and therefore they are considered sustainable. These cost savings have been incorporated into the actuarial report, thus significantly restricting the growth in the Post-Employment costs to existing beneficiaries and grandfathered employees entitled to this historic benefit.

5. Connection agreement for two feeders at Glenorchy Municipal Transformer station – on May 1, 2013 Oakville Hydro and Milton Hydro reached an agreement to connect Milton Hydro to the Oakville Hydro owned Glenorchy Municipal Transformer Station. This new customer, an "embedded distributor", will share in the operating, maintenance, depreciation and capital costs related to the Glenorchy Transformer Station. This is referenced in Exhibit 3, Tab 1, Schedule 3, Page 4 of 8 and in Exhibit 7, Tab 1, Schedule 2, page 1 of 13.

6. Health and Safety – Oakville Hydro is committed to promoting continuous improvements in safety through the effective management of risks and activities in the workplace. While Oakville Hydro's primary concern is for the safety and well-being of its employees, contractors and the general public, a proactive and

effective health and safety program reduces the significant direct and indirect costs associated with injuries and illness. This is referenced in Exhibit 4, Tab 2, Schedule 1, Page 8 of 17.

In 2013, Oakville Hydro received the President's Award from the Infrastructure Health and Safety Association (IHSA) for achieving 250,000 consecutive hours without a lost time injury, illustrating the positive impact of the health and safety initiatives.

7. Organizational Effectiveness – Oakville Hydro's Organizational Effectiveness program focuses on engaging employees in order to encourage them to develop a continuous improvement-based culture. In addition, employees who are engaged in the workplace are also more likely to be committed to an organization's success. This longer-term commitment is usually reflected through increased employee engagement and service, higher job performance, increased productivity, lower absenteeism rates and reduced employee turnover. This is referenced in Exhibit 4, Tab 2, Schedule 1, Page 12 of 17 and in Exhibit 4, Tab 3, Schedule 4, Page 23 of 25.

b) Please show how these initiatives have, or will result in savings to ratepayers.

RESPONSE:

The initiatives described in a) that have resulted or will result in savings to ratepayers; the amount of savings (to the extent that savings can be quantified at this time) and the sustainability of those programs are explained in the following table.

Initiative	Savings to ratepayers	Sustainability
Asset Management & Condition Assessment	Regular maintenance of distribution assets based on the condition of the assets will avoid the associated costs of emergency breakdowns of equipment and can extend the life of the asset.	Continue diligently with program.
Halton Hills Hydro 24/7 Control room services	The annual revenue offset of $120,000 reduces the revenue to be recovered from ratepayers.	Oakville Hydro has negotiated a contract with Halton Hills Hydro for a minimum of three years. Oakville Hydro will continue to explore opportunities for the sharing of services with other electricity distributors.
Office Space - Sublease	The annual revenue offset of $146,820 reduces the revenue to be recovered from ratepayers.	Secured contract with Town of Oakville Hydro has negotiated a contract with the Town of Oakville for two years plus an additional two-year renewal, although expected to be longer.
Board of Directors costs	The annual cost savings in 2014 Test Year of $71,000 as compared to the 2010 Board approved amount reduces the OM&A component of Oakville Hydro's revenue requirement.	Oakville Hydro does not anticipate any increases to membership of its Board of Directors.
Unionized employee wage costs	The reduction in the annual wage reduces the upward pressure on OM&A for the 2014 Test Year.	Oakville Hydro has negotiated four year contract. Reduced increases will have a long term benefit as new negotiations are on existing base labour rates

Part Time Call Centre Agents	The replacement of full-time staff with part-time staff reduces the number of full time equivalent customer service representatives thereby decreasing the OM&A component of Oakville Hydro's revenue requirement.	The savings associated with this initiative are sustainable due to the matching of the customer service demand with the staffing levels which have been negotiated into the contract.
Post Employment Costs	The reduction in post-employment costs reduces the OM&A component of Oakville Hydro's revenue requirement.	The savings will increase as current employees retire and new employees not eligible for the plan join the organization Growth in post-retirement health care costs are substantially reduced.
Connection Agreement for two feeders at the Glenorchy Transformer Station	The savings realized as Milton Hydro (an embedded distributor) will share in the operating, maintenance and depreciation and capital costs associated with this transformer station.	Oakville Hydro negotiated a contract with notice of termination no less than one year prior to the date of filing Oakville Hydro's Cost of Service application.
Health and Safety	Oakville Hydro's health and safety program has a direct impact on its ability to control the costs associated with injury and illness and therefore the costs to be recovered from its ratepayers.	In 2013, Oakville Hydro received the President's Award from the Infrastructure Health and Safety Association (IHSA) for achieving 250,000 consecutive hours without a lost time injury.
Organizational Effectiveness	Oakville Hydro's organizational effectiveness initiative has a direct impact on the OM&A component of Oakville Hydro's costs to be recovered from rate payers.	Oakville Hydro will sustain its productivity through continued engagement with its employees.

c) Please explain how the savings identified in part (b) above are sustainable.

RESPONSE:

Please see the Column entitled "Sustainability" in above answer to part (b).

6.2-SEC-24

Please describe or provide evidence references for each operational effectiveness initiatives undertaken, and describe how the savings are sustainable.

RESPONSE:

See response 6.2-EP-27 a, b and c.

Appendix 6 – A

Board Self Assessment

2013 BOARD ASSESSMENT SURVEY QUESTIONS

1. The Board has a clear understanding of its mandate and responsibilities.
2. The Board understands the most significant risks and opportunities facing the organization.

2b Does the Board ensures that adequate steps are in place to mitigate the potential impact of those significant risks and ensure that significant opportunities are fully explored.

3. The Board understands the strategy of maximizing the Company's long term value for the benefit of its shareholder.

3b. The Board understand the opportunities presented to the Company to advance the long term interest of it shareholder and address the concerns of other stakeholders including employees, customers, suppliers and the public at large.

4. The Board's level of contribution to the process for approving Oakville Hydro Corporation's strategic direction on an annual basis is sufficient. The Board approves all material strategic decisions including acquisitions, joint ventures, mergers and divestitures.
5. The Board is focused on the alignment of CEO leadership with the Company's strategic challenges, and on Management succession. The Board has sufficient exposure to management below the Executive Management Team, particularly high potentials, in order to assess succession planning recommendations etc.
6. The Board and the Board Committees foster a performance-oriented culture.
7. The Board fosters a culture of ethical conduct and ensures compliance is monitored effectively.
8. The Board effectively monitors management's compliance with major Board approved decisions.
9. The Shareholder / Board have qualified directors with the appropriate mix of experience and skills relative to Oakville Hydro Corporation's business needs. The Board is satisfied that the Director In Camera sessions are candid and constructive.
10. The Board has a Director reappointment and succession planning process in place that will help ensure Oakville Hydro Corporation's Board attracts and retains the right mix of skills and competencies relative to Oakville Hydro Corporation's business challenges and risks.
11. The Board Chair understands and fulfills the responsibilities outlined in the Board Chair mandate.
12. The Board encourages a culture that promotes candid communication among Board members and executive management, critical questioning, rigorous decision making and timely resolution of issues.
13. The Board and CEO have an excellent working relationship and work together to achieve a healthy atmosphere of constructive interaction.
14. The Board and Management understand and respect the division of authority and the allocation of responsibilities between the Board and Management.
15. The format and content of the Board's annual strategic meeting is sufficient.

16. Deliberations and discussions at Board meetings are strategic (high level) and focus on priority (key) issues, recognizing there are core Board accountabilities.
17. The Board materials are received in a timely manner, and are sufficiently informative and analytical for making decisions and resolving issues.
18. Directors are well prepared for Board meetings and focus on relevant information in order to spend Board time effectively and make informed decisions.
19. The Board has an effective system to identify and deal with real or potential conflicts of interest by Board members.
20. Agendas are appropriately planned for content and for the amount of time available for Board and Committee meetings.
21. The Board minutes are clear and useful and adequately and accurately document discussion, actions taken and performance by the Directors of their duties.
22. The Board is sufficiently informed of material issues on a timely basis.
23. The Board receives adequate feedback on the Board's performance individually and collectively.
24. Evaluations lead to a clearer understanding of what the Board must do to become a strategic asset.
25. The Board effectively follows through on its recommendations developed during the evaluation process.

Proposed Rating Scale

5 = strongly agree
4 = agree
3 = sometimes agree and sometimes disagree
2 = disagree
1 = strongly disagree

Appendix 6 – B

2014 Board Annual Work Plan

2014 Board Annual Work Plan

	Q1	Q2	Q3	Q4	As Reqd.	Comments
Annual Activities						
Review of Mandate, Charter and Annual Work Plan			X			
Board Assessment Surveys				X		
Approval of the Strategic Plan		X				
Approval of the Business Plan				X		
Oversee Executive Management Succession Planning			X			
Annual Financial statements	X					
Review Board Skills/Matrix					X	
Rotation of Directors					X	
Conduct Performance Appraisal with President and CEO on prior year results and leadership	X					
Director Education			X		X	
Quarterly						
Monitor Safety process and progress	X	X	X	X		
Compliance with Laws and Regulations	X	X	X	X		
Assess principal risks and opportunities	X	X	X	X		
Monitor Internal Control	X	X	X	X		
As Required						
Appointment of members to Committees (Core/Adhoc)					X	
Review Communication Policy					X	
Approval of Capital expenditures					X	
Regulatory Rate Setting					X	

Adopted: October 3, 2013

Appendix 6 – C

Shareholder Direction

AMENDED AND RESTATED

SHAREHOLDER DIRECTION

AND

UNANIMOUS SHAREHOLDER DECLARATION

June 8, 2011, Consolidation

TOWN OF OAKVILLE

SHAREHOLDER DIRECTION

1. *Purpose*

This Shareholder Direction outlines the expectations of The Corporation of the Town of Oakville (the "Shareholder") relating to the principles of governance and other fundamental principles and policies of Oakville Hydro Corporation (the "Corporation"). Except as provided in Sections 10 and 11, this Shareholder Direction is not intended to constitute a unanimous shareholder declaration under the *Business Corporations Act* (Ontario) (the "OBCA") or to formally restrict the exercise of the powers of the Board of Directors of the Corporation (the "Board").

2. *Corporate Governance*

The Board shall supervise the management of the business and affairs of the Corporation and, in doing so, shall act honestly and in good faith with a view to the best interests of the Corporation and each director shall exercise the same degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Shareholder expects that the Board will adopt appropriate policies to address the following governance issues:

(a) stewardship – the Board will assume responsibility for the stewardship of the Corporation including
   (i) adoption of a strategic planning process;
   (ii) identification of the principle risks of the Corporation's and its Affiliates' businesses and ensuring the implementation of appropriate systems to manage these risks;
   (iii) implementation of succession planning, including, appointing, training and monitoring senior management;
   (iv) implementation of a communication policy for the Corporation and its Affiliates; and
   (v) integration of the Corporation's internal control and management information systems;

(b) Board training – the Board will adopt and provide an appropriate orientation and education program for new Board members; and

(c) Position descriptions – the Board will develop position descriptions for the Board, its committees and the CEO, including the definition of limits to management's responsibilities and corporate objectives for which the CEO is responsible for meeting.

3. *Permitted Business Activities*

Subject to the restrictions in Section 10 of this Shareholder Direction, the Corporation and its Affiliates (as defined in the OBCA) may engage in the business activities which are permitted by any laws applicable to the Corporation and its Affiliates from time to time, including the *Electricity Act, 1998,* and as the Board of Directors may authorize. In so doing, the Corporation and its Affiliates shall conform to all requirements of the Ontario Energy Board, the Ontario Independent Electricity System Operator ("IESO") and all other applicable regulatory or governmental authorities.

4. *Decisions of the Shareholder*

Approvals or decisions of the Shareholder required pursuant to this Shareholder Direction or the OBCA shall require a resolution or by-law of the Town Council of the Shareholder which shall be passed at a meeting of Council and shall be given in writing to the Corporation and signed by the Shareholder Representative.

5. *Board of Directors*

(1) The Corporation shall be managed by the Board which shall consist of 9 directors to be elected by the Shareholder. One of the nine directors of the Board shall be the Mayor or an alternative representative of Council, appointed annually. Additional members of Council and staff of the Town of Oakville may also be elected at the Shareholder's discretion. If the Corporation wishes to increase or decrease the number of directors to be elected annually, then the Corporation must obtain approval from the Shareholder at least six months prior to the date upon which such a change is to take effect. In selecting directors, the Shareholder shall consider candidates nominated by the nominating committee of the Board (the "Nominating Committee"), but shall not be obliged to select such candidates. It is expected that the Nominating Committee will develop a process to identify and evaluate potential Board candidates in order to recommend a slate of candidates acceptable to the Shareholder.

(a) The Nominating Committee shall annually review and update its list of citizens who have expressed interest in serving on the Board or the boards of its Affiliates.

(b) The Nominating Committee shall annually recommend to the Shareholder the directors to be elected as the directors of the Corporation recognizing the Shareholder's right to accept, reject or modify such recommendations in the sole discretion of the Shareholder.

(2) In addition to independence of judgment and integrity and the requirements of the OBCA, the qualifications of candidates for the Board may include:

(a) business experience;

(b) experience on boards of significant corporations;

(c) financial, legal, accounting and/or marketing experience;

(d) industry knowledge;

(e) knowledge of public policy and government regulation issues relating to the Corporation and the electricity industry;

(f) knowledge and experience with risk management strategy and corporate governance; and

(g) knowledge and experience concerning environmental matters, labour relations and occupational health and safety.

(3) Preference shall be given to qualified candidates for the Board who are residents of Oakville.

(4) The President and Chief Executive Officer of the Corporation may be a director of the Corporation or an Affiliate.

(5) The term of office for each director shall be one (1) year and directors shall be elected annually, except that:

(a) subject to (b), (c), (d) and (e), no person shall be elected director for more than five (5) terms;

(b) not more than three (3) existing directors shall be required to retire annually as a result of the limitation in (a);

(c) notwithstanding (a), the maximum term of appointment of 5 one year terms for those members of the Board as of September 18, 2006, shall be extended on a graduated basis to provide for the rotation of one (1) Director off the Board each year commencing in 2007;

(d) notwithstanding (a) any member of Council of the Town of Oakville or Town of Oakville staff, who are elected as a director, shall not be subject to the maximum appointment of five (5) one year terms; and

(e) where Council in its absolute discretion determines that it is appropriate to make an exception to (a), a person may be re-elected for more than five (5) terms.

(6) The Chair of the Board shall be selected by the Shareholder and shall preside at each meeting of the Board if present.

(7) The Board may establish committees of the Board in the Board's discretion. It is anticipated that the Board will establish the following committees:

(a) Audit and Finance Committee to review financial results;

(b) Compensation Committee to determine senior management and directors' compensation; and

(c) Nominating Committee to identify, evaluate and recommend Board candidates to the Shareholder.

(8) The Board shall recommend annually to the Shareholder for approval compensation for directors in an amount sufficient to attract directors with necessary qualifications, recognizing Shareholder guidelines, if any. Members of the Council of the Town of Oakville or Town of Oakville staff who are serving as directors of the Corporation or any of its Affiliates shall do so without compensation from the Corporation and its Affiliates.

(9) The directors of the Affiliates shall be chosen by the Board of Directors of the Corporation. The Board of Directors of Oakville Hydro Corporation shall select the directors for its Affiliates by applying the same criteria as set forth in section 5(2) of the Shareholder Direction and evaluate such directors of its subsidiary corporations for recommendation to the Shareholder.

(10) The directors and officers of the Corporation and the Affiliates will strictly abide by the conflict of interest requirements of the OBCA and the conflict of interest rules set forth in the by-laws or any policy of the Corporation and the Affiliates, including requirements in respect of disclosure and abstention from voting, with the exception that Members of Council or Town employees who are Board members shall not be deemed to be in a conflict of interest where the Board is considering matters in relation to the Shareholder..

6. *Shareholder Expectations*

The Shareholder expects that the Board will establish policies and practices to:

(1) develop and maintain a prudent financial and capitalization structure for the Corporation and its Affiliates consistent with Ontario Energy Board benchmarks and sound financial principles and established on the basis that the Corporation and its Affiliates are intended to be self-financing entities;

(2) establish just and reasonable rates for the regulated distribution business of the Corporation, or any of its Affiliates, which are:

  (a) consistent with similar utilities in comparable growth areas and as may be permitted by the Ontario Energy Board under the *Ontario Energy Board Act 1998* (the "OEB Act");

  (b) intended to enhance the value of the Corporation and its Affiliates; and

  (c) consistent with the encouragement of economic development and activity within the Town of Oakville;

(3) provide the Shareholder with a reasonable return:

  (a) comparable to the return received by other growth municipalities as permitted by the Ontario Energy Board pursuant to the OEB Act;

  (b) through the payment of dividends, interest or otherwise; and

  (c) consistent with a prudent financial and capitalization structure and maintaining just and reasonable rates;

(4) consult with the Treasurer of the Shareholder by October 31 of each year to provide forecasts of the dividends to be declared by the Board of Directors with respect to the Corporation's then current fiscal year to allow for the Shareholder to proceed with its own budgetary processes;

(5) manage all risks related to the business conducted by the Corporation and its Affiliates, through the adoption of appropriate risk management strategies and internal controls consistent with industry norms; and

(6) develop a long range strategic plan for the Corporation and its Affiliates which is consistent with the maintenance of a viable, competitive business and preserves the value of the business.

7. *Annual Meeting*

(1) Within 6 months after the end of each fiscal year, the Board shall report to a public meeting of Town Council and provide such information concerning the Corporation and its Affiliates as the Board considers appropriate.

(2) The Shareholder shall annually, at an in camera meeting of Council, consider candidates for the Board as proposed by the Nominating Committee.

(3) The Shareholder shall annually, at a public meeting of Council, consider the appointment of the auditors of the Corporation and receive the audited financial statements of the Corporation for the last completed fiscal year.

(4) Within 6 months after the end of each fiscal year, the Shareholder by resolution in writing signed by the Shareholder Representatives in accordance with Section 4, shall elect the members of the Board and appoint the auditors for the Corporation and complete such other business as would normally be completed at an annual meeting of shareholders under the OBCA.

8. *Reporting on Major Developments*

(1) In addition to the annual meeting described in Section 7, the Board shall report to Town Council on major business developments or materially adverse results as the Board, in its discretion, considers appropriate and such reports received may be considered by the Shareholder at an in camera meeting of Council.

(2) Town Council may, from time to time, request that a senior member of the Corporation's management and/or a member of the Board attend at a public meeting of Council and respond to questions raised by Council or the general public concerning the Corporation and/or its Affiliates.

9. *Shareholder Representative*

The Shareholder hereby designates the Mayor or the individual designated by the Mayor from time to time as the legal representative of the Shareholder (the "Shareholder Representative") for purposes of providing, pursuant to Section 4, any consent or approval required by this Shareholder Direction or by the OBCA.

10. *Matters Requiring Shareholder Approval*

Without Shareholder approval given in accordance with Section 4 of this Shareholder Direction, the Corporation shall not:

(1) change the name of the Corporation or an Affiliate; add, change or remove any restriction on the business of the Corporation or an Affiliate; create new classes of shares; or in any other manner amend its articles of incorporation or make, amend or repeal any by-law of the Corporation or an Affiliate;

(2) except when in the normal course of business, sell assets of the Corporation or of an Affiliate or purchase assets of any business, enterprise or undertaking;

(3) amalgamate with any other corporation(s) other than wholly-owned subsidiaries or Affiliates which amalgamations may, under the OBCA, be approved by a resolution of directors;

(4) take or institute proceedings for any winding up, arrangement, or dissolution of the Corporation;

(5) issue, or enter into any agreement to issue, any shares of any class, or any securities convertible into any shares of any class, of the Corporation or any of its Affiliates;

(6) establish any requirement for capital contributions to the Corporation by the Shareholder;

(7) take on or assume any financial obligation which would increase the debt/equity ratio of the Corporation and its Affiliates on a consolidated basis above the ratio of 60:40;

(8) redeem or purchase any of its outstanding shares;

(9) apply to continue as a corporation under the laws of another jurisdiction;

(10) make any decision that would materially adversely affect the tax or regulatory status of the Corporation or any of its Affiliates;

(11) materially alter the nature of or geographic extent of the business of the Corporation or any of its Affiliates;

(12) enter into any joint venture, partnership, strategic alliance or other venture, including ventures in respect of the generation or co-generation of electricity; and

(13) make any donations of cash and/or goods and services, including purchasing tickets to political events, to any political party, constituency association, candidate or for any other partisan political purpose whatsoever at any level of government, including federal, provincial, municipal or school board.

11. *Disposition of Real Property*

Notwithstanding any of the provisions of Section 10 of this Shareholder Direction, where the Corporation or any of its Affiliates intends to sell any real property under its control, the Corporation or Affiliate must first offer to sell the real property to the Shareholder and, in the event that the Shareholder wishes in good faith to use the real property for a municipal purpose, the Shareholder may:

(i) agree to purchase the real property, in which case the Shareholder shall compensate the Corporation or Affiliate for the real property at its actual cost, less accrued depreciation as shown on the books of the Corporation or Affiliate or the assessed value of the real property, whichever is the greater; or

(ii) decline to purchase the real property, in which case the Corporation or Affiliate may sell, lease or otherwise dispose of the real property as it sees fit.

12. *Paramountcy*

In the event of any inconsistency between the terms of this Shareholder Direction and the terms of the by-laws of the Corporation or any of its Affiliates, the terms of this Shareholder Direction shall prevail to the extent of the conflict.

13. *Revisions to this Direction*

The Shareholder acknowledges that this Shareholder Direction may be revised from time to time as circumstances may require and that the Shareholder shall promptly provide the Board of Directors with copies of such revisions.

DATED at Oakville, Ontario as of the 8th day of June, 2011.

THE CORPORATION OF THE TOWN OAKVILLE

By:______________________________
Mayor

By:______________________________
Clerk

7- Revenue Requirement

Issue 7.1 *Is the proposed Test year rate base including the working capital allowance reasonable?*

7.1-Staff-36

Ref: 1) Exhibit 4/Tab6/Schedule 1

2) 2014 Filing Requirements For Electricity Distribution Rate Applications, Chapter 2, Cost of Service (COS) dated July 17, 2013, S. 2.3.2.2

3) Board letter to All Licenced Electricity Distributors, dated February 24, 2010: "Accounting for Overhead Costs Associated with Capital Work"

4) International Accounting Standards 16, S. 19

<u>Capitalization of Overhead</u>

The 2014 COS filing requirements indicated that electricity distributors electing to remain on CGAAP must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory in 2013 for all distributors that have not yet made these changes, and therefore all applications for 2014 rates should reflect that these changes were made in 2012 or 2013.

The Board letter and IAS 16 explicitly prohibits the capitalization of administrative and general overhead under IFRS.

Oakville Hydro indicated that 50% of its administration burden related to General and Administrative (G & A) costs of Engineering and Operations that are directly attributable to PP&E should be capitalized.

a) Please explain why Oakville Hydro is capitalizing 50% of its administration burden related to G & A costs of Engineering and Operations when this is inconsistent with IAS 16 and Ontario Energy Board policy.

RESPONSE:

For clarification, the section this question refers to, is describing the process that Oakville Hydro followed under OLD CGAAP prior to 2013. Under OLD CGAAP, rather than having Operations and Engineering management staff prepare time sheets to charge their time to specific jobs, their costs were recovered through a burden of 50% of the actual labour cost charged to the job. Effective 2013, under NEW CGAAP and in accordance with the Board Letter to All Licenced Electricity Distributors, dated February 24, 2010: "Accounting for Overhead Costs Associated with Capital Work", burdens (other than the benefit burden) have been eliminated. Effective 2013 Oakville Hydro's procedures are consistent with both IAS 16 and OEB policy.

b) Please quantify the 50% capitalized portion of G & A costs and make any adjustments needed to expense these capitalized G & A costs.

RESPONSE:

As responded to in response (a) above, effective 2013, the 50% capitalized portion of G&A costs are no longer capitalized under NEW CGAAP. Therefore there are no adjustments required.

7.1-Energy Probe-28

Ref: Exhibit 2, Tab 1, Schedule 2

Table 2-5 indicates that the average net book value in 2010 was more than $3 million below the Board approved forecast.

a) Please confirm that the removal of stranded meters from rate base in 2010 resulted in a reduction in the average NBV in 2010 of $1,397,625. If this cannot be confirmed, please indicate the reduction in average NBV in 2010 due to the removal of the stranded meters.

RESPONSE:

The removal of the stranded meter from rate base in 2010 resulted in a reduction in the average NBV in 2010 of $3,891,085.

b) What is the difference in the average net book value reduction in 2010 compared to Board approved of more than $3 million and the amount associated with the removal of the stranded meters related to?

RESPONSE:

For financial statement purposes, Oakville Hydro transferred a portion of the NBV value of its stranded meters to the variance account and out of net book value of capital asset as at December 31, 2009. In 2010 Oakville Hydro transferred the remainder of the total value of its stranded assets into the variance account. Therefore, since a full year applies to the 2009 stranded meter value, the total impact of stranded meters is $3,891,085, which is illustrated in the table below.

Impact of Stranded Meters on Average Net Book Value

Description	2010 Board Approved	2009 Adjustment for Stranded Meters	2010 Adjusted Opening Balance	Total Adjustment for Stranded Meters
Gross Fixed Assets - Opening	$ 187,960,573	$ 3,136,209	$ 184,824,364	$ 3,136,209
Gross Fixed Assets - Closing	202,681,800	-	202,681,800	7,813,757
Average Gross Fixed Assets	195,321,187	1,568,105	193,753,082	5,474,983
		-		
Accumulated Deprciation - Opening	79,297,219	628,763	78,668,456	628,763
Accumulated Deprciation - Closing	89,104,901	-	89,104,901	2,539,033
Average Accumulated Depreciation	84,201,060	314,382	83,886,679	1,583,898
		-		
Average Net Fixed Assets	$ 111,120,127	$ 1,253,723	$ 109,866,404	$ 3,891,085

c) Please reconcile the reduction in average NBV, after the removal of the impact of the stranded meters, with the fact that Oakville Hydro's capital expenditures in 2010 were almost $2 million more than the Board approved figure.

RESPONSE:

As shown in the table provided below, the increase in net fixed assets, excluding the impact of stranded meters, is an increase of $838,461. Given that the net fixed assets is based on the average of the opening and closing balance, $838,461 is reasonable given that Oakville Hydro's capital expenditures were almost $2M more than the Board approved amount.

Net Fixed Assets		Amount
2010 Board Approved		$ 111,120,127
2010 Actual	108,067,503	
Impact of Smart Meters	3,891,085	
2010 Actual Excluding Impact of Smart Meters		111,958,588
Change in Net Fixed Assets (Excluding Stranded Meters)		$ 838,461

d) The reduction in the closing balance of gross fixed assets as shown in Table 2-5 is $7,337,209. Please indicate how much of this decrease was related to the stranded meters.

RESPONSE:

As shown in the table provided in response to part b) of this interrogatory, the transfer of the stranded meters to the variance account decreased the closing balance of the gross fixed assets by $7,813,757. The reduction of $7,337,209 related to smart meters is offset by an increase in gross fixed assets of $476,548 related to incremental capital spending.

e) Please provide a version of Table 2-5 that shows the comparison between 2010 actual and 2010 Board approved, but leaving the stranded meters (gross assets and accumulated depreciation) in the 2010 actual figures.

RESPONSE:

The following version of Table 2-5 shows the comparison between 2010 actual and 2010 Board approved leaving the stranded meters in the 2010 actual figures.

Description	2010 Board Approved	2010 Actual - Including Stranded Meters
Net Book Value		
Gross Fixed Assets - Closing	$ 202,681,800	$ 203,158,348
Accumulated Deprciation - Closing	89,104,901	87,904,526
Net Book Value- Closing	113,576,899	115,253,822
Average Net Book Value	111,120,127	113,606,205
Working Capital - 15% Allowance Approach		
Cost of Power	17,975,706	19,557,632
OM&A	1,775,910	1,680,328
15% Working Capital	19,751,616	21,237,960
Total Rate Base	$ 130,871,743	$ 134,844,165

7.1-Energy Probe-29

Ref: Exhibit 2, Tab 1, Schedule 2

a) Please update Tables 2-16 and 2-17 to reflect actual data for the most recent year-to-date period currently available along with a forecast for the remainder of the year as to what will be in-service by the end of 2013. Please also include any disposals now forecast for 2013.

RESPONSE:

Oakville Hydro has updated Table 2-16 and 2-17 to reflect actual unaudited data for 2013.

Table 2-16 Fixed Asset Continuity Schedule, as at December 31st, 2013 (Old CGAAP)

including WIP (Unaudited 2013 Data)

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2013
CGAAP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	101,230		366,775	462,925
13	1810	Leasehold Improvements	3,505,475	20,756		3,526,231	1,190,359	351,586		1,541,945	1,984,286
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	40,982		21,643,184	647,283	137,448		784,732	20,858,452
47	1820	Distribution Station Equipment - Normally Primary	7,310,742	587,835		7,898,578	2,558,874	543,535		3,102,409	4,796,169
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	2,414,045		24,961,430	5,959,170	900,996		6,860,166	18,101,264
47	1835	Overhead Conductors and Devices	31,791,864	1,873,789		33,665,652	12,148,124	1,326,179		13,474,302	20,191,350
47	1840	Underground Conduit	60,446,766	3,488,226		63,934,992	26,455,432	2,651,053		29,106,485	34,828,507
47	1845	Underground Conductors and Devices	46,080,876	4,149,767		50,230,643	17,990,209	2,004,107		19,994,315	30,236,327
47	1850	Line Transformers	44,916,673	1,698,078		46,614,752	20,215,405	1,930,295		22,145,701	24,469,051
47	1855	Services	9,684,898	1,411,111		11,096,009	1,480,039	415,618		1,895,658	9,200,352
47	1860	Meters	12,935,065	488,444		13,423,509	2,177,884	344,709		2,522,593	10,900,916
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187	40,257		912,444	750,494	25,878		776,372	136,073
10	1920	Computer Equipment - Hardware	7,371,011	1,226,436		8,597,447	5,994,187	1,039,424		7,033,612	1,563,836
12	1925	Computer Software	5,286,592	45,060		5,331,652	4,395,627	300,589		4,696,216	635,435
10	1930	Transportation Equipment	4,488,353	259,738	222,595	4,525,496	2,439,959	545,784	220,600	2,765,142	1,760,354
8	1935	Stores Equipment	166,334			166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	63,999		1,343,205	866,772	96,021		962,793	380,412
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premises	171,648			171,648	171,648			171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876			49,876	0
47	1980	System Supervisory Equipment	4,486,620	270,400		4,757,019	2,381,175	283,366		2,664,541	2,092,478
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(3,902,433)		(45,396,718)	(9,836,144)	(1,737,820)		(11,573,964)	(33,822,753)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	246,286		7,825,621	3,863,763
		Total before Work in Process	**257,748,723**	**14,176,491**	**222,595**	**271,702,619**	**106,035,180**	**11,509,227**	**220,600**	**117,323,806**	**154,378,813**
WIP	2055	Work in Process	1,792,056	576,809		2,368,865	0			0	2,368,865
		Total after Work in Process	**259,540,778**	**14,753,300**	**222,595**	**274,071,484**	**106,035,180**	**11,509,227**	**220,600**	**117,323,806**	**156,747,678**

Table 2-17 Fixed Asset Continuity Schedule, as at December 31st, 2013 (New CGAAP) including WIP (Unaudited 2013 Data)

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2013
MCGAAP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0	0		0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	100,941		366,485	463,215
13	1810	Leasehold Improvements	3,505,475	20,756		3,526,231	1,190,359	351,585		1,541,944	1,984,287
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	33,746		21,635,948	647,283	152,432		799,715	20,836,232
47	1820	Distribution Station Equipment - Normally Primar	7,310,742	484,046		7,794,788	2,558,874	744,648		3,303,522	4,491,266
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	1,987,815		24,535,200	5,959,170	430,219		6,389,389	18,145,811
47	1835	Overhead Conductors and Devices	31,791,864	1,542,948		33,334,812	12,148,124	587,345		12,735,468	20,599,343
47	1840	Underground Conduit	60,446,766	2,872,336		63,319,102	26,455,432	1,004,104		27,459,536	35,859,566
47	1845	Underground Conductors and Devices	46,080,876	3,417,074		49,497,949	17,990,209	1,294,482		19,284,690	30,213,259
47	1850	Line Transformers	44,916,673	1,374,407		46,291,081	20,215,405	1,047,926		21,263,332	25,027,749
47	1855	Services	9,684,898	1,161,962		10,846,860	1,480,039	217,899		1,697,938	9,148,922
47	1860	Meters	12,935,065	402,203		13,337,268	2,177,884	1,131,931		3,309,815	10,027,453
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187	40,257		912,444	750,494	25,878		776,372	136,072
10	1920	Computer Equipment - Hardware	7,371,011	1,166,502		8,537,513	5,994,187	958,057		6,952,244	1,585,269
12	1925	Computer Software	5,286,592	45,060		5,331,652	4,395,627	15,394		4,411,021	920,631
10	1930	Transportation Equipment	4,488,353	259,738	222,595	4,525,496	2,439,959	344,118	220,600	2,563,477	1,962,019
8	1935	Stores Equipment	166,334	0		166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	52,699		1,331,905	866,772	183,385		1,050,157	281,749
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098	0		8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premises	171,648	0		171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876	0		49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,486,620	222,657		4,709,277	2,381,175	269,990		2,651,165	2,058,112
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(3,355,216)		(44,849,501)	(9,836,144)	(874,911)		(10,711,056)	(34,138,445)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	246,286		7,825,621	3,863,763
		Total before Work in Process	**257,748,723**	**11,728,990**	**222,595**	**269,255,118**	**106,035,180**	**8,234,650**	**220,600**	**114,049,230**	**155,205,889**
WIP	2055	Work in Process	1,792,056	(70,469)		1,721,587	0			0	1,721,587
		Total after Work in Process	**259,540,778**	**11,658,522**	**222,595**	**270,976,705**	**106,035,180**	**8,234,650**	**220,600**	**114,049,230**	**156,927,476**

b) Please updated Table 2-18 to reflect any changes as a result of the update to 2013 requested in part (a).

RESPONSE:

Oakville Hydro has updated Table 2-18 to reflect actual unaudited data for 2013.

Table 2-18 Fixed Asset Continuity Schedule, as at December 31st, 2014 (New CGAAP) including WIP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2014
MCGAAP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	366,485	20,299		386,784	442,916
13	1810	Leasehold Improvements	3,526,231	341,615		3,867,846	1,541,944	374,233		1,916,177	1,951,669
47	1815	Transformer Station Equipment - Normally Prima	21,635,948			21,635,948	799,715	507,260		1,306,976	20,328,972
47	1820	Distribution Station Equipment - Normally Primar	7,794,788	678,906		8,473,694	3,303,522	302,804		3,606,327	4,867,368
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	24,535,200	1,637,803		26,173,004	6,389,389	465,819		6,855,208	19,317,796
47	1835	Overhead Conductors and Devices	33,334,812	918,536		34,253,347	12,735,468	566,617		13,302,085	20,951,262
47	1840	Underground Conduit	63,319,102	2,709,064		66,028,166	27,459,536	970,588		28,430,123	37,598,042
47	1845	Underground Conductors and Devices	49,497,949	3,928,777		53,426,727	19,284,690	1,318,141		20,602,831	32,823,895
47	1850	Line Transformers	46,291,081	7,080,429		53,371,510	21,263,332	1,063,753		22,327,084	31,044,426
47	1855	Services	10,846,860	641,411		11,488,272	1,697,938	227,333		1,925,272	9,563,000
47	1860	Meters	13,337,268	481,706		13,818,975	3,309,815	1,347,647		4,657,462	9,161,513
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	912,444			912,444	776,372	23,865		800,237	112,207
10	1920	Computer Equipment - Hardware	8,537,513	380,000		8,917,513	6,952,244	688,714		7,640,957	1,276,556
12	1925	Computer Software	5,331,652	1,231,000		6,562,652	4,411,021	639,742		5,050,763	1,511,889
10	1930	Transportation Equipment	4,525,496	688,079		5,213,575	2,563,477	407,542		2,971,019	2,242,557
8	1935	Stores Equipment	166,334			166,334	152,812	2,133		154,945	11,389
8	1940	Tools, Shop and Garage Equipment	1,331,905	93,333		1,425,239	1,050,157	126,914		1,177,071	248,168
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	4,058	810		4,868	3,231
47	1970	Load Management Controls - Customer Premises	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,709,277	147,635		4,856,912	2,651,165	271,238		2,922,403	1,934,509
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(44,849,501)	(3,299,281)		(48,148,782)	(10,711,056)	(967,295)		(11,678,351)	(36,470,431)
13	2005	Property under Capital Lease	11,689,385	738,210		12,427,595	7,825,621	286,508		8,112,129	4,315,466
		Total before Work in Process	**269,255,118**	**18,397,225**	**0**	**287,652,343**	**114,049,230**	**8,644,663**	**0**	**122,693,893**	**164,958,450**
WIP	2055	Work in Process	1,721,587	(1,721,587)		0	0			0	0
		Total after Work in Process	**270,976,705**	**16,675,638**	**0**	**287,652,343**	**114,049,230**	**8,644,663**	**0**	**122,693,893**	**164,958,450**

c) Please explain why there is no WIP forecast for the end of 2014 despite the fact that there was been WIP in every other year shown.

RESPONSE:

Oakville Hydro has only included those projects in the 2014 Test Year that it expects to complete and be in service in 2014. Of the material projects to be completed in 2014, 24% were started in 2013 and 86% will have started before the end of the first quarter of 2014. Those projects that are shown as having a December 31, 2014 end date are the projects that have not been fully defined as they are outside of Oakville Hydro's control. Oakville Hydro will update the in-service date if more information becomes available.

Project #	Project Description	Start Date	In-service Date	Amount
16-U1	Gang-Op Switch Replacement Program	1-Mar-13	21-May-14	$ 267,139
46-A	Replace Overhead Assets on John Street	1-May-13	30-Jun-14	207,270
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	1-May-13	1-Sep-14	358,919
42-B	Live front Padmount Transformer Replacements	1-Jun-13	30-May-14	275,730
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	1-Jun-13	1-Jul-14	184,665
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	1-Jun-13	1-Aug-14	385,205
45-D	Poletran Removals and Replace U/G Assets Various Locations	3-Jun-13	30-Jun-14	292,164
45-A	Vault Transformer Replacements	1-Sep-13	30-Nov-14	316,241
46-C	Replace Overhead Assets on Robinson St.	15-Sep-13	30-Jun-14	458,981
16-G2	27.6kV Air insulated switchgear upgrades to G&W	1-Oct-13	15-May-14	379,340
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	1-Jan-14	1-Oct-14	300,000
14-62	2014 Fleet	1-Jan-14	1-Nov-14	384,762
14-50C	New Development Investment	1-Jan-14	31-Dec-14	423,729
14-54	New General Services	1-Jan-14	31-Dec-14	351,604
14-61	Distribution Meters	1-Jan-14	31-Dec-14	481,706
16-64F	IT Infrastructure	2-Jan-14		420,000
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	1-Feb-14	5-Sep-14	153,800
	3rd Party Indefeasable Right of Use	1-May-14	1-May-14	738,210
05-N	On-site Emergency Back-up Transformer			$ 5,000,000
15-I	Road Widening TBD		19-Mar-14	203,234
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403		20-Jun-14	420,973
05-P2	Power Transformer Replacement Program		22-Oct-14	268,190
05-Q2	Victoria MS Low Voltage Breaker Replacement Program		22-Oct-14	547,715
14-64D	ERP - GP & Business Intelligence			203,000
LSHOLD	HVAC upgrade - 5 year replacement program			230,000
				$ 13,252,577

7.1-Energy Probe-30

Ref: Exhibit 2, Tab 2, Schedule 2

What was the driver for the nearly $8 million higher WIP shown in Table 2-20 for 2010 as compared to the Board approved level?

RESPONSE:

The design and construction of Oakville Hydro's Glenorchy Municipal Transformer Station began in 2009 and completed in 2011. By December 31, 2010, Oakville Hydro had incurred costs of $11.0M that was included in WIP. The forecasted WIP for the Glenorchy Municipal Transformer Station was not included in Oakville Hydro's 2010 Cost of Service Application as it is Oakville Hydro's practice to include only those projects which it expects to complete in its cost of service applications.

7.1-Energy Probe-31

Ref: Exhibit 2, Tab 3, Schedule 1

a) When did or when will Oakville Hydro convert all rate classes to monthly billing?

RESPONSE:

Oakville Hydro plans is to convert all rate classes to monthly billing in the 3rd or 4th quarter of 2014 once approval has been received from the Board as part of this Application and additional discussions with the Region of Halton regarding billing for water and wastewater services.

b) What rate classes did Oakville Hydro bill on a monthly basis before converting all classes to monthly billing? Were all other rate classes billed on a bi-monthly basis? If not, please provide the billing frequency for any other rate classes that were not billed on a monthly or bi-monthly basis.

RESPONSE:

Oakville Hydro currently bills the following rate classes on a monthly basis:

- General Service > 50 kW
- General Service > 1,000 kW
- Unmetered scattered loads
- Street lighting
- Micro fit and FIT
- Residential –suite metered customers

All other rate classes are currently being billed on a bi-monthly basis.

c) Given the significant impact on cash flow of monthly billing versus bi-monthly billing, why did Oakville Hydro determine that it did not need to do a lead/lag study to determine an appropriate working cash allowance?

RESPONSE:

Oakville Hydro has adopted the Board's 13% working capital allowance rate. It was not required to perform a lead/lag study in its previous Cost of Service proceeding, and chose to use the Board's default 13% value in accordance with the Board's Filing Requirements. Additionally, Oakville Hydro determined that it did not need to do a lead/lag study because, although it is proposing to move to monthly billing which intuitively should have a positive impact on cash flow, it began paying the Independent Electricity System Operator ("IESO")'s monthly energy consumption invoices in weekly instalments rather than the usual ten days after the month effective January 2013. This change became necessary as a result of continuous Margin Calls and early prepayments requirements made by the IESO, along with the proposed increase in bank charges associated with the Letter of Credits required by the IESO. Therefore, Oakville Hydro believes the positive cash flow from the change to monthly billing will be offset by the negative impact of the weekly payments it now makes to the IESO.

d) Does Oakville Hydro agree that by moving all rate classes to monthly billing, its cash flow will be significantly improved? If not, please explain.

RESPONSE:

Oakville agrees that intuitively monthly billing should improve its cash flow. Oakville Hydro has not made any changes to its proposed working capital allowance of 13% as a result of this in the 2014 Test Year for the reasons described in (c) above.

e) What is the incremental impact on OM&A costs of moving to monthly billing of the recent announcement by Canada Post that postage rates will increase significantly over the next number of years?

RESPONSE:

The incremental impact of the recent announcement by Canada Post to the 2014 Test Year's current annual 400,000 bills sent is $80,000 which has not been included in the 2014 Test Year Revenue Requirement.

The incremental impact of the recent announcement by Canada Post on the additional 300,000 bills anticipated in the 2014 Test Year with the move to monthly billing is $60,000.

7.1-Energy Probe-32

Ref: Exhibit 2, Tab 3, Schedule 1

a) Do the controllable expenses include any amounts of depreciation expense associated with transportation equipment that has been allocated to OM&A expense in 2014? If yes, please provide the amount.

RESPONSE:

Oakville Hydro confirms that the controllable expenses used in the calculation of the working capital allowance do not include any amounts of depreciation expense associated with transportation equipment that has been allocated to OM&A expense in 2014.

b) Please update Tables 2-26 and 2-27 to reflect the October 17, 2013 Regulated Price Plan Price Report.

RESPONSE:

Oakville Hydro has updated Table 2-26 to reflect the October 17, 2013 Regulated Price Plan Price Report.

Table 2-26 – Weighted Average HOEP for Non-RPP Customers

Month	HOEP ($ per MWH)
January	25.38
February	19.39
March	19.39
April	19.39
May	16.99
June	16.99
July	16.99
August	16.92
September	16.92
October	16.92
November	23.88
December	23.88
Average	19.42

Oakville Hydro has updated Table 2-27 to reflect the October 17, 2013 Regulated Price Plan Price Report and the Rural or Remote Electricity Rate Protection (“RRRP”) benefit and charge as per the Boards Decision in EB-2013-0396.

Table 2-27 – 2014 Cost of Power Calculation

2014 Cost of Power Calculations

Forecasted Purchases	Residential	General Service < 50 kW	Unmetered	General Service > 50 kW	General Service > 1,000 kW	Embedded Distributor	Sentinel Lighting	Street Lighting	Total
Average Number of Customers	59,243	4,923							
Non-RPP Forecast (kWh)	30,723,902	25,813,211	25,991	539,610,046	152,869,265	31,839,095	-	9,275,778	790,157,289
RPP Forecast (kWh)	586,875,919	138,591,589	3,608,378	85,111,792	-	-	121,132	-	814,308,810
Total kWh	617,599,821	164,404,801	3,634,370	624,721,838	152,869,265	31,839,095	121,132	9,275,778	1,604,466,099
Commodity Charges									
Non-RPP Coommodity Charge ($0.08735/kWh)	$ 2,683,733	$ 2,254,784	$ 2,270	$ 47,134,938	$ 13,353,130	$ 2,781,145	$ -	$ 810,239	$ 69,020,239
RPP Commodity Charge($0.08900/kWh)	$ 52,231,957	$ 12,334,651	$ 321,146	$ 7,574,949	$ -	$ -	$10,781	$ -	$ 72,473,484
Total Commodity Charges	**$ 54,915,690**	**$ 14,589,435**	**$ 323,416**	**$ 54,709,887**	**$ 13,353,130**	**$ 2,781,145**	**$10,781**	**$ 810,239**	**$ 141,493,723**
Retail Transmission Charges									
Forecasted Billing Determinants (kW/kWh)	617,599,821	164,404,801	3,634,370	1,589,641	329,822	73,000	324	24,961	
Transmission Network Rate	$ 0.0072	$ 0.0067	$ 0.0067	$ 2.4866	$ 2.5669	$ 2.5669	$0.4984	$ 2.0744	
Transmission Network Charges	**$4,446,718.71**	**$ 1,101,512.16**	**$24,350.28**	**$ 3,952,802.03**	**$ 846,619.70**	**$187,383.70**	**$161.69**	**$51,778.11**	**$ 10,611,326**
Transmission Connection Rate	$ 0.0036	$ 0.0033	$ 0.0033	$ 1.2375	$ 1.2776	$ 1.2776	$0.2480	$ 1.0324	
Transmission Connection Charges	**$ 2,223,359**	**$ 542,536**	**$ 11,993**	**$ 1,967,181**	**$ 421,380**	**$ 93,265**	**$ 80**	**$ 25,769**	**$ 5,285,565**
Regulatory Charges									
Wholesale Market Service Rate	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$0.0044	$ 0.0044	
Rural Rate Protection Rate	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$0.0013	$ 0.0013	
Regulator Charges	**$ 3,499,732**	**$ 931,627**	**$ 20,595**	**$ 3,540,090**	**$ 866,259**	**$ 180,422**	**$ 686**	**$ 52,563**	**$ 9,091,975**
Smart Metering Charge									
Monthly Smart Metering Rate per Customer	$ 0.79	$ 0.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Metering Charge	**$ 561,628**	**$ 46,666**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 608,293**
Total Cost of Power	**$ 65,647,128**	**$ 17,211,776**	**$ 380,354**	**$ 64,169,961**	**$ 15,487,390**	**$ 3,242,215**	**$11,709**	**$ 940,349**	**$ 167,090,882**

c) Please explain why the Adjustment to Address Bias Towards Unfavourable Variance and the Adjustment to Clear Existing Variance are not used in the calculation of the non-RPP price whereas it is included in the RPP price.

RESPONSE:

Oakville Hydro has included the Adjustment to Address Bias Towards Unfavourable Variance in its calculation of the RPP price but not the Non-RPP price since these adjustments are only applicable to RPP customers. They are not applicable to non-RPP Customers.

d) What is the impact of include the two Adjustments noted in part (c) above on the cost of power based on the October, 2013 Report?

RESPONSE:

The Adjustment to Address Bias Towards Unfavourable Variance of $1.00 per MWh would increase Oakville Hydro's cost of power by $814,309. The Adjustment to Clear Existing Variances of $(1.50) would decrease Oakville Hydro's cost of power by $1,221,463. The net effect of the two adjustments would be a decrease of $407,154.

7.1-Energy Probe-33

Ref: Exhibit 2, Tab 3, Schedule 1

For each of the components of the cost of power shown in Table 2-27, please indicate when the distributor pays the corresponding invoices.

RESPONSE:

The commodity charges, regulatory charges, smart metering charge and the transmission charges for four of the five transmission stations in Oakville Hydro's service area are billed monthly by the Independent Electricity System Operator ("IESO"). The IESO issues its invoices on the 10th business day following month end and payment is due on the 12th business day. As discussed previously, in an effort to reduce the cost of providing the IESO with a Letter of Credit security deposit and to reduce the number of margin calls from the IESO, Oakville Hydro also makes a weekly pre-payment to the IESO of $2,500,000. The retail transmission charges for the 5th transmission station (Trafalgar) are billed monthly by Hydro One Networks Inc. Hydro One sets its own monthly billing periods (to date in 2014 it has typically been from the 10th of a month to the 9th of the following month). The bill is sent 19 days later and is due in another 19 days.

7.1-Energy Probe-34

Ref: Exhibit 4, Appendix A &
Exhibit 3, Tab 2, Schedule 1

a) Please reconcile the number of residential and GS< 50 customers impacted (55,003 and 4,941, respectively) as shown on page 2 of Exhibit 4, Appendix A with the number of customers shown in Table 3-22 in Exhibit 3, Tab 2, Schedule 1.

RESPONSE:

The number of residential and GS<50 kW customers impacted as shown on page 2 of Exhibit 4, Appendix A are the number of residential and GS<50 kW customers that were being billed on a bi-monthly basis in July 2013 when the Monthly Billing Report was created. The number of residential and GS<50 kW customers shown in Table 3-22 in Exhibit 3, Tab 2, Schedule 1 are the actual number of customers at year-end for the years 2008 to 2012 and the forecasted number of customers at year-end for the 2013 Bridge Year and the 2014 Test Year.

A portion of Oakville Hydro's residential customers were already being billed on a monthly basis. While Oakville Hydro had 58,286 residential customers on December 31, 2012 as per Table 3-22 in Exhibit 3, Tab 2, Schedule 1, 54,877 residential customers were being billed on a bi-monthly basis and 3,339 residential customers were being billed on a monthly basis. The increase from 54,877 residential customers being billed on a bi-monthly basis on December 31, 2012 to 55,003 customers being billed on a bi-monthly basis on July 31, 2013 represents customer growth.

All of Oakville Hydro's GS<50 kW customers are billed on a bi-monthly basis. The increase from 4,911 GS<50 kW customers being billed on a bi-monthly basis on December

31, 2012 to 4,941 customers being billed on a bi-monthly basis on July 31, 2013 represents customer growth.

b) How many bills does the distributor issue monthly for the Street Lights and Sentinel lights? Please confirm that bills are issued for each customer and not for each connection.

RESPONSE:

Oakville Hydro issues three bills per month for the Street Lighting rate class and approximately 24 bills per month for the Sentinel Light rate class. Oakville Hydro confirms that bills are issued for each customer for these rate classes and not for each connection.

7.1-Energy Probe-35

Ref: Exhibit 2, Tab 5, Schedule 6

a) Do the figures shown in Table 2-49 for 2014 include a full year of the revenue requirement, or the revenue requirement for only the January through April period?

RESPONSE:

The figures shown in Table 2-49 include revenue for the period beginning on May 1, 2011 and ending April 30, 2014 as detailed in the following table.

Description	2011	2012	2013	2014	Total
	May 1-Dec 31	Jan 1-Dec 31	Jan 1-Dec 31	Jan 1-Apr 30	
Board Approved Revenue Requirement	$1,212,567	$1,818,850	$1,818,850	$606,283	$5,456,550
ICM Collected/To be Collected	$1,221,995	$1,871,603	$1,843,604	$612,391	$5,549,594
Recalculated Revenue Requirement	$1,296,653	$1,944,979	$1,944,979	$648,326	$5,834,937
Variance Recalculated Revenue Requirement vs. ICM Collected - Due from/(Owed to Customer)					**$285,343**

b) Please provide a breakdown of the revenues received through the rate rider shown in Table 2-48 by rate class for each of the years shown.

RESPONSE:

Oakville Hydro has updated the revenues received in Table 2-48 to provide actual revenues received for the years 2011, 2012 and 2013 and estimated revenues received for the period January to April 2014 by rate class.

Revenues Received through the Incremental Capital Module Rate Rider

Rate Classification	2011 Actual	2012 Actual	2013 Actual	2014 Estimate
Residential	$ 701,293	$ 1,085,913	$ 1,034,373	$ 358,188
General Service < 50 kW	154,036	250,450	250,151	79,158
Unmetered	5,075	7,399	7,465	2,336
General Service > 50 kW	279,891	413,144	417,879	133,124
General Service > 1,000 kW	53,963	74,323	80,619	24,530
Street Lighting	27,162	39,606	39,702	9,404
Sentinel Lighting	576	769	771	222
Milton	-	-	9,039	5,429
Total	$ 1,221,995	$ 1,871,604	$ 1,839,999	$ 612,391

c) Please confirm that the revenues shown in Table 2-48 for 2014 are a forecast for the January through April period.

RESPONSE:

Oakville Hydro confirms that the revenues shown in Table 2-48 are a forecast for the period January through April 2014.

d) Where any rate rider amounts associated with this project collected from Milton Hydro? If yes, please provide the amount collected/forecast to be collected from the first month the rider was recovered from Milton Hydro to the end of April, 2014.

RESPONSE:

Milton Hydro is currently classed as a General Service > 1,000 kW customer and has been paying all of the rate riders applicable to that rate class, including the ICM rate rider, since its connection in August 2013. As shown in the table provided in response to part b) of this interrogatory to the actual and forecasted amounts collected from Milton Hydro is $14,468.

e) When did Milton Hydro connect to this station?

RESPONSE:

Milton Hydro connected to Oakville Hydro's Glenorchy Municipal transformer station in August 2013.

f) How will the costs associated with this station be allocated to Oakville Hydro customers and to Milton Hydro in 2014?

RESPONSE:

As discussed in Exhibit 7, Tab 1, Schedule 2, Oakville Hydro is seeking approval for an Embedded Distributor rate class in its Application. Oakville Hydro is proposing to allocate costs directly to the Embedded Distributor rate class based upon Milton Hydro's forecasted average peak demand of 6 MW for the 2014 Test Year and the total station capacity of 156 MW. The remaining costs will be allocated to Oakville Hydro's customers based upon the allocators in the Board's cost allocation model.

g) Will any of the variance in the revenue requirement shown in Table 2-49 to be collected from customers be collected from Milton Hydro? If yes, please indicate where in Table 2-50 the new embedded distributor rate is shown along with rider to be applied.

RESPONSE:

Oakville Hydro has not proposed to collect any of the variance in the revenue requirement from Milton Hydro as the amount attributable to the Milton for the period August 2013 to April 2014 is estimated to be $1,548 which is immaterial.

Amount to be recovered	$285,343
Amount attributable to the period August 2013 to April 2014 (25%)	$71,336
Milton Hydro's percentage of total kWh - 2014 Forecast	2.2%
Amount allocated to Milton Hydro (2.2% of $71,336)	$1,548

7.1-VECC-23

Ref: E2/T1/S5/pg.1 & T5/S2/pg.9

Redwood Square

a) When did the negotiations for the Redwood Square Lease occur? When was the lease signed? What were the reasons for the approximate 10% reduction in lease costs from the 2010 forecast value?

RESPONSE:

The negotiations for the lease renewal occurred during the late 2009 and well into 2010, with the lease amendment being effective January 15, 2010. Oakville Hydro retained a third party real estate company to provide rental values in the area and an estimate of what the current rate should be for negotiations.

b) At page 9 it appears that Oakville contributed $851,368 for renovations to the Redwood Square property, including re-roofing. Please explain why Oakville Hydro pays for these leasehold improvements.

RESPONSE:

It is a standard in longer term leases that the tenant is responsible for their leasehold improvements made to the leased premises.

c) Does Oakville Hydro pay property tax on this building? If so please provide the amount forecast for 2014.

RESPONSE:

Yes, Oakville Hydro pays property taxes, again consistent with many long-term commercial leases. The 2014 Test Year updated forecasted property taxes for the Redwood Building is $184,720 (see Response 4.2-EP-37c).

7.1-VECC-24

Ref: E2/T4/S1/pg.4

Please provide the total number of residential meters installed and the installed cost, for each year 2006 through 2010. Please also provide the number of installed meters for each year that were subject to contribution policies and the total amount of related contributions in each year.

RESPONSE:

Oakville Hydro has the number of residential meters installed by year, however the installed costs were not segregated by residential and commercial meters in those years. Oakville Hydro has provided the approximate number of installed meters based on their in service date that were subject to the contribution policy and the costs associated to it. These meters were no longer installed subsequent to 2008. The contributed capital for the meters is provided however, the contribution by the developer is made after the new subdivision services are activated is assumed could be up to a two-year period lag from when Oakville Hydro incurred the cost to install it.

Description	2006	2007	2008	2009	2010
# of residentail meters	1568	1340	1230	528	573
# of commercial meters	89	143	105	98	57
Total Install cost for residential and commercial meters	$ 1,386,661	$ 1,137,448	$ 421,864	$ 285,463	$ 235,430
#of residential meters(with contribution policies)	1317	1024	758		
Installed cost for residential meters (with contribution policies)	$ 875,501	$ 491,712	151,548	-	
contributed capital	$ 698,736	$ 607,527	$ 671,063	$ 249,760	$ 115,674

7.1-VECC-25

Ref: E4/T2/S1/pg.11

Has Oakville Hydro changed its billing cycle since 2010?

RESPONSE:

Oakville Hydro has not changed its billing cycle since 2010.

7.1-VECC-26

Ref: E2/T5/S2/pg.9

How many customers does Oakville Hydro suite meter?

RESPONSE:

Oakville Hydro currently has 3,588 suite meter customers.

7.1-VECC-27

Ref: E2/T5/S1-5

Please provide a table which shows the capital contributions for each year 2010 through 2014 and the total capital expenditures associated with those contributions. Please show the percentage of contributions to capital.

RESPONSE:

The table below shows the capital contribution for each year 2010 through 2014.

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual (Unaudited)	2014 Test Year
Capital Contributions	3,743,516	4,712,987	4,872,160	3,355,216	3,299,281
Total Capital expenditures associated with those contributions	4,114,981	3,048,043	5,167,593	3,982,237	4,554,191
%	91%	155%	94%	84%	72%

Issue 7.2 *Are the proposed levels of depreciation/amortization expense appropriately reflective of the useful lives of the assets and the Board`s accounting policies?*

7.2-Energy Probe-36

Ref: Exhibit 4, Tab 4, Schedule 1

Oakville Hydro is using a useful life of 10 years for smart meters and smart meters - infrastructure.

a) For each of the other utilities listed on page 8 that contracted with Kinetrics for the depreciation study, please indicate the useful lives used for the smart meter accounts.

RESPONSE:

To the best of Oakville Hydro's knowledge, each of the other utilities listed on page 8 that contracted with Kinectrics for the depreciation study is using 15 years.

b) Please explain why Oakville Hydro has used a 10-year life for the smart meters when most distributors have used a 15 year life. In particular, what difference is there with the Oakville Hydro smart meters?

RESPONSE:

See response to question 9.2-Staff-55 (a)

Oakville Hydro does not believe that there is a significant difference in the technology used in its smart meters, except for a requirement to encrypt the transmission of data from the smart meters, pursuant to a direction from the Ontario Privacy Commission.

c) What would be the impact on (i) the depreciation expense in each of 2013 and 2014 and (ii) the rate base for 2014, if the useful life for smart meters and smart meters - infrastructure was set to 15 years for both 2013 and 2014?

RESPONSE:

The impact on the depreciation expense in 2013 and 2014 if the useful life for Smart Meter and Smart Meter Infrastructure was set to 15 years for both 2013 and 2014 is provided in the Table below.

Description	Rate Application	Energy Probe	Variance
Useful Life	10	15	
2013 Depreciation -Smart Meters and Smart Meters - Infrastructu	$1,248,663	$774,231	-$474,433
2014 Depreciation -Smart Meters and Smart Meters - Infrastructu	$1,272,136	$802,383	-$469,753
2013 Depreciation - Total	$8,346,829	$7,872,396	-$474,433
2014 Depreciation - Total	$8,611,141	$8,141,388	-$469,753

The impact on the rate base for 2014 if the useful life for Smart Meter and Smart Meter Infrastructure was set to 15 years for both 2013 and 2014 is provided in the Table below.

Description	2014 Test Year - In the application	2014 Test Year - Energy Probe	Variance
Use Life of Smart Meters and Smart Meters - Infrastructure	10	15	
Rate Base			
Opening Balance Gross Fixed Assets	$ 269,443,469	$ 269,443,469	
Closing Balance Gross Fixed Assets	286,050,896	286,050,896	
Average Gross Fixed Assets	**277,747,183**	**277,747,183**	-
Opening Balance Accumulated Depreciation	114,382,008	114,856,441	
Closing Balance Accumulated Depreciation	122,993,150	123,462,903	
Average Accumulated Depreciation	**118,687,579**	**119,159,672**	**472,093**
Average Net Fixed Assets	**$ 159,059,604**	**$ 158,587,511**	**-$ 472,093**
Working Capital Allowance	**$ 23,275,727**	**$ 23,275,727**	**$ -**
Rate Base	**$ 182,335,331**	**$ 181,863,238**	**-$ 472,093**

d) Does the distributor have any concerns related to benchmarking given its outlier status with respect to the depreciation of smart meters? If not, why not?

RESPONSE:

Oakville Hydro does not have any concerns relating to benchmarking with respect to the depreciation of smart meters. As per the response to (b) above, Oakville Hydro believes that a 10-year amortization, more accurately represents the life cycle of the smart meters installed and expects that other LDC's will have issues similar to those described.

Issue 7.3 *Are the proposed levels of taxes appropriate?*

7.3-Energy Probe-37

Ref: Exhibit 4, Tab 5, Schedule 4

a) Please update Table 4-37 to reflect actual property taxes for 2013.

RESPONSE:

Oakville Hydro has updated Table 4-37 for the actual 2013 property taxes. In addition, Oakville Hydro corrected an error in the 2012 figures for the "Property Taxes- Transformer station" and "Property Taxes- Building". Lastly, Oakville Hydro has updated the 2014 Test Year property taxes based on the actual 2013 expenses and the inflationary factor of 1.7%.

	OEB Account	2010 Approved	2010 Actual	2011 Actual	2012 Actual Revised	2013 Actual	2014 Test Year (updated)
Total Property Taxes							
Property Taxes - substations	5012	$ 181,500	$ 158,748	$ 155,140	$ 161,281	$ 167,104	$ 169,945
Property Taxes - transformer station	5017				13,313	20,646	20,997
Property Taxes - building	6105	210,600	184,443	181,762	170,969	181,633	184,721
Total Taxes Paid		**$392,100**	**$ 343,191**	**$ 336,902**	**$ 345,563**	**$ 369,383**	**$ 375,663**

b) Please explain the increases in property taxes for substations and for the building between 2012 and 2013.

RESPONSE:

Oakville Hydro has updated the 2013 actual (unaudited) property taxes, which reflect the Town of Oakville's annual increase in tax rates versus 2012.

c) Please explain why only the building property taxes in Table 4-37 are shown as property taxes in the RRWF. Are the other property taxes shown in Table 4-37 included in OM&A costs?

RESPONSE:

In accordance with the Board's Accounting Procedures Handbook for Electricity Distributors, the building property taxes in Table 4-37 are shown as property taxes in the RRWF and all other property taxes (substations and transformer station) are included in Operations category

d) Where is the reduction in the building property taxes associated with the rental of space in the building to an affiliate reflected in the evidence?

RESPONSE:

Oakville Hydro partially recovers property taxes (as well as all other costs for occupying space in the building such as hydro, gas etc.) from all its affiliates that occupy the building. The reduction in building property taxes associated with the rental of space to the Town of Oakville and Oakville Hydro's other affiliates is reflected in Appendix 2-H as a revenue offset in Exhibit 3, Tab 3, Schedule 1, Account 4390 and Account 4220.

7.3-Energy Probe-38

Ref: Exhibit 4, Tab 5, Schedule 1

a) Are the tax credits associated with the 0.7 equivalent cooperative students and the 4.0 full-time equivalent apprentices in addition to the $36,694 in investment tax credits?

RESPONSE:

As discussed in Exhibit 4, Tab 5, Schedule 1, Page 3, Oakville Hydro has not included an amount for the investment tax credit in the 2014 Test Year as the amount is immaterial. Oakville Hydro has included tax credits of $36,964 associated with the cooperative students and apprentices to bring its taxes payable to zero. Oakville Hydro has corrected Table 4-35 to show the tax credits on the correct line - Miscellaneous Tax Credits

Tax Credits	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Investment Tax Credits	$ 35,591	40,693	-	-	-
Miscellaneous Tax Credits	55,282	86,250	-	-	36,964
Total Tax Credits	**$ 90,873**	**126,943**	**-**	**-**	**36,964**

b) Please confirm that the tax credits associated with the cooperative students and the apprentices would total about $42,000 (0.7 x 3,000 + 4.0 x 10,000). If this is not correct, please provide the estimated tax credits.

RESPONSE:

Oakville Hydro confirms that the tax credits associated with the cooperative students and the apprentices would total about $42,000. However, as discussed in Exhibit 4, Tab 5, Schedule 1, Page 2, Oakville Hydro has included tax credits of $36,964 to bring its taxes payable to zero. In the event that Oakville Hydro's taxes payable increase as a result of changes to its Application Oakville Hydro will adjust the tax credits accordingly.

c) Does Oakville Hydro have any apprentice positions that would qualify for the $2,000 federal employment tax credit? If so, please quantify this tax credit.

RESPONSE:

In the 2014 Test Year, Oakville Hydro will have four apprentices that would qualify for the $2,000 federal employment tax credit. Therefore the tax credit would be $8,000.

d) Table 4-35 does not appear to reconcile with the statement on page 3 that no investment tax credits have been included for 2014. Please reconcile.

RESPONSE:

Please see response to part a).

7.3-Energy Probe-39

Ref: Exhibit 4, Appendix G &

Exhibit 2, Tab 1, Schedule 3, Appendix 2-BA

a) Please explain why the computer software additions shown for 2013 and 2014 in Appendix 2-BA in Exhibit 2, Tab 1, Schedule 3 (account 1611) are shown as being in CCA class 12 in those exhibits, but in the CCA schedules in the PILS model are included in CCA class 50.

RESPONSE:

Oakville Hydro did not alter the Board's template for Appendix 2-BA to reflect the appropriate classes of depreciable property for Oakville Hydro. Oakville Hydro notes that the classes of depreciable property shown in Appendix 2-BA in Exhibit 2, Tab 1, Schedule 3 do not drive the calculation of taxes payable. These calculations are made in the PILs model which accurately reflects Oakville Hydro's classes of depreciable property.

The CRA defines class 50 as follows:

Include in Class 50 with a CCA rate of 55%, property acquired after March 18, 2007, that is general-purpose electronic data processing equipment and systems software for that equipment, including ancillary data processing equipment, but not including property that is included in Class 29 or Class 52 or that is mainly or is used mainly as:

1. electronic process control or monitor equipment;
2. electronic communications control equipment;
3. systems software for equipment referred to in 1. or 2.; or
4. data handling equipment (other than data handling equipment that is ancillary to general-purpose electronic data processing equipment).

Since Oakville Hydro's software is systems software for general-purpose electronic data processing equipment it is appropriate to include these assets in class 50.

b) Please explain why computer hardware (account 1920) additions to rate base shown in Appendix 2-BA are included in CCA class 10, rather than in CCA class 50.

RESPONSE:

As discussed in response to part a) Oakville Hydro did not alter the Board's template for Appendix 2-BA. However, Oakville Hydro notes that it included computer hardware in class 10 in the Board's Income Tax PILs Work Form. Oakville Hydro will file a corrected Income Tax PILs Work Form updated with 2013 Actuals (unaudited) with its responses to these interrogatories. The impact of the reclassification on the CCA deduction as originally filed is provided in Oakville Hydro's response to part c) of this interrogatory.

The net impact on the PILs calculation including the reclassification discussed above and the updated 2013 Actuals is an increase in PILs from zero to $176,472 (net of applicable tax credits). Oakville Hydro's PILs model is provided as Appendix 7-A to Oakville Hydro's interrogatory response.

c) Please provide revised CCA schedules for 2013 and 2014 based on including computer software in CCA class 12 and computer hardware in CCA class 50. What is the impact on the CCA deduction available for 2014 of these changes?

RESPONSE:

Oakville Hydro has provided revised CCA schedules for 2013 and 2014 based on including computer software in CCA class 12 and computer hardware in CCA class 50 although it is appropriate to include both computer software and computer hardware in class 50.

Oakville Hydro notes that the changes proposed in part b) and c) of this interrogatory do not impact the calculation of taxes payable. Oakville Hydro's taxes payable are zero in each case.

CCA Deduction	Application	Revised	EP 39
2013	14,852,926	14,907,739	15,146,908
2014	14,805,427	14,852,927	15,237,529
2014 Taxes Payable	-	-	-

Issue 7.4 *Is the proposed allocation of shared services and corporate costs appropriate?*

7.4-Energy Probe-40

Ref: Exhibit 1, Tab 3, Schedule 3

Are any of the costs associated with the board of directors of Oakville Hydro Corporation included in the historical and/or forecast costs for Oakville Hydro Electricity Distribution? If yes, please quantify by year from 2010 through 2014.

RESPONSE:

The costs associated with the Board of Directors of Oakville Hydro Corporation that are included in the historical and forecast costs for Oakville Hydro are provided in the following table.

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test
Costs of members of the Board of Directors of Oakville Hydro Corporation included in Oakville Hydro Electricity Distribution Costs	$11,421	$ 9,654	$9,850	$ 8,000	$ 9,600

7.4-Energy Probe-41

Ref: Exhibit 4, Tab 3, Schedule 5

a) A number of costs are allocated to affiliates without markup. Please explain how these costs and the associated revenues from the affiliates are accounted for. Does Table 4-17 imply that of the $2,193,924 in costs recovered from affiliates, that $381,450 is recorded as revenues with the remainder recorded as a reduction to OM&A costs?

RESPONSE:

As shown in Exhibit 4, Tab 3, Schedule 5, and Table 4-17, $381,450 is recorded in revenue accounts 4220, 4210 and 4390. Oakville Hydro confirms that the remaining recoveries of $1,812,474 are recorded as a reduction in Administrative costs in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors.

b) Please confirm that because there is no markup applied to the OM&A costs recovered from affiliates, that no return on capital or depreciation associated with the assets used to provide services to affiliates are recovered from those affiliates. For example, are any of the asset-related costs associated with billing for water, sewer and rental tanks recovered from the affiliates?

RESPONSE:

As discussed on page 10 of Exhibit 4, Appendix A – Study of Affiliate Service Costs and Cost Allocation In Respect of Oakville Hydro Electricity Distribution Inc. prepared by BDR (the "Cost Allocation Study"), pricing for services is cost based. "In reviewing the transfer pricing for the cost-based services, consideration was given to whether the total amounts are appropriate (i.e. costs as incurred, without arbitrary "markup", but including where applicable, depreciation, return on assets, and any payments in lieu of tax attracted by the return)."

For example, as discussed on page 15 of the Cost Allocation Study, depreciation on assets related to Billing, Bill Printing, Mailing and Payment Processing is also included in the allocated costs. An allocation for hardware and software is made based on the cost related to Oakville Hydro's Customer Information System ("CIS"). An allocation of building depreciation is made based on the basis of the square footage occupied by the affiliate.

7.4-Energy Probe-42

Ref: Exhibit 4, Tab 3, Schedule 5

Please explain why Oakville Hydro ratepayers should pay for any of the costs associated with the parent corporation's Board of Directors?

RESPONSE:

In Exhibit 4, Tab 3, Schedule 5, Page 15, Oakville Hydro has included a small allocation of $9,600 in the 2014 Test Year for the parent corporation’s Board of Directors. This parent corporation’s Board of Directors, although not directly responsible for the utility itself, is responsible for the consolidated entity as a whole (which includes the utility) and those directors are kept abreast by the Oakville Hydro’s Board of Directors on the utility and their decisions.

7.4-SEC-25

Ref: Ex.4/Appendix C/p.22

Has the Applicant implement BDR’s recommendation that “OHEDI implement market pricing when this [tree trimming] contract expires in 2013”

RESPONSE:

The contract for tree trimming expired at the end of 2013. Oakville Hydro has engaged the services of an industry specialist who has expertise in this area to assist in the negotiations for the scope and cost applicable under a new contract. It is expected that the costs for tree trimming will increase as a result of the increased scope of the service, however, the new contract will be at market pricing and is expected to be performed by a third party. At present, Oakville Hydro is operating under a month-to-month extension of the old agreement.

7.4-HVAC-7

Please provide a detailed description of how the HVAC and water heater equipment and services business is divided up between OHESI and Sandpiper Energy Solutions.

RESPONSE:

Oakville Hydro's affiliates are not before the Board for a rate application and the questions directed to provide specific details of their operations are not relevant, other than with respect intercompany charges between Oakville Hydro and its affiliates. However, Oakville will advise that water heaters that were traditionally within Oakville Hydro's licensed territory, and historically were billed on Oakville Hydro's invoices have been grandfathered to remain on Oakville Hydro's invoices and are held within OHESI. New customers within Oakville and water heaters outside Oakville Hydro's service territory are held within Sandpiper Energy Solutions. All HVAC equipment and services business are held by Sandpiper Energy Solutions.

7.4-HVAC-8

Ref: Ex. 1/1/1, p. 12

Please provide a detailed explanation as to all ways, if any, that OHESI or Sandpiper Energy Solutions are expected to use the "new web presentment tool" or any of the data it presents.

RESPONSE:

Sandpiper Energy Solutions will not being using the new web presentment tool. Those OHESI legacy customers that are billed for their water tanks on their hydro bill will be able to view their bill through the new web presentment tool but there is no enhancement related to bill presentment in the new web presentment tool as it accesses Oakville Hydro's existing document management tool in the same way as the current web presentment tool.

7.4-HVAC-9

Ref: Ex. 1/1/1, p. 21

Please advise how many employees who provide services to, or are employed by, each of the affiliates are covered by the current collective agreement.

RESPONSE:

No employees employed by the affiliates of Oakville Hydro are covered under the Oakville Hydro collective agreement. There are approximately five employees who provide services to the affiliates that are covered under the collective agreement.

7.4-HVAC-10

Ref: Ex. 4/3/4, p. 5

Please provide details of any services the new Communications and Website Co-ordinator will provide, directly or indirectly, to each of the affiliates.

RESPONSE:

The Communication and Website Co-ordinator provides some assistance to the affiliates to coordinate minor changes to the affiliate's websites through the external service provider and may assist in some general customer correspondence.

7.4-HVAC-11

Ref: Ex. 4/3/5, p. 3

With respect to the provision of billing and related services by the utility to OHESI and Sandpiper Energy Solutions,

(a) Please provide details of all billing and related services provided to the two affiliates relating to billing of water heater rentals, rentals of any other HVAC equipment, or provision of any HVAC services.

RESPONSE:

Oakville Hydro provides the following services to OHESI and Sandpiper:

- Billing for Sandpiper – separate invoice
- Billing for OHESI – grandfathered water heater rental charges and water and waste water included on Oakville Hydro's invoice
- Bill printing and mailing

- Payment processing including pre-authorized payment
- Customer Service
- Collections for charges relating to OHESI

b) To the extent that billing and related services are provided as described in (a), please advise whether the billing is on the utility bill, or on separate bill. If both types of billing are provided, please provide details on the respective percentages, charges for each and their basis, and any plans to change these arrangements.

RESPONSE:

- Billing for Sandpiper – separate invoice
- Billing for OHESI – grandfathered rental charges included on Oakville Hydro invoice
- Approximately 5.5% of Oakville Hydro bills include OHESI water heater charges at $1.50 per bi-monthly bill
- Sandpiper is charged an hourly charge for billing, mailing/printing, payment processing. Over the last 6 months, Oakville Hydro has invoiced for approximately 26.5 hours/month

There are no plans at the current time to change these arrangements.

(c) If any of the goods and services described in (a) are billed on the utility bill, please explain in detail what arrangements have been made, or are planned, to ensure that the affiliate's competitors have similar access to the bill, or to ensure that the affiliate's exclusivity is or will be removed or the subject of fair market value compensation.

RESPONSE:

As discussed in response to part b) of this interrogatory, the water tank rental charges included on the utility bill are limited to grandfathered customers that have a history of tank rental appearing on their utility bill, and those customers are with OHESI. New customers within the Oakville Hydro service area are not billed on the utility bill. Oakville Hydro has no plans to make arrangements to provide competitors with access to its utility bill or to terminate the practice of including the water tank rental charges for grandfathered customers within its service territory.

7.4-HVAC-12

Ref: Ex. 4/3/5, p. 9

Please add two lines to Table 4-17 showing:

(a) The total amount of all salaries and wages included in the lines of the current version of the table.

RESPONSE:

Oakville Hydro has revised Table 4-17 to include the amount of salaries and wages and the total FTE's represented by those salaries.

Item	Source	Notes	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Revenues arising from Affiliates	Appendix 2-N		$ 2,182,581	$ 1,662,482	$ 2,015,384	$ 1,994,669	$ 2,193,924
Exhibit 3-Other Revenues							
	Account 4220 (intercompany accounts)	1	267,282	186,258	183,815	195,478	234,650
	Account 4210 (Pole rental -Blink)	2	7,171	-	-	-	-
	Account 4390 (Office space rental- Town of Oakville)	3	-	-	36,707	146,800	146,800
Exhibit 4- Program Activities							
(Appendix 2-JC)	Administrative services recovered from affiliates	4	1,417,975	1,007,727	1,215,154	1,245,757	1,377,849
Exhibit 4 -General & administrative costs recovery (Account 5615)							
	Payroll Benenfits recovered from Affiliates	5	459,169	440,635	483,831	394,634	384,625
	Material Management & Purchasing Services	6	30,984	27,862	95,877	12,000	50,000
			$ 2,182,581	$ 1,662,482	$ 2,015,384	$ 1,994,669	$ 2,193,924
Salaries & Benefits			591,888	625,551	769,653	797,922	844,468
FTE's			12	13	15	16	17

Notes:

1. In Appendix 2-N this consists of services called: Vehicle Charges, Water Heater billing and Vehicle Insurance
2. In Appendix 2-N this consists of services called:Pole Rental
3. In Appendix 2-N this consists of services called: Sub-lease of Office Space
4. In Appendix 2-N this consists of services called: Executive services, Financial services, Human Resources & Safety Services, Information Technology Services and Water & Sewer Billing Services
5. In Appendix 2-N this consists of services called: Payroll Benefits
6. In Appendix 2-N this consists of services called: Material Management & Purchasing services

(b) The total FTEs represented by those salaries and wages for each of the years on the table.

RESPONSE:

See response to part a) of this interrogatory.

7.4-HVAC-13

Ref: Ex. 4/3/5, p. 9

Please advise which affiliates have operations in "separate locations", which of those also have operations in locations shared with the utility, and in each of the affiliates with both separate and shared locations, the percentage of activities and costs for each of separate and shared locations.

RESPONSE:

The following chart shows the operational location for the affiliates

Affiliate	Operation Location	Percentage of Activities	Occupancy Shared Service Cost (1)
Oakville Hydro Corporation (OHC)	861 Redwood Square	100%	34,900
Oakville Hydro Energy Services Inc. (OHESI)	861 Redwood Square	30%	55,000
Golden Horseshoe Metering Systems Inc. (GHMS)	861 Redwood Square	20%	incl in OHESI
Sandpiper Energy Solutions Inc. (Sandpiper)	861 Redwood Square	30%	incl in OHESI
El-Con Construction Inc. (El-Con)			
Management Team	861 Redwood Square	15%	37,700
Operations	2176 Speers Road, Oakville		

(1) see Appendix 2-N - Shared Services and Corporate Cost Allocation

7.4-HVAC-14

Ref: Ex. 4/3/5, p. 13/4

Please provide two tables, one for each of 2013 and 2014, showing, for each category of expenditures that is incurred by the Applicant but includes any work done for or services provided to any affiliate:

(a) The total amount of the expenditure for that category in the accounts of the Applicant, before any allocations or charges to any affiliates;

(b) The amount allocated to each of the affiliates, by name, using direct allocation, and the basis for determining the amount of the direct allocation;

(c) All amounts allocated or charged to each of the affiliates, by name, using any method other than direct allocation, and the allocation method used.

(d) The total number of FTEs included in the FTEs of the Applicant for that category of expenditures, before any allocations or charges to any affiliates; and

(e) The FTEs allocated to each of the affiliates, by name, for that category of expenditures.

RESPONSE:

The following table provides the total costs, the amount allocated to affiliates, the number of FTEs, and allocation method for each of Oakville Hydro's affiliates

2013 Actual (unaudited)	Allocated costs	Headcount	Allocation method	CORP	OHESI	ELCON	PVS	GTEL	Total
Human Resources & Safety Services	534,303	4	Headcount	4,307	32,415	104,999			141,721
FTE				*0.03*	*0.24*	*0.79*	-	-	*1.06*
Executive Services	1,026,115	3	% time	10,087	46,208	11,285	23,612	4,953	96,145
FTE				*0.03*	*0.14*	*0.03*	*0.07*	*0.01*	*0.28*
Finance Services	971,376	8	% time	9,714	92,281	48,569	19,428	4,857	174,848
FTE				*0.08*	*0.76*	*0.40*	*0.16*	*0.04*	*1.44*
Information Technology Services	972,998	5	IT users	5,121	89,106	30,726			124,953
FTE				*0.03*	*0.46*	*0.16*	-	-	*0.64*
Building Maintenance	1,617,665		% space	19,585	33,627	21,187			74,399
Region Billing Services	712,757		% of time/# of bills		712,757				712,757
Waterheater Billing	51,331		% of time/# of bills		51,331				51,331

2014	Allocated costs	Headcount	Allocation method	CORP	OHESI	ELCON	PVS	GTEL	Total
Human Resources & Safety Services	667,816	4	Headcount	3,702	55,818	173,317			232,836
FTE				*0.02*	*0.33*	*1.04*	-	-	*1.39*
Executive Services	994,276	3	% time	7,111	48,743	36,635	17,000	5,000	114,489
FTE				*0.02*	*0.15*	*0.11*	*0.05*	*0.02*	*0.35*
Finance Services	1,083,355	9	% time	8,834	88,336	35,334	22,000	5,000	159,503
FTE				*0.07*	*0.73*	*0.29*	*0.18*	*0.04*	*1.33*
Information Technology Services	1,192,369	5	IT Users	10,368	72,579	51,842	-	-	134,790
FTE				*0.04*	*0.30*	*0.22*	-	-	*0.57*
Building Maintenance	1,862,877		% space	34,861	55,266	37,714	-	-	127,841
Region Billing Services	744,869		% of time/# of bills		744,869				744,869
Waterheater Billing	65,150		% of time/# of bills		65,150				65,150

Oakville Hydro is updating its 2014 Test Year evidence to include a $10,000 reduction of OM&A as a direct result of an acquisition of a business (GTEL), which is included in the Table above.

7.4-HVAC-15

Ref: Ex. 4, App. C

With respect to the BDR study:

(a) P. 12. Please explain what steps BDR took to ensure that the one month of time logging was a representative month on which annual extrapolations could be made.

RESPONSE:

As noted in the BDR report at page 12, the starting point of the methodology for finance functions was an estimate of time made by the staff members in the function. Management and BDR were concerned that a continuous process of time logging would prove unreasonably onerous for the staff. However, it was considered desirable to obtain confirmation of the estimates from a sample of data produced by time logging. Management selected a one-month timeframe, chosen to be a month in which there were no unusual activities occurring, such as budgeting or year-end. The one month of data provided confirmation of the annual estimates, when adjusted to account for estimates of activity related to budgeting and year end. BDR therefore considered data for a "base" level of activity had been confirmed by two independent approaches – staff estimation and time logging.

Carrying out the one month time logging also confirmed that the functions of the finance staff are extremely time-consuming to log accurately as many of the positions have responsibilities in all of the affiliates and are constantly switching the focus of their activity between affiliates, as well as performing functions that provide a benefit to several affiliates at once. Management therefore concluded, and BDR concurred, that in view of the fact that a sample confirmed the estimates, it would be unduly onerous to implement permanent time logging.

Staff in the finance function will periodically review their estimates of amount of work associated with reporting on affiliate activity, and if there is a significant change, another month of time logging will be carried out for comparison with the revised estimates, and if indicated, changes in the allocations will be made.

(b) P. 14. Please confirm that only legacy water heaters are billed on the OHEDI bill, and all other water heaters and HVAC goods and services are billed on bills separate from the utility bill. If that is not true, please provide details.

RESPONSE:

Only the legacy water heaters in Oakville Hydro Energy Services Inc. (OHESI) are billed on the OHEDI bills on a legacy basis. OHESI pays OHEDI a per bill charge. All other water heater and HVAC bills are printed on their own separate invoices.

(c) P. 15. Please explain how bad debts associated with water heaters or other HVAC goods or services provided by affiliates and billed by the utility are treated.

RESPONSE:

As discussed in response to part b) of this interrogatory, only legacy water heaters are billed on the OHEDI bill. Oakville Hydro does not currently segregate the bad debt component relating to legacy water heater customers. As referenced in HVAC-16p, Oakville Hydro has 3,300 legacy customers for which this could apply.

d) P. 16 and others. Please confirm that all of BDR's recommendations have been implemented for the purposes of the figures in the Application.

RESPONSE:

BDR's recommendations on page 16, with respect to "the allocator be refined so that building costs associated with a shared employee are shared in proportion to the time or work done by that employee for different affiliates" has not been implemented. The reason for not allocating the occupancy costs is that the total amount was deemed immaterial. Oakville Hydro had intended to implement the "fully allocated costs of assets include cost of capital (both interest and a return on equity) at the rates approved by the OEB", but appears to have been missed in its 2014 Test Year calculations. All other recommendations made by BDR have been implemented.

e) P. 16. Please confirm that all references to "Oakville Hydro" in the report refer to the Applicant, and not to Oakville Hydro Corporation.

RESPONSE:

Yes, the term "Oakville Hydro" as referenced in the Appendix to the BDR report is meant to refer to OHEDI and not Oakville Hydro Corporation.

f) P. 18. Please explain what steps BDR took to ensure that allocating Warehousing and Purchasing costs based on value of inventory, rather than on different types of inventory based on the time involved, or any other methodology, was the most reasonable allocation method.

RESPONSE:

The methodology of allocating the 18% to the cost of inventory, referred to in the BDR Report on page 18, was the description under "old" GAAP. Under "New GAAP"/IFRS, this allocation is no longer applied, as only costs directly attributable to a piece of inventory may be capitalized. Subsequent to the BDR study, alternate arrangements have been made and inventory purchased by affiliates is held by the supplier and/or HVAC contractors and not inventoried at 861 Redwood Square (Oakville Hydro's location).

7.4-HVAC-16

With respect to the Services Agreement between the Applicant and OHESI:

(a) P. 3. Please advise the number of people that will be included in the definition of Management and Office Personnel in the Test Year, and the number in respect of whom some or all of their time will be allocated to services provided to OHESI.

RESPONSE:

Full time employees of Oakville Hydro Energy Services Inc. (OHESI) are charged directly to OHESI and not allocated. There are 24 people who will have a portion of their time allocated to OHESI.

(b) P. 3. Please advise the number of people that were included, in 2013, and are expected to be included, in 2014, in the definition of Service Personnel.

RESPONSE:

There were two Service Personnel that had a portion of their time allocated to OHESI in 2013 and two who are expected to be included the test year.

(c) P. 7. Please provide the full detailed calculation of all amounts calculated pursuant to Section 3.6 for each of 2013 and 2014. Please ensure that the response includes express disaggregation of the amounts in (i), (ii) and (iii) of that Section.

RESPONSE:

Although the services agreement states that the charge includes (i), (ii) and (iii), in practice, Oakville Hydro either: 1) takes the total departmental expenses, charges any expenses that are applicable to a specific affiliate(s) and then allocates the remainder, or 2) takes the departmental wages & benefit costs and adds the appropriate other expenses to be allocated to the other affiliates (i.e. – Finance wages & benefits plus General Liability Insurance).

(d) P. 8. Please provide a copy of each work order prepared under Section 4.1 with respect to services to be provided to OHESI in 2013. Please provide the budget for these amounts in 2014, and the basis for that budget.

RESPONSE:

The supply of service personnel in the OHESI service agreement relates to the supply of Oakville Hydro operations and line staff as it relates streetlight maintenance. There is a general service work order in OHESI that Oakville Hydro line staff charge their time for any specific related requests to assist in any electrical related issues that arise in any given year which creates an intercompany transaction payable to Oakville Hydro. . In 2013, Oakville Hydro recovered $39,132 from OHESI. In 2014, the amount is budgeted for recovery is $45,600. This is only one work order created for each year.

(e) P. 10. Please provide the Time Sheets referred to in Section 4.4.

RESPONSE:

Oakville Hydro attaches a sample of five 2013 timesheets where Oakville Hydro line staff have charged OHESI for their time spent on streetlight maintenance. This is in Appendix 7-B.

(f) P. 10. Please provide the current rates chargeable for each category of Service Personnel in 2014, and the full calculation that forms the basis of those rates.

RESPONSE:

Based on the current collective agreement, Oakville Hydro charges the wages rates applicable to the service personnel performing the work which can change depending on which line staff are available to perform the duties. (Power Line Technician is $38.87 per hour and Lead Power Line Technician is $42.09 per hour) plus a 108% benefit charge added to the total labour cost (identified Exhibit 4, Tab 6, Schedule 2 line 16-24). These rates are identical to the rate charged for all service calls irrespective of the customer.

(g) P. 12. For each Service Provider who directly or indirectly provided services to both the Applicant and OHESI during 2013, please provide the nature of the contract, the total value, the nature of the services provided to each of the Applicant and the affiliate, the amounts allocated, and the basis of the allocation.

RESPONSE:

There are three service providers (contractor) who are billing both Oakville Hydro & OHESI on one invoice (other than lawyers who itemize their bill by each legal entity billed on the same invoice) and they are the MEARIE for insurance purposes, Bell Mobility for cell phone usage and Olameter for meter reading and related metering issues. The MEARIE invoice for insurance is allocated on the basis of the inputs requested to calculate the premium – revenues for general liability insurance, vehicle type for the automobile insurance and replacement values for the property insurance. Bell Mobility's consolidated billing breaks out the costs by user, so the charges can be directly charged to the appropriate affiliate. The Olameter invoice is itemized in such a way that it can be readily identified as to whether the line item relates to water meters or hydro meters

Vendor	Total Invoiced	Allocated to OHEDI	Allocated to OHESI	Allocated to Others
MEARIE	601,139	475,825	61,624	63,690
Bell Mobility	88,877	50,726	8,907	29,245
Olameter	277,647	50,135	227,512	-

(h) P. 12. Please provide details of all instances in 2013 in which Section 6.1 applied.

RESPONSE:

There were no charges for particular Hydro Service Equipment during without the applicable Service Personnel 2013. As stated above, where Oakville Hydro's linemen provide service for streetlight maintenance, there is also a charge for the vehicle they use to travel to and work at the site. The rates charged for the vehicle and equipment used is the same charge applicable to any other chargeable work irrespective of the customer.

(i) P. 14. Please describe in detail how the cost or value for the use of computer hardware and software is incorporated into each of the other charges referred to in the Agreement.

RESPONSE:

The Information technology department has all costs for staffing and all annual software and hardware costs in its department for which all these costs are recovered/allocated by the affiliates based upon the number of regular IT users that are set up on the Oakville Hydro systems. If there are any specific cost hardware or software costs attributed only to one affiliate a direct charge is made. For the 2014 budget, OHESI was charged based on seven users out of a total 115 users. This allocation is in accordance with the guidelines established by the BDR Cost allocation study as provided in Exhibit 4 Appendix C

j) P. 15. Please provide details of all insurance policies under which both the Applicant and OHESI are insured, the total annual cost of each policy, the amounts allocated to each, and the basis of the allocation.

RESPONSE:

OHEDI & OHESI are both insured through MEARIE for General Liability and Property Insurance. In 2013 the allocation the liability insurance was included in the management fee calculation and the property insurance was included in the occupancy costs. In 2014 the liability insurance allocation was revised to the methodology used by MEARIE in calculating the premium (a fixed charge + a variable charge based upon revenues) and the property insurance was allocated based upon the ratio of replacement costs for buildings and contents of each affiliate to the total replacement costs.

	2014			2013		
		Allocated	Allocated		Allocated	Allocated
	Total	to OHEDI	to OHESI	Total	to OHEDI	to OHESI
Liability	205,940	176,103	6,006	178,747	146,573	4,469
Property	168,788	150,438	11,545	168,434	138,404	31,563

k) P. 16. Please provide details of the office and warehouse space used by OHESI in 2013, or expected to be used by OHESI in 2014, to which Section 10.1 has applied or will apply. Please include the area of each type used, the amount of all costs to Applicant per square foot or meter for such space, and the amount allocated to the affiliate.

RESPONSE:

For both 2013 actual and 2014 Test Year, OHESI(and its affiliates) has been charged for 1,578 square feet of office space, with the costs being $34,730 in 2013 actual (unaudited) and $55,300 in the 2014 Test Year. OHESI is not currently using any warehouse space and is not expected to use any warehouse space.

l) P. 18. Please provide any presentation provided by management or any consultant at the meeting referred to in Section 12.4.

RESPONSE:

Oakville Hydro explains the requirements of the Codes to Administrative and Service Personnel that might be expected to provide services under the agreement between OHEDI and OHESI on a regular basis. A copy of the presentation that is provided to these employees is provided as an Appendix 7-C.

m) P. 22. Please confirm that both parties have complied with Section 19.1, and the first date such compliance was in place.

RESPONSE:

Oakville Hydro confirms that the insurance policy has been maintained in excess of the minimum level per occurrence as stated in the agreement. This has been in place since the agreement was reached.

n) P. 23. Please advise the name of the current Chief Executive Officer of each of the parties to this Agreement.

RESPONSE:

The Chief Executive Officer for both parties to the agreement is Robert Lister.

o) P. 24. Please provide a copy of any “prior written consent” provided by the Applicant to OHESI.

RESPONSE:

This interrogatory relates to the Affiliate Relationship Code and not considered relevant as part of Oakville Hydro's 2014 Cost of Service Application.

(p) Sched 1. Please confirm that the amount of $32,000 per annum is for billing of legacy water heater rentals. Please confirm that this is made up of monthly billing of approximately 900 legacy water heaters at $1.50 per bill per month. If that is not the case, please provide the basis of this charge.

RESPONSE:

Oakville Hydro confirms the $32,000 per annum is for the legacy of billing water heaters within Oakville based upon the $1.50 per bi-monthly bill. There are approximately 3,300 legacy water heaters owned by OHESI. With the exception of these legacy customers, and the Region of Halton water billing, Oakville Hydro does not permit any other affiliate or third party to bill charges on its electricity bill.

(q) Sched. 1. Please break down the amount of $137,500 between the components to which it applies, and show the calculations that produce that final total.

RESPONSE:

The breakdown the 2013 budgeted management fee charge to Oakville Hydro is as follows:

Description	Total to be Charged	Allocation Basis	Budget Total
Human Resources & Safety	569,407	Specific Identifiable Charges / Headcount	54,831
Executive	613,294	Specific Identifiable Charges / Est. Time	25,152
Finance	857,291	Est. Time	31,986
Information Technology	1,066,227	Specific Identifiable Charges / IT Users	25,487
		Total	137,456
		Rounded to	137,500

7.4-HVAC-17

With respect to the Services Agreement between the Applicant and Sandpiper Energy Solutions:

(a) P. 3. Please advise the number of people that will be included in the definition of Management and Office Personnel in the Test Year, and the number in respect of whom some or all of their time will be allocated to services provided to Sandpiper Energy Solutions.

RESPONSE:

There are 21 people whose time is partially charged to Sandpiper Energy Solutions and that number is expected to increase by one in 2014.

(b) P. 3. Please advise the number of people that were included, in 2013, and are expected to be included, in 2014, in the definition of Service Personnel.

RESPONSE:

There are no Service Personnel charged to Sandpiper in 2013 and none are anticipated in 2014.

(c) P. 7. Please provide the full detailed calculation of all amounts calculated pursuant to Section 3.6 for each of 2013 and 2014. Please ensure that the response includes express disaggregation of the amounts in (i), (ii) and (iii) of that Section.

RESPONSE:

Although the services agreement states that the charge includes (i), (ii) and (iii), in practice, Oakville Hydro either: 1) takes the total departmental expenses, charges any expenses that are applicable to a specific affiliate(s) and then allocates the remainder, or 2) takes the departmental wages & benefit costs and adds the appropriate other expenses to be allocated to the other affiliates (i.e. – Finance wages & benefits plus General Liability Insurance).

(d) P. 8. Please provide a copy of each work order prepared under Section 4.1 with respect to services to be provided to Sandpiper Energy Solutions in 2013. Please provide the budget for these amounts in 2014, and the basis for that budget.

RESPONSE:

As mentioned in (b) above, there were no Service Personnel charges to Sandpiper Energy Solutions in 2013 and none are anticipated in 2014.

(e) P. 10. Please provide the Time Sheets referred to in Section 4.4.

RESPONSE:

The time sheets referred to in Section 4.4 provide log of the number of hours spent in providing services to Sandpiper Energy Solutions each day.

(f) P. 10. Please provide the current rates chargeable for each category of Service Personnel in 2014, and the full calculation that forms the basis of those rates.

RESPONSE:

As discussed in response to interrogatory number 7.4-EP-41, transfer pricing for the cost-based services are based on costs as incurred.

(g) P. 13. For each Service Provider who directly or indirectly provided services to both the Applicant and Sandpiper Energy Solutions during 2013, please provide the nature of the contract, the total value, the nature of the services provided to each of the Applicant and the affiliate, the amounts allocated, and the basis of the allocation.

RESPONSE:

The only Service Providers that directly or indirectly provide services to both Oakville Hydro and Sandpiper Energy Services and issue a combined bill is Bell Mobility and its billings provide details by user such that the charges are allocated to each affiliate. The only other possibility would be the potential for a legal bill, which always provides the hours by affiliate of their time being charged.

(h) P. 13. Please provide details of all instances in 2013 in which Section 6.1 applied.

RESPONSE:

There have been no charges from Oakville Hydro to Sandpiper Energy Solutions for equipment usage under Section 6.1 as Sandpiper Energy Solutions has not had an occasion to use “Hydro Equipment”.

(i) P. 16. Please describe in detail how the cost or value for the use of computer hardware and software is incorporated into each of the other charges referred to in the Agreement.

RESPONSE:

Any software purchased solely for the use by Sandpiper Energy Solutions would be paid directly by Sandpiper. All other “general” costs associated with hardware and software that are corporate or global in nature such as the operation and maintenance of the mail server and network are allocated to Sandpiper based upon the relative percentage of Sandpiper IT users to the total IT users.

(j) P. 17. Please provide details of all insurance policies under which both the Applicant and Sandpiper Energy Solutions are insured, the total annual cost of each policy, the amounts allocated to each, and the basis of the allocation.

RESPONSE:

Sandpiper Energy Solutions' coverage for General Liability Insurance is through the corporate policy with MEARIE. In 2013 Sandpiper paid $ 8,937 and is forecasted to pay $4,201 in the 2014 Test Year which is based on an identified fixed charge plus a variable charge based upon revenues.

(k) P. 17. Please provide details of the office and warehouse space used by Sandpiper Energy Solutions in 2013, or expected to be used by Sandpiper Energy Solutions in 2014, to which Section 10.1 has applied or will apply. Please include the area of each type used, the amount of all costs to Applicant per square foot or meter for such space, and the amount allocated to the affiliate.

RESPONSE:

As shown in Exhibit 4, Tab 3, Schedule 5, Appendix 2-N, Oakville Hydro allocates occupancy costs to OHESI, the parent company of Sandpiper Energy Solutions.

(l) P. 20. Please provide any presentation provided by management or any consultant at the meeting referred to in Section 12.4.

RESPONSE:

Please see Oakville Hydro's response to interrogatory 16 (l)

(m) P. 24. Please confirm that both parties have complied with Section 19.1, and the first date such compliance was in place.

RESPONSE:

Yes, the insurance policy has been maintained in excess of the minimum level per occurrence as stated in the agreement.

(n) P. 24. Please advise the name of the current Chief Executive Officer of each of the parties to this Agreement.

RESPONSE:

The Chief Executive for both parties to the agreement is Robert Lister. Robert Lister is the CEO of the consolidated Oakville Hydro Corporation (OHC) group and as such holds the title for all subsidiary Companies.

(o) P. 25. Please provide a copy of any "prior written consent" provided by the Applicant to Sandpiper Energy Solutions.

RESPONSE:

This interrogatory relates to the Affiliate Relationship Code and not considered relevant as part of Oakville Hydro's 2014 Cost of Service Application.

(p) Sched 1. Please confirm that the amount of $32,000 per annum is solely for billing of water heater rentals. Please confirm that this is made up of monthly billing of approximately 900 legacy water heaters at $1.50 per bill per month. If that is not the case, please provide the basis of this charge.

RESPONSE:

Consistent with the answer to 7.4-HVAC-17 (p) the amount of $32,000 per annum is solely for billing of legacy water heater rentals.

(q) Sched. 1. Please advise why there is no amount for the services to be provided under Section 3.6 of the Agreement, as listed in this Schedule. If that amount has been included in the Application, but inadvertently omitted from this Schedule, please provide the amount as well as a full breakdown of that amount between the services listed on this Schedule, and the full calculation of the total.

RESPONSE:

The charge for Section 3.6 of the Services Agreement was not included in 2013 as the agreement was effective May 1, 2013 and therefore was not included on Schedule 1. In 2013, Sandpiper Energy Services was charged $137,800 (unaudited) and the budget for the 2014 Test Year is $114,500.

7.4-VECC-28

Ref: E4/T3/S5/pg.8, Table 4-16

Please expand Table 4-16 to include the actuals for 2011 and 2013.

RESPONSE:

Oakville Hydro has expanded Table 4-16 to include the actuals for 2011 and 2013.

Revised Table 4-16 – Variance Analysis of Shared Services

Description	2010 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2014 Test Year vs 2010 Board Approved	2014 Test Year vs 2012 Actual
Services provided by Oakville Hydro	2,165	1,662	2,015	1,791	2,090	(75)	75
Services received by Oakville Hydro	5,638	5,677	6,264	7,644	6,089	451	(175)

7.4-VECC-29

Ref: E4/T3/S5/pg.

Please provide the forecast amount to be paid in 2014 to El-Con Construction for locate services. Please also explain if this contract was tendered. If not please explain if the contracting meets Oakville Hydro's purchasing policies.

RESPONSE:

Effective July 1, 2013, El-Con Construction Inc. transferred its locating division to PVS Contractors Inc. The 2014 budget for locating services from PVS Contractors is $ 825,000. Oakville Hydro's locating services rates are based on the same scales as preferred customers such as Union Gas and Bell.

Issue 7.5 *Are the proposed capital structure, rate of return on equity and short and long term debt costs appropriate?*

7.5-Staff-37

Ref: Exhibit 5/Tab 1/Schedule 2

Long-term Debt

Please update Table 5-3 reflecting the 2014 Cost of Capital parameters as documented in the letter issued by the Board on November 25, 2013, available at:

http://www.ontarioenergyboard.ca/OEB/_Documents/2014EDR/OEB_Ltr_Cost_of_Capital_update_2014Jan01_20131125.pdf

RESPONSE:

Oakville Hydro has updated Table 5-3 to reflect the 2014 Cost of Capital parameters as documented in the letter issued by the Board on November 25, 2013.

Table 5-3 – 2014 Deemed vs. Actual Interest Rates on Long Term Debt

	2014 Ending Balance	Deemed Interest Rate	Deemed Interest Amount	Forecasted Interest Rate	Actual Interest Amount
Promissory Notes	$ 67,945,839	4.88%	$ 3,315,757	5.36%	$ 3,639,632
Infrastructure Ontario Loan	21,140,578	4.00%	853,118	4.00%	853,118
Total	**$89,086,417**	**4.68%**	**$4,168,875**	**5.04%**	**$4,492,750**

7.5-Energy Probe-43

Ref: Exhibit 5, Tab 1, Schedule 1

Please update the 2014 table found in Appendix 2-OA (page 6) and in Appendix 2-OB (page 7) to reflect the update cost of capital parameters applicable to 2014 cost of service applications, as issued by the Board on November 25, 2013.

RESPONSE:

Oakville Hydro has updated Appendix 2-OA and Appendix 2-OB to reflect the update cost of capital parameters applicable to 2014 cost of service applications, as issued by the Board on November 25, 2013. The Appendix 2-OA and Appendix 2-OB were provided below.

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2010 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$73,288,176	5.87%	$4,302,016
2	Short-term Debt	4.00%	(1)	5,234,870	2.07%	108,362
3	**Total Debt**	60.0%		78,523,046	5.62%	4,410,378
	Equity					
4	Common Equity	40.00%		52,348,697	9.85%	5,156,347
5	Preferred Shares			0		0
6	**Total Equity**	40.0%		52,348,697	9.85%	5,156,347
7	**Total**	100.0%		$130,871,743	7.31%	$9,566,724

Year: 2014

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$102,107,785	4.68%	$4,778,221
2	Short-term Debt	4.00%	(1)	7,293,413	2.11%	153,891
3	**Total Debt**	60.0%		109,401,199	4.51%	4,932,112
	Equity					
4	Common Equity	40.00%		72,934,132	9.36%	6,826,635
5	Preferred Shares			0		0
6	**Total Equity**	40.0%		72,934,132	9.36%	6,826,635
7	**Total**	100.0%		$182,335,331	6.45%	$11,758,747

Notes

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

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	$ 51,957,430	5.87%	$3,049,901	
2	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	15,988,409	5.87%	938,520	
Total							$ 67,945,839	5.87%	$3,988,421	

Year 2011

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	$ 51,957,430	5.87%	$3,049,901	
2	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	15,988,409	5.87%	938,520	
Total							$ 67,945,839	5.87%	$3,988,421	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Loan	Infrastructure Ontari	Third-Party	Fixed Rate	10/1/12	30	$ 21,936,498	4.00%	$219,683	
2	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	51,957,430	5.87%	3,049,901	
3	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	15,988,409	5.87%	938,520	
Total							$ 89,882,337	4.68%	$4,208,103	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Loan	Infrastructure Ontari	Third-Party	Fixed Rate	10/1/12	30	$ 21,546,483	4.00%	$869,061	
2	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	51,957,430	5.87%	3,049,901	
3	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	15,988,409	5.87%	938,520	
Total							$ 89,492,322	5.43%	$4,857,482	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Loan	Infrastructure Ontari	Third-Party	Fixed Rate	10/1/12	30	$ 21,140,578	4.00%	$853,118	
2	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	51,957,430	4.88%	2,535,523	
3	Promissory note	Town of Oakville	Affiliated	Variable Rate	2/1/00	20	15,988,409	4.88%	780,234	
Total							$ 89,086,417	4.68%	$4,168,875	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009
3 Add more lines above row 12 if necessary.

Issue 7.6 *Is the proposed forecast of other revenues including those from specific service charges appropriate?*

7.6-Staff-38

Ref: Exhibit 3/Tab3/Schedule 1/p. 6/ Appendix 2-H

Other Operating Revenue

Please explain why forecasted revenues under Other Income or Deductions fall from $994,892 in 2012 to $583,097 in 2013 Bridge and then to $564,820 in 2014.

RESPONSE:

In 2012, Other Income or Deductions includes a number of one-time unusual items including:

- "Interest earned on deferral accounts" of $127,231 referenced in Exhibit 3, Tab3, Schedule 1, Page 8 of 10.
- Account 4405, two one-time items in Account 4390 for an employee benefit refund of $127,779 and miscellaneous recovery for defective meters of $54,603, and
- One one-time cost in Account 4375 for the recovery for storm assistance in Long Island, New York of $ 199,776.

The normalized amount in 2012, excluding one-time items, $435,503.

The 2014 Test year decreases slightly from 2013 Bridge year based on a forecasted decrease in interest earned from its bank and sentinel light rental revenues which are non-utility revenues and not included in "revenue offsets".

7.6-Energy Probe-44

Ref: Exhibit 3, Tab 3, Schedule 1

a) Please provide an updated version of Appendix 2-H (page 6) that reflects the most recent year-to-date information available for 2013, along with the forecast for the remainder of the year. In answering this, please adjust the historical years to remove any interest earned on regulatory accounts and any CDM revenues and costs.

RESPONSE:

A revised Appendix 2-H with 2013 Actuals (unaudited), the removal interest earned on regulatory accounts and CDM Revenues and costs is provided below. Please note however, that in Account 4375 Revenues from non- utility operations,

i. the 2010 Actual includes the one-time accounting revenue entry for the "Late payment penalty" of $257,572,

ii. the 2012 Actuals include the unusual event for the revenues earned for Oakville Hydro's assistance in Long Island New York of $199,776 and with the costs associated with the offsetting associated with this in OM&A costs

iii. The 2013 Actuals (unaudited) include non –recurring events, namely the revenue earned for the assistance to other distributors for both the windstorm and the ice storm. The costs associated with this are included in OM&A.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual²	2013 Actual	Test Year (updated)
					(unaudited)	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4080-2	SSS Admin Charge	$170,451	$174,932	$185,838	$182,257	$194,383
	MicroFIT charges	149	1,042	1,719	2,004	2,000
4210	Rent from Electric Property	129,628	142,904	144,365	156,550	159,212
4220	Other Electric Revenues	583,421	515,797	515,844	525,227	547,650
4225	Late Payment Charges	288,100	314,134	335,244	362,617	325,000
4235	Miscellaneous Service Revenues From Non-Utility Operations	300,454	278,387	314,040	292,662	282,200
4385	Non-Utility Rental Income	9,510	9,168	9,202	8,699	0
4375/4380	Revenues from non utility operations	257,572	0	199,776	161,398	0
4390	Miscellaneous Non-Operating Inco	922,739	767,618	404,874	357,237	356,820
4398	Foreign Exchange Gains and Losses, Including Amortization	83,547	17,522	3,781	2,740	4,000
4405	Interest and Dividend Income	277,636	110,435	200,028	257,274	204,000
Specific Service Charges		300,454	278,387	314,040	292,662	282,200
Late Payment Charges		288,100	314,134	335,244	362,617	325,000
Other Operating Revenues		883,648	834,675	847,766	866,039	903,245
Other Income or Deductions		1,551,004	904,743	817,661	787,347	564,820
Total		$ 3,023,206	$ 2,331,939	$ 2,314,711	$ 2,308,666	$ 2,075,265

Account 4210-Rent from Electric Property

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MGAAP	MGAAP
Pole Rental - Rogers/Bell/Other	$122,457	$142,904	$144,365	$156,550	$159,212
Pole Rental- Blink (Intercompany)	7,171	0	0		0
Total	**$129,628**	**$142,904**	**$144,365**	**$156,550**	**$159,212**

Account 4220-Other Electric Revenues					
	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MGAAP	MGAAP
Point of Presence Site Rental-Rogers	$27,900	$27,900	$27,900	$27,900	$28,500
Data Ctr & Generator - Rogers	113,575	123,900	125,377	125,999	128,000
Duct Rental-Rogers	19,922	21,733	22,720	23,228	23,500
Line Rental - Burlington	156,000	156,000	156,000	156,000	13,000
Other	(1,258)	6	32		0
Intercompany- billing charges/vehicles insuranc	85,766	75,058	100,599	86,600	106,750
Intercompany - Occupancy recovery	179,705	111,200	83,216	75,500	127,900
Control Room services -Halton Hills Hydro Inc.	0	0	0	30,000	120,000
Blink - Duct Rental	1,811				
Total	**$583,421**	**$515,797**	**$515,844**	**$525,227**	**$547,650**
	-	-	-		

Account 4225-Late Payment Charges

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MGAAP	MGAAP
LPC-Energy	$218,019	$232,557	$249,041	$269,409	$240,500
LPC - Water/Sewer	70,081	81,576	86,203	93,208	84,500
Total	**$288,100**	**$314,134**	**$335,244**	**$362,617**	**$325,000**
	-	-	-		-

Account 4235-Miscellaneous Service Revenues From Non-Utility Operations

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MGAAP	MGAAP
Temporary Service Charg	$29,249	$25,500	$29,139	$27,900	$31,200
Arrears Certificate Cha	4,997	3,718	4,665	3,328	5,600
Returned Cheque Collect	11,803	8,130	10,180	13,680	8,700
Reconnect Charge	15,075	14,875	14,970	16,315	13,800
Deposit Waiver Fees	10,446	4,339	5,352	5,260	4,600
Other	645	1,710	1,845	1,425	1,000
Occupancy Charge	214,170	207,510	232,680	209,850	204,000
Disconnect Fee	14,070	12,605	15,210	14,905	13,300
Total	**$300,454**	**$278,387**	**$314,040**	**$292,662**	**$282,200**

Account 4375-Revenues from Non-Utility Operations

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MGAAP**	**MGAAP**
Long Island , New York Storm Assistance	0	0	199,776		0
Late payment penalty	257,572				
Wind storm assistance - Burlington & Horizon				49,201	
Ice storm assistance - Milton/Halton Hills				112,197	
Total	**$257,572**	**$0**	**$199,776**	**$161,398**	**$0**

Account 4385-Non-Utility Rental Income

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MGAAP**	**MGAAP**
Sentinel Light Rental	$9,510	$9,168	$9,202	$8,699	$0
Total	**$9,510**	**$9,168**	**$9,202**	**$8,699**	**$0**

Account 4390-Miscellaneous Non-Operating Income

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MGAAP**	**MGAAP**
Rogers- Temporary Transitional Services	$430,938	$318,222	$26,191		$0
Office Space rental-Town of Oakville	0	0	36,707	146,829	146,820
Billable Sevices	121,424	184,720	156,802	158,786	153,000
Benefit Refund Deposit Account	0	111,455	127,779		0
Cash Discount on Purchases	16,201	19,796	7,226	13,495	6,000
SR & ED Credits	99,110	0	0		0
Miscellaneous Income	131,349	-299	-79,355	11,622	6,000
Miscellaneous one time- (defect meter	69,093	31,097	54,603		0
Proceeds on Sale of Materials	54,623	71,627	58,703	0	45,000
Proceeds on Sale of Capital Assets	0	31,000	16,218	26,505	0
Total	**$922,739**	**$767,618**	**$404,874**	**$357,237**	**$356,820**
	-	-	-		-

Account 4398-Foreign Exchange Gains and Losses, Including Amortization

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MGAAP**	**MGAAP**
Exchange Gain or Loss	$83,547	$17,522	$3,781	$2,740	$4,000
Total	**$83,547**	**$17,522**	**$3,781**	**$2,740**	**$4,000**

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012Actual[2]	2013 Actual	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MGAAP**	**MGAAP**
Interest Income	$95,156	$5,842	$81,725	$257,274	$204,000
Interest earned from affiliates - for notes payable	182,481	104,593	118,303		0
Total	**$277,636**	**$110,435**	**$200,028**	**$257,274**	**$204,000**

b) Please provide the most recent year-to-date figures available for 2013 in the same level of detail as found in Appendix 2-H (page 6), along with the figures for the corresponding period in 2012.

RESPONSE:

The revised Appendix 2-H provided in response to part a) has annual actual figures for 2012 and the unaudited 2013 actual figures.

c) Please explain why there are no microFIT revenues shown in Appendix 2-H for either 2013 or 2014.

RESPONSE:

Oakville Hydro inadvertently grouped the MicroFIT charges for 2013 and 2014 in the line above "4080-2 SSS Admin Charges". In the revised Appendix 2-H provided in response to part a), the MicroFIT charge has been reallocated correctly. The forecasted amount for the 2013 Bridge Year and the 2014 Test Year is $2,004.

7.6-Energy Probe-45

Ref: Exhibit 3, Tab 3, Schedule 1, pages 6-8

a) Please explain the reduction in pole rental (account 4210) between 2012 and 2013. Is Oakville Hydro renting fewer poles in 2013 than it did in 2012?

RESPONSE:

Oakville Hydro's pole rental for the 2013 actuals (unaudited) was $156,551 which is identified below. Oakville Hydro is not renting fewer poles and has updated its evidence for the 2014 Test Year and to increase its pole rental revenues in account 4210 to $159,212, which is more reflective of the anticipated revenues.

Description	2012 Actual	2013 Actual (unaudited)	2014 Test Year
Account 4210			
Pole rental- Rogers/Bell/Other	144,365	156,550	159,212

b) Please explain why there is no revenue forecast for 2014 in account 4385 for sentinel light rentals. What costs are incurred on a fully allocated basis in order to provide these rentals? Where are these costs included in the revenue requirement?

RESPONSE:

Oakville Hydro has not included the revenue for 2014 or the associated costs in the revenue requirement. This is immaterial in nature. The details for the 2012 and 2013 are provided below:

	2012 Actual	2013 Actual (unaudited)
Revenue	9,202	8,699
Costs	6,776	2,961

c) Please explain why almost all of the line items shown in account 4235 show a decrease between actual 2012 and the forecast for 2013, in light of the comment on page 3 that this account has been forecast based on a 2% increase from the last actual results.

RESPONSE:

Oakville Hydro's comment on Page 3 that it has forecasted based on a 2% increase, actually related to the 2014 Test Year. In addition, the comment on Page 3 was incorrect made and should have read "primarily based on a 2% increase in the 2014 Test Year from the 2013 Forecast". Based on the 2013 (unaudited) actuals for account 4235, this total has declined from 2012.

d) Please explain why there are no proceeds on the sale of capital assets shown in account 4390 in 2014 when Oakville Hydro is replacing a number of vehicles.

ESPONSE:

Oakville Hydro has not included any proceeds on sale of capital assets as the vehicles being replaced range from 8-24 years which would have likely have no remaining net book value. The details are provided in Oakville Hydro's Distribution System Plan in Exhibit 2, Appendix A, Page 76.

e) Please provide the number of vehicles being replaced in 2014 and the net book value of those vehicles being replaced, along with an estimated sale value of the vehicles.

RESPONSE:

The table below provides the details requested.

Unit #	Vehicle Description	Year Acquired	Original Cost	Accumulated Depreciationt o Dec 31 2013	NBV	Estimated SalesPrice
20	1990 International Flatdeck - replace chassis with 5 yr old chassis	Town				
65	2003 Chev pickup	2004	25,722.12	25,722.12	-	2,500-3,500
69	2004 Chev crew cab	2004	29,040.63	29,040.63	-	2,500-3,500
75	2005 Chev crew cab	2005	31,405.18	31,405.18	-	2,500-3,500
80	2006 Chev crew cab	2006	32,991.10	32,991.10	-	2,500-3,500
77	2005 Chev Van	2005	36,389.37	36,389.37	-	2,500-3,500
68	2004 4 door Chev Malibu car	2004	22,404.03	22,404.03	-	2,500.00
406	1991-92 Toyota Series propane Forklift	Town				2-,4000
			177,952.43	177,952.43	-	32,000 - 42,000

7.6-Energy Probe-46

Ref: Exhibit 3, Tab 3, Schedule 1, pages 9-10

a) How many customer requested service calls during regular hours has Oakville Hydro received on average over the last 3 years?

RESPONSE:

Oakville Hydro has received approximately 470 service calls each year over the last three years. However, it is Oakville Hydro's intention to charge customers for service calls only in circumstances where there are repeated requests for service calls. As noted in Exhibit 3, Tab, 3 Schedule 1, Page 9 Oakville Hydro does not expect revenues for these services to be material. Oakville Hydro estimates that it will have approximately 10 repeated requests for service calls per year.

b) How many customer requested service calls outside of regular hours has Oakville Hydro received on average over the last 3 years?

RESPONSE:

Oakville Hydro has not received requests for service calls outside of regular hours over the last three years. However, a service call may have extended outside of regular hours.

c) What are the current charges for the services where Oakville Hydro is proposing a charge of $30 and $165 per hour?

RESPONSE:

To date, Oakville Hydro has not charged for the services. Consequently there are no current rates for the services that that Oakville Hydro is proposing a charge of $30 and $165 per hour.

7.6-HVAC-18

Ref: Ex. 1/3/3, p. 16

Please confirm that all references in the Application to "Oakville Hydro" refer to the regulated utility OHEDI, and not to Oakville Hydro Corporation, the parent company.

RESPONSE:

Oakville Hydro confirms that all references to Oakville Hydro in the Application refer to the regulated utility, Oakville Hydro Electricity Distribution Inc. and not to the parent company as set out in Exhibit 1, Tab 1, Schedule 1, Page 1.

7.6-VECC-30

Ref: E3/T3/S1, page 2

a) What is Burlington Hydro's alternative to renting the two distribution lines from Oakville Hydro?

RESPONSE:

Burlington Hydro has advised Oakville Hydro that it will continue to rent Oakville Hydro's two distribution lines until May 31, 2014 and has not provided Oakville Hydro with any other details regarding their future plans.

7.6-VECC-31

Ref: E3/T3/S1, page 9

a) To what types of customer-requested special or extra services will these charges apply? Please provide examples.

RESPONSE:

The types of requests for these charges to apply are for repeated requests by the same customers for disconnections and reconnections for their purposes of upgrading their AMP services to their homes during renovations, rebuilds and new home construction.

Issue 7.7 *Has the proposed revenue requirement been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues?*

7.7-Staff-39

Ref: Exhibit 6/Appendix A

RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

RESPONSE:

A copy of RRWF is provided in Appendix 7-D. The table below lists all the corrections and adjustments Oakville Hydro had made in the RRWF model. Oakville Hydro has provided the calculations for the revised cost of power in the table below.

Intervenor	Question #	Change
Board Staff	1.1-Staff-9	2014 Capital addition from 2013 WIP in amount of $1,789,798
Board Staff	4.2-Staff-21	Update OM&A
Board Staff	4.2-Staff-27a	Update Other Revenue - Halton Hills Agreement
Board Staff	7.7-Staff-39	Update Cost of Power
Board Staff	8.2-Staff-44	Revenue to Cost Ratios
Board Staff	8.5-Staff-47	RSTR Rates
Board Staff	8.4-VECC-48	Line loss factor
Board Staff	9.1-Staff-48b	Remove Group 2 account -Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs from the disposed accounts
Board Staff	9.1-Staff-50	"Interest Disposition during 2013 instructed by Board" for Group 1 Account 1589 – RSVA- Global Adjustment. The correct amount should be $530,089 instead of negative $530,089
Board Staff	9.2-Staff-51	Account 1576 Balance
Board Staff	9.2-Staff-52	LRAM Rate Riders
Energy Probe	7.3-EP-37a	Update Property Taxes - Corporate Offices (1.7%)
Energy Probe	7.3-EP-39	Update PILs
Energy Probe	7.5-EP-43	Update Cost of Capital parameters
Energy Probe	7.6-EP-45	Update Other Revenue - Pole Rentals
SEC	4.3-SEC-22	Update Appendix 2-BA (Continuity) to include 2013 year-end actuals

2014 Cost of Power Calculations

Forecasted Purchases	Residential	General Service < 50 kW	Unmetered	General Service > 50 kW	General Service > 1,000 kW	Embedded Distributor	Sentinel Lighting	Street Lighting	Total
Average Number of Customers	59,243	4,923							
Non-RPP Forecast (kWh)	30,735,751	25,823,166	26,001	539,818,148	152,928,220	31,851,374	-	9,279,355	790,462,016
RPP Forecast (kWh)	587,102,250	138,645,038	3,609,770	85,144,616	-	-	121,179	-	814,622,851
Total kWh	617,838,000	164,468,204	3,635,771	624,962,764	152,928,220	31,851,374	121,179	9,279,355	1,605,084,867
Commodity Charges									
Non-RPP Coommodity Charge ($0.08735/kWh)	$ 2,684,768	$ 2,255,654	$ 2,271	$ 47,153,115	$ 13,358,280	$ 2,782,217	$ -	$ 810,552	$ 69,046,857
RPP Commodity Charge($0.08900/kWh)	$ 52,252,100	$ 12,339,408	$ 321,270	$ 7,577,871	$ -	$ -	$10,785	$ -	$ 72,501,434
Total Commodity Charges	**$ 54,936,868**	**$ 14,595,062**	**$ 323,541**	**$ 54,730,986**	**$ 13,358,280**	**$ 2,782,217**	**$10,785**	**$ 810,552**	**$ 141,548,291**
Retail Transmission Charges									
Forecasted Billing Determinants (kW/kWh)	617,838,000	164,468,204	3,635,771	1,589,641	329,822	73,000	324	24,961	
Transmission Network Rate	$ 0.0072	$ 0.0067	$ 0.0067	$ 2.4866	$ 2.5669	$ 2.5669	$0.4984	$ 2.0744	
Transmission Network Charges	**$4,448,433.60**	**$ 1,101,936.97**	**$24,359.67**	**$ 3,952,802.03**	**$ 846,619.70**	**$187,383.70**	**$161.69**	**$51,778.11**	**$ 10,613,475**
Transmission Connection Rate	$ 0.0036	$ 0.0033	$ 0.0033	$ 1.2375	$ 1.2776	$ 1.2776	$0.2480	$ 1.0324	
Transmission Connection Charges	**$ 2,224,217**	**$ 542,745**	**$ 11,998**	**$ 1,967,181**	**$ 421,380**	**$ 93,265**	**$ 80**	**$ 25,769**	**$ 5,286,636**
Low Voltage Charge									
Low Voltage Rate	$ 0.0004	$ 0.0003	$ 0.0003	$ 0.1313	$ 0.1313	$ 0.1313	$0.0255	$ 0.1061	
Low Voltage Charges	**$ 247,135**	**$ 49,340**	**$ 1,091**	**$ 208,720**	**$ 43,306**	**$ 9,585**	**$ 8**	**$ 2,648**	**$ 561,833**
Regulatory Charges									
Wholesale Market Service Rate	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$0.0044	$ 0.0044	
Rural Rate Protection Rate	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$0.0013	$ 0.0013	
Regulator Charges	**$ 3,501,082**	**$ 931,986**	**$ 20,603**	**$ 3,541,456**	**$ 866,593**	**$ 180,491**	**$ 687**	**$ 52,583**	**$ 9,095,481**
Smart Metering Charge									
Monthly Smart Metering Rate per Customer	$ 0.79	$ 0.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Metering Charge	**$ 561,628**	**$ 46,666**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 608,293**
Total Cost of Power	**$ 65,672,228**	**$ 17,218,396**	**$ 380,501**	**$ 64,192,425**	**$ 15,492,873**	**$ 3,243,357**	**$11,714**	**$ 940,682**	**$ 167,714,010**

7.7-Staff-40

Ref: Exhibit 8/Appendix C

Appendix 2-W

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50kW, etc.).

RESPONSE:

An updated Appendix 2-W is provided in Appendix 7-E.

7.7-Energy Probe-47

Ref: Exhibit 6

a) Please update the RRWF found in Appendix 6A to reflect any changes or corrections resulting from the interrogatory responses, as well as the updated cost of capital parameters applicable to 2014 cost of service applications as issued by the Board on November 25, 2013.

RESPONSE:

Please see response to 7.7-Staff-39.

b) Please provide a tracking sheet showing the changes and/or corrections made to the revenue deficiency/sufficiency calculation as noted in part (a) above. For each change, please provide a reference to the associated interrogatory response that results in the change.

RESPONSE:

Please see response to 7.7-Staff-39.

Appendix 7 - A

2014_Income_Tax_PILs_Workform

Income Tax/PILs Workform for 2014 Filers

Version **2.0**

Utility Name	Oakville Hydro Electricity Distribution Inc.
Assigned EB Number	EB-2013-0159
Name and Title	Maryanne Wilson, Manager Regulatory Affairs
Phone Number	905-825-4422
Email Address	mwilson@oakvillehydro.com
Date	01-Oct-13
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Income Tax/PILs
Workform for 2014 Filers

Income Tax/PILs
Workform for 2014 Filers

Rate Base			**$**	**184,414,917**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	7,376,597	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	103,272,354	*X = S * U*
Deemed Equity %	40.00%	V	$	73,765,967	*Y = S * V*
Short Term Interest Rate	2.11%	Z	$	155,646	*AC = W * Z*
Long Term Interest	4.68%	AA	$	4,832,718	*AD = X * AA*
Return on Equity (Regulatory Income)	9.36%	AB	**$**	**6,904,494**	*AE = Y * AB*
Return on Rate Base			**$**	**11,892,859**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	**Bridge**	**Test Year**
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	No	Yes
2. Does the applicant have any SRED Expenditures?	Yes	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	Yes	Yes	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Income Tax/PILs Workform for 2014 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2014 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	85,896,081		85,896,081
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	6,774,908		6,774,908
10	Computer Hardware/ Vehicles	828,605		828,605
10.1	Certain Automobiles			0
12	Computer Software			0
13_1	Lease # 1	2,712,401		2,712,401
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	68,260		68,260
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	89,178,703		89,178,703
50	Data Network Infrastructure Equipment - post Mar 2007	1,911,747		1,911,747
52	Computer Hardware and system software			0
95	CWIP	1,791,956		1,791,956
38	Mobile Equipment	713,839		713,839
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	189,876,500	0	189,876,500

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital

Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	251,689		251,689
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**251,689**	**0**	**251,689**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost	248,459		248,459
- Other Post-Employment Benefits	7,641,300		7,641,300
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs	45,000		45,000
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	177,136		177,136
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other	3,890		3,890
			0
			0
Total	**8,115,785**	**0**	**8,115,785**

Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	5,137,192		5,137,192
Additions:				
Interest and penalties on taxes	103	17,044		17,044
Amortization of tangible assets	104	13,351,727		13,351,727
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	21,152		21,152
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	18,636		18,636
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	9,981,943		9,981,943
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290	1,073,748		1,073,748
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293	55,000		55,000
Ontario Co-op Credit and OATTC	294	47,756		47,756
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**24,567,006**	**0**	**24,567,006**
Deductions:				
Gain on disposal of assets per financial statements	401	42,218		42,218
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	14,436,057		14,436,057
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	16,295,022		16,295,022
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	1,372,368		1,372,368
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**32,145,665**	**0**	**32,145,665**
Net Income for Tax Purposes		**-2,441,467**	**0**	**-2,441,467**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**-2,441,467**	**0**	**-2,441,467**

Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

					Wires Only	
Regulatory Taxable Income					-$ 2,441,467	**A**
Ontario Income Taxes						
Income tax payable	**Ontario Income Tax**		**B**		**C = A * B**	
Small business credit	Ontario Small Business Threshold	$ -	**D**			
	Rate reduction (negative)		**E**		**F = D * E**	
Ontario Income tax					$ -	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			0.00%	**K = J / A**	
	Federal tax rate				**L**	
	Combined tax rate				0.00%	**M = K + L**
Total Income Taxes					$ -	**N = A * M**
Investment Tax Credits						**O**
Miscellaneous Tax Credits						**P**
Total Tax Credits					$ -	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year					$ -	**R = N - Q**

Income Tax/PILs
Workform for 2014 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 85,896,081			$ 85,896,081	$ -	$ 85,896,081	4%	$ 3,435,843	$ 82,460,238
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 6,774,908	$ 92,956		$ 6,867,864	$ 46,478	$ 6,821,386	20%	$ 1,364,277	$ 5,503,587
10	Computer Hardware/ Vehicles	$ 828,605	$ 1,166,502		$ 1,995,107	$ 583,251	$ 1,411,856	30%	$ 423,557	$ 1,571,550
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software				$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ 2,712,401	$ 20,756		$ 2,733,157	$ 10,378	$ 2,722,779	20%	$ 544,556	$ 2,188,601
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 68,260			$ 68,260	$ -	$ 68,260	45%	$ 30,717	$ 37,543
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 89,178,703	$ 10,143,979		$ 99,322,682	$ 5,071,989	$ 94,250,692	8%	$ 7,540,055	$ 91,782,626
50	Data Network Infrastructure Equipment - post Mar 2007	$ 1,911,747	$ 45,060		$ 1,956,807	$ 22,530	$ 1,934,277	55%	$ 1,063,852	$ 892,955
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 1,791,956			$ 1,791,956	$ -	$ 1,791,956		$ -	$ 1,791,956
38	Mobile Equipment	$ 713,839	$ 259,738	-$ 222,595	$ 750,982	$ 18,572	$ 732,411	30%	$ 219,723	$ 531,259
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 189,876,500	$ 11,728,990	-$ 222,595	$ 201,382,895	$ 5,753,198	$ 195,629,698		$ 14,622,581	$ 186,760,315

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	251,689		251,689	48,311		300,000	48,311	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**251,689**	**0**	**251,689**	**48,311**	**0**	**300,000**	**48,311**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	248,459		248,459		248,459	0	-248,459	
- Other Post-Employment Benefits	7,641,300		7,641,300	100,000		7,741,300	100,000	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	45,000		45,000			45,000	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	177,136		177,136		177,136	0	-177,136	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	3,890		3,890	10,110		14,000	10,110	
	0		0			0	0	
	0		0			0	0	
Total	**8,115,785**	**0**	**8,115,785**	**110,110**	**425,595**	**7,800,300**	**-315,485**	**0**

Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	4,364,684
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	8,234,650
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	21,601
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	251,689
Reserves from financial statements- balance at end of year	126	7,800,300
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	1,019,569
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Co-op ON current year		5,250
Other additions		37,292
Apprentice ON current year		43,333
Total Additions		**17,413,684**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	14,622,581
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	300,000
Reserves from financial statements - balance at beginning of year	414	8,115,785
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	1,371,569
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**24,409,935**
Net Income for Tax Purposes		**-2,631,567**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**-2,631,567**

Income Tax/PILs Workform for 2014 Filers

PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						-$ 2,631,567	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ -	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ -	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			0.00%	**K = J / A**		
	Federal tax rate			0.00%	**L**		
	Combined tax rate					0.00%	**M = K + L**
Total Income Taxes						**$ -**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ -**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workforms for 2014 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 82,460,238			$ 82,460,238	$ -	$ 82,460,238	4%	$ 3,298,410	$ 79,161,828
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 5,503,587	93,333		$ 5,596,920	$ 46,667	$ 5,550,253	20%	$ 1,110,051	$ 4,486,869
10	Computer Hardware/ Vehicles	$ 1,571,550	380,000		$ 1,951,550	$ 190,000	$ 1,761,550	30%	$ 528,465	$ 1,423,085
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ -			$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ 2,188,601	1,079,825		$ 3,268,426	$ 539,912	$ 2,728,514	20%	$ 545,703	$ 2,722,723
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 37,543			$ 37,543	$ -	$ 37,543	45%	$ 16,894	$ 20,649
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 91,782,626	14,924,987		$ 106,707,613	$ 7,462,494	$ 99,245,120	8%	$ 7,939,610	$ 98,768,004
50	Data Network Infrastructure Equipment - post Mar 2007	$ 892,955	1,231,000		$ 2,123,955	$ 615,500	$ 1,508,455	55%	$ 829,650	$ 1,294,305
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 1,791,956			$ 1,791,956	$ -	$ 1,791,956	0%	$ -	$ 1,791,956
38	Mobile Equipment	$ 531,259	688,079		$ 1,219,338	$ 344,040	$ 875,298	30%	$ 262,590	$ 956,748
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	-$ 0				$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 186,760,315	$ 18,397,225	$ -	$ 205,157,539	$ 9,198,612	$ 195,958,927		$ 14,531,371	$ 190,626,168

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	300,000		300,000			300,000	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**300,000**	**0**	**300,000**	**0**	**0**	**300,000**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	7,741,300		7,741,300	100,000		7,841,300	100,000	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	45,000		45,000			45,000	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	14,000		14,000			14,000	0	
	0		0			0	0	
	0		0			0	0	
Total	**7,800,300**	**0**	**7,800,300**	**100,000**	**0**	**7,900,300**	**100,000**	**0**

Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Income Tax/PILs Workform for 2014 Filers

Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		6,904,494

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	8,644,663
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	21,601
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	300,000
Reserves from financial statements- balance at end of year	126	7,900,300
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	990,453
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Apprentice ON current year	294	40,000
Co-op ON current year	295	2,000
Other Additions	296	37,292
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**17,936,309**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	14,531,371
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	300,000
Reserves from financial statements - balance at beginning of year	414	7,800,300
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	1,371,103

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
-6,066,466		
Total Deductions		**24,002,774**
NET INCOME FOR TAX PURPOSES		**838,029**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**838,029**

Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 838,029	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	B	$	96,373	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D					
	Rate reduction	-7.00%	E	-$	35,000	F = D * E		
Ontario Income tax							$ 61,373	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				7.32%	K = J / A		
	Federal tax rate				15.00%	L		
	Combined tax rate						22.32%	M = K + L
Total Income Taxes							$ 187,078	N = A * M
Investment Tax Credits								O
Miscellaneous Tax Credits							$ 50,000	P
Total Tax Credits							$ 50,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							$ 137,078	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					77.68%	S = 1 - M	$ 39,395	T = R / S - R
Income Tax (grossed-up)							$ 176,472	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Appendix 7 - B

Samples of OHEDI Time Sheets

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

BATCH ID # OPS-[redacted] JAN06 (E)

LINE SECTION - 432

YEAR: 2014 MONTH: 01 DAY: 06

Overtime Hours Worked (24 Hour Clock)

1) From:	To:		☐ UNPLANNED	☐ PLANNED
2) From:	To:		☐ UNPLANNED	☐ PLANNED
3) From:	To:		☐ UNPLANNED	☐ PLANNED

EMPLOYEE NAME	[redacted]	Truck#	Truck#	Truck#	Truck#
EMPLOYEE ID #	[redacted]	85			

Activity (Circle One)	Comp # per WO	Job Notes/ Inspected and no undue hazard exists	(✓)	JOB COST SERVICE OR GL NUMBER	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Truck Hrs	Truck Hrs	Truck Hrs	Truck Hrs
INS / REM		TX11547- buckt hot leg +	✓	1461-0024	4		4						4			
INS / REM		neutral														
INS / REM		Vault inspections	✓	1312-0133	2		2						2			
INS / REM		L.S.L.E + Dunn. S/L	✓	ESI 1461-0005	2		2						2			
INS / REM		hit.														
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
				TOTAL HOURS	8		8						8			

Approved By: [redacted]

CONFIRMATION OF NO UNDUE HAZARD FOR EACH JOB/SITE CHECKED

Signature [redacted] Printed Name [redacted]

Pay Codes		GL Numbers
09R	LinePerson Journeyman	
10R	Lead Line Person	
11R	Line Person Sub Foreman	
SUPV	Acting Line Foreman	
08R	Cable Locator	
04R	Utility Outside Person	
05R	Operations Line Clerk	
15	Sick Phoned In	432-4044-0010
16	Sick Left Work	432-4044-0010
20	Dental Appointment	432-4044-0010
21	Medical Appointment	432-4044-0010
25	Statutory Holiday	432-4049-0010
26	Vacation	432-4051-0010
3	Double Time	
3A	Double Time Rate 2	
3B	Double Time Rate 3	

Pay Codes		GL Numbers
43	Bereavement (3 days) Immediate Family	432-4043-0010
71	Bereavement (1 day) Extended Family	432-4043-0010
72	Bereavement (2 Floating) Non Family	432-4043-0010
	Accident - Short Term	432-4041-0010
	Apprentice Training	432-4042-0010
	Safety Meetings	432-4048-0010
	Non-Productive Time	432-4050-0010
	Union Business	432-4053-0010
40	Leave of Absence	110-1610-2056
41	Personal	110-1610-2056
42	Late	110-1610-2056
	Inclement Weather	432-4045-0010
	Lieu Time Earned	
30	Overtime Hours (Lieu Time) Charged to Job	432-4046-0010
32	OT Hrs Banked at 1.5 Lieu Rate (Enter as a -ve)	432-4046-0010
33	Lieu Time Hours Taken	432-4046-0010

JC-COMP	#	Component description
01OHS	01	Overhead Pole System
02OHD	02	O/H Devices
03OHM	03	O/H Local Motor/Rem Auto Switch
04OHW	04	O/H Wires
05TRN	05	Distribution Transformers
06UGS	06	Duct and Civil ex Metal
07UGM	07	Metal Frames and Covers
08UGG	08	SWG
09UGC	09	U/G Cable System
10MSE	10	Substation Eq - MS
11MSS	11	MS Main Switch Air
12MST	12	MS Transformers
13SCD	13	System Supervisory Equipment
14TSE	14	Substation Equipment - TS
15TSS	15	TS Station Switch Gear - Gas
16TST	16	TS Transformers (>50kv)
17MTD	17	Meters
18MTS	18	Smart Meters - Individual
19MTI	19	Smart Meters - Infrastructure
20SDC	20	Services - Duct and Civil
21SUG	21	Services - U/G Cable System

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC. BATCH ID # 0P[redacted] JAN/13

LINE SECTION - 432

YEAR: 2014 MONTH: DAY:

Overtime Hours Worked (24 Hour Clock)

1) From:		To:		☐ UNPLANNED	☐ PLANNED
2) From:		To:		☐ UNPLANNED	☐ PLANNED
3) From:		To:		☐ UNPLANNED	☐ PLANNED

				EMPLOYEE NAME	[redacted]		[redacted]						Truck# 44	Truck#	Truck#	Truck#
				EMPLOYEE ID #	[redacted]		[redacted]									
Activity (Circle One)	Comp # per WO	Job Notes/ Inspected and no undue hazard exists	(✓)	JOB COST SERVICE OR GL NUMBER	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Truck Hrs	Truck Hrs	Truck Hrs	Truck Hrs
INS / REM																
INS / REM		375 Gloucester	✓	ES1 31000	2		2						2			
INS / REM		S/L connection for		═══												
INS / REM		Elom.														
INS / REM																
INS / REM		Tx Maint	✓	1312-0134	5		5						5			
INS / REM																
INS / REM		Time Sheet	✓	43240500010	1		1						1			
INS / REM		Meeting														
INS / REM																
INS / REM																
INS / REM																
Approved By: [redacted]				TOTAL HOURS	8		8						8			

CONFIRMATION OF NO UNDUE HAZARD FOR EACH JOB/SITE CHECKED Signature [redacted] Printed Name [redacted]

Pay Codes		GL Numbers
09R	LinePerson Journeyman	
10R	Lead Line Person	
11R	Line Person Sub Foreman	
SUPV	Acting Line Foreman	
08R	Cable Locator	
04R	Utility Outside Person	
05R	Operations Line Clerk	
15	Sick Phoned In	432-4044-0010
16	Sick Left Work	432-4044-0010
20	Dental Appointment	432-4044-0010
21	Medical Appointment	432-4044-0010
25	Statutory Holiday	432-4049-0010
26	Vacation	432-4051-0010
3	Double Time	
3A	Double Time Rate 2	
3B	Double Time Rate 3	

Pay Codes		GL Numbers
43	Bereavement (3 days) Immediate Family	432-4043-0010
71	Bereavement (1 day) Extended Family	432-4043-0010
72	Bereavement (2 Floating) Non Family	432-4043-0010
	Accident - Short Term	432-4041-0010
	Apprentice Training	432-4042-0010
	Safety Meetings	432-4048-0010
	Non-Productive Time	432-4050-0010
	Union Business	432-4053-0010
40	Leave of Absence	110-1610-2055
41	Personal	110-1610-2055
42	Late	110-1610-2055
	Inclement Weather	432-4045-0010
	Lieu Time Earned	432-4046-0010
30	Overtime Hours (Lieu Time) Charged to Job	432-4046-0010
32	OT Hrs Banked at 1.5 Lieu Rate (Enter as a -ve)	432-4046-0010
33	Lieu Time Hours Taken	432-4046-0010

JC-COMP	#	Component description
01OHS	01	Overhead Pole System
02OHD	02	O/H Devices
03OHM	03	O/H Local Motor/Rem Auto Switch
04OHW	04	O/H Wires
05TRN	05	Distribution Transformers
06UGS	06	Duct and Civil ex Metal
07UGM	07	Metal Frames and Covers
08UGG	08	SWG
09UGC	09	U/G Cable System
10MSE	10	Substation Eq - MS
11MSS	11	MS Main Switch Air
12MST	12	MS Transformers
13SCD	13	System Supervisory Equipment
14TSE	14	Substation Equipment - TS
15TSS	15	TS Station Switch Gear - Gas
16TST	16	TS Transformers (>50kv)
17MTD	17	Meters
18MTS	18	Smart Meters - Individual
19MTI	19	Smart Meters - Infrastructure
20SDC	20	Services - Duct and Civil
21SUG	21	Services - U/G Cable System

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC. BATCH ID # OPS-[redacted]-JAN20(E)

LINE SECTION - 432

YEAR: 2014 MONTH: 01 DAY: 20

Overtime Hours Worked (24 Hour Clock)

1) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED
2) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED
3) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED

													Truck#	Truck#	Truck#	Truck#
				EMPLOYEE NAME	[redacted]		[redacted]									
				EMPLOYEE ID #	[redacted]		[redacted]						66			
Activity (Circle One)	Comp # per WO	Job Notes/ Inspected and no undue hazard exists	(✓)	JOB COST SERVICE OR GL NUMBER	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Truck Hrs	Truck Hrs	Truck Hrs	Truck Hrs
INS / REM																
INS / REM		474 HARLATT - Fack Lts	✓	1401-055	3	3	3	3					3			
INS / REM																
INS / REM		S/L REPAIRS	✓	ESi 31000	2½	3	2½	3					2½			
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
				TOTAL HOURS	5½		5½						5½			

Approved By: [redacted]

CONFIRMATION OF NO UNDUE HAZARD FOR EACH JOB/SITE CHECKED | Signature | | Printed Name |

Pay Codes		GL Numbers
09R	LinePerson Journeyman	
10R	Lead Line Person	
11R	Line Person Sub Foreman	
SUPV	Acting Line Foreman	
06R	Cable Locator	
04R	Utility Outside Person	
05R	Operations Line Clerk	
15	Sick Phoned In	432-4044-0010
16	Sick Left Work	432-4044-0010
20	Dental Appointment	432-4044-0010
21	Medical Appointment	432-4044-0010
25	Statutory Holiday	432-4049-0010
26	Vacation	432-4051-0010
3	Double Time	
3A	Double Time Rate 2	
3B	Double Time Rate 3	

Pay Codes		GL Numbers
43	Bereavement (3 days) Immediate Family	432-4043-0010
71	Bereavement (1 day) Extended Family	432-4043-0010
72	Bereavement (2 Floating) Non Family	432-4043-0010
	Accident - Short Term	432-4041-0010
	Apprentice Training	432-4042-0010
	Safety Meetings	432-4048-0010
	Non-Productive Time	432-4050-0010
	Union Business	432-4053-0010
40	Leave of Absence	110-1610-2065
41	Personal	110-1610-2065
42	Late	110-1610-2065
	Inclement Weather	432-4045-0010
	Lieu Time Earned	432-4046-0010
30	Overtime Hours (Lieu Time) Charged to Job	432-4046-0010
32	OT Hrs Banked at 1.5 Lieu Rate (Enter as a -ve)	432-4046-0010
33	Lieu Time Hours Taken	432-4046-0010

IC-COMP	#	Component description
01OHS	01	Overhead Pole System
02OHD	02	O/H Devices
03OHM	03	O/H Local Motor/Rem Auto Switch
04OHW	04	O/H Wires
05TRN	05	Distribution Transformers
06UGS	06	Duct and Civil ex Metal
07UGM	07	Metal Frames and Covers
08UGG	08	SWG
09UGC	09	U/G Cable System
10MSE	10	Substation Eq - MS
11MSS	11	MS Main Switch Air
12MST	12	MS Transformers
13SCD	13	System Supervisory Equipment
14TSE	14	Substation Equipment - TS
15TSS	15	TS Station Switch Gear - Gas
16TST	16	TS Transformers (>50kv)
17MTD	17	Meters
18MTS	18	Smart Meters - Individual
19MTI	19	Smart Meters - Infrastructure
20SDC	20	Services - Duct and Civil
21SUG	21	Services - U/G Cable System

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC. BATCH ID # DPS [redacted] - JAN 25 (E)

LINE SECTION - 432

YEAR: 2014 MONTH: JAN DAY: 25 SAT

Overtime Hours Worked (24 Hour Clock)

1) From:	To:	☐ UNPLANNED	☐ PLANNED
2) From:	To:	☐ UNPLANNED	☐ PLANNED
3) From:	To:	☐ UNPLANNED	☐ PLANNED

EMPLOYEE NAME	[redacted]		[redacted]						Truck#	Truck#	Truck#	Truck#
EMPLOYEE ID #	[redacted]		[redacted]						99	97		

Activity (Circle One)	Comp # per WO	Job Notes/ Inspected and no undue hazard exists (√)	JOB COST SERVICE OR GL NUMBER	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Truck Hrs	Truck Hrs	Truck Hrs	Truck Hrs
INS / REM		CALL-OUT.													
INS / REM		0430 - 0630 HRS													
INS / REM		ST/LT UPPER + PEMBROOK. CAR ACCIDENT	ESI 1401-0015	2	3	2	3					2	2		
INS / REM		TRAVEL TIME.	ESI 1401-0015	.5	3	.5	3								
INS / REM															
INS / REM															
INS / REM															
INS / REM															
INS / REM															
INS / REM															
INS / REM		STAND BY	11200	1	11	1	11								
INS / REM															
			TOTAL HOURS	2.5		2.5						2	2		

Approved By: [redacted]

CONFIRMATION OF NO UNDUE HAZARD FOR EACH JOB/SITE CHECKED Signature [redacted] Printed Name

Pay Codes		GL Numbers
09R	LinePerson Journeyman	
10R	Lead Line Person	
11R	Line Person Sub Foreman	
SUPV	Acting Line Foreman	
06R	Cable Locator	
04R	Utility Outside Person	
08R	Operations Line Clerk	
16	Sick Phoned In	432-4044-0010
16	Sick Left Work	432-4044-0010
20	Dental Appointment	432-4044-0010
21	Medical Appointment	432-4044-0010
25	Statutory Holiday	432-4049-0010
26	Vacation	432-4051-0010
3	Double Time	
3A	Double Time Rate 2	
3B	Double Time Rate 3	

Pay Codes		GL Numbers
43	Bereavement (3 days) Immediate Family	432-4043-0010
71	Bereavement (1 day) Extended Family	432-4043-0010
72	Bereavement (2 Floating) Non Family	432-4043-0010
	Accident - Short Term	432-4041-0010
	Apprentice Training	432-4042-0010
	Safety Meetings	432-4048-0010
	Non-Productive Time	432-4050-0010
	Union Business	432-4053-0010
40	Leave of Absence	110-1610-2055
41	Personal	110-1610-2055
42	Late	110-1610-2055
	Inclement Weather	432-4045-0010
	Lieu Time Earned	432-4046-0010
30	Overtime Hours (Lieu Time) Charged to Job	432-4046-0010
32	OT Hrs Banked at 1.5 Lieu Rate (Enter as a -ve)	432-4046-0010
33	Lieu Time Hours Taken	432-4046-0010

JC-COMP	#	Component description
01OHS	01	Overhead Pole System
02OHD	02	O/H Devices
03OHM	03	O/H Local Motor/Rem Auto Switch
04OHW	04	O/H Wires
05TRN	05	Distribution Transformers
06UGS	06	Duct and Civil ex Metal
07UGM	07	Metal Frames and Covers
08UGG	08	SWG
09UGC	09	U/G Cable System
10MSE	10	Substation Eq - MS
11MSS	11	MS Main Switch Air
12MST	12	MS Transformers
13SCD	13	System Supervisory Equipment
14TSE	14	Substation Equipment - TS
15TSS	15	TS Station Switch Gear - Gas
16TST	16	TS Transformers (>50kv)
17MTD	17	Meters
18MTS	18	Smart Meters - Individual
19MTI	19	Smart Meters - Infrastructure
20SDC	20	Services - Duct and Civil
21SUG	21	Services - U/G Cable System

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC. BATCH ID # OPS- [redacted] -JAN27

LINE SECTION - 432

YEAR: 2014 MONTH: Jan DAY: 27

Overtime Hours Worked (24 Hour Clock)

1) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED
2) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED
3) From: ____ To: ____ ☐ UNPLANNED ☐ PLANNED

				EMPLOYEE NAME	[redacted]		[redacted]		[redacted]				Truck#	Truck#	Truck#	Truck#
				EMPLOYEE ID #	[redacted]		[redacted]		[redacted]				91	66		
Activity (Circle One)	Comp # per WO	Job Notes/ Inspected and no undue hazard exists	(✓)	JOB COST SERVICE OR GL NUMBER	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Hours	Pay Code	Truck Hrs	Truck Hrs	Truck Hrs	Truck Hrs
INS / REM																
INS / REM		O/H Tx maintenance	✓	1312-0134	7		7		7				7	7		
INS / REM		Various locations														
INS / REM																
INS / REM		Oakpark & Sawgrass	✓	BS140-0016	1		1		1				1	1		
INS / REM		S/L Hit by car. Pole														
INS / REM		Seems fine														
INS / REM																
INS / REM																
INS / REM																
INS / REM																
INS / REM																
Approved By: [redacted]				TOTAL HOURS	8		8		8				8	8		

CONFIRMATION OF NO UNDUE HAZARD FOR EACH JOB/SITE CHECKED Signature [redacted] Printed Name [redacted]

Pay Codes		GL Numbers
09R	LinePerson Journeyman	
10R	Lead Line Person	
11R	Line Person Sub Foreman	
SUPV	Acting Line Foreman	
06R	Cable Locator	
04R	Utility Outside Person	
05R	Operations Line Clerk	
15	Sick Phoned In	432-4044-0010
16	Sick Left Work	432-4044-0010
20	Dental Appointment	432-4044-0010
21	Medical Appointment	432-4044-0010
25	Statutory Holiday	432-4049-0010
26	Vacation	432-4051-0010
3	Double Time	
3A	Double Time Rate 2	
3B	Double Time Rate 3	

Pay Codes		GL Numbers
43	Bereavement (3 days) Immediate Family	432-4043-0010
71	Bereavement (1 day) Extended Family	432-4043-0010
72	Bereavement (2 Floating) Non Family	432-4043-0010
	Accident - Short Term	432-4041-0010
	Apprentice Training	432-4042-0010
	Safety Meetings	432-4048-0010
	Non-Productive Time	432-4050-0010
	Union Business	432-4053-0010
40	Leave of Absence	110-1610-2055
41	Personal	110-1610-2055
42	Late	110-1610-2055
	Inclement Weather	432-4045-0010
	Lieu Time Earned	432-4046-0010
30	Overtime Hours (Lieu Time) Charged to Job	432-4046-0010
32	OT Hrs Banked at 1.5 Lieu Rate (Enter as a -ve)	432-4046-0010
33	Lieu Time Hours Taken	432-4046-0010

JC-COMP	#	Component description
01OHS	01	Overhead Pole System
02OHD	02	O/H Devices
03OHM	03	O/H Local Motor/Rem Auto Switch
04OHW	04	O/H Wires
05TRN	05	Distribution Transformers
06UGS	06	Duct and Civil ex Metal
07UGM	07	Metal Frames and Covers
08UGG	08	SWG
09UGC	09	U/G Cable System
10MSE	10	Substation Eq - MS
11MSS	11	MS Main Switch Air
12MST	12	MS Transformers
13SCD	13	System Supervisory Equipment
14TSE	14	Substation Equipment - TS
15TSS	15	TS Station Switch Gear - Gas
16TST	16	TS Transformers (>50kv)
17MTD	17	Meters
18MTS	18	Smart Meters - Individual
19MTI	19	Smart Meters - Infrastructure
20SDC	20	Services - Duct and Civil
21SUG	21	Services - U/G Cable System

Appendix 7 - C

ARC Training

Affiliate Relationships Code for Electricity Distributors and Transmitters

General Overview:

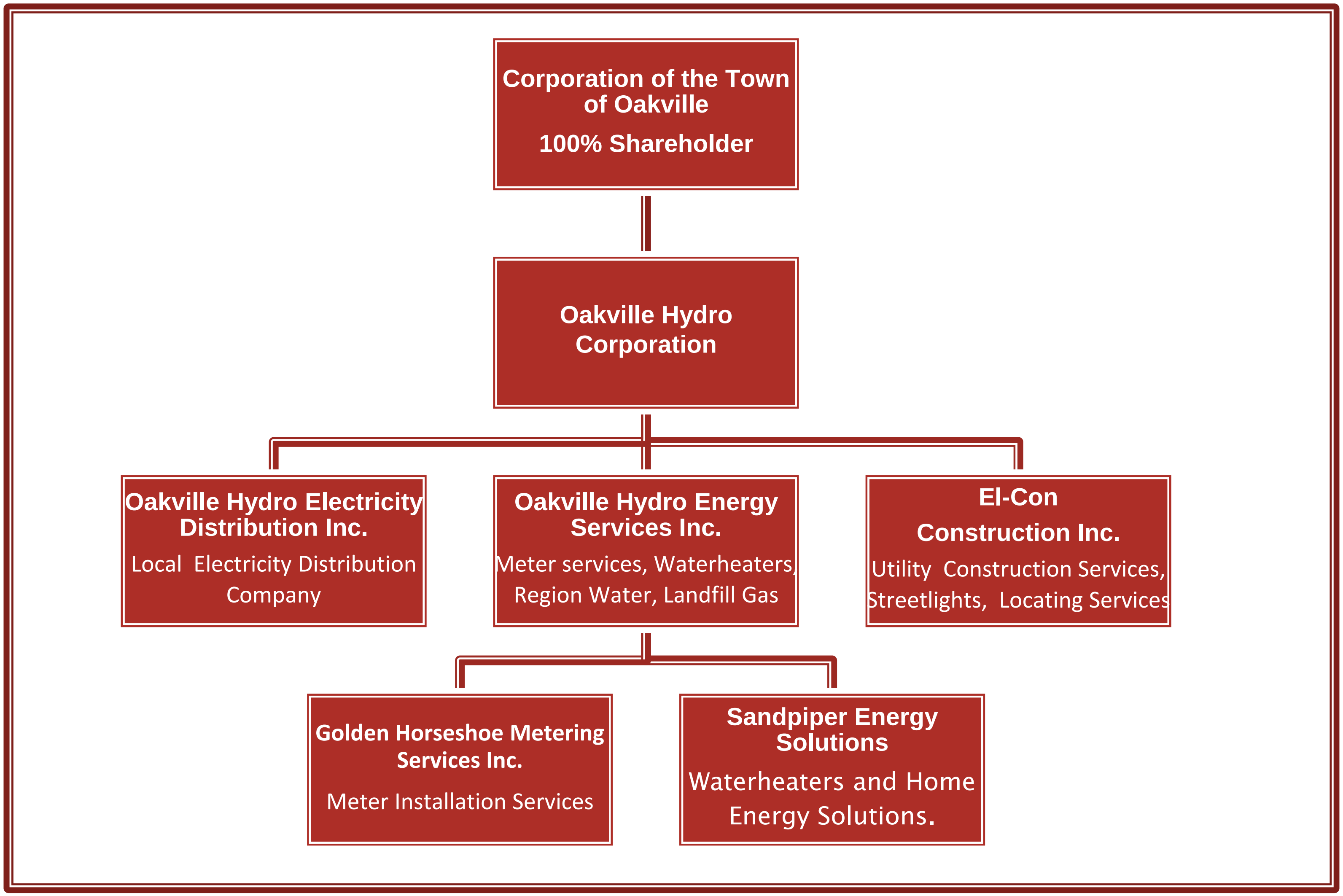
- Originally issued on April 1, 1999 and revised March 2010
- ARC applies to all electricity distributors licensed by the OEB
- ARC prevails over all other OEB codes including the Distribution System Code and Retail Settlement Code
- It is available on the OEB website at http://www.ontarioenergyboard.ca

Purpose:

ARC sets out rules that govern the conduct of utilities as that conduct relates to their respective affiliates to:

- Protect ratepayers from harm
- Prevent a utility from cross-subsidizing affiliates
- Protect the confidentiality of information
- Ensure there is no preferential access to utility services
- Prevent a utility from providing an unfair business advantage to an affiliate that is a energy service provider
- Prevent customer confusion that may arise from the relationship between a utility and its affiliate

Affiliate Companies:



Standards of Conduct

Degree of Separation:

- Maintain accounting and financial separation from all affiliates
- Separate financial records and books of accounts
- Ensure that at least one-third of its Board of Directors is independent from any affiliate

Sharing of Services and Resources

- Service agreements must be in place
- Type, quantity, quality, price, risk, dispute resolution, etc.
- Confidential information must be protected from affiliates
- Utility employees may be shared with an affiliate, but those employees must be respectful of confidential information

Transfer Pricing:

- Competitive market exists:
  - Utility service provider must charge at least market price.
  - Utility service purchaser must not pay more than market price.
- No competitive Market:
  - pricing must be at fully allocated cost.

Equal Access to Services

- Ensure that an affiliate does not use the utility's name or logo
- No favoured treatment or preferential service
- Process requests / services in the same manner as would be processed or provided for non-affiliated parties

Confidentiality of Information:

- A Utility shall not disclose information to an affiliate without written consent from customer
- Unless aggregated
- Or made available to all non-affiliated parties at the same time

Compliance:

- Utilities shall
- Perform periodic compliance reviews
- Communicate the code to employees
- Monitor employee compliance
- Breaches of the Code may result in OEB Administrative Penalties as compliance is a requirement of our Distributor's license

Questions to ask yourself

- Is the completion of this request likely to provide an affiliate with any advantage over their competitors? If yes, it is likely a breach of the Code.
- Would I be willing to provide this information to a non-affiliated company? If no, it is likely a breach of the Code.

If a situation arises where you are unsure:

- Review with Supervisor
- Review with Manager of Regulatory Affairs

Appendix 7 - D

Oakville_2014_Rev_Reqt_Work_Form

Revenue Requirement Workform

Version 4.00

Utility Name	Oakville Hydro Distribution Inc.
Service Territory	*Town of Oakville*
Assigned EB Number	EB-2013-0159
Name and Title	Maryanne Wilson , Manager, Regulatory Affairs
Phone Number	905-825-4422
Email Address	mwilson@oakvillehydro.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)		(6)	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$278,453,731		$ 278,453,731		$278,453,731	
	Accumulated Depreciation (average)	($118,371,561)	(5)	($118,371,561)		($118,371,561)	
	Allowance for Working Capital:						
	Controllable Expenses	$19,460,972		$ 19,460,972		$19,460,972	
	Cost of Power	$167,714,010		$ 167,714,010		$167,714,010	
	Working Capital Rate (%)	13.00%	(9)	13.00%	(9)	13.00%	(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$31,499,496					
	Distribution Revenue at Proposed Rates	$38,099,702					
	Other Revenue:						
	Specific Service Charges	$282,200					
	Late Payment Charges	$325,000					
	Other Distribution Revenue	$1,260,065					
	Other Income and Deductions	$208,000					
	Total Revenue Offsets	$2,075,265	(7)				
	Operating Expenses:						
	OM+A Expenses	$19,276,251		$ 19,276,251		$19,276,251	
	Depreciation/Amortization	$8,644,663		$ 8,644,663		$8,644,663	
	Property taxes	$184,721		$ 184,721		$184,721	
	Other expenses	$ -		0		$0	
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($6,066,466)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$137,078					
	Income taxes (grossed up)	$176,472					
	Federal tax (%)	15.00%					
	Provincial tax (%)	7.32%					
	Income Tax Credits	($50,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%					
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	4.68%					
	Short-term debt Cost Rate (%)	2.11%					
	Common Equity Cost Rate (%)	9.36%					
	Prefered Shares Cost Rate (%)	0.00%					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$278,453,731	$ -	$278,453,731	$ -	$278,453,731
2	Accumulated Depreciation (average)	(3)	($118,371,561)	$ -	($118,371,561)	$ -	($118,371,561)
3	Net Fixed Assets (average)	(3)	$160,082,169	$ -	$160,082,169	$ -	$160,082,169
4	Allowance for Working Capital	(1)	$24,332,748	$ -	$24,332,748	$ -	$24,332,748
5	**Total Rate Base**		$184,414,917	$ -	$184,414,917	$ -	$184,414,917

(1) **Allowance for Working Capital - Derivation**

6	Controllable Expenses		$19,460,972	$ -	$19,460,972	$ -	$19,460,972
7	Cost of Power		$167,714,010	$ -	$167,714,010	$ -	$167,714,010
8	Working Capital Base		$187,174,982	$ -	$187,174,982	$ -	$187,174,982
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$24,332,748	$ -	$24,332,748	$ -	$24,332,748

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$38,099,702	($38,099,702)	$ -	$ -	$ -
2	Other Revenue	(1)	$2,075,265	($2,075,265)	$ -	$ -	$ -
3	Total Operating Revenues		$40,174,967	($40,174,967)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$19,276,251	$ -	$19,276,251	$ -	$19,276,251
5	Depreciation/Amortization		$8,644,663	$ -	$8,644,663	$ -	$8,644,663
6	Property taxes		$184,721	$ -	$184,721	$ -	$184,721
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$28,105,636	$ -	$28,105,636	$ -	$28,105,636
10	Deemed Interest Expense		$4,988,365	($4,988,365)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$33,094,000	($4,988,365)	$28,105,636	$ -	$28,105,636
12	**Utility income before income taxes**		$7,080,967	($35,186,602)	($28,105,636)	$ -	($28,105,636)
13	Income taxes (grossed-up)		$176,472	$ -	$176,472	$ -	$176,472
14	**Utility net income**		$6,904,494	($35,186,602)	($28,282,108)	$ -	($28,282,108)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$282,200		$ -		$ -
	Late Payment Charges	$325,000		$ -		$ -
	Other Distribution Revenue	$1,260,065		$ -		$ -
	Other Income and Deductions	$208,000		$ -		$ -
	Total Revenue Offsets	$2,075,265	$ -	$ -	$ -	$ -

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$6,904,494	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($6,066,466)	$ -	($6,066,466)
3	Taxable income	$838,028	$ -	($6,066,466)
	Calculation of Utility income Taxes			
4	Income taxes	$137,078	$137,078	$137,078
6	Total taxes	$137,078	$137,078	$137,078
7	Gross-up of Income Taxes	$39,395	$39,395	$39,395
8	Grossed-up Income Taxes	$176,472	$176,472	$176,472
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$176,472	$176,472	$176,472
10	Other tax Credits	($50,000)	($50,000)	($50,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7.32%	7.32%	7.32%
13	Total tax rate (%)	22.32%	22.32%	22.32%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$103,272,354	4.68%	$4,832,718
2	Short-term Debt	4.00%	$7,376,597	2.11%	$155,646
3	**Total Debt**	60.00%	$110,648,950	4.51%	$4,988,365
	Equity				
4	Common Equity	40.00%	$73,765,967	9.36%	$6,904,494
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$73,765,967	9.36%	$6,904,494
7	**Total**	100.00%	$184,414,917	6.45%	$11,892,859

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$184,414,917	0.00%	$ -

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Per Board Decision				
	Debt				
8	Long-term Debt	0.00%	$ -	4.68%	$ -
9	Short-term Debt	0.00%	$ -	2.11%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.36%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$184,414,917	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$6,600,206		($5,201,679)		$28,105,636
2	Distribution Revenue	$31,499,496	$31,499,496	$31,499,496	$43,301,381	$ -	($28,105,636)
3	Other Operating Revenue Offsets - net	$2,075,265	$2,075,265	$ -	$ -	$ -	$ -
4	**Total Revenue**	$33,574,761	$40,174,967	$31,499,496	$38,099,702	$ -	$ -
5	Operating Expenses	$28,105,636	$28,105,636	$28,105,636	$28,105,636	$28,105,636	$28,105,636
6	Deemed Interest Expense	$4,988,365	$4,988,365	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$33,094,000	$33,094,000	$28,105,636	$28,105,636	$28,105,636	$28,105,636
9	**Utility Income Before Income Taxes**	$480,761	$7,080,967	$3,393,861	$9,994,066	($28,105,636)	($28,105,636)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($6,066,466)	($6,066,466)	($6,066,466)	($6,066,466)	$ -	$ -
11	**Taxable Income**	($5,585,705)	$1,014,501	($2,672,605)	$3,927,600	($28,105,636)	($28,105,636)
12	Income Tax Rate	22.32%	22.32%	22.32%	22.32%	22.32%	22.32%
13	**Income Tax on Taxable Income**	($1,246,927)	$226,472	($596,620)	$876,779	($6,274,170)	($6,274,170)
14	**Income Tax Credits**	($50,000)	($50,000)	($50,000)	($50,000)	$ -	$ -
15	**Utility Net Income**	$1,777,688	$6,904,494	$4,040,481	($28,282,108)	($21,831,465)	($28,282,108)
16	**Utility Rate Base**	$184,414,917	$184,414,917	$184,414,917	$184,414,917	$184,414,917	$184,414,917
17	Deemed Equity Portion of Rate Base	$73,765,967	$73,765,967	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	2.41%	9.36%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	9.36%	9.36%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-6.95%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	3.67%	6.45%	2.19%	0.00%	-11.84%	0.00%
22	Requested Rate of Return on Rate Base	6.45%	6.45%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-2.78%	0.00%	2.19%	0.00%	-11.84%	0.00%
24	Target Return on Equity	$6,904,494	$6,904,494	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$5,126,807	($0)	($4,040,481)	$ -	$21,831,465	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$6,600,206 **(1)**		($5,201,679) **(1)**		$28,105,636 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$19,276,251		$19,276,251		$19,276,251	
2	Amortization/Depreciation	$8,644,663		$8,644,663		$8,644,663	
3	Property Taxes	$184,721		$184,721		$184,721	
5	Income Taxes (Grossed up)	$176,472		$176,472		$176,472	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$4,988,365		$ -		$ -	
	Return on Deemed Equity	$6,904,494		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$40,174,967		$28,282,108		$28,282,108	
9	Revenue Offsets	$2,075,265		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$38,099,702		$28,282,108		$28,282,108	
11	Distribution revenue	$38,099,702		$ -		$ -	
12	Other revenue	$2,075,265		$ -		$ -	
13	**Total revenue**	$40,174,967		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	**(1)**	($28,282,108)	**(1)**	($28,282,108)	**(1)**

Notes

(1) Line 11 - Line 8

Appendix 7 - E

Oakville Hydro_Appendix_2-W_Bill Impacts

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	800.00	11.44	0.0179	800.00	14.32	2.88	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		800.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	800.00	0.24	0.0002	800.00	0.16	-0.08	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	800.00	1.44		800.00	0.00	-1.44	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	800.00	-0.24		800.00	0.00	0.24	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E	per kWh		800.00	0.00	-0.0001	800.00	-0.08	-0.08	
ICM Rate Rider	per kWh		800.00	0.00	0.0002	800.00	0.16	0.16	
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 28.45**			**$ 31.75**	**$ 3.30**	**11.60%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	800.00	0.24	-0.0007	800.00	-0.56	-0.80	-333.33%
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	800.00	0.16	0.0004	800.00	0.32	0.16	100.00%
Line Losses on Cost of Power	per kWh	0.0839	30.16	2.53	0.0839	30.08	2.52	-0.01	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.17**			**$ 34.82**	**$ 2.65**	**8.25%**
RTSR - Network	per kWh	0.0080	830.16	6.64	0.0075	830.08	6.23	-0.42	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	830.16	4.57	0.0039	830.08	3.24	-1.33	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 43.38**			**$ 44.29**	**$ 0.91**	**2.10%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	830.16	3.65	0.0044	830.08	3.65	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	830.16	1.00	0.0012	830.08	1.00	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	800	5.60	0.0070	800	5.60	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	512	34.30	0.0670	512	34.30	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	144	14.98	0.1040	144	14.98	0.00	0.00%
TOU - On Peak	per kWh	0.1240	144	17.86	0.1240	144	17.86	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	600	45.00	0.0750	600	45.00	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	200	17.60	0.0880	200	17.60	0.00	0.00%
Total Bill on TOU (before Taxes)				**121.01**			**121.92**	**0.91**	**0.75%**
HST		13%		15.73	13%		15.85	0.12	0.75%
Total Bill (including HST)				136.74			137.77	1.03	0.75%
Ontario Clean Energy Benefit [1]				-13.67			-13.78	-0.11	0.80%
Total Bill on TOU (including OCEB)				**$ 123.07**			**$ 123.99**	**$ 0.92**	**0.74%**
Total Bill on RPP (before Taxes)				**116.48**			**117.39**	**0.91**	**0.78%**
HST		13%		15.14	13%		15.26	0.12	0.78%
Total Bill (including HST)				131.62			132.65	1.03	0.78%
Ontario Clean Energy Benefit [1]				-13.16			-13.26	-0.10	0.76%
Total Bill on RPP (including OCEB)				**$ 118.46**			**$ 119.39**	**$ 0.93**	**0.78%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 100 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	100.00	1.43	0.0179	100.00	1.79	0.36	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	100.00	0.03	0.0002	100.00	0.02	-0.01	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	100.00	0.18		100.00	0.00	-0.18	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	100.00	-0.03		100.00	0.00	0.03	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			100.00	0.00	-0.0001	100.00	-0.01	-0.01	
ICM Rate Rider			100.00	0.00	0.0002	100.00	0.02	0.02	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 17.18**			**$ 19.01**	**$ 1.83**	**10.65%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	100.00	0.03	-0.0007	100.00	-0.07	-0.10	-333.33%
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	100.00	0.02	0.0004	100.00	0.04	0.02	100.00%
Line Losses on Cost of Power	per kWh	0.0839	3.77	0.32	0.0839	3.76	0.32	0.00	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 18.34**			**$ 20.09**	**$ 1.75**	**9.54%**
RTSR - Network	per kWh	0.0080	103.77	0.83	0.0075	103.76	0.78	-0.05	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	103.77	0.57	0.0039	103.76	0.40	-0.17	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19.74**			**$ 21.27**	**$ 1.53**	**7.76%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	103.77	0.46	0.0044	103.76	0.46	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	103.77	0.12	0.0012	103.76	0.12	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	100	0.70	0.0070	100	0.70	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	64	4.29	0.0670	64	4.29	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	18	1.87	0.1040	18	1.87	0.00	0.00%
TOU - On Peak	per kWh	0.1240	18	2.23	0.1240	18	2.23	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	100	7.50	0.0750	100	7.50	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	0	0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**29.66**			**31.19**	**1.53**	**5.16%**
HST		13%		3.86	13%		4.05	0.20	5.16%
Total Bill (including HST)				33.52			35.25	1.73	5.16%
Ontario Clean Energy Benefit [1]				-3.35			-3.52	-0.17	5.07%
Total Bill on TOU (including OCEB)				**$ 30.17**			**$ 31.73**	**$ 1.56**	**5.17%**
Total Bill on RPP (before Taxes)				**28.77**			**30.30**	**1.53**	**5.32%**
HST		13%		3.74	13%		3.94	0.20	5.32%
Total Bill (including HST)				32.51			34.24	1.73	5.32%
Ontario Clean Energy Benefit [1]				-3.25			-3.42	-0.17	5.23%
Total Bill on RPP (including OCEB)				**$ 29.26**			**$ 30.82**	**$ 1.56**	**5.33%**

Loss Factor (%) 3.77% 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 kWh   ○ May 1 - October 31   ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	250.00	3.58	0.0179	250.00	4.48	0.90	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	250.00	0.08	0.0002	250.00	0.05	-0.03	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	250.00	0.45		250.00	0.00	-0.45	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	250.00	-0.08		250.00	0.00	0.08	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			250.00	0.00	-0.0001	250.00	-0.03	-0.03	
ICM Rate Rider			250.00	0.00	0.0002	250.00	0.05	0.05	
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 19.60**			**$ 21.74**	**$ 2.15**	**10.95%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	250.00	0.08	-0.0007	250.00	-0.18	-0.25	-333.33%
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	250.00	0.05	0.0004	250.00	0.10	0.05	100.00%
Line Losses on Cost of Power	per kWh	0.0839	9.43	0.79	0.0839	9.40	0.79	0.00	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.30**			**$ 23.24**	**$ 1.94**	**9.12%**
RTSR - Network	per kWh	0.0080	259.43	2.08	0.0075	259.40	1.95	-0.13	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	259.43	1.43	0.0039	259.40	1.01	-0.42	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.80**			**$ 26.20**	**$ 1.40**	**5.64%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	259.43	1.14	0.0044	259.40	1.14	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	259.43	0.31	0.0012	259.40	0.31	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	250	1.75	0.0070	250	1.75	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	160	10.72	0.0670	160	10.72	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	45	4.68	0.1040	45	4.68	0.00	0.00%
TOU - On Peak	per kWh	0.1240	45	5.58	0.1240	45	5.58	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	250	18.75	0.0750	250	18.75	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	0	0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**49.24**			**50.63**	**1.40**	**2.84%**
HST		13%		6.40	13%		6.58	0.18	2.84%
Total Bill (including HST)				55.64			57.22	1.58	2.84%
Ontario Clean Energy Benefit [1]				-5.56			-5.72	-0.16	2.88%
Total Bill on TOU (including OCEB)				**$ 50.08**			**$ 51.50**	**$ 1.42**	**2.83%**
Total Bill on RPP (before Taxes)				**47.01**			**48.40**	**1.40**	**2.97%**
HST		13%		6.11	13%		6.29	0.18	2.97%
Total Bill (including HST)				53.12			54.70	1.58	2.97%
Ontario Clean Energy Benefit [1]				-5.31			-5.47	-0.16	3.01%
Total Bill on RPP (including OCEB)				**$ 47.81**			**$ 49.23**	**$ 1.42**	**2.97%**

Loss Factor (%)   Current: 3.77%   Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 500 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	500.00	7.15	0.0179	500.00	8.95	1.80	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	500.00	0.15	0.0002	500.00	0.10	-0.05	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	500.00	0.90		500.00	0.00	-0.90	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	500.00	-0.15		500.00	0.00	0.15	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			500.00	0.00	-0.0001	500.00	-0.05	-0.05	
ICM Rate Rider			500.00	0.00	0.0002	500.00	0.10	0.10	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 23.62**			**$ 26.29**	**$ 2.67**	**11.30%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	500.00	0.15	-0.0007	500.00	-0.35	-0.50	-333.33%
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	500.00	0.10	0.0004	500.00	0.20	0.10	100.00%
Line Losses on Cost of Power	per kWh	0.0839	18.85	1.58	0.0839	18.80	1.58	0.00	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.24**			**$ 28.51**	**$ 2.27**	**8.63%**
RTSR - Network	per kWh	0.0080	518.85	4.15	0.0075	518.80	3.89	-0.26	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	518.85	2.85	0.0039	518.80	2.02	-0.83	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.25**			**$ 34.42**	**$ 1.18**	**3.54%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	518.85	2.28	0.0044	518.80	2.28	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	518.85	0.62	0.0012	518.80	0.62	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	500	3.50	0.0070	500	3.50	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	320	21.44	0.0670	320	21.44	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	90	9.36	0.1040	90	9.36	0.00	0.00%
TOU - On Peak	per kWh	0.1240	90	11.16	0.1240	90	11.16	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	500	37.50	0.0750	500	37.50	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	0	0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**81.86**			**83.04**	**1.18**	**1.44%**
HST		13%		10.64	13%		10.79	0.15	1.44%
Total Bill (including HST)				92.50			93.83	1.33	1.44%
Ontario Clean Energy Benefit [1]				-9.25			-9.38	-0.13	1.41%
Total Bill on TOU (including OCEB)				**$ 83.25**			**$ 84.45**	**$ 1.20**	**1.44%**
Total Bill on RPP (before Taxes)				**77.40**			**78.58**	**1.18**	**1.52%**
HST		13%		10.06	13%		10.22	0.15	1.52%
Total Bill (including HST)				87.46			88.79	1.33	1.52%
Ontario Clean Energy Benefit [1]				-8.75			-8.88	-0.13	1.49%
Total Bill on RPP (including OCEB)				**$ 78.71**			**$ 79.91**	**$ 1.20**	**1.52%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	1,000.00	14.30	0.0179	1,000.00	17.90	3.60	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	1,000.00	0.30	0.0002	1,000.00	0.20	-0.10	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	1,000.00	1.80		1,000.00	0.00	-1.80	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	1,000.00	-0.30		1,000.00	0.00	0.30	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			1,000.00	0.00	-0.0001	1,000.00	-0.10	-0.10	
ICM Rate Rider			1,000.00	0.00	0.0002	1,000.00	0.20	0.20	
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 31.67**			**$ 35.39**	**$ 3.72**	**11.75%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	1,000.00	0.30	-0.0007	1,000.00	-0.70	-1.00	-333.33%
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	1,000.00	0.20	0.0004	1,000.00	0.40	0.20	100.00%
Line Losses on Cost of Power	per kWh	0.0839	37.70	3.16	0.0839	37.60	3.16	-0.01	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 36.12**			**$ 39.04**	**$ 2.91**	**8.06%**
RTSR - Network	per kWh	0.0080	1,037.70	8.30	0.0075	1,037.60	7.78	-0.52	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	1,037.70	5.71	0.0039	1,037.60	4.05	-1.66	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 50.13**			**$ 50.86**	**$ 0.73**	**1.46%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	1,037.70	4.57	0.0044	1,037.60	4.57	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	1,037.70	1.25	0.0012	1,037.60	1.25	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	1000	7.00	0.0070	1000	7.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	640	42.88	0.0670	640	42.88	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	180	18.72	0.1040	180	18.72	0.00	0.00%
TOU - On Peak	per kWh	0.1240	180	22.32	0.1240	180	22.32	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	600	45.00	0.0750	600	45.00	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	400	35.20	0.0880	400	35.20	0.00	0.00%
Total Bill on TOU (before Taxes)				**147.11**			**147.84**	**0.73**	**0.50%**
HST		13%		19.12	13%		19.22	0.09	0.50%
Total Bill (including HST)				166.24			167.06	0.83	0.50%
Ontario Clean Energy Benefit [1]				-16.62			-16.71	-0.09	0.54%
Total Bill on TOU (including OCEB)				**$ 149.62**			**$ 150.35**	**$ 0.74**	**0.49%**
Total Bill on RPP (before Taxes)				**143.39**			**144.12**	**0.73**	**0.51%**
HST		13%		18.64	13%		18.74	0.09	0.51%
Total Bill (including HST)				162.04			162.86	0.83	0.51%
Ontario Clean Energy Benefit [1]				-16.20			-16.29	-0.09	0.56%
Total Bill on RPP (including OCEB)				**$ 145.84**			**$ 146.57**	**$ 0.74**	**0.50%**

Loss Factor (%) 3.77% 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,500 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	1,500.00	21.45	0.0179	1,500.00	26.85	5.40	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	1,500.00	0.45	0.0002	1,500.00	0.30	-0.15	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	1,500.00	2.70		1,500.00	0.00	-2.70	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	1,500.00	-0.45		1,500.00	0.00	0.45	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			1,500.00	0.00	-0.0001	1,500.00	-0.15	-0.15	
ICM Rate Rider			1,500.00	0.00	0.0002	1,500.00	0.30	0.30	
			1,500.00	0.00		1,500.00	0.00	0.00	
			1,500.00	0.00		1,500.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 39.72**			**$ 44.49**	**$ 4.77**	**12.01%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	1,500.00	0.45	-0.0007	1,500.00	-1.05	-1.50	-333.33%
			1,500.00	0.00		1,500.00	0.00	0.00	
			1,500.00	0.00		1,500.00	0.00	0.00	
			1,500.00	0.00		1,500.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	1,500.00	0.30	0.0004	1,500.00	0.60	0.30	100.00%
Line Losses on Cost of Power	per kWh	0.0839	56.55	4.75	0.0839	56.40	4.73	-0.01	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.01**			**$ 49.56**	**$ 3.56**	**7.73%**
RTSR - Network	per kWh	0.0080	1,556.55	12.45	0.0075	1,556.40	11.67	-0.78	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	1,556.55	8.56	0.0039	1,556.40	6.07	-2.49	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 67.02**			**$ 67.31**	**$ 0.29**	**0.43%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	1,556.55	6.85	0.0044	1,556.40	6.85	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	1,556.55	1.87	0.0012	1,556.40	1.87	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	1500	10.50	0.0070	1500	10.50	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	960	64.32	0.0670	960	64.32	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	270	28.08	0.1040	270	28.08	0.00	0.00%
TOU - On Peak	per kWh	0.1240	270	33.48	0.1240	270	33.48	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	600	45.00	0.0750	600	45.00	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	900	79.20	0.0880	900	79.20	0.00	0.00%
Total Bill on TOU (before Taxes)				**212.37**			**212.65**	**0.29**	**0.13%**
HST		13%		27.61	13%		27.64	0.04	0.13%
Total Bill (including HST)				239.97			240.30	0.32	0.13%
Ontario Clean Energy Benefit [1]				-24.00			-24.03	-0.03	0.13%
Total Bill on TOU (including OCEB)				**$ 215.97**			**$ 216.27**	**$ 0.29**	**0.14%**
Total Bill on RPP (before Taxes)				**210.69**			**210.97**	**0.29**	**0.14%**
HST		13%		27.39	13%		27.43	0.04	0.14%
Total Bill (including HST)				238.07			238.40	0.32	0.14%
Ontario Clean Energy Benefit [1]				-23.81			-23.84	-0.03	0.13%
Total Bill on RPP (including OCEB)				**$ 214.26**			**$ 214.56**	**$ 0.29**	**0.14%**

	Current	Proposed
Loss Factor (%)	3.77%	3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 2,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$16.43	1	$ 16.43	$ 3.32	25.32%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	2,000.00	28.60	0.0179	2,000.00	35.80	7.20	25.17%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		1.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	2,000.00	0.60	0.0002	2,000.00	0.40	-0.20	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	2,000.00	3.60		2,000.00	0.00	-3.60	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	2,000.00	-0.60		2,000.00	0.00	0.60	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E			2,000.00	0.00	-0.0001	2,000.00	-0.20	-0.20	
ICM Rate Rider			2,000.00	0.00	0.0002	2,000.00	0.40	0.40	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 47.77**			**$ 53.59**	**$ 5.82**	**12.18%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	2,000.00	0.60	-0.0007	2,000.00	-1.40	-2.00	-333.33%
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	2,000.00	0.40	0.0004	2,000.00	0.80	0.40	100.00%
Line Losses on Cost of Power	per kWh	0.0839	75.40	6.33	0.0839	75.20	6.31	-0.02	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 55.89**			**$ 60.09**	**$ 4.20**	**7.52%**
RTSR - Network	per kWh	0.0080	2,075.40	16.60	0.0075	2,075.20	15.56	-1.04	-6.26%
RTSR - Line and Transformation Connection	per kWh	0.0055	2,075.40	11.41	0.0039	2,075.20	8.09	-3.32	-29.10%
Sub-Total C - Delivery (including Sub-Total B)				**$ 83.91**			**$ 83.75**	**-$ 0.16**	**-0.19%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	2,075.40	9.13	0.0044	2,075.20	9.13	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	2,075.40	2.49	0.0012	2,075.20	2.49	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	2000	14.00	0.0070	2000	14.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	1280	85.76	0.0670	1280	85.76	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	360	37.44	0.1040	360	37.44	0.00	0.00%
TOU - On Peak	per kWh	0.1240	360	44.64	0.1240	360	44.64	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	600	45.00	0.0750	600	45.00	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	1400	123.20	0.0880	1400	123.20	0.00	0.00%
Total Bill on TOU (before Taxes)				**277.62**			**277.46**	**-0.16**	**-0.06%**
HST		13%		36.09	13%		36.07	-0.02	-0.06%
Total Bill (including HST)				313.71			313.53	-0.18	-0.06%
Ontario Clean Energy Benefit [1]				-31.37			-31.35	0.02	-0.06%
Total Bill on TOU (including OCEB)				**$ 282.34**			**$ 282.18**	**-$ 0.16**	**-0.06%**
Total Bill on RPP (before Taxes)				**277.98**			**277.82**	**-0.16**	**-0.06%**
HST		13%		36.14	13%		36.12	-0.02	-0.06%
Total Bill (including HST)				314.11			313.94	-0.18	-0.06%
Ontario Clean Energy Benefit [1]				-31.41			-31.39	0.02	-0.06%
Total Bill on RPP (including OCEB)				**$ 282.70**			**$ 282.55**	**-$ 0.16**	**-0.06%**

Loss Factor (%) — Current: 3.77% — Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS < 50 KW

TOU / non-TOU: TOU

Consumption 2,000 kWh

● May 1 - October ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 39.40	1	$ 39.40	$ 7.16	22.21%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	2,000.00	28.40	0.0174	2,000.00	34.80	6.40	22.54%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	2,000.00	0.00	0.0001	2,000.00	0.20	0.20	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	2,000.00	3.00		2,000.00	0.00	-3.00	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	2,000.00	-0.60		2,000.00	0.00	0.60	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		2,000.00	0.00	-0.0001	2,000.00	-0.20	-0.20	
ICM Rate Rider	per kWh		2,000.00	0.00	0.0002	2,000.00	0.40	0.40	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 75.00**			**$ 76.79**	**$ 1.79**	**2.39%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	2,000.00	0.60	-0.0007	2,000.00	-1.40	-2.00	-333.33%
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	2,000.00	0.40	0.0003	2,000.00	0.60	0.20	50.00%
Line Losses on Cost of Power	per kWh	0.0839	75.40	6.33	0.0839	75.20	6.31	-0.02	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 83.12**			**$ 83.09**	**-$ 0.03**	**-0.03%**
RTSR - Network	per kWh	0.0074	2,075.40	15.36	0.0070	2,075.20	14.53	-0.83	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	2,075.40	10.38	0.0035	2,075.20	7.26	-3.11	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 108.85**			**$ 104.88**	**-$ 3.97**	**-3.65%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	2,075.40	9.13	0.0044	2,075.20	9.13	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	2,075.40	2.49	0.0012	2,075.20	2.49	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	2000	14.00	0.0070	2000	14.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	1280	85.76	0.0670	1280	85.76	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	360	37.44	0.1040	360	37.44	0.00	0.00%
TOU - On Peak	per kWh	0.1240	360	44.64	0.1240	360	44.64	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	1250	110.00	0.0880	1250	110.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**302.56**			**298.59**	**-3.97**	**-1.31%**
HST		13%		39.33	13%		38.82	-0.52	-1.31%
Total Bill (including HST)				341.90			337.41	-4.49	-1.31%
Ontario Clean Energy Benefit [1]				-34.19			-33.74	0.45	-1.32%
Total Bill on TOU (including OCEB)				**$ 307.71**			**$ 303.67**	**-$ 4.04**	**-1.31%**
Total Bill on RPP (before Taxes)				**300.97**			**297.00**	**-3.97**	**-1.32%**
HST		13%		39.13	13%		38.61	-0.52	-1.32%
Total Bill (including HST)				340.10			335.61	-4.49	-1.32%
Ontario Clean Energy Benefit [1]				-34.01			-33.56	0.45	-1.32%
Total Bill on RPP (including OCEB)				**$ 306.09**			**$ 302.05**	**-$ 4.04**	**-1.32%**

Loss Factor (%) 3.77% 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010*.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS < 50 KW

TOU / non-TOU: TOU

Consumption 1,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 39.40	1	$ 39.40	$ 7.16	22.21%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	1,000.00	14.20	0.0174	1,000.00	17.40	3.20	22.54%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	1,000.00	0.00	0.0001	1,000.00	0.10	0.10	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	1,000.00	1.50		1,000.00	0.00	-1.50	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	1,000.00	-0.30		1,000.00	0.00	0.30	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		1,000.00	0.00	-0.0001	1,000.00	-0.10	-0.10	
ICM Rate Rider	per kWh		1,000.00	0.00	0.0002	1,000.00	0.20	0.20	
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 59.60**			**$ 59.19**	**-$ 0.41**	**-0.69%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	1,000.00	0.30	-0.0007	1,000.00	-0.70	-1.00	-333.33%
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
			1,000.00	0.00		1,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	1,000.00	0.20	0.0003	1,000.00	0.30	0.10	50.00%
Line Losses on Cost of Power	per kWh	0.0839	37.70	3.16	0.0839	37.60	3.16	-0.01	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 64.05**			**$ 62.74**	**-$ 1.32**	**-2.06%**
RTSR - Network	per kWh	0.0074	1,037.70	7.68	0.0070	1,037.60	7.26	-0.42	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	1,037.70	5.19	0.0035	1,037.60	3.63	-1.56	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 76.92**			**$ 73.63**	**-$ 3.29**	**-4.28%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	1,037.70	4.57	0.0044	1,037.60	4.57	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	1,037.70	1.25	0.0012	1,037.60	1.25	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	1000	7.00	0.0070	1000	7.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	640	42.88	0.0670	640	42.88	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	180	18.72	0.1040	180	18.72	0.00	0.00%
TOU - On Peak	per kWh	0.1240	180	22.32	0.1240	180	22.32	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	250	22.00	0.0880	250	22.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**173.90**			**170.61**	**-3.29**	**-1.89%**
HST		13%		22.61	13%		22.18	-0.43	-1.89%
Total Bill (including HST)				196.51			192.79	-3.72	-1.89%
Ontario Clean Energy Benefit [1]				-19.65			-19.28	0.37	-1.88%
Total Bill on TOU (including OCEB)				**$ 176.86**			**$ 173.51**	**-$ 3.35**	**-1.89%**
Total Bill on RPP (before Taxes)				**168.23**			**164.94**	**-3.29**	**-1.96%**
HST		13%		21.87	13%		21.44	-0.43	-1.96%
Total Bill (including HST)				190.10			186.38	-3.72	-1.96%
Ontario Clean Energy Benefit [1]				-19.01			-18.64	0.37	-1.95%
Total Bill on RPP (including OCEB)				**$ 171.09**			**$ 167.74**	**-$ 3.35**	**-1.96%**

Loss Factor (%) Current: 3.77% Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS < 50 KW

TOU / non-TOU: TOU

Consumption 5,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 39.40	1	$ 39.40	$ 7.16	22.21%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	5,000.00	71.00	0.0174	5,000.00	87.00	16.00	22.54%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	5,000.00	0.00	0.0001	5,000.00	0.50	0.50	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	5,000.00	7.50		5,000.00	0.00	-7.50	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	5,000.00	-1.50		5,000.00	0.00	1.50	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		5,000.00	0.00	-0.0001	5,000.00	-0.50	-0.50	
ICM Rate Rider	per kWh		5,000.00	0.00	0.0002	5,000.00	1.00	1.00	
			5,000.00	0.00		5,000.00	0.00	0.00	
			5,000.00	0.00		5,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 121.20**			**$ 129.59**	**$ 8.39**	**6.92%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	5,000.00	1.50	-0.0007	5,000.00	-3.50	-5.00	-333.33%
			5,000.00	0.00		5,000.00	0.00	0.00	
			5,000.00	0.00		5,000.00	0.00	0.00	
			5,000.00	0.00		5,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	5,000.00	1.00	0.0003	5,000.00	1.50	0.50	50.00%
Line Losses on Cost of Power	per kWh	0.0839	188.50	15.82	0.0839	188.00	15.78	-0.04	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 140.31**			**$ 144.16**	**$ 3.85**	**2.74%**
RTSR - Network	per kWh	0.0074	5,188.50	38.39	0.0070	5,188.00	36.32	-2.08	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	5,188.50	25.94	0.0035	5,188.00	18.16	-7.78	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 204.65**			**$ 198.63**	**-$ 6.02**	**-2.94%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	5,188.50	22.83	0.0044	5,188.00	22.83	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	5,188.50	6.23	0.0012	5,188.00	6.23	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	5000	35.00	0.0070	5000	35.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	3200	214.40	0.0670	3200	214.40	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	900	93.60	0.1040	900	93.60	0.00	0.00%
TOU - On Peak	per kWh	0.1240	900	111.60	0.1240	900	111.60	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	4250	374.00	0.0880	4250	374.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**688.55**			**682.53**	**-6.02**	**-0.87%**
HST		13%		89.51	13%		88.73	-0.78	-0.87%
Total Bill (including HST)				778.06			771.26	-6.80	-0.87%
Ontario Clean Energy Benefit [1]				-77.81			-77.13	0.68	-0.87%
Total Bill on TOU (including OCEB)				**$ 700.25**			**$ 694.13**	**-$ 6.12**	**-0.87%**
Total Bill on RPP (before Taxes)				**699.20**			**693.18**	**-6.02**	**-0.86%**
HST		13%		90.90	13%		90.11	-0.78	-0.86%
Total Bill (including HST)				790.10			783.30	-6.80	-0.86%
Ontario Clean Energy Benefit [1]				-79.01			-78.33	0.68	-0.86%
Total Bill on RPP (including OCEB)				**$ 711.09**			**$ 704.97**	**-$ 6.12**	**-0.86%**

Loss Factor (%) — Current: 3.77% — Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS < 50 KW

TOU / non-TOU: TOU

Consumption 10,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 39.40	1	$ 39.40	$ 7.16	22.21%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	10,000.00	142.00	0.0174	10,000.00	174.00	32.00	22.54%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	10,000.00	0.00	0.0001	10,000.00	1.00	1.00	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	10,000.00	15.00		10,000.00	0.00	-15.00	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	10,000.00	-3.00		10,000.00	0.00	3.00	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		10,000.00	0.00	-0.0001	10,000.00	-1.00	-1.00	
ICM Rate Rider	per kWh		10,000.00	0.00	0.0002	10,000.00	2.00	2.00	
			10,000.00	0.00		10,000.00	0.00	0.00	
			10,000.00	0.00		10,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 198.20**			**$ 217.59**	**$ 19.39**	**9.78%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	10,000.00	3.00	-0.0007	10,000.00	-7.00	-10.00	-333.33%
			10,000.00	0.00		10,000.00	0.00	0.00	
			10,000.00	0.00		10,000.00	0.00	0.00	
			10,000.00	0.00		10,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	10,000.00	2.00	0.0003	10,000.00	3.00	1.00	50.00%
Line Losses on Cost of Power	per kWh	0.0839	377.00	31.64	0.0839	376.00	31.55	-0.08	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 235.63**			**$ 245.93**	**$ 10.31**	**4.37%**
RTSR - Network	per kWh	0.0074	10,377.00	76.79	0.0070	10,376.00	72.63	-4.16	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	10,377.00	51.89	0.0035	10,376.00	36.32	-15.57	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 364.30**			**$ 354.88**	**-$ 9.42**	**-2.59%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	10,377.00	45.66	0.0044	10,376.00	45.65	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	10,377.00	12.45	0.0012	10,376.00	12.45	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	10000	70.00	0.0070	10000	70.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	6400	428.80	0.0670	6400	428.80	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	1800	187.20	0.1040	1800	187.20	0.00	0.00%
TOU - On Peak	per kWh	0.1240	1800	223.20	0.1240	1800	223.20	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	9250	814.00	0.0880	9250	814.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**1331.86**			**1322.44**	**-9.43**	**-0.71%**
HST		13%		173.14	13%		171.92	-1.23	-0.71%
Total Bill (including HST)				1505.01			1494.35	-10.65	-0.71%
Ontario Clean Energy Benefit [1]				-150.50			-149.44	1.06	-0.70%
Total Bill on TOU (including OCEB)				**$ 1,354.51**			**$ 1,344.91**	**-$ 9.59**	**-0.71%**
Total Bill on RPP (before Taxes)				**1362.91**			**1353.49**	**-9.43**	**-0.69%**
HST		13%		177.18	13%		175.95	-1.23	-0.69%
Total Bill (including HST)				1540.09			1529.44	-10.65	-0.69%
Ontario Clean Energy Benefit [1]				-154.01			-152.94	1.07	-0.69%
Total Bill on RPP (including OCEB)				**$ 1,386.08**			**$ 1,376.50**	**-$ 9.58**	**-0.69%**

Loss Factor (%) Current: 3.77% Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS < 50 KW

TOU / non-TOU: TOU

Consumption 15,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 39.40	1	$ 39.40	$ 7.16	22.21%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	15,000.00	213.00	0.0174	15,000.00	261.00	48.00	22.54%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	15,000.00	0.00	0.0001	15,000.00	1.50	1.50	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	15,000.00	22.50		15,000.00	0.00	-22.50	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	15,000.00	-4.50		15,000.00	0.00	4.50	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		15,000.00	0.00	-0.0001	15,000.00	-1.50	-1.50	
ICM Rate Rider	per kWh		15,000.00	0.00	0.0002	15,000.00	3.00	3.00	
			15,000.00	0.00		15,000.00	0.00	0.00	
			15,000.00	0.00		15,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 275.20**			**$ 305.59**	**$ 30.39**	**11.04%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	15,000.00	4.50	-0.0007	15,000.00	-10.50	-15.00	-333.33%
			15,000.00	0.00		15,000.00	0.00	0.00	
			15,000.00	0.00		15,000.00	0.00	0.00	
			15,000.00	0.00		15,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	15,000.00	3.00	0.0003	15,000.00	4.50	1.50	50.00%
Line Losses on Cost of Power	per kWh	0.0839	565.50	47.46	0.0839	564.00	47.33	-0.13	-0.27%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 330.95**			**$ 347.71**	**$ 16.76**	**5.07%**
RTSR - Network	per kWh	0.0074	15,565.50	115.18	0.0070	15,564.00	108.95	-6.24	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	15,565.50	77.83	0.0035	15,564.00	54.47	-23.35	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 523.96**			**$ 511.13**	**-$ 12.83**	**-2.45%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	15,565.50	68.49	0.0044	15,564.00	68.48	-0.01	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	15,565.50	18.68	0.0012	15,564.00	18.68	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	15000	105.00	0.0070	15000	105.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	9600	643.20	0.0670	9600	643.20	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	2700	280.80	0.1040	2700	280.80	0.00	0.00%
TOU - On Peak	per kWh	0.1240	2700	334.80	0.1240	2700	334.80	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	14250	1254.00	0.0880	14250	1254.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**1975.18**			**1962.34**	**-12.83**	**-0.65%**
HST		13%		256.77	13%		255.10	-1.67	-0.65%
Total Bill (including HST)				2231.95			2217.45	-14.50	-0.65%
Ontario Clean Energy Benefit [1]				-223.19			-221.74	1.45	-0.65%
Total Bill on TOU (including OCEB)				**$ 2,008.76**			**$ 1,995.71**	**-$ 13.05**	**-0.65%**
Total Bill on RPP (before Taxes)				**2026.63**			**2013.79**	**-12.83**	**-0.63%**
HST		13%		263.46	13%		261.79	-1.67	-0.63%
Total Bill (including HST)				2290.09			2275.58	-14.50	-0.63%
Ontario Clean Energy Benefit [1]				-229.01			-227.56	1.45	-0.63%
Total Bill on RPP (including OCEB)				**$ 2,061.08**			**$ 2,048.02**	**-$ 13.05**	**-0.63%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **GS > 50 KW - RPP Non-Interval Metered**

TOU / non-TOU: non-TOU

● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

Consumption 100 kW
30,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	100.00	367.76	4.9028	100.00	490.28	122.52	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	100.00	0.33	0.0121	100.00	1.21	0.88	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	100.00	25.11		100.00	0.00	-25.11	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	100.00	-4.65		100.00	0.00	4.65	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		100.00	0.00	-0.0458	100.00	-4.58	-4.58	
ICM Rate Rider	per kW		100.00	0.00	0.0682	100.00	6.82	6.82	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 507.00**			**$ 652.25**	**$ 145.25**	**28.65%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	100.00	9.53	-0.5297	100.00	-52.97	-62.50	-655.82%
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	100.00	6.38	0.1313	100.00	13.13	6.75	105.80%
Line Losses on Cost of Power	per kWh	0.0880	1,131.00	99.53	0.0880	1,128.00	99.26	-0.26	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 622.44**			**$ 711.67**	**$ 89.24**	**14.34%**
RTSR - Network	per kW	2.7667	103.77	287.10	2.6020	103.76	269.98	-17.12	-5.96%
RTSR - Line and Transformation Connection	per kW	1.8766	103.77	194.73	1.3173	103.76	136.68	-58.05	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,104.27**			**$ 1,118.34**	**$ 14.07**	**1.27%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	31,131.00	136.98	0.0044	31,128.00	136.96	-0.01	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	31,131.00	37.36	0.0012	31,128.00	37.35	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	30000	210.00	0.0070	30000	210.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	19200	1286.40	0.0670	19200	1286.40	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	5400	561.60	0.1040	5400	561.60	0.00	0.00%
TOU - On Peak	per kWh	0.1240	5400	669.60	0.1240	5400	669.60	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	29250	2574.00	0.0880	29250	2574.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**4006.46**			**4020.51**	**14.05**	**0.35%**
HST		13%		520.84	13%		522.67	1.83	0.35%
Total Bill (including HST)				4527.30			4543.17	15.88	0.35%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 4,527.30**			**$ 4,543.17**	**$ 15.88**	**0.35%**
Total Bill on RPP (before Taxes)				**4119.11**			**4133.16**	**14.05**	**0.34%**
HST		13%		535.48	13%		537.31	1.83	0.34%
Total Bill (including HST)				4654.59			4670.47	15.88	0.34%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 4,654.59**			**$ 4,670.47**	**$ 15.88**	**0.34%**

Loss Factor (%) Current: 3.77% Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

Consumption 160 kW; 64,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	160.00	588.42	4.9028	160.00	784.45	196.03	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	160.00	0.53	0.0121	160.00	1.94	1.41	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	160.00	40.18		160.00	0.00	-40.18	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	160.00	-7.44		160.00	0.00	7.44	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		160.00	0.00	-0.0458	160.00	-7.33	-7.33	
ICM Rate Rider	per kW		160.00	0.00	0.0682	160.00	10.91	10.91	
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 740.13**			**$ 948.49**	**$ 208.36**	**28.15%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	160.00	15.25	-0.5297	160.00	-84.75	-100.00	-655.82%
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	160.00	10.21	0.1313	160.00	21.01	10.80	105.80%
Line Losses on Cost of Power	per kWh	0.0880	2,412.80	212.33	0.0880	2,406.40	211.76	-0.56	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 977.91**			**$ 1,096.51**	**$ 118.59**	**12.13%**
RTSR - Network	per kW	2.7667	166.03	459.36	2.6020	166.02	431.97	-27.39	-5.96%
RTSR - Line and Transformation Connection	per kW	1.8766	166.03	311.58	1.3173	166.02	218.69	-92.88	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,748.85**			**$ 1,747.17**	**-$ 1.68**	**-0.10%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	66,412.80	292.22	0.0044	66,406.40	292.19	-0.03	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	66,412.80	79.70	0.0012	66,406.40	79.69	-0.01	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	64000	448.00	0.0070	64000	448.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	40960	2744.32	0.0670	40960	2744.32	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	11520	1198.08	0.1040	11520	1198.08	0.00	0.00%
TOU - On Peak	per kWh	0.1240	11520	1428.48	0.1240	11520	1428.48	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	63250	5566.00	0.0880	63250	5566.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**7939.89**			**7938.18**	**-1.71**	**-0.02%**
HST		13%		1032.19	13%		1031.96	-0.22	-0.02%
Total Bill (including HST)				8972.08			8970.14	-1.93	-0.02%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 8,972.08**			**$ 8,970.14**	**-$ 1.93**	**-0.02%**
Total Bill on RPP (before Taxes)				**8191.26**			**8189.55**	**-1.71**	**-0.02%**
HST		13%		1064.86	13%		1064.64	-0.22	-0.02%
Total Bill (including HST)				9256.12			9254.19	-1.93	-0.02%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 9,256.12**			**$ 9,254.19**	**-$ 1.93**	**-0.02%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

	Consumption	300	kW						
		120,000	kWh						
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	300.00	1103.28	4.9028	300.00	1470.84	367.56	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	300.00	0.99	0.0121	300.00	3.63	2.64	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	300.00	75.33		300.00	0.00	-75.33	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	300.00	-13.95		300.00	0.00	13.95	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		300.00	0.00	-0.0458	300.00	-13.74	-13.74	
ICM Rate Rider	per kW		300.00	0.00	0.0682	300.00	20.46	20.46	
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 1,284.10**			**$ 1,639.71**	**$ 355.61**	**27.69%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	300.00	28.59	-0.5297	300.00	-158.91	-187.50	-655.82%
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	300.00	19.14	0.1313	300.00	39.39	20.25	105.80%
Line Losses on Cost of Power	per kWh	0.0880	4,524.00	398.11	0.0880	4,512.00	397.06	-1.06	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,729.94**			**$ 1,917.25**	**$ 187.30**	**10.83%**
RTSR - Network	per kW	2.7667	311.31	861.30	2.6020	311.28	809.95	-51.35	-5.96%
RTSR - Line and Transformation Connection	per kW	1.8766	311.31	584.20	1.3173	311.28	410.05	-174.16	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,175.45**			**$ 3,137.25**	**-$ 38.20**	**-1.20%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	124,524.00	547.91	0.0044	124,512.00	547.85	-0.05	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	124,524.00	149.43	0.0012	124,512.00	149.41	-0.01	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	120000	840.00	0.0070	120000	840.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	76800	5145.60	0.0670	76800	5145.60	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	21600	2246.40	0.1040	21600	2246.40	0.00	0.00%
TOU - On Peak	per kWh	0.1240	21600	2678.40	0.1240	21600	2678.40	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	119250	10494.00	0.0880	119250	10494.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**14783.43**			**14745.16**	**-38.27**	**-0.26%**
HST		13%		1921.85	13%		1916.87	-4.97	-0.26%
Total Bill (including HST)				16705.28			16662.03	-43.24	-0.26%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 16,705.28**			**$ 16,662.03**	**-$ 43.24**	**-0.26%**
Total Bill on RPP (before Taxes)				**15263.28**			**15225.01**	**-38.27**	**-0.25%**
HST		13%		1984.23	13%		1979.25	-4.97	-0.25%
Total Bill (including HST)				17247.51			17204.26	-43.24	-0.25%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 17,247.51**			**$ 17,204.26**	**-$ 43.24**	**-0.25%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

	Consumption	500	kW						
		200,000	kWh						
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	500.00	1838.80	4.9028	500.00	2451.40	612.60	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	500.00	1.65	0.0121	500.00	6.05	4.40	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	500.00	125.55		500.00	0.00	-125.55	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	500.00	-23.25		500.00	0.00	23.25	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		500.00	0.00	-0.0458	500.00	-22.90	-22.90	
ICM Rate Rider	per kW		500.00	0.00	0.0682	500.00	34.10	34.10	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 2,061.20**			**$ 2,627.17**	**$ 565.97**	**27.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	500.00	47.65	-0.5297	500.00	-264.85	-312.50	-655.82%
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	500.00	31.90	0.1313	500.00	65.65	33.75	105.80%
Line Losses on Cost of Power	per kWh	0.0880	7,540.00	663.52	0.0880	7,520.00	661.76	-1.76	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,804.27**			**$ 3,089.73**	**$ 285.46**	**10.18%**
RTSR - Network	per kW	2.7667	518.85	1435.50	2.6020	518.80	1349.92	-85.58	-5.96%
RTSR - Line and Transformation Connection	per kW	1.8766	518.85	973.67	1.3173	518.80	683.42	-290.26	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5,213.45**			**$ 5,123.06**	**-$ 90.38**	**-1.73%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	207,540.00	913.18	0.0044	207,520.00	913.09	-0.09	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	207,540.00	249.05	0.0012	207,520.00	249.02	-0.02	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	200000	1400.00	0.0070	200000	1400.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	128000	8576.00	0.0670	128000	8576.00	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	36000	3744.00	0.1040	36000	3744.00	0.00	0.00%
TOU - On Peak	per kWh	0.1240	36000	4464.00	0.1240	36000	4464.00	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	199250	17534.00	0.0880	199250	17534.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**24559.92**			**24469.42**	**-90.50**	**-0.37%**
HST		13%		3192.79	13%		3181.03	-11.76	-0.37%
Total Bill (including HST)				27752.71			27650.45	-102.26	-0.37%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 27,752.71**			**$ 27,650.45**	**-$ 102.26**	**-0.37%**
Total Bill on RPP (before Taxes)				**25366.17**			**25275.67**	**-90.50**	**-0.36%**
HST		13%		3297.60	13%		3285.84	-11.76	-0.36%
Total Bill (including HST)				28663.77			28561.51	-102.26	-0.36%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 28,663.77**			**$ 28,561.51**	**-$ 102.26**	**-0.36%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Consumption 100 kW
30,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	100.00	367.76	4.9028	100.00	490.28	122.52	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	100.00	0.33	0.0121	100.00	1.21	0.88	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	100.00	25.11		100.00	0.00	-25.11	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	100.00	-4.65		100.00	0.00	4.65	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		100.00	0.00	-0.0458	100.00	-4.58	-4.58	
ICM Rate Rider	per kW		100.00	0.00	0.0682	100.00	6.82	6.82	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 507.00**			**$ 652.25**	**$ 145.25**	**28.65%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	100.00	9.53	-0.5297	100.00	-52.97	-62.50	-655.82%
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
			100.00	0.00		100.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	100.00	6.38	0.1313	100.00	13.13	6.75	105.80%
Line Losses on Cost of Power	per kWh	0.0880	1,131.00	99.53	0.0880	1,128.00	99.26	-0.26	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 622.44**			**$ 711.67**	**$ 89.24**	**14.34%**
RTSR - Network	per kW	2.8561	103.77	296.38	2.6861	103.76	278.71	-17.67	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	103.77	201.04	1.3600	103.76	141.11	-59.93	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,119.86**			**$ 1,131.50**	**$ 11.64**	**1.04%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	31,131.00	136.98	0.0044	31,128.00	136.96	-0.01	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	31,131.00	37.36	0.0012	31,128.00	37.35	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	30000	210.00	0.0070	30000	210.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	19200	1286.40	0.0670	19200	1286.40	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	5400	561.60	0.1040	5400	561.60	0.00	0.00%
TOU - On Peak	per kWh	0.1240	5400	669.60	0.1240	5400	669.60	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	29250	2574.00	0.0880	29250	2574.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**4022.04**			**4033.66**	**11.62**	**0.29%**
HST		13%		522.87	13%		524.38	1.51	0.29%
Total Bill (including HST)				4544.91			4558.04	13.13	0.29%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 4,544.91**			**$ 4,558.04**	**$ 13.13**	**0.29%**
Total Bill on RPP (before Taxes)				**4134.69**			**4146.31**	**11.62**	**0.28%**
HST		13%		537.51	13%		539.02	1.51	0.28%
Total Bill (including HST)				4672.20			4685.33	13.13	0.28%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 4,672.20**			**$ 4,685.33**	**$ 13.13**	**0.28%**

Loss Factor (%) Current: 3.77% Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

Consumption 160 kW; 64,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	160.00	588.42	4.9028	160.00	784.45	196.03	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	160.00	0.53	0.0121	160.00	1.94	1.41	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	160.00	40.18		160.00	0.00	-40.18	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	160.00	-7.44		160.00	0.00	7.44	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		160.00	0.00	-0.0458	160.00	-7.33	-7.33	
ICM Rate Rider	per kW		160.00	0.00	0.0682	160.00	10.91	10.91	
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 740.13**			**$ 948.49**	**$ 208.36**	**28.15%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	160.00	15.25	-0.5297	160.00	-84.75	-100.00	-655.82%
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
			160.00	0.00		160.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	160.00	10.21	0.1313	160.00	21.01	10.80	105.80%
Line Losses on Cost of Power	per kWh	0.0880	2,412.80	212.33	0.0880	2,406.40	211.76	-0.56	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 977.91**			**$ 1,096.51**	**$ 118.59**	**12.13%**
RTSR - Network	per kW	2.8561	166.03	474.20	2.6861	166.02	445.94	-28.27	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	166.03	321.67	1.3600	166.02	225.78	-95.89	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,773.79**			**$ 1,768.22**	**-$ 5.56**	**-0.31%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	66,412.80	292.22	0.0044	66,406.40	292.19	-0.03	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	66,412.80	79.70	0.0012	66,406.40	79.69	-0.01	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	64000	448.00	0.0070	64000	448.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	40960	2744.32	0.0670	40960	2744.32	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	11520	1198.08	0.1040	11520	1198.08	0.00	0.00%
TOU - On Peak	per kWh	0.1240	11520	1428.48	0.1240	11520	1428.48	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	63250	5566.00	0.0880	63250	5566.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**7964.83**			**7959.23**	**-5.60**	**-0.07%**
HST		13%		1035.43	13%		1034.70	-0.73	-0.07%
Total Bill (including HST)				9000.26			8993.93	-6.33	-0.07%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 9,000.26**			**$ 8,993.93**	**-$ 6.33**	**-0.07%**
Total Bill on RPP (before Taxes)				**8216.20**			**8210.60**	**-5.60**	**-0.07%**
HST		13%		1068.11	13%		1067.38	-0.73	-0.07%
Total Bill (including HST)				9284.30			9277.98	-6.33	-0.07%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 9,284.30**			**$ 9,277.98**	**-$ 6.33**	**-0.07%**

Loss Factor (%) Current: 3.77% Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 50 KW - RPP Non-Interval Metered

TOU / non-TOU: non-TOU

Consumption 300 kW; 120,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	300.00	1103.28	4.9028	300.00	1470.84	367.56	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	300.00	0.99	0.0121	300.00	3.63	2.64	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	300.00	75.33		300.00	0.00	-75.33	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	300.00	-13.95		300.00	0.00	13.95	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		300.00	0.00	-0.0458	300.00	-13.74	-13.74	
ICM Rate Rider	per kW		300.00	0.00	0.0682	300.00	20.46	20.46	
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 1,284.10**			**$ 1,639.71**	**$ 355.61**	**27.69%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	300.00	28.59	-0.5297	300.00	-158.91	-187.50	-655.82%
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
			300.00	0.00		300.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	300.00	19.14	0.1313	300.00	39.39	20.25	105.80%
Line Losses on Cost of Power	per kWh	0.0880	4,524.00	398.11	0.0880	4,512.00	397.06	-1.06	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,729.94**			**$ 1,917.25**	**$ 187.30**	**10.83%**
RTSR - Network	per kW	2.8561	311.31	889.13	2.6861	311.28	836.13	-53.00	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	311.31	603.13	1.3600	311.28	423.34	-179.79	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,222.21**			**$ 3,176.72**	**-$ 45.49**	**-1.41%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	124,524.00	547.91	0.0044	124,512.00	547.85	-0.05	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	124,524.00	149.43	0.0012	124,512.00	149.41	-0.01	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	120000	840.00	0.0070	120000	840.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	76800	5145.60	0.0670	76800	5145.60	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	21600	2246.40	0.1040	21600	2246.40	0.00	0.00%
TOU - On Peak	per kWh	0.1240	21600	2678.40	0.1240	21600	2678.40	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	119250	10494.00	0.0880	119250	10494.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**14830.19**			**14784.63**	**-45.56**	**-0.31%**
HST		13%		1927.92	13%		1922.00	-5.92	-0.31%
Total Bill (including HST)				16758.12			16706.64	-51.48	-0.31%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 16,758.12**			**$ 16,706.64**	**-$ 51.48**	**-0.31%**
Total Bill on RPP (before Taxes)				**15310.04**			**15264.48**	**-45.56**	**-0.30%**
HST		13%		1990.31	13%		1984.38	-5.92	-0.30%
Total Bill (including HST)				17300.35			17248.87	-51.48	-0.30%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 17,300.35**			**$ 17,248.87**	**-$ 51.48**	**-0.30%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **GS > 50 KW - RPP Non-Interval Metered**

TOU / non-TOU: non-TOU

Consumption 500 kW; 200,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 118.45	1.00	$ 118.45	$ 158.52	1	$ 158.52	$ 40.07	33.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	3.6776	500.00	1838.80	4.9028	500.00	2451.40	612.60	33.32%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	0.0033	500.00	1.65	0.0121	500.00	6.05	4.40	266.67%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2511	500.00	125.55		500.00	0.00	-125.55	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0465	500.00	-23.25		500.00	0.00	23.25	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kW		500.00	0.00	-0.0458	500.00	-22.90	-22.90	
ICM Rate Rider	per kW		500.00	0.00	0.0682	500.00	34.10	34.10	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 2,061.20**			**$ 2,627.17**	**$ 565.97**	**27.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0953	500.00	47.65	-0.5297	500.00	-264.85	-312.50	-655.82%
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
			500.00	0.00		500.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	500.00	31.90	0.1313	500.00	65.65	33.75	105.80%
Line Losses on Cost of Power	per kWh	0.0880	7,540.00	663.52	0.0880	7,520.00	661.76	-1.76	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,804.27**			**$ 3,089.73**	**$ 285.46**	**10.18%**
RTSR - Network	per kW	2.8561	518.85	1481.89	2.6861	518.80	1393.55	-88.34	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	518.85	1005.22	1.3600	518.80	705.57	-299.65	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5,291.38**			**$ 5,188.85**	**-$ 102.53**	**-1.94%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	207,540.00	913.18	0.0044	207,520.00	913.09	-0.09	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	207,540.00	249.05	0.0012	207,520.00	249.02	-0.02	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	200000	1400.00	0.0070	200000	1400.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	128000	8576.00	0.0670	128000	8576.00	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	36000	3744.00	0.1040	36000	3744.00	0.00	0.00%
TOU - On Peak	per kWh	0.1240	36000	4464.00	0.1240	36000	4464.00	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	199250	17534.00	0.0880	199250	17534.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**24637.85**			**24535.21**	**-102.64**	**-0.42%**
HST		13%		3202.92	13%		3189.58	-13.34	-0.42%
Total Bill (including HST)				27840.77			27724.79	-115.99	-0.42%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 27,840.77**			**$ 27,724.79**	**-$ 115.99**	**-0.42%**
Total Bill on RPP (before Taxes)				**25444.10**			**25341.46**	**-102.64**	**-0.40%**
HST		13%		3307.73	13%		3294.39	-13.34	-0.40%
Total Bill (including HST)				28751.83			28635.85	-115.99	-0.40%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 28,751.83**			**$ 28,635.85**	**-$ 115.99**	**-0.40%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 1000 KW - Non-RPP

TOU / non-TOU: non-TOU ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Consumption 1,200 kW
600,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 3,399.83	1.00	$ 3,399.83	$ 4,482.03	1	$ 4,482.03	$ 1,082.20	31.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	1.8569	1,200.00	2228.28	2.4480	1,200.00	2937.60	709.32	31.83%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	-0.0014	1,200.00	-1.68	0.0004	1,200.00	0.48	2.16	-128.57%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2231	1,200.00	267.72		1,200.00	0.00	-267.72	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0405	1,200.00	-48.60		1,200.00	0.00	48.60	-100.00%
Rate Rider for Recovery of GA for Non-RPP Customers	per kW	1.3157	1,200.00	1578.84	-0.7144	1,200.00	-857.28	-2436.12	-154.30%
Rate Rider for PP & E	per kW		1,200.00	0.00	-0.0561	1,200.00	-67.32	-67.32	
ICM Rate Rider	per kW		1,200.00	0.00	0.0836	1,200.00	100.32	100.32	
			1,200.00	0.00		1,200.00	0.00	0.00	
			1,200.00	0.00		1,200.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 7,424.39**			**$ 6,595.83**	**-$ 828.56**	**-11.16%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.1113	1,200.00	133.56	-0.7345	1,200.00	-881.40	-1014.96	-759.93%
			1,200.00	0.00		1,200.00	0.00	0.00	
			1,200.00	0.00		1,200.00	0.00	0.00	
			1,200.00	0.00		1,200.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	1,200.00	76.56	0.1313	1,200.00	157.56	81.00	105.80%
Line Losses on Cost of Power	per kWh		22,620.00	0.00	0.0000	22,560.00	0.00	0.00	
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7,634.51**			**$ 5,871.99**	**-$ 1,762.52**	**-23.09%**
RTSR - Network	per kW	2.8561	1,245.24	3556.53	2.6861	1,245.12	3344.52	-212.01	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	1,245.24	2412.53	1.3600	1,245.12	1693.36	-719.16	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 13,603.57**			**$ 10,909.87**	**-$ 2,693.70**	**-19.80%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	622,620.00	2739.53	0.0044	622,560.00	2739.26	-0.26	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	622,620.00	747.14	0.0012	622,560.00	747.07	-0.07	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	600000	4200.00	0.0070	600000	4200.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	398477	26697.95	0.0670	398438	26695.37	-2.57	-0.01%
TOU - Mid Peak	per kWh	0.1040	112072	11655.45	0.1040	112061	11654.32	-1.12	-0.01%
TOU - On Peak	per kWh	0.1240	112072	13896.88	0.1240	112061	13895.54	-1.34	-0.01%
Energy - RPP - Tier 1	per kWh	0.0750	0	0.00	0.0750	0	0.00	0.00	
Energy - RPP - Tier 2	per kWh	0.0880	622620	54790.56	0.0880	622560	54785.28	-5.28	-0.01%
Total Bill on TOU (before Taxes)				**73540.76**			**70841.69**	**-2699.07**	**-3.67%**
HST		13%		9560.30	13%		9209.42	-350.88	-3.67%
Total Bill (including HST)				83101.06			80051.11	-3049.95	-3.67%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 83,101.06**			**$ 80,051.11**	**-$ 3,049.95**	**-3.67%**
Total Bill on RPP (before Taxes)				**76081.05**			**73381.74**	**-2699.31**	**-3.55%**
HST		13%		9890.54	13%		9539.63	-350.91	-3.55%
Total Bill (including HST)				85971.59			82921.36	-3050.22	-3.55%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 85,971.59**			**$ 82,921.36**	**-$ 3,050.22**	**-3.55%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 1000 KW - Non-RPP

TOU / non-TOU: non-TOU

Consumption 2,200 kW; 1,000,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 3,399.83	1.00	$ 3,399.83	$ 4,482.03	1	$ 4,482.03	$ 1,082.20	31.83%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	1.8569	2,200.00	4085.18	2.4480	2,200.00	5385.60	1300.42	31.83%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	-0.0014	2,200.00	-3.08	0.0004	2,200.00	0.88	3.96	-128.57%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2231	2,200.00	490.82		2,200.00	0.00	-490.82	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0405	2,200.00	-89.10		2,200.00	0.00	89.10	-100.00%
Rate Rider for Recovery of GA for Non-RPP Customers	per kW	1.3157	2,200.00	2894.54	-0.7144	2,200.00	-1571.68	-4466.22	-154.30%
Rate Rider for PP & E	per kW		2,200.00	0.00	-0.0561	2,200.00	-123.42	-123.42	
ICM Rate Rider	per kW		2,200.00	0.00	0.0836	2,200.00	183.92	183.92	
			2,200.00	0.00		2,200.00	0.00	0.00	
			2,200.00	0.00		2,200.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 10,778.19**			**$ 8,357.33**	**-$ 2,420.86**	**-22.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.1113	2,200.00	244.86	-0.7345	2,200.00	-1615.90	-1860.76	-759.93%
			2,200.00	0.00		2,200.00	0.00	0.00	
			2,200.00	0.00		2,200.00	0.00	0.00	
			2,200.00	0.00		2,200.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	2,200.00	140.36	0.1313	2,200.00	288.86	148.50	105.80%
Line Losses on Cost of Power	per kWh		37,700.00	0.00		37,600.00	0.00	0.00	
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 11,163.41**			**$ 7,030.29**	**-$ 4,133.12**	**-37.02%**
RTSR - Network	per kW	2.8561	2,282.94	6520.30	2.6861	2,282.72	6131.61	-388.69	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	2,282.94	4422.97	1.3600	2,282.72	3104.50	-1318.47	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22,106.68**			**$ 16,266.40**	**-$ 5,840.28**	**-26.42%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	1,037,700.00	4565.88	0.0044	1,037,600.00	4565.44	-0.44	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	1,037,700.00	1245.24	0.0012	1,037,600.00	1245.12	-0.12	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	1000000	7000.00	0.0070	1000000	7000.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	664128	44496.58	0.0670	664064	44492.29	-4.29	-0.01%
TOU - Mid Peak	per kWh	0.1040	186786	19425.74	0.1040	186768	19423.87	-1.87	-0.01%
TOU - On Peak	per kWh	0.1240	186786	23161.46	0.1240	186768	23159.23	-2.23	-0.01%
Energy - RPP - Tier 1	per kWh	0.0750	0	0.00	0.0750	0	0.00	0.00	
Energy - RPP - Tier 2	per kWh	0.0880	1037700	91317.60	0.0880	1037600	91308.80	-8.80	-0.01%
Total Bill on TOU (before Taxes)				**122001.84**			**116152.61**	**-5849.23**	**-4.79%**
HST		13%		15860.24	13%		15099.84	-760.40	-4.79%
Total Bill (including HST)				137862.08			131252.44	-6609.63	-4.79%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 137,862.08**			**$ 131,252.44**	**-$ 6,609.63**	**-4.79%**
Total Bill on RPP (before Taxes)				**126235.65**			**120386.01**	**-5849.64**	**-4.63%**
HST		13%		16410.63	13%		15650.18	-760.45	-4.63%
Total Bill (including HST)				142646.29			136036.20	-6610.09	-4.63%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 142,646.29**			**$ 136,036.20**	**-$ 6,610.09**	**-4.63%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: GS > 1000 KW - Non-RPP

TOU / non-TOU: non-TOU

Consumption 4,000 kW
1,600,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 3,399.83	1	$ 3,399.83	$ 4,482.03	1	$ 4,482.03	$ 1,082.20	31.83%
Smart Meter Rate Adder	Monthly		1	0.00		1	0.00	0.00	
			1	0.00		1	0.00	0.00	
			1	0.00		1	0.00	0.00	
			1	0.00		1	0.00	0.00	
			1	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	1.8569	4,000	7427.60	2.4480	4,000	9792.00	2364.40	31.83%
Smart Meter Disposition Rider	Monthly		1	0.00		1	0.00	0.00	
LRAM & SSM Rate Rider	per kW	-0.0014	4,000	-5.60	0.0004	4,000	1.60	7.20	-128.57%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2231	4,000	892.40		4,000	0.00	-892.40	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0405	4,000	-162.00		4,000	0.00	162.00	-100.00%
Rate Rider for Recovery of GA for Non-RPP Customers	per kW	1.3157	4,000	5262.80	-0.7144	4,000	-2857.60	-8120.40	-154.30%
Rate Rider for PP & E	per kW		4,000	0.00	-0.0561	4,000	-224.40	-224.40	
ICM Rate Rider	per kW		4,000	0.00	0.0836	4,000	334.40	334.40	
			4,000	0.00		4,000	0.00	0.00	
			4,000	0.00		4,000	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 16,815.03**			**$ 11,528.03**	**-$ 5,287.00**	**-31.44%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.1113	4,000	445.20	-0.7345	4,000	-2938.00	-3383.20	-759.93%
			4,000	0.00		4,000	0.00	0.00	
			4,000	0.00		4,000	0.00	0.00	
			4,000	0.00		4,000	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	4,000	255.20	0.1313	4,000	525.20	270.00	105.80%
Line Losses on Cost of Power	per kWh		60,320	0.00		60,160	0.00	0.00	
Smart Meter Entity Charge	Monthly	0.0000	1	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17,515.43**			**$ 9,115.23**	**-$ 8,400.20**	**-47.96%**
RTSR - Network	per kW	2.8561	4,151	11855.10	2.6861	4,150	11148.39	-706.71	-5.96%
RTSR - Line and Transformation Connection	per kW	1.9374	4,151	8041.76	1.3600	4,150	5644.54	-2397.22	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37,412.29**			**$ 25,908.16**	**-$ 11,504.13**	**-30.75%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	1,660,320	7305.41	0.0044	1,660,160	7304.70	-0.70	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	1,660,320	1992.38	0.0012	1,660,160	1992.19	-0.19	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	1600000	11200.00	0.0070	1600000	11200.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	1062605	71194.52	0.0670	1062502	71187.66	-6.86	-0.01%
TOU - Mid Peak	per kWh	0.1040	298858	31081.19	0.1040	298829	31078.20	-3.00	-0.01%
TOU - On Peak	per kWh	0.1240	298858	37058.34	0.1240	298829	37054.77	-3.57	-0.01%
Energy - RPP - Tier 1	per kWh	0.0750	0	0.00	0.0750	0	0.00	0.00	
Energy - RPP - Tier 2	per kWh	0.0880	1660320	146108.16	0.0880	1660160	146094.08	-14.08	-0.01%
Total Bill on TOU (before Taxes)				**197244.39**			**185725.94**	**-11518.45**	**-5.84%**
HST		13%		25641.77	13%		24144.37	-1497.40	-5.84%
Total Bill (including HST)				222886.16			209870.31	-13015.85	-5.84%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 222,886.16**			**$ 209,870.31**	**-$ 13,015.85**	**-5.84%**
Total Bill on RPP (before Taxes)				**204018.49**			**192499.39**	**-11519.10**	**-5.65%**
HST		13%		26522.40	13%		25024.92	-1497.48	-5.65%
Total Bill (including HST)				230540.90			217524.31	-13016.59	-5.65%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 230,540.90**			**$ 217,524.31**	**-$ 13,016.59**	**-5.65%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Embedded Distributor - Non-RPP

TOU / non-TOU: non-TOU — ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Consumption 6,000 kW; 2,810,800 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 3,399.83	1.00	$ 3,399.83	$ 2,984.12	1	$ 2,984.12	-$ 415.71	-12.23%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	1.8569	6,000.00	11141.40	1.6299	6,000.00	9779.40	-1362.00	-12.22%
Smart Meter Disposition Rider	Monthly		1.00	0.00		6,000.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW	-0.0014	6,000.00	-8.40	0.0000	6,000.00	0.00	8.40	-100.00%
Rate Rider for recovery of Incremental Capital Costs	per kW	0.2231	6,000.00	1338.60		6,000.00	0.00	-1338.60	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.0405	6,000.00	-243.00		6,000.00	0.00	243.00	-100.00%
Rate Rider for Recovery of GA for Non-RPP Customers	per kW	1.3157	6,000.00	7894.20		6,000.00	0.00	-7894.20	-100.00%
			6,000.00	0.00		6,000.00	0.00	0.00	
			6,000.00	0.00		6,000.00	0.00	0.00	
			6,000.00	0.00		6,000.00	0.00	0.00	
			6,000.00	0.00		6,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 23,522.63**			**$ 12,763.52**	**-$ 10,759.11**	**-45.74%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.1113	6,000.00	667.80		6,000.00	0.00	-667.80	-100.00%
			6,000.00	0.00		6,000.00	0.00	0.00	
			6,000.00	0.00		6,000.00	0.00	0.00	
			6,000.00	0.00		6,000.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0638	6,000.00	382.80	0.1313	6,000.00	787.80	405.00	105.80%
Line Losses on Cost of Power	per kWh		13,210.76	0.00		12,648.60	0.00	0.00	
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24,573.23**			**$ 13,551.32**	**-$ 11,021.91**	**-44.85%**
RTSR - Network	per kW	2.8561	6,028.20	17217.14	2.6861	6,027.00	16189.12	-1028.02	-5.97%
RTSR - Line and Transformation Connection	per kW	1.9374	6,028.20	11679.03	1.3600	6,027.00	8196.72	-3482.31	-29.82%
Sub-Total C - Delivery (including Sub-Total B)				**$ 53,469.41**			**$ 37,937.16**	**-$ 15,532.24**	**-29.05%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	2,824,010.76	12425.65	0.0044	2,823,448.60	12423.17	-2.47	-0.02%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	2,824,010.76	3388.81	0.0012	2,823,448.60	3388.14	-0.67	-0.02%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh		2810800	0.00		2810800	0.00	0.00	
TOU - Off Peak	per kWh	0.0670	1807367	121093.58	0.0670	1807007	121069.48	-24.11	-0.02%
TOU - Mid Peak	per kWh	0.1040	508322	52865.48	0.1040	508221	52854.96	-10.52	-0.02%
TOU - On Peak	per kWh	0.1240	508322	63031.92	0.1240	508221	63019.37	-12.55	-0.02%
Energy - RPP - Tier 1	per kWh	0.0750	754	56.51	0.0750	753	56.50	-0.01	-0.02%
Energy - RPP - Tier 2	per kWh	0.0880	2823257	248446.64	0.0880	2822695	248397.18	-49.46	-0.02%
Total Bill on TOU (before Taxes)				**306275.10**			**290692.53**	**-15582.57**	**-5.09%**
HST		13%		39815.76	13%		37790.03	-2025.73	-5.09%
Total Bill (including HST)				346090.86			328482.56	-17608.30	-5.09%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 346,090.86**			**$ 328,482.56**	**-$ 17,608.30**	**-5.09%**
Total Bill on RPP (before Taxes)				**317787.27**			**302202.41**	**-15584.86**	**-4.90%**
HST		13%		41312.34	13%		39286.31	-2026.03	-4.90%
Total Bill (including HST)				359099.61			341488.72	-17610.89	-4.90%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 359,099.61**			**$ 341,488.72**	**-$ 17,610.89**	**-4.90%**
Loss Factor (%)		0.47%			0.45%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

TOU / non-TOU: non-TOU ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	1 Connections
Consumption	1 kW
	150 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 3.10	1.00	$ 3.10	$ 4.18	0.59	$ 2.46	-$ 0.64	-20.68%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
' '			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	19.0338	1.00	19.03	25.6462	1.00	25.65	6.61	34.74%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW		1.00	0.00	0.0000	1.00	0.00	0.00	
Rate Rider for recovery of Incremental Capital Costs	per kW	1.2014	1.00	1.20		1.00	0.00	-1.20	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.4006	1.00	-0.40		1.00	0.00	0.40	-100.00%
Rate Rider for PP & E	per kW		1.00	0.00	-0.0446	1.00	-0.04	-0.04	
ICM Rate Rider	per kW		1.00	0.00	0.0664	1.00	0.07	0.07	
			1.00	0.00		1.00	0.00	0.00	
			1.00	0.00		1.00	0.00	0.00	
			1.00	0.00		1.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 22.93**			**$ 28.13**	**$ 5.19**	**22.64%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0941	1.00	0.09	-0.5864	1.00	-0.59	-0.68	-723.17%
			1.00	0.00		1.00	0.00	0.00	
			1.00	0.00		1.00	0.00	0.00	
			1.00	0.00		1.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0516	1.00	0.05	0.1061	1.00	0.11	0.05	105.62%
Line Losses on Cost of Power	per kWh	0.0750	5.66	0.42	0.0750	5.64	0.42	0.00	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 23.50**			**$ 28.07**	**$ 4.57**	**19.42%**
RTSR - Network	per kW	2.3081	1.04	2.40	2.1707	1.04	2.25	-0.14	-5.96%
RTSR - Line and Transformation Connection	per kW	1.5656	1.04	1.62	1.0990	1.04	1.14	-0.48	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.52**			**$ 31.46**	**$ 3.94**	**14.31%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	155.66	0.68	0.0044	155.64	0.68	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	155.66	0.19	0.0012	155.64	0.19	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	150	1.05	0.0070	150	1.05	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	96	6.43	0.0670	96	6.43	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	27	2.81	0.1040	27	2.81	0.00	0.00%
TOU - On Peak	per kWh	0.1240	27	3.35	0.1240	27	3.35	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	150	11.25	0.0750	150	11.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	0	0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**42.28**			**46.22**	**3.94**	**9.31%**
HST		13%		5.50	13%		6.01	0.51	9.31%
Total Bill (including HST)				47.78			52.23	4.45	9.31%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 47.78**			**$ 52.23**	**$ 4.45**	**9.31%**
Total Bill on RPP (before Taxes)				**40.95**			**44.88**	**3.94**	**9.62%**
HST		13%		5.32	13%		5.83	0.51	9.62%
Total Bill (including HST)				46.27			50.72	4.45	9.62%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 46.27**			**$ 50.72**	**$ 4.45**	**9.62%**

Loss Factor (%) — Current: 3.77% — Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Street Lighting

TOU / non-TOU: non-TOU

	15,600	Connections
Consumption	2,000	kW
	700,000	kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 3.10	15,600.00	$ 48,360.00	$ 4.18	9176.470588	$ 38,357.65	-$ 10,002.35	-20.68%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	19.0338	2,000.00	38067.60	25.6462	2,000.00	51292.40	13224.80	34.74%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW		1.00	0.00	0.0000	1.00	0.00	0.00	
Rate Rider for recovery of Incremental Capital Costs	per kW	1.2014	2,000.00	2402.80		2,000.00	0.00	-2402.80	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.4006	2,000.00	-801.20		2,000.00	0.00	801.20	-100.00%
Rate Rider for PP & E	per kW		2,000.00	0.00	-0.0446	2,000.00	-89.20	-89.20	
ICM Rate Rider	per kW		2,000.00	0.00	0.0664	2,000.00	132.80	132.80	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 88,029.20**			**$ 89,693.65**	**$ 1,664.45**	**1.89%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0941	2,000.00	188.20	-0.5864	2,000.00	-1172.80	-1361.00	-723.17%
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0516	2,000.00	103.20	0.1061	2,000.00	212.20	109.00	105.62%
Line Losses on Cost of Power	per kWh		26,390.00	0.00		26,320.00	0.00	0.00	
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 88,320.60**			**$ 88,733.05**	**$ 412.45**	**0.47%**
RTSR - Network	per kW	2.3081	2,075.40	4790.23	2.1707	2,075.20	4504.64	-285.59	-5.96%
RTSR - Line and Transformation Connection	per kW	1.5656	2,075.40	3249.25	1.0990	2,075.20	2280.64	-968.60	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 96,360.08**			**$ 95,518.33**	**-$ 841.75**	**-0.87%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	726,390.00	3196.12	0.0044	726,320.00	3195.81	-0.31	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	726,390.00	871.67	0.0012	726,320.00	871.58	-0.08	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	700000	4900.00	0.0070	700000	4900.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	464890	31147.60	0.0670	464845	31144.60	-3.00	-0.01%
TOU - Mid Peak	per kWh	0.1040	130750	13598.02	0.1040	130738	13596.71	-1.31	-0.01%
TOU - On Peak	per kWh	0.1240	130750	16213.02	0.1240	130738	16211.46	-1.56	-0.01%
Energy - RPP - Tier 1	per kWh	0.0750	778	58.37	0.0750	778	58.37	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	725612	63853.83	0.0880	725542	63847.67	-6.16	-0.01%
Total Bill on TOU (before Taxes)				**166286.76**			**165438.74**	**-848.01**	**-0.51%**
HST		13%		21617.28	13%		21507.04	-110.24	-0.51%
Total Bill (including HST)				187904.04			186945.78	-958.26	-0.51%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 187,904.04**			**$ 186,945.78**	**-$ 958.26**	**-0.51%**
Total Bill on RPP (before Taxes)				**169240.31**			**168392.01**	**-848.30**	**-0.50%**
HST		13%		22001.24	13%		21890.96	-110.28	-0.50%
Total Bill (including HST)				191241.55			190282.97	-958.58	-0.50%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 191,241.55**			**$ 190,282.97**	**-$ 958.58**	**-0.50%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referencec consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Light**

TOU / non-TOU: non-TOU

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	160	Connections
Consumption	25	kW
	10,000	kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 2.95	160.00	$ 472.00	$ 2.95	160	$ 472.00	$ -	0.00%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kW	50.0589	25.00	1251.47	50.0683	25.00	1251.71	0.23	0.02%
Smart Meter Disposition Rider	Monthly		1.00	0.00		1.00	0.00	0.00	
LRAM & SSM Rate Rider	per kW		25.00	0.00	0.0000	25.00	0.00	0.00	
Rate Rider for recovery of Incremental Capital Costs	per kW	2.0569	25.00	51.42		25.00	0.00	-51.42	-100.00%
Rate Rider for Application of Tax Change (2013)	per kW	-0.7497	25.00	-18.74		25.00	0.00	18.74	-100.00%
Rate Rider for PP & E	per kW		25.00	0.00	-0.0447	25.00	-1.12	-1.12	
Rate Rider for Recovery of GA for Non-RPP Customers	per kW	1.10	25.00	27.55		25.00	0.00	-27.55	-100.00%
ICM Rate Rider	per kW		25.00	0.00	0.0666	25.00	1.67	1.67	
			25.00	0.00		25.00	0.00	0.00	
			25.00	0.00		25.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 1,783.70**			**$ 1,724.26**	**-$ 59.44**	**-3.33%**
Deferral/Variance Account Disposition Rate Rider	per kW	0.0932	25.00	2.33	-1.0448	25.00	-26.12	-28.45	-1221.03%
			25.00	0.00		25.00	0.00	0.00	
			25.00	0.00		25.00	0.00	0.00	
			25.00	0.00		25.00	0.00	0.00	
Low Voltage Service Charge	per kW	0.0124	25.00	0.31	0.0255	25.00	0.64	0.33	105.65%
Line Losses on Cost of Power	per kWh	0.0880	377.00	33.18	0.0880	376.00	33.09	-0.09	-0.27%
Smart Meter Entity Charge	Monthly	0.0000	1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,819.51**			**$ 1,731.86**	**-$ 87.65**	**-4.82%**
RTSR - Network	per kW	0.5546	25.94	14.39	0.5216	25.94	13.53	-0.86	-5.96%
RTSR - Line and Transformation Connection	per kW	0.3761	25.94	9.76	0.2640	25.94	6.85	-2.91	-29.81%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,843.66**			**$ 1,752.24**	**-$ 91.42**	**-4.96%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	10,377.00	45.66	0.0044	10,376.00	45.65	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	10,377.00	12.45	0.0012	10,376.00	12.45	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	10000	70.00	0.0070	10000	70.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	6400	428.80	0.0670	6400	428.80	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	1800	187.20	0.1040	1800	187.20	0.00	0.00%
TOU - On Peak	per kWh	0.1240	1800	223.20	0.1240	1800	223.20	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	9250	814.00	0.0880	9250	814.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**2811.22**			**2719.79**	**-91.42**	**-3.25%**
HST		13%		365.46	13%		353.57	-11.89	-3.25%
Total Bill (including HST)				3176.68			3073.37	-103.31	-3.25%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on TOU (including OCEB)				**$ 3,176.68**			**$ 3,073.37**	**-$ 103.31**	**-3.25%**
Total Bill on RPP (before Taxes)				**2842.27**			**2750.84**	**-91.42**	**-3.22%**
HST		13%		369.50	13%		357.61	-11.89	-3.22%
Total Bill (including HST)				3211.76			3108.45	-103.31	-3.22%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 3,211.76**			**$ 3,108.45**	**-$ 103.31**	**-3.22%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered and Scattered Loads**

TOU / non-TOU: non-TOU ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Consumption **250** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 11.58	1.00	$ 11.58	$ 11.19	1	$ 11.19	-$ 0.39	-3.37%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0108	250.00	2.70	0.0104	250.00	2.60	-0.10	-3.70%
Smart Meter Disposition Rider	Monthly		1.00	0.00		250.00	0.00	0.00	
LRAM & SSM Rate Rider	per kWh	0.0003	250.00	0.08	0.0000	250.00	0.00	-0.08	-100.00%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0020	250.00	0.50		250.00	0.00	-0.50	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0004	250.00	-0.10		250.00	0.00	0.10	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kWh		250.00	0.00	-0.0001	250.00	-0.03	-0.03	
ICM Rate Rider	per kWh		250.00	0.00	0.0002	250.00	0.05	0.05	
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 14.76**			**$ 13.82**	**-$ 0.94**	**-6.37%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	250.00	0.08	-0.0007	250.00	-0.18	-0.25	-333.33%
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
			250.00	0.00		250.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	250.00	0.05	0.0003	250.00	0.08	0.03	50.00%
Line Losses on Cost of Power	per kWh	0.0750	9.43	0.71	0.0750	9.40	0.71	0.00	-0.27%
Smart Meter Entity Charge	Monthly		1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 15.59**			**$ 14.42**	**-$ 1.17**	**-7.49%**
RTSR - Network	per kWh	0.0074	259.43	1.92	0.0070	259.40	1.82	-0.10	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	259.43	1.30	0.0035	259.40	0.91	-0.39	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 18.80**			**$ 17.14**	**-$ 1.66**	**-8.83%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	259.43	1.14	0.0044	259.40	1.14	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	259.43	0.31	0.0012	259.40	0.31	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	250	1.75	0.0070	250	1.75	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	160	10.72	0.0670	160	10.72	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	45	4.68	0.1040	45	4.68	0.00	0.00%
TOU - On Peak	per kWh	0.1240	45	5.58	0.1240	45	5.58	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	250	18.75	0.0750	250	18.75	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880		0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**43.24**			**41.58**	**-1.66**	**-3.84%**
HST		13%		5.62	13%		5.40	-0.22	-3.84%
Total Bill (including HST)				48.86			46.98	-1.88	-3.84%
Ontario Clean Energy Benefit [1]				-4.89			-4.70	0.19	-3.84%
Total Bill on TOU (including OCEB)				**$ 43.97**			**$ 42.28**	**-$ 1.69**	**-3.84%**
Total Bill on RPP (before Taxes)				**41.01**			**39.35**	**-1.66**	**-4.05%**
HST		13%		5.33	13%		5.12	-0.22	-4.05%
Total Bill (including HST)				46.34			44.46	-1.88	-4.05%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 46.34**			**$ 44.46**	**-$ 1.88**	**-4.05%**
Loss Factor (%)		3.77%			3.76%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: Unmetered and Scattered Loads

TOU / non-TOU: non-TOU

Consumption 550 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 11.58	1.00	$ 11.58	$ 11.19	1	$ 11.19	-$ 0.39	-3.37%
Smart Meter Rate Adder	Monthly		1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0108	550.00	5.94	0.0104	550.00	5.72	-0.22	-3.70%
Smart Meter Disposition Rider	Monthly		1.00	0.00		550.00	0.00	0.00	
LRAM & SSM Rate Rider	per kWh	0.0003	550.00	0.17	0.0000	550.00	0.00	-0.17	-100.00%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0020	550.00	1.10		550.00	0.00	-1.10	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0004	550.00	-0.22		550.00	0.00	0.22	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00		1.00	0.00	0.00	
Rate Rider for PP & E	per kWh		550.00	0.00	-0.0001	550.00	-0.06	-0.06	
ICM Rate Rider	per kWh		550.00	0.00	0.0002	550.00	0.11	0.11	
			550.00	0.00		550.00	0.00	0.00	
			550.00	0.00		550.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 18.57**			**$ 16.97**	**-$ 1.60**	**-8.62%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	550.00	0.17	-0.0007	550.00	-0.39	-0.55	-333.33%
			550.00	0.00		550.00	0.00	0.00	
			550.00	0.00		550.00	0.00	0.00	
			550.00	0.00		550.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	550.00	0.11	0.0003	550.00	0.17	0.06	50.00%
Line Losses on Cost of Power	per kWh	0.0750	20.74	1.56	0.0750	20.68	1.55	0.00	-0.27%
Smart Meter Entity Charge	Monthly		1.00	0.00		1	0.00	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.40**			**$ 18.30**	**-$ 2.10**	**-10.29%**
RTSR - Network	per kWh	0.0074	570.74	4.22	0.0070	570.68	3.99	-0.23	-5.41%
RTSR - Line and Transformation Connection	per kWh	0.0050	570.74	2.85	0.0035	570.68	2.00	-0.86	-30.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.47**			**$ 24.29**	**-$ 3.18**	**-11.59%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	570.74	2.51	0.0044	570.68	2.51	0.00	-0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	570.74	0.68	0.0012	570.68	0.68	0.00	-0.01%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	550	3.85	0.0070	550	3.85	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	352	23.58	0.0670	352	23.58	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	99	10.30	0.1040	99	10.30	0.00	0.00%
TOU - On Peak	per kWh	0.1240	99	12.28	0.1240	99	12.28	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	550	41.25	0.0750	550	41.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	0	0.00	0.0880	0	0.00	0.00	
Total Bill on TOU (before Taxes)				**80.92**			**77.74**	**-3.18**	**-3.94%**
HST		13%		10.52	13%		10.11	-0.41	-3.94%
Total Bill (including HST)				91.44			87.85	-3.60	-3.94%
Ontario Clean Energy Benefit [1]				-9.14			-8.78	0.36	-3.94%
Total Bill on TOU (including OCEB)				**$ 82.30**			**$ 79.06**	**-$ 3.24**	**-3.94%**
Total Bill on RPP (before Taxes)				**76.02**			**72.83**	**-3.18**	**-4.19%**
HST		13%		9.88	13%		9.47	-0.41	-4.19%
Total Bill (including HST)				85.90			82.30	-3.60	-4.19%
Ontario Clean Energy Benefit [1]				0.00			0.00	0.00	
Total Bill on RPP (including OCEB)				**$ 85.90**			**$ 82.30**	**-$ 3.60**	**-4.19%**

Loss Factor (%) — Current: 3.77% — Proposed: 3.76%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

8-Load Forecast, Cost Allocation and Rate Design

Issue 8.1: *Is the proposed load forecast, including billing determinants an appropriate reflection of the energy and demand requirements of the applicant?*

8.1-Staff-41

Ref: Exhibit 3/Tab 1/Schedule 3 & Appendix A

Addition of Embedded Distributor – Milton Hydro

Oakville Hydro indicates that Milton Hydro became an Oakville Hydro customer in August 2013 and provided Milton Hydro's load forecast for the 2014 test year (which is filed at Appendix A). Did Oakville Hydro take steps to verify or confirm the load forecast provided by Milton Hydro? Please explain how this forecast was verified by Oakville Hydro.

RESPONSE:

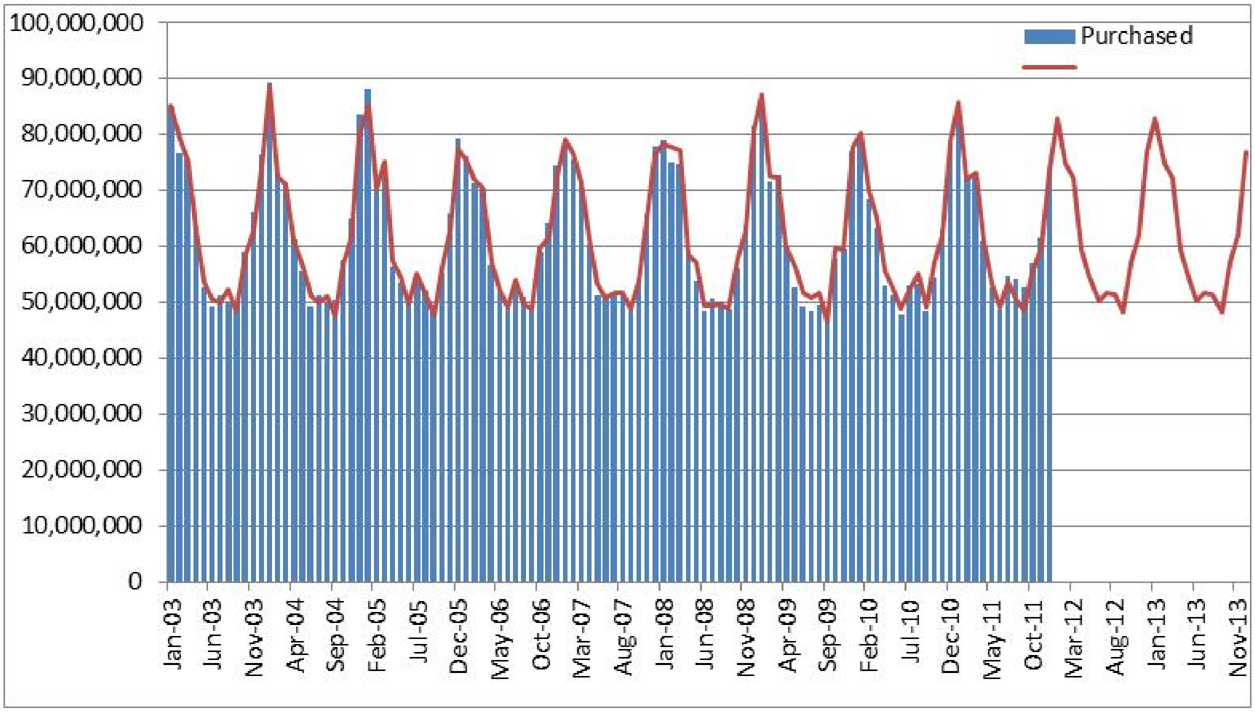
On January 14, 2014, Oakville Hydro contacted Milton Hydro to request that they update their load forecast for the 2014 Test Year. On January 24, 2014, Milton Hydro confirmed that their load forecast for 2014 had not changed and provided the same letter that was filed at Appendix A to Exhibit 3.

8.1-Staff-42

Ref: Exhibit 3/Tab 1/Schedule 2

Load Forecast Regression Equation

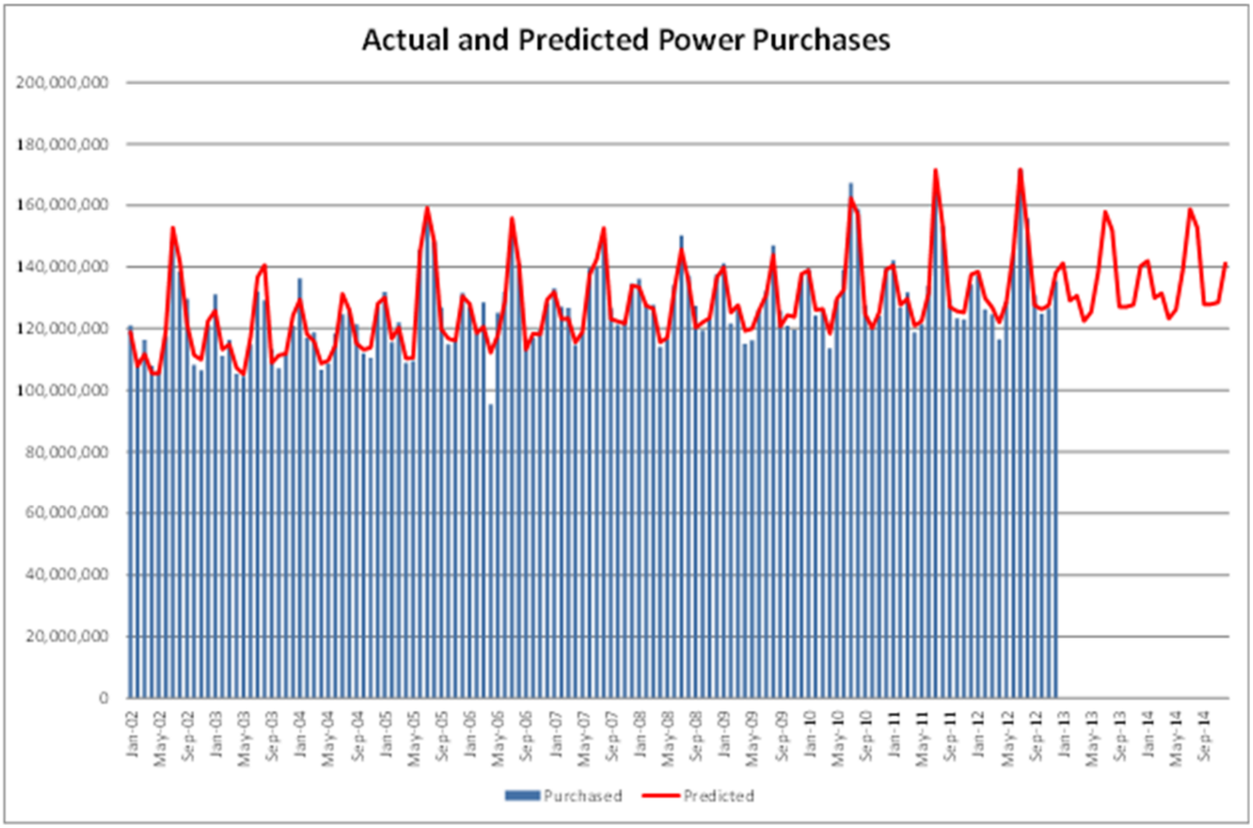
Please provide a variation on the predicted and residual graph shown on page 6 of this Exhibit showing the actual and predicted kWh values based on the monthly values, in a format similar to the following:



a) Please provide the Mean Absolute Percentage Error of the regression model based on the monthly data.

RESPONSE:

Oakville Hydro has provided a variation on the predicted and residual graph shown of page 6 of Exhibit 3, Tab 1, Schedule 2 on the following page. The Mean Absolute Percentage Error of the regression model based on the monthly data is 2.1%.



8.1-Staff-43

Ref: Exhibit 3/Tab1/Schedule 2

<u>Billed Forecast Before CDM Adjustment</u>

On pages 7-8 of this Exhibit, Oakville Hydro states:

"To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast, excluding the impact of CDM activities, is adjusted by a historical loss factor. This adjustment has been made by Oakville Hydro using the average loss factor from 2002 to 2012 of 1.040 applied to each year. With this average loss factor the total weather normalized billed energy will be 1,577 GWh for 2013 and 1,567 GWh for 2014 before the adjustment for CDM discussed below."

In Table 3-13 on page 12 of this exhibit, Oakville Hydro documents 1,557,192,865 kWh (= 1,557 GWh) for the 2013 Bridge Year and 1,566,604,928 kWh (= 1,567 GWh) for the 2014 Test Year, before CDM adjustments. The 2014 Test Year matches, but there is a 20 GWh difference for the 2013 Bridge Year. Please reconcile the difference and identify which 2013 Bridge Year forecast is correct.

RESPONSE:

Oakville Hydro inadvertently made a typographical error. The bridge year forecast was 1,557 GWh and the statement should have read as follows:

"To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast, excluding the impact of CDM activities, is adjusted by a historical loss factor. This adjustment has been made by Oakville Hydro using the average loss factor from 2002 to 2012 of 1.040 applied to each year. With this average loss factor the total weather normalized billed energy will be 1,557 GWh for 2013 and 1,567 GWh for 2014 before the adjustment for CDM discussed below."

8.1-Energy Probe-48

Ref: Exhibit 3, Tab 1, Schedule 2 &
Exhibit 3, Tab 2, Schedule 1

a) Please re-estimate the power purchased equation by dropping the daylight hours variable and replacing the spring fall flag variable with two variables - a spring flag (equal to 1 in March, April and May, 0 otherwise) and a fall flag (1 in September, October and November, 0 otherwise). Please provide the regression statistics as shown in the Summary Output on page 5.

RESPONSE:

Oakville Hydro has re-estimated the power purchase equation by dropping the daylight hours variable and replacing the spring fall flag variable with two variables – a spring flag and a fall flag. The prediction formula has the following statistical results.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	96.9%
R Square	94.0%
Adjusted R Square	93.7%
Standard Error	3,476,731
Observations	132

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	2.36411E+16	3.94019E+15	325.968146	8.42811E-74
Residual	125	1.51096E+15	1.20877E+13		
Total	131	2.51521E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(68,287,950.657)	12,362,039.989	(5.524)	0.000	(92,753,962.042)	(43,821,939.273)
HDD	25,496.207	2,031.384	12.551	0.000	21,475.846	29,516.567
CDD	248,708.203	11,203.126	22.200	0.000	226,535.826	270,880.580
Days	3,582,095.527	395,337.079	9.061	0.000	2,799,674.383	4,364,516.671
Spring Flag	(6,628,209.218)	942,806.992	(7.030)	0.000	(8,494,141.266)	(4,762,277.170)
Customers	1,246.291	62.749	19.861	0.000	1,122.103	1,370.480
Fall Flag	(2,672,520.000)	970,035.439	(2.755)	0.007	(4,592,340.525)	(752,699.476)

b) Please provide revised Tables 3-4, 3-13, 3-17, 3-18, 3-21, 3-22, 3-23 and any other tables that are impacted based on the forecast generated in the response to part (a) above.

RESPONSE:

Oakville Hydro has provided revised Tables 3-4, 3-13, 3-17, 3-18, 3-21, 3-22, 3-23 based on the forecast generated in the response to part a) of this interrogatory.

Table 3-4 – Forecast Summary Excluding CDM Impacts

Year	Actual (GWh)	Predicted Purchases (GWh)
2002	1,432	1,427
2003	1,398	1,419
2004	1,428	1,425
2005	1,527	1,524
2006	1,503	1,500
2007	1,555	1,547
2008	1,552	1,538
2009	1,529	1,542
2010	1,609	1,599
2011	1,609	1,614
2012	1,625	1,632
2013	10 Year HDD/CDD	1,621
2014	10 Year HDD/CDD	1,630
2014	20 Year HDD/CDD	1,633

Table 3-13 – Normalized kWh, Excluding CDM Adjustments

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads	Total
2013	613,550,413	161,830,428	617,734,801	149,214,889	11,811,086	119,132	3,600,460	1,557,861,209
2014	613,244,626	160,690,206	629,456,716	148,439,041	11,894,652	116,788	3,504,020	1,567,346,048

Table 3-17 – 2013 Weather Normalized Billed Energy Forecast (GWh)

Rate Class	Non-normalized Billed Energy	Adjustment for Weather Normalization	Normalized Billed Energy	CDM Adjustment & Embedded Distributor	Weather Normal Billed Energy Forecast (GWh)
Residential	609.6	4.0	613.6	(15.8)	597.8
General Service < 50 kW	160.9	0.9	161.8	(1.7)	160.1
Unmetered	3.6	-	3.6	-	3.6
General Service > 50 kW	614.5	3.2	617.7	(19.0)	598.7
General Service > 1,000 kW	149.1	0.1	149.2	(0.9)	148.3
Embedded Distributor	-	-	-	8.4	8.4
Sentinel Lighting	0.1	-	0.1	-	0.1
Street Lighting	11.8	-	11.8	-	11.8
Total	1,549.6	8.3	1,557.9	(29.0)	1,528.9

Table 3-18 – 2014 Weather Normalized Billed Energy Forecast

Rate Class	Non-normalized Billed Energy	Adjustment for Weather Normalization	Normalized Billed Energy	CDM Adjustment & Embedded Distributor	Weather Normal Billed Energy Forecast
Residential	608.8	4.5	613.2	(17.3)	595.9
General Service < 50 kW	159.6	1.1	160.7	(2.1)	158.6
Unmetered	3.5	-	3.5	-	3.5
General Service > 50 kW	625.8	3.7	629.5	(22.8)	606.7
General Service > 1,000 kW	148.3	0.2	148.4	(1.0)	147.4
Embedded Distributor	-	-	-	33.7	33.7
Sentinel Lighting	0.1	-	0.1	-	0.1
Street Lighting	11.9	-	11.9	(3.0)	8.9
Total	1,558.0	9.3	1,567.3	(12.4)	1,554.9

Table 3-21 – Forecasted Billing Determinants (Before CDM Adjustment)

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Street Lighting	Sentinel Lights
2013	1,619,644	333,913	32,965	331
2014	1,650,378	332,177	33,198	324

Table 3-22 – Historical and Forecasted Volumes and Customers (Including the Impact of CDM)

Rate Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential							
Customers	54,636	56,419	56,923	57,796	58,286	58,922	59,565
kWh	559,480,721	555,127,459	597,295,732	588,575,028	600,534,935	597,764,780	595,920,520
General Service < 50 kW							
Customers	4,809	4,888	4,897	4,923	4,911	4,919	4,926
kWh	175,714,453	170,241,898	170,509,443	167,110,172	162,269,747	160,098,934	158,619,544
Unmetered Loads							
Connections	675	679	665	673	676	675	674
kWh	3,915,659	3,936,855	3,816,306	3,663,023	3,696,824	3,600,460	3,504,020
General Service > 50 to 999 kW							
Customers	813	854	871	878	893	906	920
kWh	593,404,108	584,084,594	602,895,003	602,311,205	603,821,865	598,688,369	606,679,440
kW	1,614,129	1,564,795	1,595,879	1,590,500	1,631,952	1,569,706	1,590,658
General Service > 1000 kW							
Customers	17	18	17	16	16	16	16
kWh	170,191,555	147,437,802	151,840,794	148,964,252	149,411,044	148,349,142	147,403,710
kW	411,997	357,797	370,035	338,497	328,299	331,976	329,860
Large Use >5000 kW							
Customers	1	1	-	-	-	-	-
kWh	60,236,729	1,377,628	-	-	-	-	-
kW	106,448	30,509	-	-	-	-	-
Embedded Distributor							
Customers	-	-	-	-	-	1	1
kWh	-	-	-	-	-	8,432,400	33,729,600
kW	-	-	-	-	-	18,250	73,000
Street lights							
Connections	16,025	16,286	16,598	16,828	17,113	17,398	10,404
kWh	10,963,488	11,085,581	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	30,509	30,957	31,713	32,425	32,927	32,965	24,961
Sentinel Lights							
Connections	237	183	179	177	167	162	157
kWh	135,737	133,918	126,835	122,878	119,670	119,132	116,788
kW	377	372	350	339	332	331	324
Total							
Customer/Connections	77,212	79,328	80,150	81,291	82,062	82,999	76,664
kWh	1,574,042,450	1,473,425,735	1,537,840,892	1,522,342,881	1,531,679,011	1,528,864,303	1,554,916,718
kW from applicable classes	2,163,461	1,984,430	1,997,977	1,961,761	1,993,510	1,953,228	2,018,803

Table 3-23 – Weather Normalized Historical and Forecasted Volumes and Customers

Rate Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential							
Customers	54,636	56,419	56,923	57,796	58,286	58,922	59,565
kWh	557,929,818	553,583,537	598,826,330	588,720,036	606,398,134	597,764,780	595,920,520
General Service < 50 kW							
Customers	4,809	4,888	4,897	4,923	4,911	4,919	4,926
kWh	175,308,888	169,892,748	170,577,580	167,163,051	163,853,640	160,098,934	158,619,544
Unmetered Loads							
Connections	675	679	665	673	676	675	674
kWh	3,915,659	3,936,855	3,816,306	3,694,151	3,727,960	3,600,460	3,504,020
General Service > 50 to 999 kW							
Customers	813	854	871	878	893	906	920
kWh	592,172,921	582,834,946	603,272,718	602,312,136	603,854,708	598,688,369	606,679,440
kW	1,552,623	1,528,140	1,581,726	1,579,207	1,583,252	1,569,706	1,590,658
General Service > 1000 kW							
Customers	17	18	17	16	16	16	16
kWh	169,939,484	147,153,623	152,644,513	148,985,706	150,424,815	148,349,142	147,403,710
kW	380,291	329,301	341,588	333,401	336,621	331,976	329,860
Large Use >5000 kW							
Customers	1	1	-	-	-	-	-
kWh	60,236,729	1,377,628	0	0	0	0	0
kW	106,448	2,363	0	0	0	0	0
Embedded Distributor							
Customers	-	-	-	-	-	1	1
kWh	0	0	0	0	0	8,432,400	33,729,600
kW	0	0	0	0	0	18,250	73,000
Street lights							
Connections	16,025	16,286	16,598	16,828	17,113	17,398	10,404
kWh	10,963,488	11,085,581	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	377	372	350	339	332	331	324
Sentinel Lights							
Connections	237	183	179	177	167	162	157
kWh	135,737	133,918	125,971	122,014	119,670	119,132	116,788
kW	30,600	30,940	31,697	32,366	33,004	32,965	24,961
Total							
Customer/Connections	77,212	79,328	80,150	81,291	82,062	82,999	76,664
kWh	1,570,602,725	1,469,998,837	1,540,620,197	1,522,593,418	1,540,203,852	1,528,864,303	1,554,916,718
kW from applicable classes	2,070,339	1,891,116	1,955,361	1,945,312	1,953,209	1,953,228	2,018,803

c) Please provide the live Excel spreadsheet that contains the equation requested in part (a) above.

RESPONSE:

Oakville Hydro will file the live Excel spreadsheet that contains the equation requested in part (a) above.

d) Please provide the impact on revenues at existing rates based on the forecast from the equation requested in part (a). Please show the change in distribution revenue calculated by rate class.

RESPONSE:

Revenues at existing rates based on the forecast from the equation requested in part a) are $15,281 higher than revenue based on existing rates based on the proposed power purchased equation.

Customer Class	Application	EP - 48	Impact
Residential	$ 17,835,031	$ 17,841,772	$ 6,741
GS < 50 kW	4,155,428	4,157,008	1,580
GS >50 kW	7,054,966	7,058,705	3,739
GS >1000 kW	1,265,214	1,265,284	70
Embedded Distributor	176,352	176,352	(0)
Sentinel Lights	21,904	21,883	(21)
Street Lighting	858,960	862,131	3,171
Unmetered Scattered Load	131,641	131,641	0
Total	$ 31,499,496	$ 31,514,777	$ 15,281

e) What is the impact on the working cash allowance of the forecasted generated in response to part (a)? Please show all calculations.

RESPONSE:

The impact on the working cash allowance of the forecast is provided in response to part a) of this interrogatory and is an increase of $21,149 as shown in the following table. The cost of power calculations are provided on the following page.

Description	Application	Forecast in Part A	Difference
Cost of Power	159,110,509	159,273,191	162,682
OM&A	19,418,184	19,418,184	-
Total	178,528,693	178,691,375	162,682
Working Capital Allowance Rate	13%	13%	
Working Capital Allowance	23,208,730	23,229,879	21,149

Cost of Power Calculation

2014 Cost of Power Calculations

Forecasted Purchases	Residential	General Service < 50 kW	Unmetered	General Service > 50 kW	General Service > 1,000 kW	Embedded Distributor	Sentinel Lighting	Street Lighting	Total
Average Number of Customers	59,243	4,923							
Non-RPP Forecast (kWh)	30,609,623	25,714,890	25,874	541,069,481	152,197,962	34,826,643	-	9,233,966	793,678,438
RPP Forecast (kWh)	584,692,995	138,063,698	3,592,113	85,341,986	-	-	120,586	-	811,811,378
Total kWh	615,302,617	163,778,587	3,617,987	626,411,467	152,197,962	34,826,643	120,586	9,233,966	1,605,489,815
Commodity Charges									
Non-RPP Coommodity Charge ($0.08259/kWh)	$ 2,528,049	$ 2,123,793	$ 2,137	$ 44,686,928	$ 12,570,030	$ 2,876,332	$ -	$ 762,633	$ 65,549,902
RPP Commodity Charge($0.08395/kWh)	$ 49,084,977	$ 11,590,447	$ 301,558	$ 7,164,460	$ -	$ -	$10,123	$ -	$ 68,151,565
Total Commodity Charges	**$ 51,613,026**	**$ 13,714,240**	**$ 303,695**	**$ 51,851,388**	**$ 12,570,030**	**$ 2,876,332**	**$10,123**	**$ 762,633**	**$ 133,701,467**
Retail Transmission Charges									
Forecasted Billing Determinants (kW/kWh)	615,302,617	163,778,587	3,617,987	1,589,641	329,822	73,000	324	24,961	
Transmission Network Rate	$ 0.0072	$ 0.0067	$ 0.0067	$ 2.4866	$ 2.5669	$ 2.5669	$0.4984	$ 2.0744	
Transmission Network Charges	**$ 4,430,178.85**	**$ 1,097,316.53**	**$24,240.51**	**$ 3,952,802.03**	**$ 846,619.70**	**$187,383.70**	**$161.69**	**$51,778.11**	**$ 10,590,481**
Transmission Connection Rate	$ 0.0036	$ 0.0033	$ 0.0033	$ 1.2375	$ 1.2776	$ 1.2776	$0.2480	$ 1.0324	
Transmission Connection Charges	**$ 2,215,089**	**$ 540,469**	**$ 11,939**	**$ 1,967,181**	**$ 421,380**	**$ 93,265**	**$ 80**	**$ 25,769**	**$ 5,275,174**
Regulatory Charges									
Wholesale Market Service Rate	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$0.0044	$ 0.0044	
Rural Rate Protection Rate	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$ 0.0013	$0.0013	$ 0.0013	
Regulator Charges	**$ 3,486,715**	**$ 928,079**	**$ 20,502**	**$ 3,549,665**	**$ 862,455**	**$ 197,351**	**$ 683**	**$ 52,326**	**$ 9,097,776**
Smart Metering Charge									
Monthly Smart Metering Rate per Customer	$ 0.79	$ 0.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Metering Charge	**$ 561,628**	**$ 46,666**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 608,293**
Total Cost of Power	**$ 62,306,636**	**$ 16,326,770**	**$ 360,377**	**$ 61,321,036**	**$ 14,700,485**	**$ 3,354,332**	**$11,049**	**$ 892,506**	**$ 159,273,191**

8.1-Energy Probe-49

Ref: Exhibit 3, Tab 2, Schedule 1

a) Tables 3-22 and 3-23 appear to have a number of differences for 2014. For each difference, please explain the difference and indicate which figure is the forecast used to determine the revenue deficiency and to collect amounts through rate riders. For example, Tables 3-22 and 3-23 show the same kWh for the GS > 50 class, but different figures for the kW forecast for 2014.

RESPONSE:

Oakville Hydro has corrected Table 3-22 and Table 3-23.

b) Some of the street lighting and sentinel figures appear to have been reversed between Tables 3-22 and 3-23. Please provide corrected tables.

RESPONSE:

Oakville Hydro has corrected Table 3-22 and Table 3-23.

Corrected Table 3-22 –Historical and Forecasted Volumes and Customers (including the impact of CDM)

Rate Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential							
Customers	54,636	56,419	56,923	57,796	58,286	58,922	59,565
kWh	559,480,721	555,127,459	597,295,732	588,575,028	600,534,935	597,332,133	595,449,114
General Service < 50 kW							
Customers	4,809	4,888	4,897	4,923	4,911	4,919	4,926
kWh	175,714,453	170,241,898	170,509,443	167,110,172	162,269,747	159,996,164	158,508,292
Unmetered Loads							
Connections	675	679	665	673	676	675	674
kWh	3,915,659	3,936,855	3,816,306	3,663,023	3,696,824	3,600,460	3,504,020
General Service > 50 to 999 kW							
Customers	813	854	871	878	893	906	920
kWh	593,404,108	584,084,594	602,895,003	602,311,205	603,821,865	598,339,440	606,291,782
kW	1,614,129	1,564,795	1,595,879	1,590,500	1,631,952	1,568,791	1,589,641
General Service > 1000 kW							
Customers	17	18	17	16	16	16	16
kWh	170,191,555	147,437,802	151,840,794	148,964,252	149,411,044	148,333,272	147,386,488
kW	411,997	357,797	370,035	338,497	328,299	331,941	329,822
Large Use >5000 kW							
Customers	1	1	-	-	-	-	-
kWh	60,236,729	1,377,628	-	-	-	-	-
kW	106,448	30,509	-	-	-	-	-
Embedded Distributor							
Customers	-	-	-	-	-	1	1
kWh	-	-	-	-	-	8,432,400	33,729,600
kW	-	-	-	-	-	18,250	73,000
Street lights							
Connections	16,025	16,286	16,598	16,828	17,113	17,398	10,404
kWh	135,737	133,918	126,835	122,878	119,670	119,132	116,788
kW	30,509	30,957	31,713	32,425	32,927	32,965	24,961
Sentinel Lights							
Connections	237	183	179	177	167	162	157
kWh	10,963,488	11,085,581	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	377	372	350	339	332	331	324
Total							
Customer/Connections	77,212	79,328	80,150	81,291	82,062	82,999	76,664
kWh	1,574,042,450	1,473,425,735	1,537,840,892	1,522,342,881	1,531,679,011	1,527,964,086	1,553,929,178
kW from applicable classes	2,163,461	1,984,430	1,997,977	1,961,761	1,993,510	1,952,278	2,017,748

Corrected Table 3-23 – Weather Normalized Historical and Forecasted Volumes and Customers

Rate Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential							
Customers	54,636	56,419	56,923	57,796	58,286	58,922	59,565
kWh	557,929,818	553,583,537	598,826,330	588,720,036	606,398,134	597,332,133	595,449,114
General Service < 50 kW							
Customers	4,809	4,888	4,897	4,923	4,911	4,919	4,926
kWh	175,308,888	169,892,748	170,577,580	167,163,051	163,853,640	159,996,164	158,508,292
Unmetered Loads							
Connections	675	679	665	673	676	675	674
kWh	3,915,659	3,936,855	3,816,306	3,694,151	3,727,960	3,600,460	3,504,020
General Service > 50 to 999 kW							
Customers	813	854	871	878	893	906	920
kWh	592,172,921	582,834,946	603,272,718	602,312,136	603,854,708	598,339,440	606,291,782
kW	1,552,623	1,528,140	1,581,726	1,579,207	1,583,252	1,568,791	1,589,641
General Service > 1000 kW							
Customers	17	18	17	16	16	16	16
kWh	169,939,484	147,153,623	152,644,513	148,985,706	150,424,815	148,333,272	147,386,488
kW	380,291	329,301	341,588	333,401	336,621	331,941	329,822
Large Use >5000 kW							
Customers	1	1	-	-	-	-	-
kWh	60,236,729	1,377,628	0	0	0	0	0
kW	106,448	2,363	0	0	0	0	0
Embedded Distributor							
Customers	-	-	-	-	-	1	1
kWh	0	0	0	0	0	8,432,400	33,729,600
kW	0	0	0	0	0	18,250	73,000
Street lights							
Connections	16,025	16,286	16,598	16,828	17,113	17,398	6,120
kWh	135,737	133,918	125,971	122,014	119,670	119,132	116,788
kW	30,600	30,940	31,697	32,366	33,004	32,965	24,961
Sentinel Lights							
Connections	237	183	179	177	167	162	157
kWh	10,963,488	11,085,581	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	377	372	350	339	332	331	324
Total							
Customer/Connections	77,212	79,328	80,150	81,291	82,062	82,999	72,379
kWh	1,570,602,725	1,469,998,837	1,540,620,197	1,522,593,418	1,540,203,852	1,527,964,086	1,553,929,178
kW from applicable classes	2,070,339	1,891,116	1,955,361	1,945,312	1,953,209	1,952,278	2,017,748

8.1-VECC-32

Ref: E3/T1/S1, Page 4

Excel Load Forecast Model, CDM Tab

a) Please provide a matrix that shows for each year from 2006-2012 the OPA reported in impact of CDM programs in each year, by program year.

RESPONSE:

The following matrix provides the impact of CDM in MWh programs in each year by program year.

Program Year	2006	2007	2008	2009	2010	2011	2012
Third Tranche	17,274	4,246	160				
2006	5,337	5,337	5,337	5,337	927	927	848
2007	-	3,388	2,603	2,507	2,507	2,507	2,428
2008	-	-	4,481	4,384	4,384	4,384	4,125
2009	-	-	-	8,929	7,889	7,889	7,887
2010	-	-	-	-	6,548	4,708	4,700
2011	-	-	-	-	-	6,762	6,757
2012	-	-	-	-	-	-	5,977
Total	22,611	12,972	12,581	21,156	22,255	27,177	32,723

b) Please explain any differences between the annual totals reported above and the annual CDM value shown in the CDM Tab, C3-C9.

RESPONSE:

The CDM values shown in the CDM Tab, C3-C9 are the CDM savings from the pre-2011 CDM programs. The CDM savings for the 2011 and 2012 CDM programs are located in cells AA31 and AB31 respectively. These values were added to the pre-2011 CDM savings in column F of the CDM tab. The values in column F are equal to the values provided in Oakville Hydro's response to part a) of this interrogatory. Oakville Hydro notes that the values in Column F (not column C) were used to derive the impact of CDM on the historical load.

Year	OPA CDM Results (Net) 2006-2010	2011 CDM Results	2012 CDM Results	Total Net Annual CDM Results
	Column C	Cell AA31	Cell AB31	Column F
2006	22,611,108			22,611,108
2007	12,971,617			12,971,617
2008	12,580,877			12,580,877
2009	21,156,404			21,156,404
2010	22,254,506			22,254,506
2011	20,414,733	6,762,407		27,177,140
2012	19,988,288		12,734,386	32,722,674

8.1-VECC-33

Ref: E3/T1/S2, page 2 (lines 18-19)

a) To what does Oakville attribute its fast load growth over the historical period?

RESPONSE:

As illustrated in Exhibit 3, Tab 1, Schedule 2, Table 3-6, Oakville Hydro's residential growth rate ranged from three to four per cent from 2003 to 2009. During this period Oakville Hydro was a growing community as illustrated by the number of housing starts in the following table. Growth was highest during the period 2002 to 2007 with an average of 1,690 housing starts per year. The number of housing starts declined further beginning in 2008 and there was an average of 784 housing starts during the period 2008 to 2012.

Year	Housing Starts
2002	1928
2003	1890
2004	1874
2005	1406
2006	1348
2007	1689
2008	944
2009	433
2010	914
2011	824
2012	807

Source: http://www.oakville.ca/assets/2011%20planning/demo-housingstarts2012.pdf

8.1-VECC-34

Ref: E3/T1/S2. Page 4

a) What customers/customer classes are included in the "Number of Customers" variable?

RESPONSE:

Oakville Hydro included all customers in the Number of Customers variable. Oakville Hydro notes that for the Sentinel and Street Lighting classes the number of customers and not the number of connections was included in the Number of Customers variable.

b) Were any alternative specifications tested using economic variables such as GDP or Employment? If no, why not? If yes, what were the results and why were these models rejected?

RESPONSE:

As discussed on Exhibit 3, Tab 1, Schedule 2, Page 4, Oakville Hydro tested a number of other drivers but removed those that were statistically insignificant or those that produced an unintuitive result. One of those variables that were found to be statistically insignificant was the Ontario Real GDP. Oakville did not test the employment variable in its initial modelling but has included both the Ontario Real GDP and the employment variable in its model. As shown in the results below, both the Ontario Real GDP and the employment variable are statically insignificant with a t-stat of 1.35 and 0.13.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	96.96%
R Square	94.01%
Adjusted R Square	93.65%
Standard Error	351910036.62%
Observations	141

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	2.56731E+16	3.20914E+15	259.13448	8.55109E-77
Residual	132	1.6347E+15	1.23841E+13		
Total	140	2.73078E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(62,688,475.42)	16,232,373.46	(3.86)	0.00	(94,797,714.56)	(30,579,236.28)
HDD	19,249.58	2,469.88	7.79	0.00	14,363.91	24,135.26
CDD	252,124.72	11,400.08	22.12	0.00	229,574.23	274,675.21
Days	3,379,197.99	380,796.56	8.87	0.00	2,625,944.76	4,132,451.21
Spring Fall Flag	(4,535,474.31)	843,177.49	(5.38)	0.00	(6,203,362.73)	(2,867,585.90)
Customers	955.54	228.80	4.18	0.00	502.94	1,408.13
Daylight hours	(27,617.29)	7,628.05	(3.62)	0.00	(42,706.32)	(12,528.26)
Employment	9,079.25	6,746.97	1.35	0.18	(4,266.93)	22,425.43
Ontario Real GDP	20,484.06	152,838.20	0.13	0.89	(281,845.00)	322,813.12

8.1-VECC-35

Ref: E3/T1/S2, page 7

a) What are the actual 2013 kWh Purchases excluding the embedded distributor?

RESPONSE:

Oakville Hydro's actual 2013 purchases excluding the embedded distributor are 1,578,175,867 kWh.

b) Please provide a schedule that sets out:

i. The actual 2013 purchases, excluding the embedded distributor.
ii. The actual CDD and HDD values for 2013
iii. The assumed weather normal CDD and HDD values
iv. The difference between the Normal and Actual CDD values multiplied by 252,726
v. The difference between the Normal and Actual HDD values multiplied by 19,073
vi. The addition of items (i), (iv) and (v)

RESPONSE:

The table requested is provided below.

		Actual		Weather Normal		Difference		
Month	Actual Purchases*	HDD	CDD	HDD	CDD	Actual HDD and Normal HDD	Actual HDD and Normal HDD	Columns i), iv) & v)
	i)	ii)		iii)		iv) = iii) - ii) * 19073	= iii) - ii) * 252,72	i) + iv) + v)
January	136,623,837	624.4	-	710.9	-	(1,649,133)	-	134,974,703
February	123,861,409	631.5	-	616.1	-	293,043	-	124,154,452
March	127,965,347	554.8	0.0	532.4	-	427,235	5,055	128,397,637
April	118,566,561	358.6	-	308.5	1.0	955,830	(240,090)	119,282,301
May	121,894,266	109.1	23.1	144.9	15.5	(682,813)	1,909,886	123,121,339
June	133,778,511	33.0	50.8	30.4	70.7	49,862	(5,022,027)	128,806,347
July	157,605,250	1.3	123.3	2.4	132.0	(20,027)	(2,195,106)	155,390,118
August	146,693,107	4.4	93.8	5.2	112.8	(14,850)	(4,796,378)	141,881,879
September	126,652,919	83.0	18.2	53.6	39.2	561,019	(5,309,051)	121,904,887
October	122,004,826	208.5	0.4	228.8	3.3	(387,400)	(722,074)	120,895,352
November	124,440,840	478.2	-	395.3	-	1,581,969	-	126,022,809
December	138,088,993	688.1	-	608.3	-	1,521,480	-	139,610,473
Total	1,578,175,868	3,775	310	3,637	374	2,636,216	(16,369,785)	1,564,442,298

8.1-VECC-36

Ref: E3/T1/S2, page 9

a) Please provide the actual year-end 2013 customer/connection count by class.

RESPONSE:

The actual year-end 2013 customer / connection count by rate class is provided in the following table. Oakville Hydro notes that the General Service Greater > 1,000 rate kW class includes Milton Hydro. Oakville Hydro has proposed that a new Embedded Distributor rate class be created for Milton Hydro.

Rate Class	Customers / Connections
Residential	58,834
General Service < 50 kW	4,965
General Service > 50 to 999 kW	913
General Service > 1000 kW	17
Street Lights	17,123
Sentinel Lights	164
Unmetered Loads	679

8.1-VECC-37

Ref: E3/T1/S3, page 2

a) Please provide copies of the OPA's final reports for 2011 and 2012.

RESPONSE:

Oakville Hydro received the OPA's final verified 2012 CDM results on September 1, 2013 and has updated its LRAM request in response to Board staff interrogatory number 9.2-Staff-52 and provided copies of the final report for 2012 as an Appendix 9-B. A copy of the final OPA's final verified 2011 CDM results was provided as Attachment H to Exhibit 4 of Oakville Hydro's Cost of Service Application.

Oakville Hydro notes that it had updated its load forecast to reflect the OPA's Final Verified 2012 CDM results prior to submitting its Application on October 1, 2013.

b) Please provide any preliminary or part-year OPA CDM reports for 2013.

RESPONSE:

A copy of the OPA's Conservation & Demand Management Status Report – 3rd Quarter 2013 Preliminary Results is provided as Appendix 8-A.

8.1-VECC-38

Ref: E3/T1/S3, pages 3-4

a) Please confirm that Oakville's proposed LRAMVA for 2014 is based on 46,159 MWh of CDM savings. If not confirmed what is the total kWh value used to determine the LRAMVA and how was it determined?

RESPONSE:

In its Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), the Board established an LRAM variance account ("LRAMVA") to capture the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

It is Oakville Hydro's understanding that the level of CDM program activities to be included in the LRAM variance account would exclude savings related to pre-2011 plans. Therefore, while the adjustment for the load forecast is 46,159 MWh as discussed in response to part c) of this interrogatory, the CDM savings to be included in the LRAM variance account would exclude the CDM savings for pre-2011 programs.

Oakville Hydro inadvertently included the pre-2011 programs in Table 3-16. The following table provides the revised CDM savings of 27,203 MWh to be included in the LRAM variance account for the 2014 Test Year.

2014 CDM Impacts by Rate Class (MWh)

Rate Classification	2011 Programs	2012 Programs	2013 Programs	2014 Programs	Total
Residential	2,274	1,158	2,837	1,435	7,704
General Service > 50 kW	176	190	277	138	780
General Service > 50 kW	4,134	4,457	6,502	3,233	18,326
General Service > 1,000 kW	88	95	138	69	390
Streetlighting				3	3
Total CDM Savings	6,672	5,900	9,754	4,877	27,203

b) Please provide the basis for the 18,957 MWh value for pre-2011 program savings.

RESPONSE:

The value of 18,597 MWh is based on the persistent CDM savings in 2014 from pre-2011 CDM programs as reported in the OPA's 2006-2010 Final OPA CDM Results adjusted for the half-year rule. A copy of the OPA's 2006-2010 Final OPA CDM Results is provided as live excel document.

c) The text at page 3, lines 6-8 indicates that the LRAM is to be based on program savings in 2014 from 2011-2014 programs. However the proposed MWh value includes savings from pre-2011 programs. Please reconcile.

RESPONSE:

Please see Oakville Hydro's response to part a) of this interrogatory.

d) Please confirm that the OPA reports used for LRAM purposes report "annualized" savings. If so why is it appropriate to establish the LRAMVA value for 2014 using the ½ year rule for 2014 program savings?

RESPONSE:

The LRAMVA is based on the annualized savings for all years since that is the way the OPA reports results. The half-year rule only applies to the CDM adjustment being made the load forecast since the half-year rule is a reflection of what actually happens to the load when CDM programs occur over the year.

e) Please explain how the 46,159 MWh was allocated to customer classes for both load forecast and LRAMVA purposes.

RESPONSE:

Oakville Hydro allocated the MWh to customer classes for the load forecast based upon the Program Results reported by the OPA in their 2006 to 2010 Final Report, 2011 Final Report and 2012 Final Report. Oakville Hydro allocated the MWh to customer classes for LRAMVA purposes based upon the Program Results reported by the OPA in their 2006 to 2010 Final Report, 2011 Final Report and the 2012 Preliminary Results.

The results of the consumer programs are allocated to the residential rate class. The industrial and business programs are allocated to the General Service <50 kW, General Service > 50 kW and General Service > 1,000 rate classes based upon the percentage of actual CDM Savings for each rate class. The pre-2011 CDM Savings, which are no longer applicable for LRAMVA purposes, were allocated based upon the percentages used in Oakville Hydro's 2010 Cost of Service Application. The 2011 to 2014 CDM Savings were allocated based upon actual CDM Savings based on 2011 actual CDM Savings by rate class.

The street lighting savings were allocated to the Street Lighting rate class based upon the forecasted savings resulting from the conversion to LED lighting.

f) Was Milton Hydro a customer of Oakville prior to August 2013? If not, what changed as of this date that it became a customer?

RESPONSE:

As discussed on Exhibit 3, Tab 1, Schedule 3, Page 4, Oakville Hydro became a host distributor to Milton Hydro in August 2013. Milton Hydro is connected to Oakville Hydro's distribution system at the Glenorchy Municipal Transformer Station. Prior to August 2013 Milton Hydro was not one of Oakville Hydro's customers.

8.1-VECC-39

Ref: E3/T1/S3, page 5

a) Please explain how the use of LED lights changes the load profile of the Street Light class.

RESPONSE:

The use of LED lights does not change the load profile but rather the total consumption. Oakville Hydro has scaled the load profile to reflect the reduction in the forecasted consumption for the Street Lighting rate class.

b) Does the use of LED lights also change the total kWh used by the class and, if so, is this reflected in three MWh reduction shown in Table 3-18?

RESPONSE:

Yes, the use of LED lights change the total kWh used by the street lighting rate class which is reflected in 3 MWh reduction shown in Table 3-18.

8.1-VECC-40

Ref: E3/T2/S1, page 2

a) Table 3-22 shows 10,404 connections for street lights in 2014 whereas Table 3-23 shows 6,120 and Table 3-7 shows 17,688. Please reconcile.

RESPONSE:

The number of street lighting connections in Table 3-7 is the forecasted number of street lighting connections based on the historical ratio of one street light per connection. The number of street lighting connections in Table 3-22 is the number of street lighting connections based upon the revised ratio of 1.7 street lights per connections. The number of street lighting connections in Table 3-23 was inadvertently divided by 1.7 twice. The correct forecast of the number of street lighting connections is 10,404.

b) If Oakville Hydro has re-evaluated the number of street light connections for purposes of its 2014 rate application, please provide the supporting analysis for the change.

RESPONSE:

In Exhibit 7, Tab 1, Schedule 1, Page 4 of 6, lines 13-18, Oakville Hydro provided the details regarding the re-evaluated number of Street Light connections.

Issue 8.2 *Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?*

8.2-Staff-44

Ref: Exhibit 7/Tab 1/Schedule 3/p. 3 Appendix 2-P

Revenue to Cost Ratio Changes

On Page 1 of this schedule, Oakville Hydro indicates that it is re-aligning its revenue-to-cost ratios for those Rate Classes that are outside of the Board's Policy range. The Tables on page 3 show the new proposed ratios for the various classes with minor adjustments. However, in the General Service <50 kW class, the previously approved ratio of 112% is proposed to change to 87%.

Please provide a rationale for this significant change to the revenue-to-cost ratio for the GS<50kW class and include discussion of the resulting impacts on other customer classes.

RESPONSE:

Oakville Hydro entered the Proposed Base Revenue Requirement (excluding miscellaneous revenue) from line 23 of the cost allocation model in Column 7A rather than the total revenue requirement from line 40 in the cost allocation model. Oakville Hydro has corrected Appendix 2-P below. The revenue requirement and miscellaneous revenue allocate to each rate has not changed. The proposed revenue to cost ratio has been corrected for each rate class. As shown in part C of Appendix 2-P, Oakville Hydro proposed that those rate classes that are above the Board's Policy range have been lowered to the top of the Board's Policy range and the remaining rate classes be adjusted proportionately.

Oakville Hydro has updated its Cost Allocation Model to correct an error on Tab I7.1, Meter Capital and to reflect the revised 2014 revenue requirement. Oakville Hydro is proposing to update its revenue to cost ratios to change the Embedded Distributor rate class to 100% and to change the revenue to cost rations for all classes below 100% to 97.54. The updated Cost Allocation Model is provided as Appendix 8-B. The details are provided in the Proposed Appendix 2-P below.

Corrected Appendix 2-P

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 16,960,850	51.09%	$ 23,225,056	59.68%
GS < 50 kW	$ 4,174,986	12.58%	$ 3,531,132	9.07%
GS > 50 kW	$ 8,903,802	26.82%	$ 9,070,974	23.31%
GS > 1,000 kW	$ 1,075,462	3.24%	$ 1,660,523	4.27%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 1,910,416	5.75%	$ 1,160,627	2.98%
Sentinel Lighting	$ 41,453	0.12%	$ 17,857	0.05%
Unmetered Scattered Load (USL)	$ 132,845	0.40%	$ 103,030	0.26%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%	$ 146,940	0.38%
Total	$ 33,199,812	100.00%	$ 38,916,139	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 17,835,031	$ 20,881,694	$ 21,508,431	$ 1,374,927
GS < 50 kW	$ 4,155,428	$ 4,865,278	$ 3,997,189	$ 240,169
GS > 50 kW	$ 7,054,967	$ 8,260,129	$ 8,501,101	$ 297,278
GS > 1,000 kW	$ 1,265,214	$ 1,481,343	$ 1,524,423	$ 48,507
Large User, if applicable				
Street Lighting	$ 862,457	$ 1,009,786	$ 1,035,894	$ 66,829
Sentinel Lighting	$ 21,904	$ 25,645	$ 20,397	$ 1,031
Unmetered Scattered Load (USL)	$ 131,641	$ 154,129	$ 116,925	$ 6,711
Other class, if applicable				
Embedded distributor class	$ 172,855	$ 202,383	$ 176,026	$ 301
Total	$ 31,499,496	$ 36,880,386	$ 36,880,386	$ 2,035,753

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7D + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	107.00	95.83	98.53	85 - 115
GS < 50 kW	112.00	144.58	120.00	80 - 120
GS > 50 kW	85.00	94.34	96.99	80 - 120
GS > 1,000 kW	129.00	92.13	94.72	80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	92.76	95.01	70 - 120
Sentinel Lighting	70.00	149.39	120.00	80 - 120
Unmetered Scattered Load (USL)	120.00	156.11	120.00	80 - 120
Other class, if applicable				
Embedded distributor class		137.94	120.00	

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	98.53			85 - 115
GS < 50 kW	120.00			80 - 120
GS > 50 kW	96.99			80 - 120
GS > 1,000 kW	94.72			80 - 120
Large User, if applicable				85 - 115
Street Lighting	95.01			70 - 120
Sentinel Lighting	120.00			80 - 120
Unmetered Scattered Load (USL)	120.00			80 - 120
Other class, if applicable				
Embedded distributor class	120.00			

Revised Appendix 2-P

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 16,960,850	51.09%	$ 22,920,746	57.30%
GS < 50 kW	$ 4,174,986	12.58%	$ 4,232,087	10.58%
GS > 50 kW	$ 8,903,802	26.82%	$ 9,679,370	24.20%
GS > 1,000 kW	$ 1,075,462	3.24%	$ 1,709,918	4.27%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 1,910,416	5.75%	$ 1,177,241	2.94%
Sentinel Lighting	$ 41,453	0.12%	$ 18,279	0.05%
Unmetered Scattered Load (USL)	$ 132,845	0.40%	$ 106,065	0.27%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%	$ 154,789	0.39%
Total	$ 33,199,812	100.00%	$ 39,998,495	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 17,835,031	$ 22,920,746	$ 20,972,941	$ 1,385,053
GS < 50 kW	$ 4,155,428	$ 4,232,087	$ 4,824,811	$ 253,694
GS > 50 kW	$ 7,054,967	$ 9,679,370	$ 9,130,693	$ 311,028
GS > 1,000 kW	$ 1,265,214	$ 1,709,918	$ 1,618,058	$ 49,877
Large User, if applicable				
Street Lighting	$ 862,457	$ 1,177,241	$ 1,080,926	$ 67,412
Sentinel Lighting	$ 21,904	$ 18,279	$ 20,885	$ 1,050
Unmetered Scattered Load (USL)	$ 131,641	$ 106,065	$ 120,423	$ 6,855
Other class, if applicable				
Embedded distributor class	$ 172,855	$ 154,789	$ 154,492	$ 297
Total	$ 31,499,496	$ 39,998,495	$ 37,923,230	$ 2,075,265

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7D + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	107.00	106.04	97.54	85 - 115
GS < 50 kW	112.00	105.99	120.00	80 - 120
GS > 50 kW	85.00	103.21	97.54	80 - 120
GS > 1,000 kW	129.00	102.92	97.54	80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	105.73	97.54	70 - 120
Sentinel Lighting	70.00	105.74	120.00	80 - 120
Unmetered Scattered Load (USL)	120.00	106.46	120.00	80 - 120
Other class, if applicable				
Embedded distributor class		100.19	100.00	

8.2-Staff-45

Ref: Exhibit 7/Tab1/Schedule 2

Embedded Distributor Rate Class

In the Kitchener-Wilmot Distribution rates case (EB-2013-0147) a variation on direct cost allocation was proposed and adopted in the settlement by the distributor. The correction is documented in Undertaking JT1.7 of that proceeding and involves adjusting the proportion of the Net Book Value and Gross Book Value found in Worksheet I-9 in the model, at cell C148 (change the formula from =I4 C59 to I4 K58). Please apply the Kitchener-Wilmot correction to the Oakville Hydro Cost Allocation Model and provide the results.

RESPONSE:

Oakville Hydro has changed the formula in cell C148 on Sheet I-9 to point to the net fixed distribution assets on Sheet I4 rather than the gross distribution assets. As a result of this change, a larger share of the return on debt and return on equity is allocated to the Embedded Distributor.

Line Number	Line Items	Application	Revised
148	Total Net Fixed Assets Excluding General Plant	283,556,436	146,522,883
65	Directly Allocated Fixed Assets	860,670	860,670
150	Approved Total Return on Debt	4,337,328	4,337,328
151	Approved Total Return on Equity	6,549,485	6,549,485
65/148*150	Allocated Return on Debt	13,165	25,477
65/148*151	Allocated Return on Equity	19,879	38,471
	Allocated Return on Rate Base	33,044	63,949

8.2-Energy Probe-50

Ref: Exhibit 7, Tab 1, Schedule 1 &

Exhibit 3, Tab 3, Schedule 1

a) Please reconcile the number of connections used in the cost allocation model for the USL and sentinel rate classes (675 and 160, respectively) with the figures shown for 2014 in Tables 3-22 and 3-23 (674 and 157, respectively).

RESPONSE:

As noted in Exhibit 3, Tab 1, Schedule 2, Page 9, Oakville Hydro's forecasted the number of customers and connections at the end of the 2013 Bridge Year and the 2014 Test Year. Oakville Hydro has used the average number of customers for the cost allocation model and rate design.

Unmetered Loads: The number of connections used in the cost allocations is the average number of connections calculated as the average of the 2013 connections of 675 and the 2014 connections of 675 rounded up to 675. The number of connections in Table 3-22 and 3-23 are the estimated number of connections at the end of 2014.

Sentinel Lighting: The number of connections used in the cost allocations is the average number of connections in calculated as the average of the 2013 connections of 162 and the 2014 connections of 157. The number of connections in Table 3-22 and 3-23 are the number of estimated connections at the end of 2014.

b) Please reconcile the number of connections used in the cost allocation model for the street lighting class (10,413) with the figures for 2014 shown in Table 3-22 (10,404) and in Table 3-23 (6,120).

RESPONSE:

As discussed in Exhibit 7, Tab 1, Schedule 1, Page 4, Oakville Hydro conducted an in-depth review of the number of street lighting connections and concluded that the ratio of street lights to street light connections is 1.7 street lights per connection.

Table 3-22 provides the number of connections based on Oakville Hydro's current ratio of one street light per connection for the 2013 Bridge Year and the proposed street light connection of 1.7 street lights for the 2014 Test Year.

# of Connections	
2013 Bridge Year - Closing Balance	17,398
2014 Test Year - Opening Balance	10,234
2014 Test Year - Closing Balance	10,404
2014 Average Number of Connections	10,319

In calculating the average number of connection for the cost allocation model Oakville Hydro adjusted the number of connections for the 2013 Bridge Year by the proposed ratio of 1.7 street lights per connection to reflect the opening balance for the 2014 Test Year. Oakville Hydro has recalculated the average number of connections to be 10,319. Oakville Hydro has updated its cost allocation model to reflect this number in response to Board staff interrogatory number 8.2-Staff-44.

Table 3-23 provided the normalized historical and forecasted number of volumes and customers. In that table the proposed number of connections of 10,404 had been inadvertently divided by the proposed ratio of street lights to street light connections of 1.7

to 1 (10,404 / 1.7 = 6,120). Oakville Hydro has corrected Table 3-23 in response to 8.1-EP-49.

8.2-Energy Probe-51

Ref: Exhibit 7, Tab 1, Schedule 2 &
Exhibit 3, Appendix A

a) Please show how the average peak load of 6 MW was calculated based on the information provided in Exhibit 3, Appendix A.

RESPONSE:

Oakville Hydro calculated the average peak load of 6 MW based on the Maximum One-Hour Demand provided by Milton Hydro rounded to the nearest MW.

Month	Maximum One Hour Demand in MW
January	5.7
February	5.6
March	5.4
April	5
May	6.3
June	7.8
July	7.9
August	6.9
September	6.6
October	4.8
November	5.4
December	5.6
Average	6.1

b) What is the one hour demand capacity of the station? Is this the 156 MW noted on page 1 of Exhibit 7, Tab 1, Schedule 2?

RESPONSE:

The hourly demand capacity of Glenorchy MTS 1 is shown in the attached Limited Time Rating (LTR) Load Profile, and it varies with temperature. In this profile, assuming that the temperature is sustained at 30˚C, and assuming that the actual load profile matches the attached load profile, the station can handle a peak of 1.36pu (per unit) loading. 1.36pu translates to 153 MW peak load capacity assuming a steady power factor of 0.9, so this is commonly referred to as a station with a 153 MW LTR. On page 1 of Exhibit 7, Tab 1, Schedule 2, the total station capacity of 156 MW is referred to as a more practical station capacity value because it is unlikely to have 10 consecutive days with a sustained power factor as low as 0.9 and a sustained temperature as high as 30˚C.

c) Please provide a revised Table 7-5 that is based on the maximum one hour demand of 7.9 MW as identified in Exhibit 3, Appendix A.

RESPONSE:

Oakville Hydro has revised Table 7-5 based on the maximum on hour demand of 7.9 as identified in Exhibit 3, Appendix A.

However, in Oakville Hydro's view, it is appropriate to allocate costs to Milton Hydro based upon their average load forecast of 6.0 MW per month as Milton Hydro has committed to 72 MW of load per calendar year in Section 3.1 of the Connection Agreement between Oakville Hydro and Milton Hydro thereby eliminating Customer Connection Risk.

Table 7-5 – Direct Allocation of Costs to the Embedded Distributor Rate Class Based on 7.9MW

USofA Account	Description	Allocation ($)
Allocation of Net Fixed Assets		
1805	Land	74,510
1815	Transformer Station Equipment	1,093,958
1980	System Supervisory Equipment	3,095
1860	Meters	92,000
2105	Accumulated Depreciation	(77,420)
Average Net Fixed Assets		1,312,745
Allocation of OM&A and Amortization		
5005	Operation Supervision and Engineering	1,893
5014	Transformer Station Equipment	2,020
5065	Meter Expense	2,900
5012	Station Buildings and Fixtures	2,431
5110	Maintenance of Buildings and Fixtures - Distribution Stations	91
5310	Meter Reading Expense	80
5315	Customer Billing	113
5620	Office Supplies and Expenses	913
5705	Amortization	24,476
Allocated Expenses Including Amortization		34,916

8.2-Energy Probe-52

Ref: Exhibit 7, Tab 1, Schedule 2 &
Exhibit 2, Tab 5, Schedule 2

a) Has Oakville Hydro allocated the $5 million in costs associated with the on-site emergency back-up transformer for the Glenorchy Municipal Transformer Station as discussed on page 73 of Exhibit 2, Tab 5, Schedule 2 to the embedded distributor class? If not, why not?

RESPONSE:

As discussed in Exhibit 7, Tab 1, Schedule 2, Oakville Hydro consulted with Milton Hydro regarding the allocation of the costs associated with the Glenorchy Municipal Transformer Station. Milton Hydro has advised that up until 2017 it would be able to transfer all load to one of Milton Hydro's other supply points in the event that the Glenorchy Municipal Transformer Station experienced a catastrophic failure.

From 2017 to 2022, Milton Hydro would be able to transfer all load to other Milton supply points only during off peak times of the year. In the event of a catastrophic failure during peak periods where there are no contingencies at the other supply points, Milton Hydro would be able to transfer load to those other supply points. If a contingency existed at one of the other supply points Milton Hydro could be forced to shed load.

b) Will the emergency back-up transformer be used only for Oakville Hydro customers or will Milton Hydro customers also benefit from this expenditure?

RESPONSE:

As discussed in response to part a) of this question, Milton Hydro has made its own emergency plans for responding to a substantial power failure at the Glenorchy Municipal Transformer Station.

c) If Milton Hydro customers receive some of the benefits associated with this expenditure, please provide a table that shows the direct allocation to the embedded class in a manner similar to Table 7-5.

RESPONSE:

Based on Milton Hydro's emergency plans, its customers will not receive some of the benefits associated with the on-site emergency backup transformer.

8.2-Energy Probe-53

Ref: Exhibit 7, Tab 1, Schedule 3 & Appendix A

a) Please explain why the status quo ratios shown in the table at the top of page 7 are different than the ratios shown in Sheet O1 in the cost allocation model in Appendix A.

RESPONSE:

As explained in response to Board staff interrogatory 8.2-Staff-44, Oakville Hydro entered the Proposed Base Revenue Requirement (excluding miscellaneous revenue) from line 23 of the cost allocation model in Column 7A rather than the total revenue requirement from line 40 in the cost allocation model. Oakville Hydro has corrected Appendix 2-P in response to Board staff interrogatory number 8.2-Staff-44 and it is proposing to update its revenue to cost ratios to change the Embedded Distributor rate class to 100% and to change the revenue to cost rations for all classes below 100% to 97.54.

b) Please explain why Oakville Hydro is proposing to move all revenue to cost ratios to 100% in 2015.

RESPONSE:

As discussed in Exhibit 7, Tab 1, Schedule 3, Page 1, Oakville Hydro is not proposing any further adjustments during the IRM period.

8.2-Energy Probe-54

Ref: Exhibit 7, Appendix A

Using the revenue to cost ratios shown in Appendix A, Sheet O1, as the starting point, please move the revenue to cost ratio for the embedded class to 100%, lower the ratio for the USL, sentinel and GS < 50 classes to 120%. Please calculate the revenue to cost ratios for the remaining classes (residential GS > 50, GS > 1,000, street lighting) so that they are all the same and result in revenue neutrality overall. Based on this approach, what is the revenue to cost ratios for the rate classes that are currently below 100%?

RESPONSE:

Based on the approach described above, the revenue to cost ratio for the Residential, GS > 50 kW, GS > 1,000 kW and Street Lighting rate classes would be 97.84%.

Rate Class	Cost Allocation Model ($)	Proposed Revenue ($)	Revenue to Cost Ratio (%)
Residential	23,225,056	22,722,560.89	97.84
GS < 50 kW	3,531,132	4,237,358.19	120.00
GS >50 kW	9,070,974	8,874,715.50	97.84
GS >1000 kW	1,660,523	1,624,596.54	97.84
Embedded Distributor	146,940	176,327.41	120.00
Sentinel Lights	17,857	21,428.44	120.00
Street Lighting	1,160,627	1,135,515.97	97.84
Unmetered and Scattered	103,030	123,636.44	120.00
	38,916,139.39	38,916,139.39	

8.2-AMPCO-23

Ref: Exhibit 7, Tab 1, Schedule 1, Page 2

Preamble: Oakville Hydro has developed weighting factors based on discussions with staff experienced in the subject area.

a) Please discuss Oakville Hydro's knowledge of other electricity distributors that have developed and proposed weighting factors for accounts 1855 and 5315-4340 (excluding 5335) for Board approval in relation to its proposed weighting factors.

RESPONSE:

In preparing its Application, Oakville Hydro evaluated the proposed weighting factors of three electricity distributors that were, at that time, before the Board in a cost of service proceeding:

- Enersource – EB-2012-0033
- London Hydro – EB-2012-0146/EB-2012-0380
- PowerStream – E EB-2012-0161

The proposed weighting factors for Enersource, London Hydro, PowerStream and Oakville Hydro are provided in the tables below. Oakville Hydro's evaluation supported the analysis that was undertaken by Oakville Hydro's experienced staff.

Weighting for Services (Account 1855)

LDC	Residential	GS <50	GS>50	GS> 1,000	Large Use	Street Light	Sentinel	Unmetered
Enersource	1	2	10	10	30	1	0	1
London	1	1.5	7.5	7.5	0	0.6	0.6	0.6
Powerstream	1	0	0	0	0	0	0	0
Oakville Hydro	1	0	0	0	NA	0	0	0

Weighting for Billing and Collecting (Accounts 5315 to 5340, except 5335)

LDC	Residential	GS <50	GS>50	GS> 1,000	Large Use	Street Light	Sentinel	Unmetered
Enersource	1	2	7	7	15	1	NA	1
London	1	1	6.5	15	15	1	0.1	1
Powerstream	1	2	7	NA	15	2	0.1	1
Oakville Hydro	1	1	6	6	NA	2	0.5	0.5

8.2-AMPCO-24

Ref: Exhibit 7, Tab 1, Schedule 3, Page 1

Preamble: Oakville Hydro indicates it is proposing to realign its revenue-to-cost ratios by reducing the revenue to cost rations for those rate classes that are outside of the Board's policy range to the upper or lower end of the range as applicable, and allocating the revenue to the remaining rate classes proportionately. The proposed ratios are provided in Appendix 2-P on page 3.

a) Please provide more specific details on the strategy/methodology by customer class to move from the previously approved ratios in 2012 (most recent year) to the proposed ratios for the 2014 Test Year. Please discuss how the status quo ratios from the cost allocation model were considered.

RESPONSE:

As discussed in response to Board staff interrogatory number 8.2-Staff-44, Oakville Hydro entered the Proposed Base Revenue Requirement (excluding miscellaneous revenue) from line 23 of the cost allocation model in Column 7A rather than the total revenue requirement from line 40 in the cost allocation model. Oakville Hydro has provided the corrected Appendix 2-P, part C below. The proposed revenue to cost ratio has been corrected for each rate class.

As shown in part C of Appendix 2-P, those rate classes that are above the Board's Policy range have been lowered to the top of the Board's Policy range. The remaining rate classes were adjusted proportionately based upon their percentage of the total revenue requirement on line 40 of sheet O1 of the cost allocation model.

Class	Revenue Requirement	Classes to be Allocated	Per cent Alllocation
Residential	23,225,056	23,225,056	66%
GS < 50 kW	3,531,132		
GS >50 kW	9,070,974	9,070,974	26%
GS >1000 kW	1,660,523	1,660,523	5%
Embedded Distributor	146,940		
Sentinel Lights	17,857		
Street Lighting	1,160,627	1,160,627	3%
Unmetered and Scattered	103,030		
Total	38,916,139	35,117,181	100%

Corrected Part C of Appendix 2-P

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7D + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	107.00	95.83	98.53	85 - 115
GS < 50 kW	112.00	144.58	120.00	80 - 120
GS > 50 kW	85.00	94.34	96.99	80 - 120
GS > 1,000 kW	129.00	92.13	94.72	80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	92.76	95.01	70 - 120
Sentinel Lighting	70.00	149.39	120.00	80 - 120
Unmetered Scattered Load (USL)	120.00	156.11	120.00	80 - 120
Other class, if applicable				
Embedded distributor class		137.94	120.00	

b) Please explain why Oakville Hydro proposes to move the revenue to cost ratio farther away from unity for the residential customer class.

RESPONSE:

Please see response to part a) of this interrogatory. As per the corrected Appendix 2-P, part C, Oakville Hydro proposal was to move the residential rate class closer to unity. In response to Board staff interrogatory number 8.2-Staff-44, Oakville Hydro has proposed to

c) Please provide the revenue to cost ratios for 2013.

RESPONSE:

The revenue to cost ratios for 2013 were those approved in Oakville Hydro's 2012 IRM Application (EB-2011-0189) and are provided in the following table.

2013 Revenue to Cost Ratios

Rate Class	Revenue to Cost Ratio
Residential	107%
General Service Less Than 50 kW	112%
General Service 50 to 999 kW	85%
General Service Greater Than 1,000 kW	129%
Unmetered Scattered Load	120%
Sentinel Lighting	70%
Street Lighting	70%

8.2-AMPCO-25

Ref: Exhibit 7, Tab 1, Schedule 3, Page 6

Preamble: Oakville Hydro updated its cost allocation study for 2014. Oakville Hydro notes it made certain corrections to the load profiles provided by Hydro One.

Please summarize other key data improvements or changes in the updated study.

RESPONSE:

- Load profiles

  As discussed on Exhibit 7, Tab 1, Schedule 1, Page 6, Oakville Hydro scaled the Hydro One load profiles to match the 2014 load forecast.

- Number of street lighting connections

  As discussed on Exhibit 7, Tab 1, Schedule 1, Page 4, Oakville Hydro conducted an in-depth review of the number of street light connections in consultation with the Town of Oakville.

- LED street lights

  As discussed on Exhibit 7, Tab 1, Schedule 1, Page 5, Oakville Hydro consulted with the Town of Oakville in preparing its cost allocation study. During consultations Oakville

Hydro learned that the Town of Oakville plans to convert their street lights to LED lights beginning in 2014. Oakville Hydro has updated the project load to reflect the reduction in energy consumption as a result of the conversion to LED lighting.

- Weighting factors

As discussed on Exhibit 7, Tab 1, Schedule 1, Page 2, Oakville Hydro adjusted the Board's default weighting factors for Billing and Collection and Services accounts to reflect the costs associated with providing these services to each rate class.

- Direct allocation – embedded distributor

As discussed on Exhibit 7, Tab 1, Schedule 2, Page 1, Oakville Hydro allocated a portion of the capital and operating costs associated with the Glenorchy Municipal Transformer Station to the proposed embedded distributor rate class.

8.2-VECC-41

Ref: E7/T1/S1, page 2
Cost Allocation Model, Sheet I5.2

a) Please confirm that the customers in classes other than Residential are responsible for the installation, maintenance, repair and replacement of their service assets.

RESPONSE:

Oakville Hydro confirms that the customers in classes other than the Residential class are responsible for the installation of their service assets. Oakville Hydro only records the costs of service assets for the Residential rate class in OEB account 1855. Service assets for the other rate classes are funded through capital contributions and recorded in the asset account that corresponds to the type of asset installed.

Oakville Hydro is responsible for the maintenance, repair and replacement of the assets that it owns for all rate classes. For the Residential rate class, maintenance and repair costs are recorded in account 5070. For the remaining rate classes, the maintenance and repair costs are recorded in the maintenance account that corresponds to the maintenance activity performed. As assets are replaced, the costs of service assets for the Residential rate class are recorded in account 1855. The replacement costs for assets for the other rate classes are recorded in the account that corresponds to the type of asset installed.

b) If not confirmed, why are the weighting factors for these classes zero?

RESPONSE:

Please see response to part a) of this interrogatory.

8.2-VECC-42

Ref: E3/T2/S1, Tables 3-22 and 3-23

Cost Allocation Model, Sheet I6.2

a) Please explain why the customer counts forecast for 2014 in Exhibit 3 do not match the values use in the Cost Allocation model.

RESPONSE:

As noted in Exhibit 3, Tab 1, Schedule 2, Page 9, Oakville Hydro's forecasted the number of customers and connections at the end of the 2013 Bridge Year and the 2014 Test Year. Oakville Hydro has used the average number of customers for rate design and the cost allocation model.

Rate Class	2013	2014	Average	Cost Allocation
Residential	58,922	59,565	59,244	59,243
General Service < 50 kW	4,919	4,926	4,923	4,923
General Service > 50 kW	906	920	913	913
General Service > 1,000 kW	16	16	16	16
Street Lighting	10,234	10,405	10,319	10,413
Sentinel Lights	162	157	160	160
Unmetered Loads	675	674	675	675

As discussed in response to Energy Probe interrogatory number 8.2-EP-50 b), Oakville Hydro adjusted the number of connections for the 2013 Bridge Year by the proposed ratio of 1.7 street lights per connection to reflect the opening balance for the 2014 Test Year. Oakville Hydro has recalculated the average number of connections to be 10,319. Oakville Hydro will update its cost allocation model to reflect this number in its draft rate order.

8.2-VECC-43

Ref: E7/T1/S2, page 1

a) What was the average (total) monthly peak load on Glenorchy Municipal Transformer Station in each of 2012 and 2013.

RESPONSE:

The average (total) monthly peak load on Glenorchy Municipal Transformer Station was 28.3 MW in 2012 and 31 MW in 2013.

b) Why is it appropriate to allocate Milton Hydro costs based on its usage as a percentage of the station's peak capacity as opposed to based on Milton's share of the station's (total) average load?

RESPONSE:

As discussed in Oakville Hydro's response to Board staff interrogatory number 10 b) in its 2011 IRM Application (EB-2010-0104), in which its ICM related to the Glenorchy Municipal Transformer Station was approved, standard station design practice for both Hydro One and other municipal electric utilities is to size transformer stations with eight-feeders and a total capacity of 102 MW or twelve-feeders rated at 153 MW. Since the total load requirement was forecasted to be 133MW, the larger sized station was required. Therefore, Oakville Hydro believes that it would be inappropriate to allocate costs to Milton Hydro based upon its usage as a share of the station's average load as this would penalize Milton Hydro for Oakville Hydro's requirement to build excess capacity at the Glenorchy Municipal Transformer Station to service its future needs.

Oakville Hydro also notes that the connection of Milton Hydro to Oakville Hydro's distribution system benefits Oakville Hydro's customers as Milton Hydro is bearing a portion of the costs associated with the excess capacity that was necessary for Oakville Hydro's future needs.

c) Please confirm that Milton Hydro owns the two feeders that serve it from the station.

RESPONSE:

Milton Hydro owns the pole line on the public road allowance (Sixth Line) supporting the two feeders that supply Milton Hydro load. Oakville Hydro owns the underground egress feeders from the station to the Milton Hydro termination poles at Sixth Line. As discussed in Exhibit 7, Tab 1, Schedule 2, the capital costs associated with the connection of Milton Hydro to the Glenorchy Municipal Transformer Station have been directly allocated to Milton Hydro.

d) Is Milton Hydro a registered market participant for this point of delivery?

RESPONSE:

Milton Hydro is not a market participant for this point of delivery.

8.2-VECC-44

Ref: E7/T1/T2, page 2

a) Please confirm that directly allocated asset costs are not included in the allocation factor used in the Board's CA Model to assign General Plant (i.e., generally the 1900 series accounts) costs. This can be seen from an examination of Sheet O5.

RESPONSE:

Oakville Hydro agrees that directly allocated costs are not included in the allocation factor used in the Board's CA Model to assign General Plant costs in the 1900 series accounts.

However, Oakville Hydro has observed that the Board's CA Model allocates a portion of General Plant to all rate classes, including the Embedded Distributor rate class, based on the A&G ID - Net Fixed Assets Excluding Capital Contribution (NFA ECC). This can be seen from an examination of Sheet O5 which indicates that General Plant assets and Administrative costs are allocated to the embedded distributor class based on the amount in the direct allocation tab. On row 144 of the instructions in the Cost Allocation Model also states that "the numerous columns to the right of I-9 are used for the purpose of burdening directly-allocated costs for a share of overhead costs. No inputs are required." The relevant section of Sheet O5 is provided in the table below.

USoA Account #	Accounts	Residential	GS < 50 kW	GS >50 kW	GS > 1,000 kW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Total - A&G
1905	Land	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	-	-	-	-	-	-	-	-	-
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	486,490	81,813	226,336	43,236	27,314	420	2,208	4,370	872,187
1920	Computer Equipment - Hardware	4,461,983	750,373	2,075,906	396,550	250,516	3,849	20,249	40,084	7,999,511
1925	Computer Software	3,884,989	653,340	1,807,464	345,271	218,121	3,352	17,631	34,901	6,965,068
1930	Transportation Equipment	2,936,129	493,770	1,366,013	260,943	164,848	2,533	13,325	26,377	5,263,937
1935	Stores Equipment	92,778	15,602	43,164	8,245	5,209	80	421	833	166,334
1940	Tools, Shop and Garage Equipment	799,734	134,491	372,070	71,075	44,901	690	3,629	7,184	1,433,775
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	-	-	-	-	-	-	-	-	-
1960	Miscellaneous Equipment	3,206	539	1,491	285	180	3	15	29	5,747
1970	Load Management Controls - Customer Premis	95,742	16,101	44,543	8,509	5,375	83	434	860	171,648
1975	Load Management Controls - Utility Premises	27,820	4,678	12,943	2,472	1,562	24	126	250	49,876
1980	System Supervisory Equipment	2,646,890	445,128	1,231,447	235,237	148,609	2,283	12,012	23,778	4,745,385
1990	Other Tangible Property	-	-	-	-	-	-	-	-	-

b) Please confirm that Oakville has not included the capital cost of any General Plant in its direct allocation (per Table 7-5).

RESPONSE:

Oakville Hydro has included the capital cost of System Supervisory Equipment (Account 1980) in its direct allocation.

c) Is it Oakville's view that the Embedded Distributor should not be accountable for a share of any of the General Plant costs? If yes, please list the individual accounts and provide an explanation for each.

RESPONSE:

In Oakville Hydro's view the Embedded Distributor should be accountable for a share of the General Plant costs. Oakville Hydro believes that the accounts that the Board's CA Model allocates based on the A&G ID listed in response to part a) of this interrogatory are reasonable.

d) Please confirm that directly allocated expenses are not included in the allocation factor used in the Board's CA model to allocate Administrative and General Expenses (i.e. generally the 5600 series accounts). This can also be seen by inspecting Sheet O5.

RESPONSE:

Oakville Hydro agrees that directly allocated costs are not included in the allocation factor used in the Board's CA Model to assign Administrative and General Expenses in the 5600 series accounts.

However, Oakville Hydro has observed that the Board's CA Model allocates a portion of Customer Service and Administrative and General Expenses to all rate classes, including the Embedded Distributor rate class, based on the A&G Ids OM&A and Net Fixed Assets Excluding Capital Contribution (NFA ECC). This can be seen from an examination of Sheet O5. The relevant section of Sheet O5 is provided in the table below. On row 144 of the instructions in the Cost Allocation Model also states that "the numerous columns to the right of I-9 are used for the purpose of burdening directly-allocated costs for a share of overhead costs. No inputs are required."

e) Is it Oakville's view that the Embedded Distributor should not be accountable for a share of any of the other Administrative and General Costs? If yes, please list the individual accounts and provide an explanation for each.

RESPONSE:

In Oakville Hydro's view the Embedded Distributor should be accountable for a share of the Administrative and General costs. Oakville Hydro believes that the accounts that the Board's CA Model allocates based on the A&G IDs listed in response to part d) of this interrogatory are reasonable.

f) Please explain how the direct allocation was established for each of the Expense items listed in Table 7-6 (excluding depreciation).

RESPONSE:

As shown in Exhibit 4, Tab 3, Schedule 1, Appendix 2-JC, the OM&A costs associated with the operation and maintenance of the Glenorchy Municipal Transformer Station are forecasted to be $281,138 for the 2014 Test Year. As discussed on Exhibit 7, Tab 1, Schedule 2, Page 2, Oakville Hydro has allocated the OM&A costs based upon the percentage of the Embedded Distributors average peak load of 6MW for the 2014 Test Year and the total station capacity of 156MW.

g) Please calculate revised allocators for General Plant and Administrative & General Expenses that include the relevant costs directly assigned to the Embedded Distributor.

RESPONSE:

As discussed in response to part c) and part e) of this interrogatory, Oakville Hydro believes that the A&G ID allocators OM&A and Net Fixed Assets Excluding Capital Contribution (NFA ECC) in the Board's CA Model are reasonable. Oakville Hydro does not believe that it is necessary to allocate additional General Plant and Administrative & General Expenses to the Embedded Distributor rate class.

h) Per Table 7-5, why are there no customer service/accounts related costs attributable to Milton?

RESPONSE:

Oakville Hydro does not expect to incur any costs related to the accounts in the customer services accounts:

- Community Relations - Sundry
- Energy Conservation
- Community Safety Program
- Miscellaneous Customer Service and Informational Expenses

However, as discussed in response to part d) of this interrogatory the Board's CA Model allocates a portion of Customer Service to all rate classes, including the Embedded Distributor rate class, based on the A&G Id.

i) Please explain the basis for the following annual costs related to Milton:

Customer Billing - $113

Meter Reading - $80

RESPONSE:

The customer reading and meter reading costs are based on the costs allocated by the Board's CA Model to the General Service > 1,000 kW rate class on lines 167 and 168 of sheet O5 divided by the number customers in that rate class. Oakville Hydro expects that the costs associated with billing and metering for the Embedded Distributor will be similar to a General Service > 1,000 kW customer.

Meter Reading and Customer Billing Costs Allocated to the GS > 1,000 kW Rate Class

USoA Account #	Accounts	GS > 1,000 kW	Number of Customers	Cost Per Customer
5310	Meter Reading Expense	1,275	16	80
5315	Customer Billing	1,806	16	113

8.2-VECC-45

Ref: E7/T1/S2, page 1
OEB Cost Allocation Review Report
(RP-2005-0317), page 30

a) Please confirm that the OEB's Report generally limited the use of direct allocation to situations where facilities were used 100% by one customer class.

RESPONSE:

On page 30 of the Board's Cost Allocation Review – Board Directions on Cost Allocation Methodology for Electricity Distributors the Board states that "as an initial step in a cost allocation study, a distributor should identify any significant distribution facilities that are dedicated exclusively to only one customer rate classification". The Board also provided examples of circumstances in which direct allocation should be explored. One of the circumstances identified was a feeder that is 100% dedicated to customer(s) in the same classification.

b) Does Milton Hydro's use of the Glenorchy Municipal Transformer Station meet this test? If not, why is direct allocation appropriate in this circumstance?

RESPONSE:

Oakville Hydro has dedicated two out of nine feeders to Milton Hydro. Therefore it is Oakville Hydro's view that the 100% test has been met for these two specific feeders.

c) Please provide an alternative version of the Cost Allocation for 2014 with no direct allocation to Milton.

RESPONSE:

Oakville Hydro has provided an alternative version of the Cost Allocation for 2014 with no direct allocation to Milton Hydro. Oakville Hydro notes that the alternative version results in an increase in the revenue requirement allocated to the General Service > 1,000 rate class from $1,660,523 to $2,016,748. Based on Oakville Hydro's proposed fixed / variable split and, for simplicity, a revenue to cost ratio of 100%, the rates for the General Service > 1,000 rate class would increase by $638.53 per month and $0.5227 per kW. In Oakville Hydro's view it is not appropriate for Oakville Hydro's customers to subsidize Milton Hydro's customers.

Allocation of Revenue Requirement to the General Service Rate Class

CA Model Alternatives	Revenue Requirement	Fixed Revenue	Variable Revenue	Fixed Rate	Variable Rate
As per Application	$ 1,660,523	$ 856,830	$ 803,693	$ 4,462.66	$ 2.4367
Alternative CA Model	$ 2,016,748	$ 1,040,642	$ 976,106	$ 5,101.19	$ 2.9595
Increase in Rates				$ 638.53	$ 0.5227

8.2-VECC-46

Ref: E7/T1/S3, page 3

Cost Allocation Model, Sheet O1

a) The status quo ratios shown in Appendix 2-P do not match those in the Cost Allocation model. Please reconcile and file an updated/corrected version of Appendix 2-P.

RESPONSE:

Please see Oakville Hydro's response to Board staff interrogatory number 8.2-Staff-44.

b) In the current version of Appendix 2-P most of the proposed ratios are moving farther away from 100%. Please clarify Oakville's proposal regarding the revenue to cost ratios for 2014 and provide a rationale for the proposal.

RESPONSE:

Please see Oakville Hydro's response to Board staff interrogatory number 8.2-Staff-44.

Issue 8.3 *Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?*

8.3-Energy Probe-55

Ref: Exhibit 8, Tab 1, Schedule 1 &

Exhibit 8, Tab 2, Schedule 1 &

Exhibit 8, Tab 12, Schedule 1.

a) Please update all impacted tables in Exhibit 8, Tab 1, Schedule 1 and Exhibit 8, Tab 2, Schedule 1using the revenue to cost ratios requested in 8.2-EP-54.

RESPONSE:

Table 8-4, 8-5 and 8-6 are updated.

Table 8-4: Proposed Monthly Fixed Distribution Charges

Rate Class	Customer Unit Cost per month - Avoided Cost	Minimum System with PLCC Adjustment (Ceiling Fixed Charge From Cost Allocation Model)	2013 Approved Monthly Service Charge	Fixed Rate Based on Current Fixed/Variable Revenue Proportions
Residential	$6.06	$11.86	$13.11	$15.71
GS < 50 kW	0.76	32.24	32.24	32.88
GS >50 kW	6.63	29.86	118.45	140.19
GS >1000 kW	(86.33)	(74.84)	3,399.83	4,107.33
Embedded Distributor	0	0	0	3,399.36
Sentinel Lights (per connection)	0.81	5.93	2.95	2.41
Street Lighting (per connection)	0.80	5.91	3.10	3.86
Unmetered Scattered Load (per connection)	1.44	4.83	11.58	10.88

Table 8-5: Proposed Monthly Fixed Distribution Charges – 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue Proportion	Fixed Revenue Amount	Annualized 2014 Test Year Customers / Connections	Proposed Fixed Distribution Rates
	A	B	C=A*B	D	E=C/D
Residential	$21,378,560	52.26%	$11,171,862	710,916	$15.71
GS < 50 kW	4,237,358	45.83%	1,942,162	59,076	32.88
GS >50 kW	8,349,791	18.39%	1,535,917	10,956	140.19
GS >1000 kW	1,528,504	51.59%	788,608	192	4,107.33
Embedded Distributor	176,327	23.13%	40,792	12	3,399.36
Sentinel Lights (per connection)	17,857	25.86%	4,618	1,920	2.41
Street Lighting (per connection)	1,068,352	44.69%	477,443	123,828	3.86
Unmetered Scattered Load (per connection)	123,636	71.25%	88,094	8,100	10.88
Total	**$36,880,386**		**$16,049,497**		

Table 8-6: Proposed Variable Distribution Charges- 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue	Variable Revenue	Transformer Allowance	2014 Test Year Volumnes	Billing Determinant	Proposed Variable Distribution Rates
	A	B	C=A-B	D	E	F	G=(C+D)/E
Residential	$21,378,560	$11,171,862	$10,206,698		595,449,114	kWh	$0.0171
GS < 50 kW	4,237,358	1,942,162	2,295,196		158,508,292	kWh	0.0145
GS >50 kW	8,349,791	1,535,917	6,813,874	88,837	1,589,641	kW	4.3423
GS >1000 kW	1,528,504	788,608	739,896		329,822	kW	2.2433
Embedded Distributor	176,327	40,792	135,535		73,000	kW	1.8566
Sentinel Lights (per connection)	17,857	4,618	13,239		324	kW	40.8108
Street Lighting (per connection)	1,068,352	477,443	590,909		24,961	kW	23.6737
Unmetered Scattered Load (per connection)	123,636	88,094	35,542		3,504,020	kWh	0.0101
Total	**$36,880,386**	**$16,049,497**	**$20,830,890**				

b) Please provide a revised Table 8-22 from Exhibit 8, Tab 12, Schedule 1 based on the revenue to cost ratios referred to above.

RESPONSE:

The following is a revised Table 8-22 based on the revenue to cost ratios requested in 8.2-EP-54.

Table 8-22: Summary of Monthly Bill Impacts by Class for Selected Consumptions

Rate Class	Connection	Consumption kWh	Consumption kW	2013 Bridge Year Bill	2014 Test Year Bill	Difference $	Bill Impact %
Residential (On TOU)		100		$ 30.17	$ 32.03	$ 1.86	6.18%
Residential (On TOU)		250		50.08	51.82	1.75	3.49%
Residential (On TOU)		500		83.25	84.82	1.56	1.88%
Residential (On TOU)		800		123.07	124.40	1.33	1.08%
Residential (On TOU)		1,000		149.62	150.80	1.18	0.79%
Residential (On TOU)		1,500		215.97	216.77	0.79	0.37%
Residential (On TOU)		2,000		282.34	282.75	0.41	0.14%
GS < 50 kW (On TOU)		1,000		176.86	163.77	-13.09	-7.40%
GS < 50 kW (On TOU)		2,000		307.71	290.82	-16.89	-5.49%
GS < 50 kW (On TOU)		5,000		700.25	671.95	-28.30	-4.04%
GS < 50 kW (On TOU)		10,000		1,354.51	1,307.18	-47.32	-3.49%
GS < 50 kW (On TOU)		15,000		2,008.76	1,942.41	-66.34	-3.30%
GS > 50 kW (On RPP) - Non - Interval		30,000	100	4,654.59	4,621.64	-32.95	-0.71%
GS > 50 kW (On RPP) - Non - Interval		64,000	160	9,256.12	9,181.76	-74.36	-0.80%
GS > 50 kW (On RPP) - Non - Interval		12,000	300	17,247.51	17,077.75	-169.76	-0.98%
GS > 50 kW (On RPP) - Non - Interval		200,000	500	28,663.77	28,357.73	-306.05	-1.07%
GS > 50 kW (On RPP) - Interval		30,000	100	4,672.20	4,635.76	-36.45	-0.78%
GS > 50 kW (On RPP) - Interval		64,000	160	9,284.30	9,204.34	-79.96	-0.86%
GS > 50 kW (On RPP) - Interval		12,000	300	17,300.35	17,120.08	-180.26	-1.04%
GS > 50 kW (On RPP) - Interval		200,000	500	28,751.83	28,428.28	-323.55	-1.13%
GS> 1000 kW (On RPP)		600,000	1,200	85,971.59	83,550.96	-2,420.63	-2.82%
GS> 1000 kW (On RPP)		1,000,000	2,200	142,646.29	137,300.86	-5,345.43	-3.75%
GS> 1000 kW (On RPP)		1,600,000	4,000	230,540.90	219,937.17	-10,603.73	-4.60%
Embedded Distributor (On RPP)		2,810,800	6,000	359,099.61	339,341.99	-19,757.62	-5.50%
Unmetered (On RPP)	1	250		46.34	44.01	-2.33	-5.02%
Unmetered (On RPP)	1	550		85.90	81.73	-4.17	-4.85%
Street Lighting (On-RPP)	1	150	1	46.27	50.13	3.86	8.34%
Street Lighting (On-RPP)	15,600	700,000	2,000	191,241.55	188,360.32	-2,881.23	-1.51%
Sentinel Lighting (On-RPP)	160	10,000	25	3,211.76	3,069.79	-141.97	-4.42%

8.3-AMPCO-26

Ref: Exhibit 8, Tab 2, Schedule 1, Page 2

Preamble: Oakville indicates it has developed its fixed rate components as per Table 8-4 as these rates have historically been higher and the primary purpose of maintaining its existing fixed/variable revenue splits by customer class.

a) Please explain this statement more fully.

RESPONSE:

As discussed on Exhibit 8, Tab 2, Schedule 1, Page 1, Oakville Hydro is proposing to maintain its existing fixed and variable proportions consistent with recent Board Decisions:

- Hydro One Brampton – EB-2010-0132
- Kenora Hydro – EB-2010-0136
- Horizon Utilities – EB-2010-0131

- Atikocan Hydro – EB-2011-0293
- Centre Wellington – EB-2012-0113

8.3-AMPCO-27

Ref: Exhibit 8, Tab 2, Schedule 1, Page 2, Table 8-4, Table 8-5, Table 8-6

a) Table 8-4: Under the column Minimum System with PLCC Adjustment, please explain the value (74.84) for the GS>1000 kW customer class.

RESPONSE:

The Minimum System with PLCC Adjustment for the GS > 1,000 rate class is a negative value of $74.84. This value is based on avoided costs which are defined as meter-related, billing, and collection costs less allocated miscellaneous revenues. For the GS > 1,000 rate class the allocated miscellaneous revenues exceed the avoided costs.

b) Please provide Tables 8-4, 8-5 and 8-6 if the fixed monthly service charge for the GS>50 kW and GS>1000 kW customer classes is held constant at the existing 2013 approved monthly service charge.

RESPONSE:

Oakville Hydro has provided Tables 8-4, 8-5 and 8-6 with the fixed monthly service charge for the GS > 50 kW and GS > 1,000 rate classes held constant at the current 2013 approved monthly service charge below.

Table 8-4 – Proposed Monthly Fixed Distribution Charges

Rate Class	Customer Unit Cost per month - Avoided Cost	Minimum System with PLCC Adjustment (Ceiling Fixed Charge From Cost Allocation Model)	2013 Approved Monthly Service Charge	Fixed Rate Based on Current Fixed/Variable Revenue Proportions
Residential	$6.06	$11.86	$13.11	$15.81
GS < 50 kW	0.76	32.24	32.24	31.01
GS >50 kW	6.63	29.86	118.45	118.45
GS >1000 kW	(86.33)	(74.84)	3,399.83	3,399.83
Embedded Distributor	0	0	0	3,393.55
Sentinel Lights (per connection)	0.81	5.93	2.95	2.75
Street Lighting (per connection)	0.80	5.91	3.10	3.74
Unmetered Scattered Load (per connection)	1.44	4.83	11.58	10.29

Table 8-5 – Proposed Monthly Fixed Distribution Charges 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue Proportion	Fixed Revenue Amount	Annualized 2014 Test Year Customers / Connections	Proposed Fixed Distribution Rates
	A	B	C=A*B	D	E=C/D
Residential	$21,508,431	52.26%	$11,239,729	710,916	$15.81
GS < 50 kW	3,997,189	45.83%	1,832,083	59,076	31.01
GS >50 kW	8,501,101	15.27%	1,297,738	10,956	118.45
GS >1000 kW	1,524,423	42.82%	652,767	192	3,399.83
Embedded Distributor	176,026	23.13%	40,723	12	3,393.55
Sentinel Lights (per connection)	20,397	25.86%	5,274	1,920	2.75
Street Lighting (per connection)	1,035,894	44.69%	462,938	123,828	3.74
Unmetered Scattered Load (per connection)	116,925	71.25%	83,312	8,100	10.29
Total	**$36,880,386**		**$15,614,564**		

Table 8-6 – Proposed Variable Distribution Charges 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue	Variable Revenue	Transformer Allowance	2014 Test Year Volumnes	Billing Determinant	Proposed Variable Distribution Rates
	A	B	C=A-B	D	E	F	G=(C+D)/E
Residential	$21,508,431	$11,239,729	$10,268,702		595,449,114	kWh	$0.0172
GS < 50 kW	3,997,189	1,832,083	2,165,107		158,508,292	kWh	0.0137
GS >50 kW	8,501,101	1,297,738	7,203,363	88,837	1,589,641	kW	4.5873
GS >1000 kW	1,524,423	652,767	871,656		329,822	kW	2.6428
Embedded Distributor	176,026	40,723	135,303		73,000	kW	1.8535
Sentinel Lights (per connection)	20,397	5,274	15,123		324	kW	46.6162
Street Lighting (per connection)	1,035,894	462,938	572,956		24,961	kW	22.9545
Unmetered Scattered Load (per connection)	116,925	83,312	33,613		3,504,020	kWh	0.0096
Total	**$36,880,386**	**$15,614,564**	**$21,265,822**				

c) Please provide Tables 8-4, 8-5 and 8-6 if the fixed monthly service charge for the GS>50 kW and GS>1000 kW customer classes are moved to the Minimum System with PLCC Adjustment values.

RESPONSE:

Oakville Hydro has provided Tables 8-4, 8-5 and 8-6 with the fixed monthly service charge for the GS > 50 kW and GS > 1,000 rate classes based on the Minimum System with PLCC Adjustment values charge below. However, Oakville Hydro notes that this would not be appropriate as the Minimum System with PLCC Adjustment for the General Service > 1,000 rate class is a negative value.

Table 8-4 – Proposed Monthly Fixed Distribution Charges

Rate Class	Customer Unit Cost per month - Avoided Cost	Minimum System with PLCC Adjustment (Ceiling Fixed Charge From Cost Allocation Model)	2013 Approved Monthly Service Charge	Fixed Rate Based on Current Fixed/Variable Revenue Proportions
Residential	$6.06	$11.86	$13.11	$15.81
GS < 50 kW	0.76	32.24	32.24	31.01
GS >50 kW	6.63	29.86	118.45	29.86
GS >1000 kW	(86.33)	(74.84)	3,399.83	(74.84)
Embedded Distributor	0	0	0	3,393.55
Sentinel Lights (per connection)	0.81	5.93	2.95	2.75
Street Lighting (per connection)	0.80	5.91	3.10	3.74
Unmetered Scattered Load (per connection)	1.44	4.83	11.58	10.29

Table 8-5 – Proposed Variable Distribution Charges 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue Proportion	Fixed Revenue Amount	Annualized 2014 Test Year Customers / Connections	Proposed Fixed Distribution Rates
	A	B	C=A*B	D	E=C/D
Residential	$21,508,431	52.26%	$11,239,729	710,916	$15.81
GS < 50 kW	3,997,189	45.83%	1,832,083	59,076	31.01
GS >50 kW	8,501,101	3.85%	327,146	10,956	29.86
GS >1000 kW	1,524,423	-0.94%	- 14,369	192	- 74.84
Embedded Distributor	176,026	23.13%	40,723	12	3,393.55
Sentinel Lights (per connection)	20,397	25.86%	5,274	1,920	2.75
Street Lighting (per connection)	1,035,894	44.69%	462,938	123,828	3.74
Unmetered Scattered Load (per connection)	116,925	71.25%	83,312	8,100	10.29
Total	**$36,880,386**		**$13,976,835**		

Table 8-6 – Proposed Variable Distribution Charges 2014

Rate Class	Total Base Revenue Requirment	Fixed Revenue	Variable Revenue	Transformer Allowance	2014 Test Year Volumnes	Billing Determinant	Proposed Variable Distribution Rates
	A	B	C=A-B	D	E	F	G=(C+D)/E
Residential	$21,508,431	$11,239,729	$10,268,702		595,449,114	kWh	$0.0172
GS < 50 kW	3,997,189	1,832,083	2,165,107		158,508,292	kWh	0.0137
GS >50 kW	8,501,101	327,146	8,173,955	88,837	1,589,641	kW	5.1979
GS >1000 kW	1,524,423	- 14,369	1,538,792		329,822	kW	4.6655
Embedded Distributor	176,026	40,723	135,303		73,000	kW	1.8535
Sentinel Lights (per connection)	20,397	5,274	15,123		324	kW	46.6162
Street Lighting (per connection)	1,035,894	462,938	572,956		24,961	kW	22.9545
Unmetered Scattered Load (per connection)	116,925	83,312	33,613		3,504,020	kWh	0.0096

d) Table 8-6: Please add a column that shows the existing variable rate by customer class.

RESPONSE:

Oakville Hydro has updated Table 8-6 to include the existing variable rate by customer class.

Table 8-6 – Proposed Variable Distribution Charge

Rate Class	Total Base Revenue Requirment	Fixed Revenue	Variable Revenue	Transformer Allowance	2014 Test Year Volumnes	Billing Determinant	Proposed Variable Distribution Rates	2013 Approved Variable Distribution Rate
	A	B	C=A-B	D	E	F	G=(C+D)/E	
Residential	$21,508,431	$11,239,729	$10,268,702		595,449,114	kWh	$0.0172	$0.0143
GS < 50 kW	3,997,189	1,832,083	2,165,107		158,508,292	kWh	0.0137	0.0142
GS >50 kW	8,501,101	1,563,750	6,937,351	88,837	1,589,641	kW	4.4200	3.6676
GS >1000 kW	1,524,423	786,503	737,921		329,822	kW	2.2373	1.8569
Embedded Distributor	176,026	40,723	135,303		73,000	kW	1.8535	1.8569
Sentinel Lights (per connection)	20,397	5,274	15,123		324	kW	46.6162	50.0589
Street Lighting (per connection)	1,035,894	462,938	572,956		24,961	kW	22.9545	19.0338
Unmetered Scattered Load (per connection)	116,925	83,312	33,613		3,504,020	kWh	0.0096	0.0108
Total	**$36,880,386**	**$16,014,311**	**$20,866,075**					

8.3-VECC-47

Ref: E8/T2/S1, page 2

a) Why is it appropriate to increase the Residential monthly service charge from $13.11to $15.81 when the current value is already above the "ceiling value" as calculated by the Cost Allocation Model?

RESPONSE:

Oakville Hydro has proposed that it maintain the current fixed/variable split consistent with the Board Decisions identified above. .

Issue 8.4 *Are the proposed Total Loss Adjustment Factors appropriate for the distributor's system and a reasonable proxy for the expected losses?*

8.4-AMPCO-28

Ref: Exhibit 8, Tab 9, Schedule 1, Page 2

Preamble: Oakville Hydro indicates it will be implementing a load flow program, integrated with the existing GIS to perform more efficient and sophisticated studies to optimize system performance and minimize technical issues.

a) Page 2 - Please provide an update on the status of load flow program.

RESPONSE:

Oakville Hydro plans to implement the load flow program in 2014 as part of the comprehensive power system analysis software package. This software would integrate directly with the existing GIS network model to perform power system analysis calculations such load flow, impedance, voltage drop, short circuit, etc.

b) Please summarize how this program will impact this application and the 2014 Test Year revenue requirement.

RESPONSE:

There will be a $20,616 impact to revenue requirement with the implementation of the software, but we anticipate that this software will provide capabilities to drive improvements in overall system power quality and customer satisfaction.

8.4-AMPCO-29

Ref: Exhibit 8, Tab 9, Schedule 1, Page 3

a) Page 3, Appendix 2-R - Please provide historical data for 2013.

RESPONSE:

Please see 8.3-VECC-47a

b) Page 4 - Please explain why 1% of transformer losses was subtracted in the TLF for primary metered customers calculation (i.e. 1.0372 *0.99 = 1.0268).

RESPONSE:

This 1% adjustment is considered a primary metering allowance for transformer losses. This is due to the fact the meter point is on the high voltage (primary side) of the transformer, and any transformer losses will be part of the measured quantity for energy and demand.

8.4-VECC-48

Ref: E8/T9/S1, page 3

a) Can Oakville explain the material reduction in the Distribution Loss Factor experienced in 2012?

RESPONSE:

The 2012 Distribution Loss Factor is lower is due to an error Oakville Hydro had made in the kWh delivered in 2012. Oakville Hydro has updated the Appendix 2-R (Loss Factors) by correcting the 2012 "Retail" kWh delivered and updating the 2013 actual information. Oakville Hydro is proposing a 2014 Total Loss Factor of 1.0376 based on the two most recent years and reflective of Oakville Hydro's distribution system assets rather than the five-year average of 1.0384. Oakville Hydro has updated Table 8-19.

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2009	2010	2011	2012	2013	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,530,767,737	1,598,655,351	1,583,767,324	1,593,526,975	1,602,804,183	1,581,904,314
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,523,678,719	1,590,157,732	1,575,351,474	1,586,134,047	1,595,329,552	1,574,130,305
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	1,391,405	-	-	4,015,849	5,199,822	2,121,415
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,522,287,314	1,590,157,732	1,575,351,474	1,582,118,198	1,590,129,730	1,572,008,890
D	"Retail" kWh delivered by distributor	1,473,391,382	1,537,840,028	1,522,342,017	1,535,655,099	1,544,549,503	1,522,755,606
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	1,377,628	-	-	3,976,088	5,148,338	2,100,411
F	Net "Retail" kWh delivered by distributor = **D - E**	1,472,013,753	1,537,840,028	1,522,342,017	1,531,679,011	1,539,401,165	1,520,655,195
G	Loss Factor in Distributor's system = **C / F**	1.0342	1.0340	1.0348	1.0329	1.0330	1.0338
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0388	1.0387	1.0395	1.0376	1.0376	1.0384

Table 8-19: Total Loss Factors by Class

Description	Loss Adjustment Factor
Supply Facilities Loss Factor	1.0045
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0272
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

Issue 8.5 *Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?*

8.5-Staff-46

Ref: Exhibit 1/Tab3/Schedule 3/page 50

Conditions of Service

Oakville Hydro states that it's Conditions of Service include charges for work done in response to customer requests for services that are not part of the standard services, damages to Oakville Hydro's equipment and theft of power on a cost recovery basis and that Oakville Hydro believes that this practice is consistent with the Board's principle of cost causality.

a) Please identify the rates and/or charges that are included in the Applicant's Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.

RESPONSE:

The table below identifies the rates and/or charges that are included in Oakville Hydro's Conditions of Service, but do not appear on the Board-approved tariff sheet.

Condition of Services Section #	Description	Charge
1	Special study charge for the connection of a customer at a voltage other than primary voltage	Cost recovery
1	Meter information access fee	Cost recovery
1	Incremental cost for maintenance activities performed outside normal working hours at the request of the customer	Cost recovery
1	Charges for special construction requested by the customer that exceeds the standard installation	Cost recovery
1	Charges for damage to, or loss of, Oakville Hydro's equipment by a customer	Cost recovery
2	Connection charges for new services	Cost recovery
2	Charge for incremental costs associate with relocating distribution plant outside normal working hours	Cost recovery
2	Theft of power	Cost recovery
2	Power quality investigation fee if the problem lies on the customer side of the system	Cost recovery
2	Variable connection charge for instrument transformers required for primary metering	Cost recovery
2	Incremental costs associated with interval metering, including the capital cost, installation costs, ongoing maintenance , verification and re-verification of the meter etc.	Cost recovery
2	Miscellaneous non-distribution service charge where miscellaneous non-distribution services are provided to a customer that are not normally provided to all customers in the rate group	Cost recovery
2	Charge for requesting historical information to designated parties more than once a year	Cost recovery
2	Fee for all other requests for aggregated information	Cost recovery
3	Where overhead service conductors are in-place over an existing swimming pool, Oakville Hydro will provide up to 30 metres of overhead service conductors at no charge. The property owner will pay any other costs.	Cost recovery
3	Connection fee for new underground services	Cost recovery
3	Charge for re-design and inspection or repair service due to changes or deviations initiated by the customer or its agents	Cost recovery
3	Charge for Power interruption arranged outside normal business hours	Cost recovery
3	Charge associated for installation and removal of equipment required for a temporary service	Cost recovery

b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2009 to 2012 inclusive, and the revenue forecasted for the 2013 bridge and 2014 test years.

RESPONSE:

The table below provides the revenues recovered from the rates and charges mentioned in question (a) above which are identified as revenue offsets in Exhibit 3, Tab 3, Schedule 1, Page 8 of 10, Account 4390- Miscellaneous Non-operating income.

Description	Billable Services
2009 Actual	$214,160
2010 Actual	121,424
2011 Actual	184,720
2012 Actual	156,802
2013 Bridge Year	152,554
2014 Test Year	153,000

c) Please explain whether, in the Applicant's view, these rates and charges should be included on the Applicant's tariff sheet of approved rates and charges.

RESPONSE:

Oakville Hydro does not believe this should be included on the tariff sheet as it is based on a cost recovery basis and it would be difficult to arrive at a standard charge for many of these items because the nature of the work will differ on a case-by-case basis.

8.5-Staff-47

Ref: Exhibit 8/Appendix A

RTSR Work Form Updates

On January 9, 2014, the Board issued a Rate Order for the 2014 Uniform Transmission Rates and on December 19, 2013, the Board issued a Rate Order for Hydro One Distribution's Sub-transmission rates.

Please provide an updated RTSR Adjustment Work Form in working Microsoft Excel format reflecting the new UTR and Sub-Transmission Rates, as applicable, including any other corrections or adjustments that the Applicant wishes to make to the previous version of the Work Form. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

RESPONSE:

A copy of the updated RTSR Adjustment Work From is provided in Appendix 8-C.

8.5-VECC-49

Ref: E8/T8/S12, page 2

a) Are the forecast LV costs for 2014 based on HONI's 2013 or 2014 approved rates? If the former, please update the forecast costs and the proposed LV rates using HONI`s approved 2014 rates.

RESPONSE:

The forecast LV costs for 2014 are based on OHNI's 2013 approved rates. The forecast LV costs for 2014 and the proposed LV rates are updated by using HONI's approved 2014 rates. Please see the Table 8-17 and Table 8-18 for details.

Table 8-17: Historical and Projected Low Voltage Charges

	2010			2011			2012			2013 Actual			2014 Test Year		
	$	Rate	KW	$	Rate	KW	$	Rate	KW	$	Rate	KW	$	Rate	KW
Jan	$20,216.70	0.350	57,762	$28,156.19	0.485	58,054	$38,557.63	0.668	57,721	$38,511.45	0.675	57,054	$38,910.83	0.682	57,054
Feb	$25,732.00	0.350	73,520	$27,463.61	0.485	56,626	$39,102.05	0.668	58,536	$36,504.00	0.675	54,080	$36,882.56	0.682	54,080
Mar	$22,786.40	0.350	65,104	$25,448.92	0.485	52,472	$35,322.50	0.668	52,878	$38,744.33	0.675	57,399	$39,146.12	0.682	57,399
Apr	$23,344.07	0.372	62,718	$34,666.20	0.544	63,714	$7,231.77	0.668	10,826	$32,207.05	0.675	47,714	$32,541.05	0.682	47,714
May	$36,454.39	0.442	82,476	$74,378.40	0.680	109,380	$41,912.99	0.668	62,744	$53,266.03	0.675	78,913	$53,818.42	0.682	78,913
Jun	$43,708.50	0.442	98,888	$64,373.56	0.680	94,667	$56,425.29	0.668	84,469	$51,584.79	0.675	76,422	$52,119.74	0.682	76,422
Jul	$41,534.30	0.442	93,969	$57,654.48	0.680	84,786	$57,739.25	0.668	86,436	$58,551.58	0.675	86,743	$59,158.78	0.682	86,743
Aug	$42,224.26	0.442	95,530	$45,868.72	0.680	67,454	$48,285.71	0.668	72,284	$50,595.79	0.675	74,957	$51,120.49	0.682	74,957
Sep	$25,235.11	0.442	57,093	$51,297.16	0.680	75,437	$42,932.36	0.668	64,270	$56,902.55	0.675	84,300	$57,492.65	0.682	84,300
Oct	$20,039.40	0.442	45,338	$52,404.20	0.680	77,065	$35,866.92	0.668	53,693	$33,342.66	0.675	49,397	$33,688.44	0.682	49,397
Nov	$24,961.95	0.442	56,475	$49,087.16	0.680	72,187	$36,092.71	0.668	54,031	$34,654.12	0.675	51,339	$35,013.49	0.682	51,339
Dec	$32,858.27	0.452	72,742	$32,719.77	0.676	48,376	$41,001.79	0.670	61,205	$50,686.29	0.677	74,885	$51,071.72	0.682	74,885
Total	**$359,095.34**		**861,615**	**$543,518.37**		**860,218**	**$480,470.97**		**719,093**	**$535,550.65**		**793,203**	**$540,964.30**		**793,203**

Table 8-18: Low Voltage Costs Allocated by Rate Class and Proposed Rate Adders

Customer Class	Forecast 2014 kWH	Forecast 2014 kW	2014 Proposed Retail Transmissions Connection Rate ($) per kWh	per kW	Basis for Allocation	Allocation %	Allocated $	Proposed LV Rate Adder $/kWh	Proposed LV Rate Adder $/kW	Current LV Rate Adder $/kWh	Current LV Rate Adder $/kW
Residential	595,449,114		0.0055		$3,274,970	41.02%	$221,887	0.0004		0.0002	
GS <50kW	158,508,292		0.0050		$792,541	9.93%	$53,697	0.0003		0.0002	
Unmetered	3,504,020		0.0050		$17,520	0.22%	$1,187	0.0003		0.0002	
GS >50kW		1,589,641		1.9374	$3,079,771	38.57%	$208,662		0.1313		0.0638
GS > 1000kW		329,822		1.9374	$638,997	8.00%	$43,294		0.1313		0.0638
Embedded Distributor		73,000		1.9374	$141,430	1.77%	$9,582		0.1313		0.0000
Sentinel Lighting		324		0.3761	$122	0.00%	$8		0.0255		0.0124
Street Lighting		24,961		1.5656	$39,078	0.49%	$2,648		0.1061		0.0516
TOTAL	757,461,426	2,017,748			$7,984,430	100.00%	$540,964				

Issue 8.6 *Is the proposed Tariff of Rates and Charges an accurate representation of the application, subject to the Board's findings on the application?*

8.6-VECC-50
Ref: E8/T6/S2, page 2

The text (lines 3-4) indicates that the bill impacts for the existing Oakville classes of Residential Suburban and GS 50-2999 are greater than 10%. However, Table 1 suggests that this is not the case. Please clarify.

RESPONSE:

Based on an analysis of the bill impacts (Table 8-22 in Exhibit 8, Tab 12 and Schedule 1) Oakville Hydro has no rate classes with a bill impact of greater than 10% as suggested in the question. Oakville Hydro's summary of bill impacts can be found in Exhibit 8, Tab 12, Schedule 1 of its Application.

Table 8-22: Summary of Monthly Bill Impacts by Class for Selected Consumptions

Rate Class	Connection	Consumption kWh	Consumption kW	2013 Bridge Year Bill	2014 Test Year Bill	Difference $	Bill Impact %
Residential (On TOU)		100		$ 30.17	$ 31.01	$ 0.84	2.79%
Residential (On TOU)		250		50.08	50.64	0.57	1.13%
Residential (On TOU)		500		83.25	83.38	0.13	0.16%
Residential (On TOU)		800		123.07	122.66	-0.41	-0.34%
Residential (On TOU)		1,000		149.62	148.85	-0.77	-0.51%
Residential (On TOU)		1,500		215.97	214.32	-1.65	-0.76%
Residential (On TOU)		2,000		282.34	279.79	-2.55	-0.90%
GS < 50 kW (On TOU)		1,000		176.86	161.06	-15.80	-8.93%
GS < 50 kW (On TOU)		2,000		307.71	287.29	-20.42	-6.64%
GS < 50 kW (On TOU)		5,000		700.25	665.98	-34.27	-4.89%
GS < 50 kW (On TOU)		10,000		1,354.51	1,297.14	-57.36	-4.24%
GS < 50 kW (On TOU)		15,000		2,008.76	1,928.30	-80.46	-4.01%
GS > 50 kW (On RPP) - Non - Interval		30,000	100	4,654.59	4,592.26	-62.33	-1.34%
GS > 50 kW (On RPP) - Non - Interval		64,000	160	9,256.12	9,139.10	-117.03	-1.26%
GS > 50 kW (On RPP) - Non - Interval		12,000	300	17,247.51	17,004.07	-243.44	-1.41%
GS > 50 kW (On RPP) - Non - Interval		200,000	500	28,663.77	28,239.75	-424.02	-1.48%
GS > 50 kW (On RPP) - Interval		30,000	100	4,672.20	4,606.38	-65.83	-1.41%
GS > 50 kW (On RPP) - Interval		64,000	160	9,284.30	9,161.67	-122.63	-1.32%
GS > 50 kW (On RPP) - Interval		12,000	300	17,300.35	17,046.41	-253.94	-1.47%
GS > 50 kW (On RPP) - Interval		200,000	500	28,751.83	28,310.31	-441.52	-1.54%
GS> 1000 kW (On RPP)		600,000	1,200	85,971.59	83,040.39	-2,931.20	-3.41%
GS> 1000 kW (On RPP)		1,000,000	2,200	142,646.29	136,621.81	-6,024.48	-4.22%
GS> 1000 kW (On RPP)		1,600,000	4,000	230,540.90	218,954.85	-11,586.05	-5.03%
Embedded Distributor (On RPP)		2,810,800	6,000	359,099.61	342,052.35	-17,047.26	-4.75%
Unmetered (On RPP)	1	250		46.34	43.20	-3.13	-6.76%
Unmetered (On RPP)	1	550		85.90	80.75	-5.15	-5.99%
Street Lighting (On-RPP)	1	150	1	46.27	47.37	1.10	2.38%
Street Lighting (On-RPP)	15,600	700,000	2,000	191,241.55	179,589.80	-11,651.76	-6.09%
Sentinel Lighting (On-RPP)	160	10,000	25	3,211.76	2,977.90	-233.87	-7.28%

Appendix 8 - A

2013 CDM Status Report

Ontario Power Authority
Conservation & Demand Management Status Report

Q3 2013 Preliminary Results Update

Oakville Hydro Electricity Distribution Inc.

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

Unverified Progress to Targets	Incremental Q3-2013	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**2.0**	**3.7**	18%	**5.6**	27%	**39**
Net Energy Savings (GWh)	**0.7**	**50.6**	68%	**50.7**	68%	**44**

Program-to-Date towards Target: Combination of verified (2011-12) and unverified (2013) results. 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.

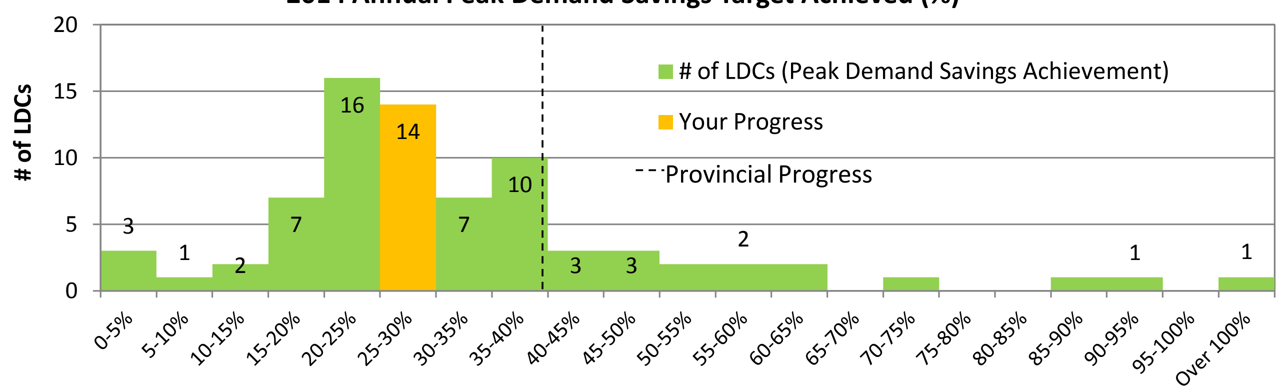
Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

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

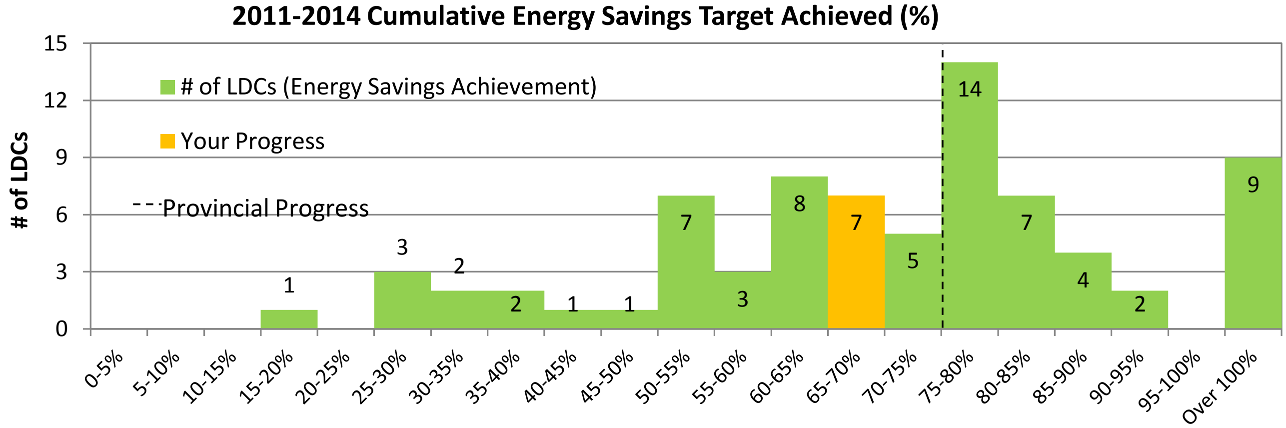
Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your 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@powerauthority.on.ca

Message from the Vice President

I am pleased to present our Q3 2013 LDC report. We continue to achieve great success across all sectors. Provincially we have achieved 75% of the cumulative 6,000 GWh energy target and progress towards the 1,330 MW demand target increased from last quarter to 40%.

A few highlights of our current activities during this reporting period:

- In collaboration with the EDA Policy group and CDM Caucus, the final wave of change management to enable the 2015 extension is underway. Including changes to the Master Services Agreement, initiative contracts, participant agreements and vendor contracts. The changes include:
  - Enabling LDCs to request PAB increases, decreases and reallocations at their discretion
  - Clarification of PAB cost-effectiveness incentive
  - Extending all relevant terms to December 31, 2015
- Targeted workshops aimed at HVAC contractors focused on bringing attention to enhanced incentives and improved processes for replacing rooftop HVAC units (RTUs) within Retrofit has lead to an increase in RTU
- Business program continues to perform well and exceed expectations

Stay tuned for more information on these and more customer focused enhancements. We look forward to continuing to work together on evolving our conservation programs, and engaging channel partners across all sectors to further drive participation.

We encourage you to continue to contact us and tell us your ideas and success stories so we can share our experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-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 Q3 2013 using unverified quarterly results for 2013 and final verified results for 2011-12
- Program activity data (i.e. projects completed, appliances picked up) completed on or before Sept 30, 2013 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarter's participation as a result of further 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. At what point the data becomes available to the OPA;
  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 October 17, 2013
  - Retrofit projects completed after December 31, 2011 will be tracked as part of the Business program only
- Preliminary results for peaksaverPLUS® representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system
- peaksaver PLUS® reporting is split into two line items: Switch/Thermostat and IHD

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 Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q3 2013 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 through to 2014 from program activity completed as of Q3 2013 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, and Q3 2013). 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 1: Net Peak Demand Savings at the End-User Level (MW)

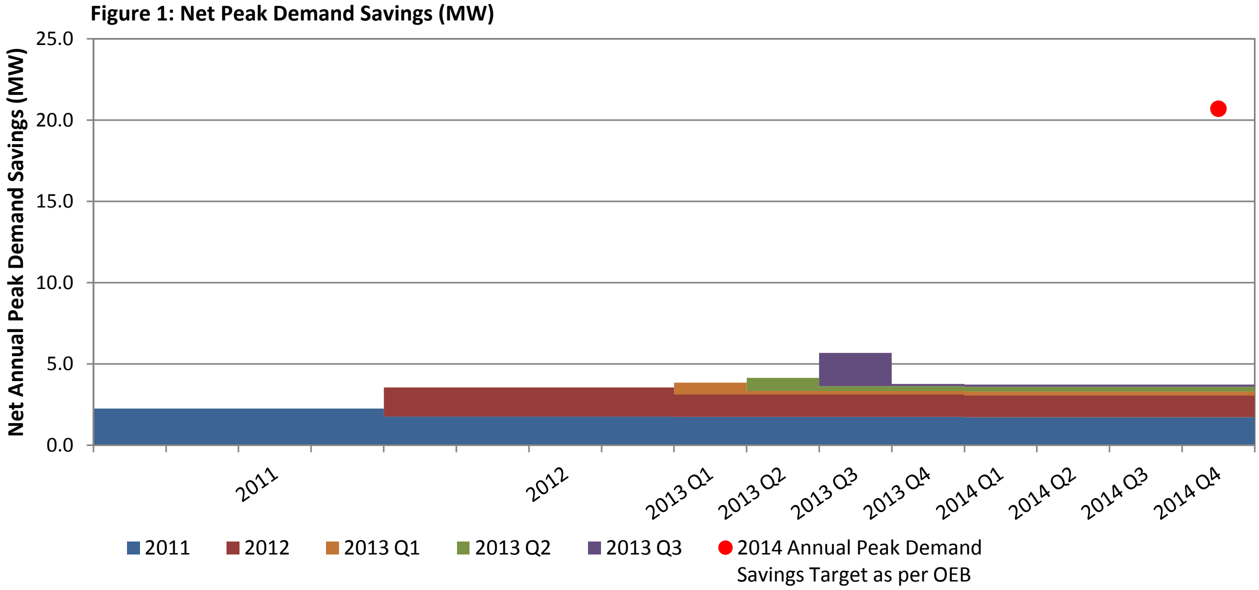
#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	2.24	1.75	1.75	1.72	1.72
2	2012 - Final*		1.81	1.37	1.35	1.35
3	2013 - Reported - Quarter 1			0.22	0.22	0.22
4	2013 - Reported - Quarter 2			0.30	0.30	0.30
5	2013 - Reported - Quarter 3			2.04	0.14	2.04
6	2014					
	Energy Efficiency	1.75	3.11	3.77	3.72	3.72
	Demand Response	0.49	0.44	1.90	0.00	1.90
	Net Annual Peak Demand Savings	2.24	3.55	5.67	3.72	5.62
	Unverified Net Annual Peak Demand Savings in 2014:				**3.7**	**5.6**
	2014 Annual Peak Demand Savings Target as per OEB:				**20.7**	**20.7**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**18%**	**27%**
	Incremental Reported (Unverified)	0.94	1.51	2.56		
	Incremental Final (Verified)	2.24	1.81	n/a		

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Reported DR3 (Ex Ante) (MW)**	0.83
Contracted DR3 (MW)**	0.97

** Consistent with monthly DR3 reports at the end of each quarter

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 Tier 1 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 aligns with Scenario 1 and 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 year-to-date.

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*	6.76	6.76	6.75	6.67	26.94
2	2012 - Final*	0.30	5.98	5.97	5.90	18.14
3	2013 - Reported - Quarter 1			0.82	0.82	1.65
4	2013 - Reported - Quarter 2			1.27	1.27	2.53
5	2013 - Reported - Quarter 3			0.70	0.68	1.37
6	2014					
	Energy Efficiency	6.76	13.03	15.49	15.33	50.60
	Demand Response	0.01	0.00	0.02	0.00	0.03
	Net Energy Savings	7.06	12.73	15.51	15.33	50.63
	Unverified Net Cumulative Energy Savings 2011-2014:					**50.6**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**74.1**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**68%**
	Incremental Reported (Unverified)	2.67	5.47	2.79		
	Incremental Final (Verified)	6.76	5.98	n/a		

Figure 2: Net Cumulative Energy Savings (GWh)

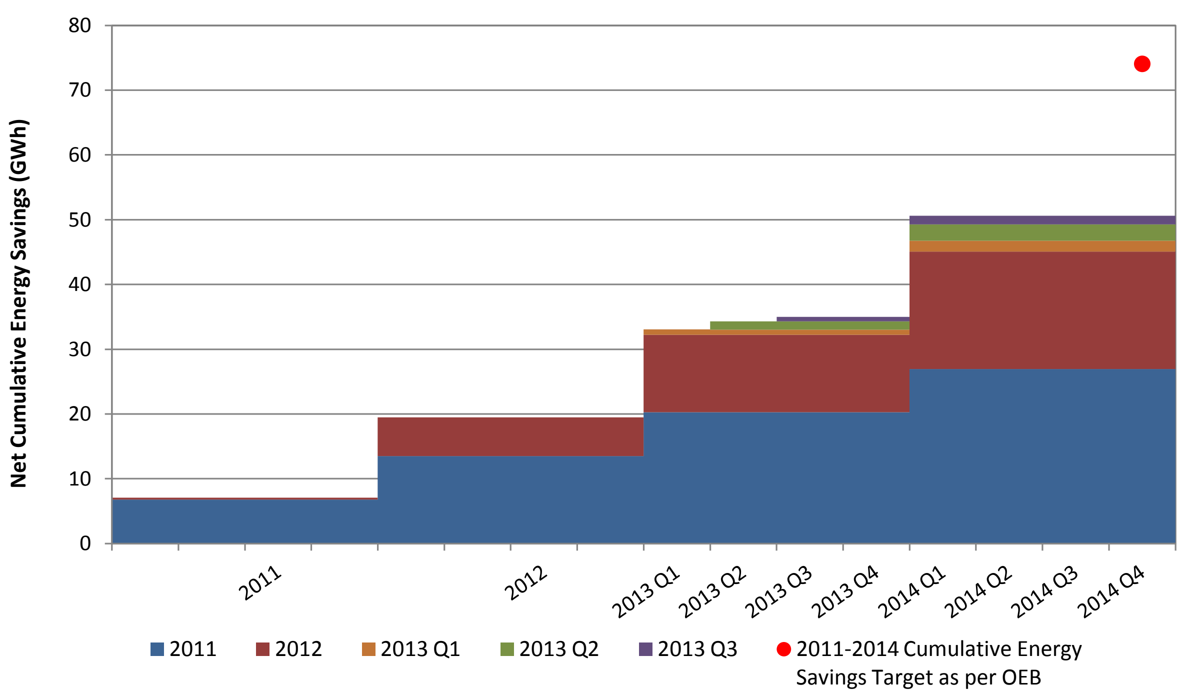


Table 3A: Oakville Hydro Electricity Distribution Inc. Initiative and Program Level Savings by Year (Scenario 1)

#	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 (excludes DR)	
															2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	879	598	286		47	33	16		352,333	238,004	114,871		96	2,353,085
2	Appliance Exchange	Appliances	32	35	8		3	5	1		4,163	8,911	1,364		7	44,372
3	HVAC Incentives	Equipment	2,179	1,990	994		697	414	199		1,241,226	678,390	316,796		1,310	7,633,665
4	Conservation Instant Coupon Booklet	Coupons	7,515	452	462		17	3	3		276,221	20,458	18,891		24	1,204,041
5	Bi-Annual Retailer Event	Coupons	13,931	15,523	3,118		25	22	7		429,984	391,857	100,660		53	3,096,825
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-		-	-
7	Residential Demand Response (switch/pstat)*	Devices	696	772	1,909		390	355	1,069		1,009	2,674	4,104		-	7,788
8	Residential Demand Response (IHD)	Devices	-	67	1,734		-		-		-		-		-	-
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-		-	-
Consumer Program Total							**1,179**	**833**	**1,295**		**2,304,937**	**1,340,294**	**556,686**		**1,490**	**14,339,776**
Business Program																
10	Retrofit	Projects	44	99	48		415	755	429		2,093,673	3,837,793	2,163,581		1,583	24,156,302
11	Direct Install Lighting	Projects	208	112	1		220	89	2		564,846	336,964	11,442		284	3,206,160
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-		-	-
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-		-	-
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	5		-	-	3		-	-	11		-	11
16	Small Commercial Demand Response (IHD)	Devices	-	-	2		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	1	1	1		82	82	82		3,198	1,194	1,832		-	6,224
Business Program Total							**717**	**926**	**516**		**2,661,717**	**4,175,952**	**2,176,865**		**1,867**	**27,368,697**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-		-	-
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-		-	-
21	Retrofit	Projects	5		-		60		-		336,825		-		60	1,347,300
22	Demand Response 3*	Facilities	1	-	2		21	-	746		1,237	-	16,758		-	17,995
Industrial Program Total							**81**	**-**	**746**		**338,062**	**-**	**16,758**		**60**	**1,365,295**
Home Assistance Program																
23	Home Assistance Program	Homes	-	-	50		-	-	2		-	-	37,710		2	75,420
Home Assistance Program Total							**-**	**-**	**2**		**-**	**-**	**37,710**		**2**	**75,420**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-		-	-
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	26	-	-		240	-	-		1,343,088	-	-		240	5,372,354
26	High Performance New Construction	Projects	2	1	-		22	52	-		114,603	164,845	-		74	952,949
27	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-		-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-		-	-
29	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-		-	-
Pre-2011 Programs completed in 2011 Total							**262**	**52**	**-**		**1,457,692**	**164,845**	**-**		**314**	**6,325,303**
Other																
30	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-		-	-
31	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-		-	-
Other Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Adjustment to Previous Year's Verified Results								**(3)**				**296,333**			**(12)**	**1,160,199**
Energy Efficiency Total							**1,746**	**1,373**	**659**		**6,756,963**	**5,677,222**	**2,765,315**		**3,733**	**49,442,473**
Demand Response Total (Scenario 1)							**493**	**438**	**1,900**		**5,444**	**3,869**	**22,705**		**-**	**32,018**
OPA-Contracted LDC Portfolio Total							**2,239**	**1,808**	**2,559**		**6,762,407**	**5,977,423**	**2,788,020**		**3,721**	**50,634,690**
														Full OEB Target:	**20,700**	**74,060,000**
														% of Full OEB Target Achieved to Date (Scenario 1):	**18%**	**68%**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

Table 3B: Oakville Hydro Electricity Distribution Inc. 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 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	89	99	97		5	6	6		36,162	39,711	38,998	
2	Appliance Exchange	Appliances	-	2	6		-	0	1		-	341	1,023	
3	HVAC Incentives	Equipment	330	504	160		76	94	28		131,202	143,447	42,148	
4	Conservation Instant Coupon Booklet	Coupons	266	158	38		3	0	0		11,653	5,880	1,358	
5	Bi-Annual Retailer Event	Coupons	65	3,031	22		0	7	0		1,843	98,160	657	
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-	
7	Residential Demand Response (switch/pstat)*	Devices	752	891	1,909		421	416	1,069		1,617	3,114	4,104	
8	Residential Demand Response (IHD)	Devices	740	833	161				-				-	
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-	
Consumer Program Total							**505**	**522**	**1,104**		**182,477**	**290,652**	**88,288**	
Business Program														
10	Retrofit	Projects	15	18	15		134	188	107		631,107	941,594	590,879	
11	Direct Install Lighting	Projects	1	-	-		2	-	-		11,442	-	-	
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-	
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-	
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-	
15	Small Commercial Demand Response (switch/pstat)*	Devices	1	-	5		1	-	3		2	-	11	
16	Small Commercial Demand Response (IHD)	Devices	-	2	-		-	-	-		-	-	-	
17	Demand Response 3*	Facilities	1	1	1		82	94	82		3,215	2,097	1,832	
Business Program Total							**219**	**282**	**192**		**645,766**	**943,691**	**592,722**	
Industrial Program														
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-	
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-	
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-	
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	1	1	2		-	-	746		-	-	16,758	
Industrial Program Total							**-**	**-**	**746**		**-**	**-**	**16,758**	
Home Assistance Program														
23	Home Assistance Program	Homes	1	49	-		0	2	-		1,166	36,544	-	
Home Assistance Program Total							**0**	**2**	**-**		**1,166**	**36,544**	**-**	
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-	
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**	
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							**221**	**297**	**141**		**824,575**	**1,265,677**	**675,063**	
Demand Response Total (Scenario 1)							**504**	**510**	**1,900**		**4,833**	**5,211**	**22,705**	
OPA-Contracted LDC Portfolio Total							**724**	**807**	**2,042**		**829,409**	**1,270,888**	**697,768**	

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

***Includes adjustments after Final Reports were issued**

**** 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 (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Unverified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,146	15,997		3,299	2,011	978		23,005,812	13,424,518	6,266,108		6,149	144,709,073
2	Appliance Exchange	Appliances	3,688	3,836	302		371	556	32		450,187	974,621	43,168		722	4,598,860
3	HVAC Incentives	Equipment	92,721	85,221	41,082		32,037	19,060	9,005		59,437,670	32,841,283	15,310,950		60,102	366,896,430
4	Conservation Instant Coupon Booklet	Coupons	567,678	30,891	31,584		1,344	230	225		21,211,537	1,398,202	1,291,133		1,800	91,623,019
5	Bi-Annual Retailer Event	Coupons	952,149	1,060,901	213,100		1,681	1,480	459		29,387,468	26,781,674	6,879,644		3,620	211,654,185
6	Retailer Co-op	Items	152	-	-		0	-	-		2,652	-	-		0	10,607
7	Residential Demand Response (switch/pstat)*	Devices	19,550	98,388	107,013		10,947	49,038	59,927		24,870	359,408	230,077		-	614,356
8	Residential Demand Response (IHD)	Devices	-	49,689	45,619		-		-		-		-		-	-
9	Residential New Construction	Homes	26	-	5		0	2	1		743	17,152	2,182		2	58,794
Consumer Program Total							**49,681**	**72,377**	**70,627**		**133,520,941**	**75,796,859**	**30,023,262**		**72,396**	**820,165,325**
Business Program																
10	Retrofit	Projects	2,819	5,605	3,875		24,467	61,147	30,118		136,002,258	314,922,468	197,951,323		114,136	1,876,550,105
11	Direct Install Lighting	Projects	20,741	18,494	10,815		23,724	15,284	11,102		61,076,701	57,345,798	47,871,034		42,283	486,814,937
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	22	64	21		123	764	455		411,717	1,814,721	1,052,514		1,342	9,196,060
14	Energy Audit	Audits	196	280	95		-	1,450	492		-	7,049,351	2,391,744		1,941	25,931,542
15	Small Commercial Demand Response (switch/pstat)*	Devices	132	294	359		84	187	201		157	1,068	772		-	1,996
16	Small Commercial Demand Response (IHD)	Devices	-	-	82		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	145	151	171		16,218	19,389	24,055		633,421	281,823	536,899		-	1,452,143
Business Program Total							**64,617**	**98,221**	**66,422**		**198,124,253**	**381,415,230**	**249,804,286**		**159,702**	**2,399,946,783**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	1		-	-	270		-	-	825,000		270	1,650,000
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	39	35		-	1,086	679		-	7,372,108	6,958,584		1,765	36,033,492
21	Retrofit	Projects	433		-		4,615		-		28,866,840		-		4,613	115,462,282
22	Demand Response 3*	Facilities	124	185	281		52,484	74,056	149,404		3,080,737	1,784,712	3,354,125		-	8,219,574
Industrial Program Total							**57,098**	**75,141**	**150,354**		**31,947,577**	**9,156,820**	**11,137,709**		**6,648**	**161,365,347**
Home Assistance Program																
23	Home Assistance Program	Homes	46	5,033	11,239		2	566	1,631		39,283	5,442,232	9,455,190		2,200	35,394,211
Home Assistance Program Total							**2**	**566**	**1,631**		**39,283**	**5,442,232**	**9,455,190**		**2,200**	**35,394,211**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-		-	-
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
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	9		5,098	3,251	1,806		26,185,591	11,901,944	12,769,879		10,155	165,987,955
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**	**1,806**		**243,251,550**	**11,901,944**	**12,769,879**		**50,001**	**1,034,251,788**
Other																
29	Program Enabled Savings	Projects	-	-	-		-	2,304	-		-	1,188,362	-		2,304	3,565,086
30	Time-of-Use Savings	Homes	-	-	-		-	-			-	-	-		-	-
Other Total							**-**	**2,304**	**-**		**-**	**1,188,362**	**-**		**2,304**	**3,565,086**
Adjustment to Previous Year's Verified Results								**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total							**136,610**	**109,191**	**57,253**		**603,144,419**	**482,474,435**	**309,068,454**		**293,251**	**4,444,400,472**
Demand Response Total (Scenario 1)							**79,733**	**142,670**	**233,587**		**3,739,185**	**2,427,011**	**4,121,872**		**-**	**10,288,069**
OPA-Contracted LDC Portfolio Total							**216,343**	**253,267**	**290,840**		**606,883,604**	**503,590,526**	**313,190,326**		**294,407**	**4,528,607,138**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Full OEB Target:	**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**22%**	**75%**

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 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	4,372	5,381	6,244		262	331	385		1,726,524	2,098,963	2,440,621	
2	Appliance Exchange	Appliances	10	130	162		1	14	18		1,138	17,249	24,780	
3	HVAC Incentives	Equipment	13,780	18,689	8,613		3,406	3,865	1,734		6,143,456	6,366,357	2,801,138	
4	Conservation Instant Coupon Booklet	Coupons	18,180	10,830	2,574		195	24	7		796,461	401,881	92,790	
5	Bi-Annual Retailer Event	Coupons	4,425	207,168	1,507		7	445	7		125,949	6,708,799	44,896	
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-	
7	Residential Demand Response (switch/pstat)*	Devices	71,642	96,264	107,013		40,120	50,316	59,927		153,447	363,663	230,077	
8	Residential Demand Response (IHD)	Devices	15,153	25,864	4,602				-				-	
9	Residential New Construction	Homes	3	1	1		0	1	0		756	1,272	154	
Consumer Program Total							**43,990**	**54,995**	**62,077**		**8,947,731**	**15,958,184**	**5,634,456**	
Business Program														
10	Retrofit	Projects	1,321	1,509	1,045		11,208	11,615	7,295		70,694,979	66,323,123	60,933,222	
11	Direct Install Lighting	Projects	3,877	4,676	2,262		3,986	4,853	2,264		15,540,497	22,208,242	10,122,295	
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-	
13	New Construction	Buildings	12	7	2		233	97	125		735,556	220,560	96,399	
14	Energy Audit	Audits	51	38	6		264	197	31		1,283,989	956,698	151,058	
15	Small Commercial Demand Response (switch/pstat)*	Devices	241	144	359		135	92	201		463	523	772	
16	Small Commercial Demand Response (IHD)	Devices	29	47	6		-	-	-		-	-	-	
17	Demand Response 3*	Facilities	153	170	171		20,082	27,275	24,055		786,518	608,767	536,899	
Business Program Total							**35,907**	**44,129**	**33,970**		**89,042,001**	**90,317,913**	**71,840,643**	
Industrial Program														
18	Process & System Upgrades	Projects	1	-	-		270	-	-		825,000	-	-	
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-	
20	Energy Manager	Projects	26	8	1		429	250	-		3,647,428	3,311,156	-	
21	Retrofit	Projects			-				-				-	
22	Demand Response 3*	Facilities	210	270	281		78,121	106,583	149,404		4,585,608	2,392,785	3,354,125	
Industrial Program Total							**78,820**	**106,833**	**149,404**		**9,058,036**	**5,703,941**	**3,354,125**	
Home Assistance Program														
23	Home Assistance Program	Homes	3,408	5,092	2,739		795	750	86		3,840,100	4,015,556	1,599,534	
Home Assistance Program Total							**795**	**750**	**86**		**3,840,100**	**4,015,556**	**1,599,534**	
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-	
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**	
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	-	-	-		-	-	-		-	-	-	
25	High Performance New Construction	Projects	4	-	5		731	-	1,075		5,563,680	-	7,206,199	
26	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-	
27	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-	
28	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-	
Pre-2011 Programs completed in 2011 Total							**731**	**-**	**1,075**		**5,563,680**	**-**	**7,206,199**	
Other														
29	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-	
30	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-	
Other Total							**-**	**-**	**-**		**-**	**-**	**-**	
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**21,786**	**22,442**	**13,025**		**110,925,512**	**112,629,856**	**85,513,085**	
Demand Response Total (Scenario 1)							**138,458**	**184,265**	**233,587**		**5,526,035**	**3,365,737**	**4,121,872**	
OPA-Contracted LDC Portfolio Total							**160,244**	**206,707**	**246,612**		**116,451,548**	**115,995,594**	**89,634,957**	

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

***Includes adjustments after Final Reports were issued**

**** 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 Q3 2013 report includes all program activity completed (as per the savings 'start' date) on or before September 30th, 2013.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried. Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date1	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 OPA by retailers and undergoes QA/QC by OPA 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 successfully uploaded into RDR settlement system as of Sept 30th, 2013	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC") within iCON CRM as of October 17, 2013	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 OPA and reviewed	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system	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 OPA and reviewed	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA 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 OPA and reviewed	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

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: detemines 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)
  - Understanding your Q4 2011 Report (April 11, 2012)
  - Tools from the Reporting WG (April 25, 2012)
  - A Deeper Look at: peaksaverPLUS® (May 23, 2012)
  - A Deeper Look at: Demand Response 3 (June 6, 2012)
  - Revisiting Reporting (June 20, 2012)
  - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012

Appendix 8 - B

2014 Cost Allocation Model

2014 Cost Allocation Model

EB-2013-0159

Sheet I6.1 Revenue Worksheet - Run 1

Total kWhs from Load Forecast	1,553,929,178
Total kWs from Load Forecast	1,944,748
Deficiency/sufficiency (RRWF 8. cell F51)	- 6,423,733
Miscellaneous Revenue (RRWF 5. cell F48)	2,075,265

			1	2	3	4	5	7	8	9	10
	ID	**Total**	**Residential**	**GS < 50 kW**	**GS >50 kW**	**GS> 50-TOU**	**GS > 1,000 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data											
Forecast kWh	**CEN**	1,553,929,178	595,449,114	158,508,292	606,291,782		147,386,488	8,943,095	116,788	3,504,020	33,729,600
Forecast kW	**CDEM**	1,944,748			1,589,641		329,822	24,961	324		
Forecast kW, included in CDEM, of customers receiving line transformer allowance		177,673			177,673						
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	1,549,953,178	595,449,114	158,508,292	602,315,782	-	147,386,488	8,943,095	116,788	3,504,020	33,729,600
Existing Monthly Charge			$13.11	$32.24	$118.45		$3,399.83	$3.10	$2.95	$11.58	$3,399.83
Existing Distribution kWh Rate			$0.0143	$0.0142						$0.0108	
Existing Distribution kW Rate					$3.6776		$1.8569	$19.0338	$50.0589		$1.8569
Existing TOA Rate					$0.50						
Additional Charges											
Distribution Revenue from Rates		$31,588,332	$17,835,031	$4,155,428	$7,143,803	$0	$1,265,214	$858,960	$21,883	$131,641	$176,372
Transformer Ownership Allowance		$88,837	$0	$0	$88,837	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$31,499,496.00	$17,835,031	$4,155,428	$7,054,967	$0	$1,265,214	$858,960	$21,883	$131,641	$176,372

EB-2013-0159

Sheet I6.2 Customer Data Worksheet - Run 1

			1	2	3	5	7	8	9	10
	ID	Total	Residential	GS < 50 kW	GS >50 kW	GS > 1,000 kW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$250,734	$104,444	$79,156	$67,134	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$168,376	119,901.50	48,474.01						
Number of Bills	CNB	793,536	714,780	59,112.00	11,040	192	288	36	8,088	
Number of Devices										
Number of Connections (Unmetered)	CCON	11,154					10,319	160	675	
Total Number of Customers	CCA	65,095	59,243	4,923	913	16	-	-	-	-
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	65,095	59,243	4,923	913	16	-	-	-	-
Line Transformer Customer Base	CCLT	65,053	59,243	4,923	887	-	-	-	-	-
Secondary Customer Base	CCS	65,028	59,243	4,923	862	-	-	-	-	-
Weighted - Services	CWCS	59,243	59,243	-	-	-	-	-	-	-
Weighted Meter -Capital	CWMC	15,530,045	10,604,497	3,019,099	1,868,736	37,712	-	-	-	-
Weighted Meter Reading	CWMR	72,582	59,243	4,923	8,288	128	-	-	-	-
Weighted Bills	CWNB	845,922	714,780	59,112	66,240	1,152	576	18	4,044	-

Bad Debt Data

Historic Year:	2010	167,480	64,942	44,191	58,347					
Historic Year:	2011	256,873	121,264	106,772	28,837					
Historic Year:	2012	327,847	127,126	86,504	114,216					
Three-year average		**250,734**	**104,444**	**79,156**	**67,134**	**-**	**-**	**-**	**-**	**-**

2014 Cost Allocation Model

EB-2013-0159

Sheet I8 Demand Data Worksheet - Run 1

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS < 50 kW	3 GS >50 kW	5 GS > 1,000 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	316,390	150,643	34,680	111,490	19,176	-	-	401	
Bulk Delivery CP	BCP1	316,390	150,643	34,680	111,490	19,176	-	-	401	
Total Sytem CP	DCP1	316,390	150,643	34,680	111,490	19,176	-	-	401	
4 CP										
Transformation CP	TCP4	1,096,950	488,579	124,931	404,793	77,021	-	-	1,626	
Bulk Delivery CP	BCP4	1,096,950	488,579	124,931	404,793	77,021	-	-	1,626	
Total Sytem CP	DCP4	1,096,950	488,579	124,931	404,793	77,021	-	-	1,626	
12 CP										
Transformation CP	TCP12	2,946,442	1,296,755	321,056	1,091,067	216,024	16,547	203	4,789	
Bulk Delivery CP	BCP12	2,946,442	1,296,755	321,056	1,091,067	216,024	16,547	203	4,789	
Total Sytem CP	DCP12	2,946,442	1,296,755	321,056	1,091,067	216,024	16,547	203	4,789	
NON CO_INCIDENT PEAK										
1 NCP										
Classification NCP from Load Data Provider	DNCP1	328,867	157,674	36,226	111,490	20,857	2,158	39	423	
Primary NCP	PNCP1	328,867	157,674	36,226	111,490	20,857	2,158	39	423	
Line Transformer NCP	LTNCP1	328,867	157,674	36,226	111,490	20,857	2,158	39	423	
Secondary NCP	SNCP1	328,867	157,674	36,226	111,490	20,857	2,158	39	423	
4 NCP										
Classification NCP from Load Data Provider	DNCP4	1,202,622	544,489	138,590	426,778	82,402	8,566	141	1,656	
Primary NCP	PNCP4	1,202,622	544,489	138,590	426,778	82,402	8,566	141	1,656	
Line Transformer NCP	LTNCP4	1,202,622	544,489	138,590	426,778	82,402	8,566	141	1,656	
Secondary NCP	SNCP4	1,202,622	544,489	138,590	426,778	82,402	8,566	141	1,656	
12 NCP										
Classification NCP from Load Data Provider	DNCP12	3,204,299	1,405,082	348,165	1,184,603	236,358	24,962	339	4,789	
Primary NCP	PNCP12	3,204,299	1,405,082	348,165	1,184,603	236,358	24,962	339	4,789	
Line Transformer NCP	LTNCP12	2,019,696	1,405,082	348,165	-	236,358	24,962	339	4,789	
Secondary NCP	SNCP12	2,019,696	1,405,082	348,165	-	236,358	24,962	339	4,789	

2014 Cost Allocation Model

EB-2013-0159

Sheet O1 Revenue to Cost Summary Worksheet - Run 1

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	7	8	9	10
Rate Base Assets		Total	Residential	GS < 50 kW	GS >50 kW	GS > 1,000 kW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
crev	Distribution Revenue at Existing Rates	$31,499,496	$17,835,031	$4,155,428	$7,054,967	$1,265,214	$858,960	$21,883	$131,641	$176,372
mi	Miscellaneous Revenue (mi)	$2,075,265	$1,385,053	$253,694	$311,028	$49,877	$67,412	$1,050	$6,855	$297
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$33,574,761	**$19,220,084**	**$4,409,122**	**$7,365,995**	**$1,315,091**	**$926,372**	**$22,933**	**$138,496**	**$176,668**
	Factor required to recover deficiency (1 + D)	1.2039								
	Distribution Revenue at Status Quo Rates	$37,923,230	$21,472,153	$5,002,850	$8,493,695	$1,523,230	$1,034,129	$26,346	$158,487	$212,339
	Miscellaneous Revenue (mi)	$2,075,265	$1,385,053	$253,694	$311,028	$49,877	$67,412	$1,050	$6,855	$297
	Total Revenue at Status Quo Rates	$39,998,495	**$22,857,206**	**$5,256,544**	**$8,804,723**	**$1,573,107**	**$1,101,541**	**$27,395**	**$165,342**	**$212,636**
	Expenses									
di	Distribution Costs (di)	$9,568,515	$5,185,527	$940,295	$2,608,006	$498,293	$306,555	$4,753	$25,085	$0
cu	Customer Related Costs (cu)	$4,194,016	$3,242,372	$434,841	$377,567	$5,316	$116,406	$1,823	$15,691	$0
ad	General and Administration (ad)	$5,689,769	$3,452,529	$570,399	$1,254,137	$213,457	$174,674	$2,715	$16,671	$5,186
dep	Depreciation and Amortization (dep)	$8,620,187	$4,755,917	$1,011,053	$2,203,663	$390,511	$224,469	$3,480	$18,935	$12,158
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$4,973,298	$2,635,942	$534,998	$1,357,313	$252,647	$148,959	$2,310	$12,450	$28,680
	Total Expenses	$33,045,785	**$19,272,287**	**$3,491,586**	**$7,800,686**	**$1,360,224**	**$971,064**	**$15,082**	**$88,832**	**$46,024**
	Direct Allocation	$69,069	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$69,069**
NI	Allocated Net Income (NI)	$6,883,641	$3,648,459	$740,501	$1,878,684	$349,693	$206,177	$3,197	$17,233	$39,696
	Revenue Requirement (includes NI)	$39,998,495	$22,920,746	$4,232,087	$9,679,370	$1,709,918	$1,177,241	$18,279	$106,065	$154,789
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$284,964,672	$154,553,868	$29,778,215	$76,007,810	$14,243,565	$9,479,980	$146,991	$754,243	$0
gp	General Plant - Gross	$39,070,405	$21,221,122	$4,046,895	$10,346,169	$1,934,660	$1,209,986	$18,761	$98,641	$194,172
accum dep	Accumulated Depreciation	($118,314,438)	($63,187,572)	($12,547,919)	($31,857,187)	($5,976,113)	($4,213,901)	($65,338)	($328,095)	($138,312)
co	Capital Contribution	($46,499,142)	($27,594,501)	($4,101,656)	($10,898,959)	($2,084,380)	($1,669,951)	($25,893)	($123,803)	$0
	Total Net Plant	$159,221,497	**$84,992,917**	**$17,175,534**	**$43,597,833**	**$8,117,731**	**$4,806,114**	**$74,521**	**$400,987**	**$55,859**
	Directly Allocated Net Fixed Assets	$860,670	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$860,670**
COP	Cost of Power (COP)	$167,714,010	$64,431,081	$17,151,525	$65,174,095	$15,948,081	$967,695	$12,637	$379,155	$3,649,740
	OM&A Expenses	$19,452,299	$11,880,428	$1,945,535	$4,239,710	$717,067	$597,635	$9,292	$57,447	$5,186
	Directly Allocated Expenses	$8,673	$0	$0	$0	$0	$0	$0	$0	$8,673
	Subtotal	*$187,174,982*	***$76,311,509***	***$19,097,060***	***$69,413,804***	***$16,665,148***	***$1,565,331***	***$21,929***	***$436,602***	***$3,663,600***
	Working Capital	$24,332,748	**$9,920,496**	**$2,482,618**	**$9,023,795**	**$2,166,469**	**$203,493**	**$2,851**	**$56,758**	**$476,268**
	Total Rate Base	$184,414,915	**$94,913,413**	**$19,658,152**	**$52,621,628**	**$10,284,200**	**$5,009,607**	**$77,371**	**$457,745**	**$1,392,797**
		Rate Base Input equals Output								
	Equity Component of Rate Base	$73,765,966	**$37,965,365**	**$7,863,261**	**$21,048,651**	**$4,113,680**	**$2,003,843**	**$30,949**	**$183,098**	**$557,119**
	Net Income on Allocated Assets	$6,847,673	**$3,584,919**	**$1,764,957**	**$1,004,038**	**$212,883**	**$130,477**	**$12,313**	**$76,510**	**$61,576**
	Net Income on Direct Allocation Assets	$20,853	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$20,853**
	Net Income	$6,868,527	**$3,584,919**	**$1,764,957**	**$1,004,038**	**$212,883**	**$130,477**	**$12,313**	**$76,510**	**$82,429**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**99.72%**	**124.21%**	**90.96%**	**92.00%**	**93.57%**	**149.87%**	**155.89%**	137.37%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($6,423,734)	($3,700,662)	$177,034	($2,313,375)	($394,827)	($250,869)	$4,654	$32,431	$21,880
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($63,540)	$1,024,456	($874,647)	($136,810)	($75,700)	$9,117	$59,277	$57,847
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.31%	9.44%	22.45%	4.77%	5.18%	6.51%	39.79%	41.79%	14.80%

2014 Cost Allocation Model

EB-2013-0159

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Run 1

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	5	7	8	9	10
Summary	**Residential**	**GS < 50 kW**	**GS >50 kW**	**GS > 1,000 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$5.12	$9.67	$36.61	-$54.14	$0.80	$0.81	$1.51	0
Customer Unit Cost per month - Directly Related	$6.95	$12.59	$49.32	-$40.94	$1.19	$1.20	$2.21	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$10.99	$15.06	$55.13	-$47.99	$5.89	$5.90	$4.85	0
Existing Approved Fixed Charge	$13.11	$32.24	$118.45	$3,399.83	$3.10	$2.95	$11.58	$3,399.83

Appendix 8 - C

RTSR Adjustment Work From

v 4.0

RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Oakville Hydro Distribution Inc.
Service Territory	
Assigned EB Number	EB-2013-0159
Name and Title	Maryanne Wilson , Manager, Regulatory Affairs
Phone Number	905-825-4422
Email Address	mwilson@oakvillehydro.com
Date	19-Feb-14
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

RTSR Workform for Electricity Distributors (2014 Filers)

RTSR Workform for Electricity Distributors (2014 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0080	$ 0.0055
General Service Less Than 50 kW	kWh	$ 0.0074	$ 0.0050
General Service 50 to 999 kW	kW	$ 2.7667	$ 1.8766
General Service 50 to 999 kW - Interval Metered	kW	$ 2.8561	$ 1.9374
General Service Greater Than 1,000 kW	kW	$ 2.8561	$ 1.9374
Unmetered Scattered Load	kWh	$ 0.0074	$ 0.0050
Sentinel Lighting	kW	$ 0.5546	$ 0.3761
Street Lighting	kW	$ 2.3081	$ 1.5656
Embedded Distributor	kW	$ 2.8561	$ 1.9374

RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	602,407,699		1.0377		625,118,469	-
General Service Less Than 50 kW	kWh	166,851,635		1.0377		173,141,941	-
General Service 50 to 999 kW	kW	607,509,364	1,647,015		**50.56%**	607,509,364	1,647,015
General Service 50 to 999 kW - Interval Metered	kW	607,509,364	1,647,015		**50.56%**	607,509,364	1,647,015
General Service Greater Than 1,000 kW	kW	150,201,768	332,469		**61.92%**	150,201,768	332,469
Unmetered Scattered Load	kWh	3,696,824		1.0377		3,836,194	-
Sentinel Lighting	kW	120,534	335		**49.34%**	120,534	335
Street Lighting	kW	11,824,926	32,927		**49.22%**	11,824,926	32,927
Embedded Distributor	kW	33,729,600	73,000		**63.33%**	33,729,600	73,000

RTSR Workform for Electricity Distributors (2014 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.82
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.82
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.98

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.23
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.65
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.62
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.27

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ 0.1465	$ 0.1465
RSVA Transmission connection – 4716 – which affects 1586	kW	$ -	$ 0.0667	$ 0.0667
RSVA LV – 4750 – which affects 1550	kW	$ -	$ 0.0475	$ 0.0475
RARA 1 – 2252 – which affects 1590	kW	$ -	$ 0.0419	$ 0.0419
RARA 1 – 2252 – which affects 1590 (2008)	kW	$ -	-$ 0.0270	-$ 0.0270
RARA 1 – 2252 – which affects 1590 (2009)	kW	$ -	-$ 0.0006	-$ 0.0006
Hydro One Sub-Transmission Rate Rider 9A	kW	$ -	$ 0.2750	$ 0.2750

		Historical 2012	Current 2013	Forecast 2014
Transformer Allowance Credit (if applicable, enter as a negative value)	$			

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	283,195	$2.57	$ 727,811	206,077	$0.80	$ 164,862	182,522	$1.86	$ 339,491	$ 504,353
February	236,667	$2.57	$ 608,235	192,945	$0.80	$ 154,356	173,828	$1.86	$ 323,320	$ 477,676
March	252,348	$2.57	$ 648,533	191,891	$0.80	$ 153,513	155,540	$1.86	$ 289,304	$ 442,817
April	265,337	$2.57	$ 681,916	206,050	$0.80	$ 164,840	169,132	$1.86	$ 314,586	$ 479,426
May	308,315	$2.57	$ 792,369	242,704	$0.80	$ 194,163	209,211	$1.86	$ 389,132	$ 583,296
June	376,009	$2.57	$ 966,342	289,763	$0.80	$ 231,810	247,123	$1.86	$ 459,649	$ 691,459
July	390,190	$2.57	$ 1,002,788	297,183	$0.80	$ 237,746	268,024	$1.86	$ 498,525	$ 736,271
August	340,956	$2.57	$ 876,257	258,775	$0.80	$ 207,020	236,254	$1.86	$ 439,432	$ 646,452
September	315,284	$2.57	$ 810,279	244,373	$0.80	$ 195,498	207,171	$1.86	$ 385,338	$ 580,836
October	233,175	$2.57	$ 599,260	173,624	$0.80	$ 138,899	158,567	$1.86	$ 294,935	$ 433,834
November	245,997	$2.57	$ 632,211	187,547	$0.80	$ 150,038	167,912	$1.86	$ 312,316	$ 462,354
December	253,257	$2.57	$ 650,872	197,675	$0.80	$ 158,140	176,282	$1.86	$ 327,885	$ 486,025
Total	3,500,729	$ 2.57	$ 8,996,873	2,688,607	$ 0.80	$ 2,150,886	2,351,566	$ 1.86	$ 4,373,912	$ 6,524,798

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	58,035	$2.65	$ 153,793		$0.00		58,035	$1.50	$ 87,053	$ 87,053
February	58,855	$2.65	$ 155,966		$0.00		58,855	$1.50	$ 88,283	$ 88,283
March	52,448	$2.65	$ 138,987		$0.00		53,164	$1.50	$ 79,746	$ 79,746
April	8,948	$2.65	$ 23,712		$0.00		10,859	$1.50	$ 16,289	$ 16,289
May	63,089	$2.65	$ 167,186		$0.00		63,089	$1.50	$ 94,634	$ 94,634
June	84,944	$2.65	$ 225,102		$0.00		84,944	$1.50	$ 127,416	$ 127,416
July	86,922	$2.65	$ 230,343		$0.00		86,922	$1.50	$ 130,383	$ 130,383
August	72,685	$2.65	$ 192,615		$0.00		72,685	$1.50	$ 109,028	$ 109,028
September	64,624	$2.65	$ 171,254		$0.00		64,624	$1.50	$ 96,936	$ 96,936
October	53,983	$2.65	$ 143,055		$0.00		53,983	$1.50	$ 80,975	$ 80,975
November	54,323	$2.65	$ 143,956		$0.00		54,323	$1.50	$ 81,485	$ 81,485
December	61,540	$2.79	$ 171,976		$0.00		61,540	$1.54	$ 94,492	$ 94,492
Total	720,396	$ 2.66	$ 1,917,945	-	$ -	$ -	723,023	$ 1.50	$ 1,086,716	$ 1,086,716

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		

RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	341,230	$2.58	$ 881,603	206,077	$0.80	$ 164,862	240,557	$1.77	$ 426,543	$ 591,405
February	295,522	$2.59	$ 764,201	192,945	$0.80	$ 154,356	232,683	$1.77	$ 411,603	$ 565,959
March	304,796	$2.58	$ 787,521	191,891	$0.80	$ 153,513	208,704	$1.77	$ 369,050	$ 522,563
April	274,285	$2.57	$ 705,629	206,050	$0.80	$ 164,840	179,991	$1.84	$ 330,874	$ 495,714
May	371,404	$2.58	$ 959,554	242,704	$0.80	$ 194,163	272,300	$1.78	$ 483,766	$ 677,929
June	460,953	$2.58	$ 1,191,444	289,763	$0.80	$ 231,810	332,067	$1.77	$ 587,065	$ 818,875
July	477,112	$2.58	$ 1,233,131	297,183	$0.80	$ 237,746	354,946	$1.77	$ 628,908	$ 866,654
August	413,641	$2.58	$ 1,068,872	258,775	$0.80	$ 207,020	308,939	$1.78	$ 548,460	$ 755,480
September	379,908	$2.58	$ 981,533	244,373	$0.80	$ 195,498	271,795	$1.77	$ 482,274	$ 677,772
October	287,158	$2.59	$ 742,315	173,624	$0.80	$ 138,899	212,550	$1.77	$ 375,909	$ 514,808
November	300,320	$2.58	$ 776,167	187,547	$0.80	$ 150,038	222,235	$1.77	$ 393,801	$ 543,838
December	314,797	$2.61	$ 822,848	197,675	$0.80	$ 158,140	237,822	$1.78	$ 422,376	$ 580,516
Total	4,221,125	$ 2.59	$ 10,914,818	2,688,607	$ 0.80	$ 2,150,886	3,074,589	$ 1.78	$ 5,460,629	$ 7,611,515

Transformer Allowance Credit (if applicable)	$ -
Total including deduction for Transformer Allowance Credit	$ 7,611,515

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	283,195	$ 3.6300	$ 1,027,997	206,077	$ 0.7500	$ 154,558	182,522	$ 1.8500	$ 337,666	$ 492,224
February	236,667	$ 3.6300	$ 859,103	192,945	$ 0.7500	$ 144,709	173,828	$ 1.8500	$ 321,582	$ 466,291
March	252,348	$ 3.6300	$ 916,022	191,891	$ 0.7500	$ 143,918	155,540	$ 1.8500	$ 287,749	$ 431,667
April	265,337	$ 3.6300	$ 963,174	206,050	$ 0.7500	$ 154,538	169,132	$ 1.8500	$ 312,894	$ 467,432
May	308,315	$ 3.6300	$ 1,119,182	242,704	$ 0.7500	$ 182,028	209,211	$ 1.8500	$ 387,040	$ 569,068
June	376,009	$ 3.6300	$ 1,364,911	289,763	$ 0.7500	$ 217,322	247,123	$ 1.8500	$ 457,177	$ 674,500
July	390,190	$ 3.6300	$ 1,416,389	297,183	$ 0.7500	$ 222,887	268,024	$ 1.8500	$ 495,844	$ 718,732
August	340,956	$ 3.6300	$ 1,237,670	258,775	$ 0.7500	$ 194,081	236,254	$ 1.8500	$ 437,070	$ 631,151
September	315,284	$ 3.6300	$ 1,144,480	244,373	$ 0.7500	$ 183,280	207,171	$ 1.8500	$ 383,266	$ 566,546
October	233,175	$ 3.6300	$ 846,426	173,624	$ 0.7500	$ 130,218	158,567	$ 1.8500	$ 293,349	$ 423,567
November	245,997	$ 3.6300	$ 892,968	187,547	$ 0.7500	$ 140,660	167,912	$ 1.8500	$ 310,637	$ 451,297
December	253,257	$ 3.6300	$ 919,325	197,675	$ 0.7500	$ 148,256	176,282	$ 1.8500	$ 326,122	$ 474,378
Total	3,500,729	$ 3.63	$ 12,707,646	2,688,607	$ 0.75	$ 2,016,455	2,351,566	$ 1.85	$ 4,350,397	$ 6,366,852

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	58,035	$ 3.3265	$ 193,053	-	$ 0.7667	$ -	58,035	$ 1.6300	$ 94,597	$ 94,597
February	58,855	$ 3.3265	$ 195,781	-	$ 0.7667	$ -	58,855	$ 1.6300	$ 95,934	$ 95,934
March	52,448	$ 3.3265	$ 174,468	-	$ 0.7667	$ -	53,164	$ 1.6300	$ 86,657	$ 86,657
April	8,948	$ 3.3265	$ 29,766	-	$ 0.7667	$ -	10,859	$ 1.6300	$ 17,700	$ 17,700
May	63,089	$ 3.3265	$ 209,866	-	$ 0.7667	$ -	63,089	$ 1.6300	$ 102,835	$ 102,835
June	84,944	$ 3.3265	$ 282,566	-	$ 0.7667	$ -	84,944	$ 1.6300	$ 138,459	$ 138,459
July	86,922	$ 3.3265	$ 289,146	-	$ 0.7667	$ -	86,922	$ 1.6300	$ 141,683	$ 141,683
August	72,685	$ 3.3265	$ 241,787	-	$ 0.7667	$ -	72,685	$ 1.6300	$ 118,477	$ 118,477
September	64,624	$ 3.3265	$ 214,972	-	$ 0.7667	$ -	64,624	$ 1.6300	$ 105,337	$ 105,337
October	53,983	$ 3.3265	$ 179,574	-	$ 0.7667	$ -	53,983	$ 1.6300	$ 87,992	$ 87,992
November	54,323	$ 3.3265	$ 180,705	-	$ 0.7667	$ -	54,323	$ 1.6300	$ 88,546	$ 88,546
December	61,540	$ 3.3265	$ 204,713	-	$ 0.7667	$ -	61,540	$ 1.6300	$ 100,310	$ 100,310
Total	720,396	$ 3.33	$ 2,396,397	-	$ -	$ -	723,023	$ 1.63	$ 1,178,527	$ 1,178,527

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	341,230	$3.58	$ 1,221,051	206,077	$0.75	$ 154,558	240,557	$1.80	$ 432,263	$ 586,821
February	295,522	$3.57	$ 1,054,884	192,945	$0.75	$ 144,709	232,683	$1.79	$ 417,515	$ 562,224
March	304,796	$3.58	$ 1,090,490	191,891	$0.75	$ 143,918	208,704	$1.79	$ 374,406	$ 518,325
April	274,285	$3.62	$ 992,939	206,050	$0.75	$ 154,538	179,991	$1.84	$ 330,594	$ 485,132
May	371,404	$3.58	$ 1,329,048	242,704	$0.75	$ 182,028	272,300	$1.80	$ 489,875	$ 671,903
June	460,953	$3.57	$ 1,647,477	289,763	$0.75	$ 217,322	332,067	$1.79	$ 595,636	$ 812,958
July	477,112	$3.57	$ 1,705,535	297,183	$0.75	$ 222,887	354,946	$1.80	$ 637,527	$ 860,415
August	413,641	$3.58	$ 1,479,456	258,775	$0.75	$ 194,081	308,939	$1.80	$ 555,546	$ 749,628
September	379,908	$3.58	$ 1,359,452	244,373	$0.75	$ 183,280	271,795	$1.80	$ 488,603	$ 671,883
October	287,158	$3.57	$ 1,026,000	173,624	$0.75	$ 130,218	212,550	$1.79	$ 381,341	$ 511,559
November	300,320	$3.58	$ 1,073,673	187,547	$0.75	$ 140,660	222,235	$1.80	$ 399,184	$ 539,844
December	314,797	$3.57	$ 1,124,037	197,675	$0.75	$ 148,256	237,822	$1.79	$ 426,432	$ 574,688
Total	4,221,125	$ 3.58	$ 15,104,043	2,688,607	$ 0.75	$ 2,016,455	3,074,589	$ 1.80	$ 5,528,924	$ 7,545,380

Transformer Allowance Credit (if applicable) $ -

Total including deduction for Transformer Allowance Credit $ 7,545,380

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	283,195	$ 3.8200	$ 1,081,804	206,077	$ 0.8200	$ 168,983	182,522	$ 1.9800	$ 361,394	$ 530,377
February	236,667	$ 3.8200	$ 904,069	192,945	$ 0.8200	$ 158,215	173,828	$ 1.9800	$ 344,179	$ 502,394
March	252,348	$ 3.8200	$ 963,968	191,891	$ 0.8200	$ 157,351	155,540	$ 1.9800	$ 307,969	$ 465,320
April	265,337	$ 3.8200	$ 1,013,588	206,050	$ 0.8200	$ 168,961	169,132	$ 1.9800	$ 334,881	$ 503,842
May	308,315	$ 3.8200	$ 1,177,762	242,704	$ 0.8200	$ 199,017	209,211	$ 1.9800	$ 414,238	$ 613,255
June	376,009	$ 3.8200	$ 1,436,353	289,763	$ 0.8200	$ 237,606	247,123	$ 1.9800	$ 489,303	$ 726,909
July	390,190	$ 3.8200	$ 1,490,525	297,183	$ 0.8200	$ 243,690	268,024	$ 1.9800	$ 530,688	$ 774,378
August	340,956	$ 3.8200	$ 1,302,451	258,775	$ 0.8200	$ 212,196	236,254	$ 1.9800	$ 467,783	$ 679,978
September	315,284	$ 3.8200	$ 1,204,384	244,373	$ 0.8200	$ 200,386	207,171	$ 1.9800	$ 410,199	$ 610,584
October	233,175	$ 3.8200	$ 890,729	173,624	$ 0.8200	$ 142,372	158,567	$ 1.9800	$ 313,963	$ 456,334
November	245,997	$ 3.8200	$ 939,707	187,547	$ 0.8200	$ 153,789	167,912	$ 1.9800	$ 332,466	$ 486,254
December	253,257	$ 3.8200	$ 967,444	197,675	$ 0.8200	$ 162,094	176,282	$ 1.9800	$ 349,038	$ 511,132
Total	3,500,729	$ 3.82	$ 13,372,784	2,688,607	$ 0.82	$ 2,204,658	2,351,566	$ 1.98	$ 4,656,100	$ 6,860,758

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	58,035	$ 3.3765	$ 195,955	-	$ 0.7167	$ -	58,035	$ 1.6200	$ 94,017	$ 94,017
February	58,855	$ 3.3765	$ 198,724	-	$ 0.7167	$ -	58,855	$ 1.6200	$ 95,345	$ 95,345
March	52,448	$ 3.3765	$ 177,091	-	$ 0.7167	$ -	53,164	$ 1.6200	$ 86,126	$ 86,126
April	8,948	$ 3.3765	$ 30,213	-	$ 0.7167	$ -	10,859	$ 1.6200	$ 17,592	$ 17,592
May	63,089	$ 3.3765	$ 213,020	-	$ 0.7167	$ -	63,089	$ 1.6200	$ 102,204	$ 102,204
June	84,944	$ 3.3765	$ 286,813	-	$ 0.7167	$ -	84,944	$ 1.6200	$ 137,609	$ 137,609
July	86,922	$ 3.3765	$ 293,492	-	$ 0.7167	$ -	86,922	$ 1.6200	$ 140,814	$ 140,814
August	72,685	$ 3.3765	$ 245,421	-	$ 0.7167	$ -	72,685	$ 1.6200	$ 117,750	$ 117,750
September	64,624	$ 3.3765	$ 218,203	-	$ 0.7167	$ -	64,624	$ 1.6200	$ 104,691	$ 104,691
October	53,983	$ 3.3765	$ 182,274	-	$ 0.7167	$ -	53,983	$ 1.6200	$ 87,452	$ 87,452
November	54,323	$ 3.3765	$ 183,422	-	$ 0.7167	$ -	54,323	$ 1.6200	$ 88,003	$ 88,003
December	61,540	$ 3.3765	$ 207,790	-	$ 0.7167	$ -	61,540	$ 1.6200	$ 99,695	$ 99,695
Total	720,396	$ 3.38	$ 2,432,417	-	$ -	$ -	723,023	$ 1.62	$ 1,171,297	$ 1,171,297

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	341,230	$ 3.74	$ 1,277,759	206,077	$ 0.82	$ 168,983	240,557	$ 1.89	$ 455,410	$ 624,394
February	295,522	$ 3.73	$ 1,102,793	192,945	$ 0.82	$ 158,215	232,683	$ 1.89	$ 439,525	$ 597,739
March	304,796	$ 3.74	$ 1,141,059	191,891	$ 0.82	$ 157,351	208,704	$ 1.89	$ 394,095	$ 551,446
April	274,285	$ 3.81	$ 1,043,801	206,050	$ 0.82	$ 168,961	179,991	$ 1.96	$ 352,473	$ 521,434
May	371,404	$ 3.74	$ 1,390,782	242,704	$ 0.82	$ 199,017	272,300	$ 1.90	$ 516,442	$ 715,459
June	460,953	$ 3.74	$ 1,723,166	289,763	$ 0.82	$ 237,606	332,067	$ 1.89	$ 626,913	$ 864,518
July	477,112	$ 3.74	$ 1,784,018	297,183	$ 0.82	$ 243,690	354,946	$ 1.89	$ 671,501	$ 915,191
August	413,641	$ 3.74	$ 1,547,872	258,775	$ 0.82	$ 212,196	308,939	$ 1.90	$ 585,533	$ 797,728
September	379,908	$ 3.74	$ 1,422,587	244,373	$ 0.82	$ 200,386	271,795	$ 1.89	$ 514,889	$ 715,275
October	287,158	$ 3.74	$ 1,073,003	173,624	$ 0.82	$ 142,372	212,550	$ 1.89	$ 401,415	$ 543,787
November	300,320	$ 3.74	$ 1,123,129	187,547	$ 0.82	$ 153,789	222,235	$ 1.89	$ 420,469	$ 574,258
December	314,797	$ 3.73	$ 1,175,233	197,675	$ 0.82	$ 162,094	237,822	$ 1.89	$ 448,733	$ 610,827
Total	4,221,125	$ 3.74	$ 15,805,201	2,688,607	$ 0.82	$ 2,204,658	3,074,589	$ 1.90	$ 5,827,398	$ 8,032,056

Transformer Allowance Credit (if applicable) $ -

Total including deduction for Transformer Allowance Credit $ 8,032,056

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0080	625,118,469	-	$ 5,000,948	29.8%	$ 4,494,588	$0.0072
General Service Less Than 50 kW	kWh	$ 0.0074	173,141,941	-	$ 1,281,250	7.6%	$ 1,151,520	$0.0067
General Service 50 to 999 kW	kW	$ 2.7667	607,509,364	1,647,015	$ 4,556,796	27.1%	$ 4,095,407	$2.4866
General Service 50 to 999 kW - Interval Metered	kW	$ 2.8561	607,509,364	1,647,015	$ 4,704,039	28.0%	$ 4,227,741	$2.5669
General Service Greater Than 1,000 kW	kW	$ 2.8561	150,201,768	332,469	$ 949,564	5.7%	$ 853,418	$2.5669
Unmetered Scattered Load	kWh	$ 0.0074	3,836,194	-	$ 28,388	0.2%	$ 25,513	$0.0067
Sentinel Lighting	kW	$ 0.5546	120,534	335	$ 186	0.0%	$ 167	$0.4984
Street Lighting	kW	$ 2.3081	11,824,926	32,927	$ 75,999	0.5%	$ 68,304	$2.0744
Embedded Distributor	kW	$ 2.8561	33,729,600	73,000	$ 208,495	1.2%	$ 187,385	$2.5669
					$ 16,805,664			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0055	625,118,469	-	$ 3,438,152	30.0%	$ 2,267,277	$0.0036
General Service Less Than 50 kW	kWh	$ 0.0050	173,141,941	-	$ 865,710	7.6%	$ 570,889	$0.0033
General Service 50 to 999 kW	kW	$ 1.8766	607,509,364	1,647,015	$ 3,090,788	27.0%	$ 2,038,209	$1.2375
General Service 50 to 999 kW - Interval Metered	kW	$ 1.9374	607,509,364	1,647,015	$ 3,190,926	27.9%	$ 2,104,245	$1.2776
General Service Greater Than 1,000 kW	kW	$ 1.9374	150,201,768	332,469	$ 644,125	5.6%	$ 424,766	$1.2776
Unmetered Scattered Load	kWh	$ 0.0050	3,836,194	-	$ 19,181	0.2%	$ 12,649	$0.0033
Sentinel Lighting	kW	$ 0.3761	120,534	335	$ 126	0.0%	$ 83	$0.2480
Street Lighting	kW	$ 1.5656	11,824,926	32,927	$ 51,551	0.5%	$ 33,995	$1.0324
Embedded Distributor	kW	$ 1.9374	33,729,600	73,000	$ 141,430	1.2%	$ 93,266	$1.2776
					$ 11,441,988			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$0.0072	625,118,469	-	4,494,587.61	29.8%	$ 4,703,235	$0.0075
General Service Less Than 50 kW	kWh	$0.0067	173,141,941	-	$ 1,151,520	7.6%	$ 1,204,976	$0.0070
General Service 50 to 999 kW	kW	$2.4866	607,509,364	1,647,015	$ 4,095,407	27.1%	$ 4,285,524	$2.6020
General Service 50 to 999 kW - Interval Metered	kW	$2.5669	607,509,364	1,647,015	$ 4,227,741	28.0%	$ 4,424,001	$2.6861
General Service Greater Than 1,000 kW	kW	$2.5669	150,201,768	332,469	$ 853,418	5.7%	$ 893,035	$2.6861
Unmetered Scattered Load	kWh	$0.0067	3,836,194	-	$ 25,513	0.2%	$ 26,698	$0.0070
Sentinel Lighting	kW	$0.4984	120,534	335	$ 167	0.0%	$ 175	$0.5216
Street Lighting	kW	$2.0744	11,824,926	32,927	$ 68,304	0.5%	$ 71,475	$2.1707
Embedded Distributor	kW	$2.5669	33,729,600	73,000	$ 187,385	1.2%	$ 196,083	$2.6861
					$ 15,104,043			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0036	625,118,469	-	$ 2,267,277	30.0%	$ 2,413,516	$ 0.0039
General Service Less Than 50 kW	kWh	$ 0.0033	173,141,941	-	$ 570,889	7.6%	$ 607,712	$ 0.0035
General Service 50 to 999 kW	kW	$ 1.2375	607,509,364	1,647,015	$ 2,038,209	27.0%	$ 2,169,674	$ 1.3173
General Service 50 to 999 kW - Interval Metered	kW	$ 1.2776	607,509,364	1,647,015	$ 2,104,245	27.9%	$ 2,239,969	$ 1.3600
General Service Greater Than 1,000 kW	kW	$ 1.2776	150,201,768	332,469	$ 424,766	5.6%	$ 452,163	$ 1.3600
Unmetered Scattered Load	kWh	$ 0.0033	3,836,194	-	$ 12,649	0.2%	$ 13,465	$ 0.0035
Sentinel Lighting	kW	$ 0.2480	120,534	335	$ 83	0.0%	$ 88	$ 0.2640
Street Lighting	kW	$ 1.0324	11,824,926	32,927	$ 33,995	0.5%	$ 36,188	$ 1.0990
Embedded Distributor	kW	$ 1.2776	33,729,600	73,000	$ 93,266	1.2%	$ 99,281	$ 1.3600
					$ 7,545,380			

RTSR Workform for Electricity Distributors (2014 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I.
Please note that the rate descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0075	$	0.0039
General Service Less Than 50 kW	kWh	$	0.0070	$	0.0035
General Service 50 to 999 kW	kW	$	2.6020	$	1.3173
General Service 50 to 999 kW - Interval Metered	kW	$	2.6861	$	1.3600
General Service Greater Than 1,000 kW	kW	$	2.6861	$	1.3600
Unmetered Scattered Load	kWh	$	0.0070	$	0.0035
Sentinel Lighting	kW	$	0.5216	$	0.2640
Street Lighting	kW	$	2.1707	$	1.0990
Embedded Distributor	kW	$	2.6861	$	1.3600

9-Accounting

Issue 9.1 *Are the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders appropriate?*

9.1-Staff-48

Ref: 1) Exhibit 9/Tab8/Schedule 1/p. 2, Table 9-13

2) Exhibit 9/Tab8/Schedule 1/p. 1, Table 9-14

3) 2014 Filing Requirements For Electricity Distribution Rate Applications, Chapter 2, Cost of Service (COS) dated July 17, 2013, S. 2.12.3

Account 1508, Other Regulatory Assets - Sub-Account Deferred IFRS Transition

In Table 9-13, Oakville Hydro is requesting disposition of the Deferred IFRS Transition Costs sub-account balance of $662,943.

However, as Oakville Hydro has documented elsewhere in its Application, OHEDI has not fully adopted IFRS for financial reporting purposes, and has not completed all changes necessary to adopt IFRS.

The Board's general policy and practice is not to dispose of the Account 1508 sub account Deferred IFRS Transition Costs until the distributor has completed its adoption of IFRS for financial and regulatory purposes and so has a complete record of such costs to review.

Board staff notes that S.2.12.3 of the 2014 Filing Requirements refer to Accounting Procedures Handbook – FAQ #1 and FAQ #2, dated October 2009 and states the following with respect to the disposition of Account 1508 Other Regulatory Assets, Subaccount Deferred IFRS Transition:

"As per the October 2009 APH FAQ #1 and FAQ #2, an applicant must file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance, in its next cost of service rate application immediately after the IFRS transition period."

a) Given that Oakville Hydro's IFRS adoption occurs on January 1, 2015 and given S.2.12.3 of the 2014 filing requirements, please explain why Oakville Hydro is seeking disposition of the $662,943 (Other Regulatory Assets - Sub-Account - Deferred IFRS Transition) balance in this current rate application instead of requesting disposition in the next rate proceeding when the IFRS transition period is complete.

RESPONSE:

Oakville Hydro is not seeking approval for the disposition of account Other Regulatory Assets - Sub-Account - Deferred IFRS Transition. This is referenced in Exhibit 9, Tab 1, Schedule 1, Page 1 of 2 lines 2-4 and in Exhibit 9, Tab 1, Schedule 5, Page 1 of 1, Table 9-5. However, Oakville Hydro inadvertently did not remove this from Table 9-13.

b) Please recalculate Table 9-13 without the balance of $662,943 and the related rate riders in Table 9-14 for Account 1508, Other Regulatory Assets, Sub-Account Deferred IFRS Transition Costs.

RESPONSE:

Oakville Hydro has revised Table 9-13 and Table 9-14. A copy of the updated 2014 DVA Work Form is provided in Appendix 9-A

Table 9-13: Group 2 Deferral / Variance Accounts

Account Descriptions	Account Number	Principal (Dec 31 ,2012)	Interest (Dec 31 ,2012)	Projected Interest (Dec 31 ,2013)	Projected Interest (April 30 ,2014)	Total Claim
		A	B	C=A*1.47%	D=A*1.47% /12*4	E=A+B+C+D
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	16,674	621	245	82	17,623
Retail Cost Variance Account - Retail	1518	(58,918)	(1,849)	(866)	(289)	(61,922)
Smart Grid OM&A Deferral Account	1535	20,839	480	306	102	21,727
Retail Cost Variance Account - STR	1548	(2,643)	(60)	(39)	(13)	(2,755)
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	(161,198)	(20,377)	(2,370)	(790)	(184,734)
Subtotal - Group 2 Accounts		$ (185,245)	$ (21,185)	$ (2,723)	$ (908)	$ (210,061)

Table 9-14: Proposed DVA Rate Rider by Class (Excluding 1589 Global Adjustment)

Customer Class	2012 Actual kWh	2012 Actual kW	Allocated Balance (Exclude 1589)	Recovery Period (Years)	Unit	Rate Rider
Residential	602,407,699	-	$ (391,619)	1	$/kWh	(0.0007)
General Service < 50 kW	166,851,635	-	(119,268)	1	$/kWh	(0.0007)
General Service > 50 to 999 kW	607,509,364	1,647,015	(872,488)	1	$/kWh	(0.5297)
General Service > 1000 kW	150,201,768	332,469	(244,193)	1	$/kW	(0.7345)
Unmetered Loads	3,696,824	-	(2,411)	1	$/kW	(0.0007)
Sentinel Lights	120,534	335	(350)	1	$/kWh	(1.0448)
Street lights	11,824,926	32,927	(19,308)	1	$/kW	(0.5864)
Total	**1,542,612,750**	**2,012,745**	$(1,649,635)			

c) What proportion of the transition to IFRS is complete? What proportion of total expected IFRS transition project expenditures does the $662,943 represent? Does Oakville Hydro have any material on-going costs related to IFRS transition in addition to the $662,943 being requested for disposition?

RESPONSE:

The transition to IFRS is substantially complete. At this time, with the information currently available, Oakville Hydro does not anticipate material on-going costs related to the IFRS transition.

d) If the Board decides to approve the disposition of this sub account 1508, please confirm that Oakville Hydro will not record any future transaction under this sub account 1508.

RESPONSE:

As discussed in response to part a) of this interrogatory, Oakville Hydro is not requesting disposition of this sub account 1508 at this time. Oakville Hydro will request approval for the disposition of the balance of the Other Regulatory Assets - Sub-Account - Deferred IFRS Transition in its next cost of service application immediately after the IFRS transition period in accordance with Section 2.12.3 of the 2014 Filing Requirements.

9.1-Staff-49

Ref: Exhibit 9/Appendix A/DVA Work Form for 2014 Filers, 2013 Continuity Schedule Tab

DVA Work Form

In the "Adjustment During 2011-Other" column in the DVA Work Form, Oakville Hydro provided various adjustments for various Group 1 DVA accounts.

In addition, Board staff notes that various adjustments for Accounts 1550, 1580, 1584, 1588, 1589 and 1595 (2011 sub account) were entered in the "Adjustments During 2010-Other" column.

The filing requirements footnote requires that an explanation should be provided for the listed adjustments in these columns.

a) Please explain the nature of each adjustment in the two columns (2010 and 2011adjustments) referred above and the rationale for these amounts.

RESPONSE:

The amounts shown in the 2010 and 2011adjustments columns are not adjustments but rather the ending balance of 2011 the Group 1 Accounts as at December 31, 2011. Oakville Hydro entered the 2011 ending balance in the adjustment columns in order to populate the "Closing Principal Balance as of Dec-31-11" column and "Closing Interest Amounts as of Dec-31-11" columns as the opening and closing balance cells are locked.

b) Are the amounts under "Adjustments During 2010-Other" column and the amounts in the "Adjustment During 2011-Other" column properly reflected in the right columns? If not, please make any adjustments required and update the 2014 DVA WF.

RESPONSE:

As discussed in to part a) of this interrogatory the amounts under "Adjustments During 2010-Other" column and the amounts in the "Adjustment During 2011-Other" column are properly reflected in the right columns

9.1-Staff-50

Ref: 1) Exhibit 9/Tab8/Schedule 1/p. 2, Table 9-11

2) DVA Work Form for 2014 Filers, 2013 Continuity Schedule Tab

3) Ontario Energy Board Decision, EB-2012-0154

Account 1595, Disposition and Recovery/Refund of Regulatory Balances (2011)

Oakville Hydro is requesting for disposition of the balance in Account 1595, Disposition and Recovery of Regulatory Assets (sub account 2011) in the amount of $1,005,250 refundable to customers.

In Board Decision EB-2012-0154, the Board approved the disposition of the balance of $3,359,974 in principal and the balance of $609,261(refund to customers) in interest for a total of $2,750,713 for Account 1595, sub account 2011.

In the DVA WF, Board staff notes that in the "Principal Disposition During 2013-Instructed by the Board" column, Oakville Hydro did not reflect the Board disposition of the approved principal of $3,359,974. Neither did Oakville Hydro reflect the Board approved interest of $609,261 refund to customers in the "Interest Disposition During 2013-Instructed by the Board" column.

a) Please make all the adjustments required in Account 1595 (2011 sub account) to show the Board approved amounts (principal: $3,359,974 and interest: $609,261, refund to customers) in the Board Decision EB 2012-0154 in the 2014 DVA WF.

RESPONSE:

Oakville made a typographical error in the "Interest Disposition during 2013instructed by the Board" column for Group 1 Account 1589 – RSVA- Global Adjustment. The correct amount should be debit of $530,089 rather than a credit of $530,089. Oakville Hydro has provided a corrected 2014 DVA Work Form as Appendix 9-A.

b) Please confirm if the balance requested for disposition in Account 1595, sub account 2011 in Table 9-11 has changed and if it has, please update Tables 9-11 and any other required evidence including Table 9-14.

RESPONSE:

The balance requested for disposition in Account 1589 RSVA- Global Adjustment has changed in Table 9-12 due to the typographic error identified in response to part a) of this interrogatory. Oakville Hydro has updated Table 9-12 and Table 9-15 in the tables provided below.

Table 9-12: 1589 GA Sub-Account

Account Descriptions	Account Number	Principal (Dec 31 ,2012)	Interest (Dec 31 ,2012)	Principal Disposition during 2013 - instructed by Board	Interest Disposition during 2013 - instructed by Board	Projected Interest (Dec 31 ,2013)	Projected Interest (April 30 ,2014)	Total Claim
		A	B	C	D	E=(A-C)*1.47%	F=(A-C)*1.47%/12*4	G='A+B-(C+D)+E+F
RSVA - Power - Sub-account - Global Adjustment	1589	689,970	509,847	1,822,396	530,089	(16,647)	(5,549)	(1,174,863)
Subtotal		$ 689,970	$ 509,847	$ 1,822,396	$ 530,089	$ (16,647)	$ (5,549)	$ (1,174,863)

Table 9-15: Proposed Rate Rider for RSVA - Power - Sub-account - Global Adjustment

Customer Class	2012 Actual Non-RPP kWh	2012 Actual Non-RPP kW	Allocated Balance of 1589	Recovery Period (Years)	Unit	Rate Rider
Residential	29,968,136		$ (47,389)	1	kWh	(0.0016)
General Service < 50 kW	26,197,389	-	(41,427)	1	$/kWh	(0.0016)
General Service > 50 to 999 kW	524,742,591	1,422,626	(829,789)	1	$/kW	(0.5833)
General Service > 1000 kW	150,201,768	332,469	(237,518)	1	$/kW	(0.7144)
Unmetered Loads	26,438	-	(42)	1	$/kW	(0.0016)
Sentinel Lights	-	-		1	$/kW	
Street lights	11,824,926	32,927	(18,699)	1	$/kW	(0.5679)
Total	**742,961,248**		$(1,174,863)			

9.1-Energy Probe-56

Ref: Exhibit 2, Tab 6, Schedule 4

a) Please provide a revised Table 2-60, Table 2-61 and Appendix 2-EE already that reflect the treatment of account 1576 consistent with the Board's decision in EB-2012-0161 for PowerStream.

RESPONSE:

Oakville Hydro's Table 2-60, Table 2-61 and Appendix 2-EE already reflect the treatment of account 1576 consistent to the Boards Decision in EB-2012-0161 for PowerStream. Oakville Hydro has provided an updated Appendix 2-EE to reflect 2013 Actual (unaudited), which is provided in response to Board staff interrogatory number 9.2-Staff-51(a).

b) Please provide the after-tax calculation of the WIP amount to be recovered from ratepayers, along with a table similar to Table 2-61, again consistent with the Board's decision in EB-2012-0161.

RESPONSE:

The after-tax calculation of the WIP amount to be recovered from ratepayers would be $475,749.

Description	Calculation	Total
CWIP		647,278
Tax effect of WIP in Closing Balance	26.50%	171,529
After Tax		$ 475,749

The revised Table 2-61(excluding CWIP) is provided below, and also calculated in 9.2-Staff-51b) Appendix 2-EE.

Description		Calculation	Total
2013 Closing Balance PP&E Old GCGAAP		A	$ 154,378,813
2014 Closing Balance PP&E New CGAAP		B	155,205,889
Closing Balance in Account 1576		C = A - B	(827,076)
WACC		D	6.45%
Return on Rate Base Associated with Account 1576 balance at WACC	Per Year	E = C * D	(53,346)
Disposition Period		F	1
Return on Rate Base Associated With Account 1576 balance at WACC	Total	G = E * F	(53,346)
Account 1576 Rate Rider Calculation (excluding WIP)		H = C + G	(880,422)

9.1-Energy Probe-57

Ref: Exhibit 9, Tab 11, Schedule 1 &
Exhibit 4, Tab 2, Schedule 2

a) Please show the derivation of the actual revenue requirement associated with the actual costs for the municipal transformation station in each of 2011 through 2014 that totals the amount of $5,834,937 shown in Table 9-32. In particular, please show separate lines for the revenue requirement components such as depreciation, return on equity, cost of debt, PILs, OM&A, etc. and provide all assumptions used in the calculations.

RESPONSE:

The calculation of the actual annual revenue requirement of $1,944,979 associated with the actual costs for the municipal transformer station is provided in the table below. The total amount of $5,834,937 represents the revenue requirement associated with the actual costs for the three-year period beginning May 1, 2011 and ending April 30, 2014.

Incremental Capital Adjustment			
Return on Rate Base			
Incremental Capital CAPEX		$	20,967,552
Depreciation Expense		$	562,846
Incremental Capital CAPEX to be included in Rate Base		$	20,404,706
Deemed ShortTerm Debt %	4.0%	$	816,188
Deemed Long Term Debt %	56.0%	$	11,426,636
Short Term Interest	2.07%	$	16,895
Long Term Interest	5.87%	$	670,744
Return on Rate Base - Interest		$	687,639
Deemed Equity %	40.0%	$	8,161,883
Return on Rate Base -Equity	9.85%	$	803,945
Return on Rate Base - Total		$	1,491,584
Amortization Expense			
Amortization Expense - Incremental		$	562,846
Grossed up PIL's			
Regulatory Taxable Income		$	803,945
Add Back Amortization Expense		$	562,846
Deduct CCA		$	1,644,777
Incremental Taxable Income		$	(277,985.40)
Current Tax Rate (F1.1 Z-Factor Tax Changes)	28.25%		
PIL's Before Gross Up		$	(78,530.88)
Incremental Grossed Up PIL's		$	(109,450.70)
Incremental Revenue Requirement			
Return on Rate Base - Total		$	1,491,584
Amortization Expense - Total		$	562,846
Incremental Grossed Up PIL's		$	(109,450.70)
Incremental Revenue Requirement		$	1,944,979

b) Please explain any differences in the OM&A calculated in part (a) above and the figures shown in Table 4-3 in Exhibit 4, Tab 2, Schedule 2.

RESPONSE:

Consistent with the Filing Requirements For Electricity Distribution Rate Applications, Oakville Hydro did not include any OM&A costs in its ICM model included in a) as the ICM model did not allow OM&A to be included in the ICM calculations and resulting rate rider. This is also referenced in EB-2010-0104 Oakville Hydro's reply submission dated

February 2, 2011, Page 7 of 16,"OHEDI will incur additional OM&A costs associated with the MTS of $242,000 which it is not recovering." Therefore, since there is no OM&A in the ICM model the difference is the amount shown in Table 4-3.

c) Do the depreciation expenses include use of the half-year rule in the year in which the assets went into service?

RESPONSE:

In its Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, the Board determined that the half-year rule should not apply so as not to build in a deficiency for subsequent years in the term of the plan. In its Decision in Oakville Hydro's IRM Application (EB-2010-0104), the Board stated that, "in the Report, it was determined that the half-year rule would not apply so as not to build a deficiency for subsequent years in the IRM plan term. Since Oakville Hydro is not scheduled to file a rebasing application until 2014, the Board has determined that the half-year rule will not apply".

Consistent with this guidance and the Board's Decision, Oakville Hydro has not applied the half-year rule in calculating the revenue requirement shown above in part a).

d) Do the PILs calculations include the impact of the capital cost allowance available for each of the years?

RESPONSE:

Oakville Hydro confirms that the calculation of the revenue requirement includes the impact of the capital cost allowance as calculated in part a) of this interrogatory for each of the years. Oakville Hydro did not calculate the impact of the capital cost allowance in each year. Please see the detailed calculations provided in response to part a) of this interrogatory.

9.1-AMPCO-30

Ref: Exhibit9, Tab 9, Schedule 1, Page 7

Preamble: Oakville Hydro indicates the 2012 LRAM amounts were calculated based on the OPA's 2012 4th Quarter preliminary results and that the calculation will be updated once the OPA provides final verified results.

a) Please discuss when Oakville Hydro expects to receive the OPA's final 2012 verified CDM results and update its LRAM request.

RESPONSE:

Oakville Hydro received the OPA's final verified CDM results on September 1, 2013 and has updated its LRAM request in response to Board staff interrogatory number 9.2-Staff-52.

b) Please confirm the LRAM rate riders are rounded to four decimal places.

RESPONSE:

Oakville Hydro confirms that the LRAM rate riders are rounded to four decimal places.

Issue 9.2 *Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified, and is the treatment of each of these impacts appropriate?*

9.2-Staff-51

Ref: 1) Exhibit 2/Tab6/Schedule 4/pp. 1-2

2) Exhibit 2/Tab6/Schedule 1/p. 6 Table 9-9

3) Appendix 2-EE and 2013 Appendices 2-BA, including WIP.

<u>Account 1576, Accounting Changes Under CGAAP</u>

In the calculation of Account 1576 Accounting Changes under CGAAP on PP&E balance, Oakville Hydro included work-in-progress (WIP).

a) Please state the CWIP amounts for both 2012 and 2013 which Oakville Hydro included in the rate base for the purpose of Account 1576?

RESPONSE:

Oakville Hydro has calculated its Account 1576 based on the 2013 Actuals (unaudited). The CWIP amount for 2012 and 2013 included in the rate base for the purpose of Account 1576 is $152,073 and $495,205 respectively, for a total of $647,278.

b) Please recalculate the balance of Account 1576 in Appendix 2-EE reflecting the exclusion of CWIP, provide the supporting documentation, and recalculate the related rate riders in Table 9-9.

RESPONSE:

Please see the revised Appendix 2-EE removing all CWIP balances. Oakville Hydro is requesting the inclusion of CWIP consistent to PowerStream's treatment in their Cost of service application EB-2012-0161 in Undertaking JT1.4. This is described in Exhibit 2, Tab 6, Schedule 4, Page 1 lines 21-25.

Appendix2-EE Excluding WIP

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				$151,713,543					
Net Additions - Note 4				13,953,896					
Net Depreciation (amounts should be negative) - Note 4				(11,288,626)					
Closing net PP&E (1)				154,378,813					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				151,713,543					
Net Additions - Note 4				11,506,396					
Net Depreciation (amounts should be negative) - Note 4				(8,014,050)					
Closing net PP&E (2)				155,205,889					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				(827,076)					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	(827,076)	**WACC**	6.45%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	(53,338)	**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	($880,414)		

Notes:

CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

PP&E (Excluding WIP) Rate Rider Calculation

Customer Class	2012 Actual kWh	2012 Actual kW	Allocation % Based on kWh	Allocated Balance ($)	Recovery Period (Years)	Unit	Rate Rider ($)
Residential	602,407,699	-	39.05%	-343,811	1	$/kWh	(0.0006)
General Service < 50 kW	166,851,635	-	10.8%	-95,227	1	$/kWh	(0.0006)
General Service > 50 to 999 kW	607,509,364	1,647,015	39.4%	-346,723	1	$/kW	(0.2105)
General Service > 1000 kW	150,201,768	332,469	9.7%	-85,724	1	$/kW	(0.2578)
Unmetered Loads	3,696,824	-	0.2%	-2,110	1	$/kWh	(0.0006)
Sentinel Lights	120,534	335	0.0%	-69	1	$/kW	(0.2055)
Street lights	11,824,926	32,927	0.8%	-6,749	1	$/kW	(0.2050)
Total	**1,542,612,750**	**2,012,745**	100.0%	-880,414			

c) Please explain why the Board should approve Oakville Hydro's request for including the CWIP amount in Account 1576.

RESPONSE:

In its Decision in PowerStream's cost of service application, the Board agreed with parties that argued the effect of ignoring CWIP that closes to rate base after the transition to the new capitalization and depreciation policies, results in unrecoverable spending. In PowerStream's case the Board approved the recovery of this amount. Consistent with that decision, Oakville Hydro submits that the Board should approve Oakville Hydro's request to include the CWIP amount in Account 1576.

Oakville Hydro's has updated Appendix 2-EE with 2013 actuals (unaudited) and recalculated the rate riders in Table 9-9.

Appendix2-EE Including WIP

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				$153,505,598					
Net Additions - Note 4				14,530,706					
Net Depreciation (amounts should be negative) - Note 4				(11,288,626)					
Closing net PP&E (1)				156,747,677					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				153,505,598					
Net Additions - Note 4				11,435,927					
Net Depreciation (amounts should be negative) - Note 4				(8,014,050)					
Closing net PP&E (2)				156,927,475					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				(179,798)					

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	(179,798)	**WACC**	6.45%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	(11,595)		
Amount included in Deferral and Variance Account Rate Rider Calculation	($191,393)	**# of years of rate rider disposition period**	1

Notes:
CGAAP and revised CGAAP should be the same.
2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.
3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.
4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Table 9-9 : PP&E Rate Rider Calculation

Customer Class	2012 Actual kWh	2012 Actual kW	Allocation % Based on kWh	Allocated Balance ($)	Recovery Period (Years)	Unit	Rate Rider ($)
Residential	602,407,699	-	39.05%	-74,741	1	$/kWh	(0.0001)
General Service < 50 kW	166,851,635	-	10.8%	-20,701	1	$/kWh	(0.0001)
General Service > 50 to 999 kW	607,509,364	1,647,015	39.4%	-75,374	1	$/kW	(0.0458)
General Service > 1000 kW	150,201,768	332,469	9.7%	-18,636	1	$/kW	(0.0561)
Unmetered Loads	3,696,824	-	0.2%	-459	1	$/kWh	(0.0001)
Sentinel Lights	120,534	335	0.0%	-15	1	$/kW	(0.0447)
Street lights	11,824,926	32,927	0.8%	-1,467	1	$/kW	(0.0446)
Total	**1,542,612,750**	**2,012,745**	100.0%	-191,393			

9.2-Staff-52

Ref: Exhibit 9/Tab9/Schedule 1

CDM Savings Summary

Please provide a table that lists all the appropriate OPA CDM Initiatives that produced net CDM savings which were used in the LRAMVA calculations. For each rate class, please list all relevant CDM initiatives in the applicable year and provide the subsequent net CDM savings for each, in table format as shown below.

RESPONSE:

As noted in Exhibit 4, Tab 7, Schedule 1, Oakville Hydro calculated the LRAMVA amounts for 2012 based upon the Ontario Power Authority's ("OPA") preliminary results. Therefore, Oakville Hydro has updated its 2012 LRAMVA calculations to reflect the OPA's final verified results. A copy of the OPA's final results is provide as Appendix 9-B to Oakville Hydro's interrogatory responses. The updated LRAMVA of $167,961 is not materially different from Oakville Hydro's calculation of $169,345 based upon preliminary results. However, the final verified results have resulted in lower CDM savings for the Residential rate class and higher CDM savings for the General Service rate classes. Therefore, in order to prevent cross subsidization between rate classes, Oakville Hydro is proposing the LRAM Rate Riders be updated to reflect the OPA's final verified results. The requested table is set out below.

2011 and 2012 CDM Savings Summary

2011 and 2012 OPA Initiatives	Net kWh	Net kW	2011 Lost Revenues	2012 Lost Revenues	2013 Lost Revenues	Lost Revenues	Carrying Charges	Total Lost Revenue
Residential	590,337	80	5,062	8,402	8,422	21,886	701	22,588
Appliance Retirement	13,074	8	60	186	187	432	13	445
Appliance Exchange	1,716,518	996	17,832	24,432	24,489	66,753	2,192	68,945
HVAC Incentives	300,712	20	3,968	4,280	4,290	12,539	425	12,964
Conservation Instant Coupon Booklet	853,787	49	6,177	12,152	12,181	30,510	958	31,469
Bi-Annual Retailer Event	3,683	745	14	52	53	119	4	123
Residential Demand Response								
General Service < 50 kW								
Retrofit	148,173	29	-	2,089	2,099	4,188	113	4,301
Efficiency: Equipment Replacement	75,709	15	1,073	1,067	1,073	3,213	110	3,323
Direct Install Lighting	36,072	13	289	509	511	1,309	42	1,351
Demand Response 3 (Industrial program)	116	3	2	2	2	5	0	5
Efficiency: Equipment Replacement Incentive (C&I program)	12,180	2	173	172	173	517	18	535
Demand Response 3	88	4	1	1	1	3	0	3
Electricity Retrofit Incentive Program	48,567	9	688	685	688	2,061	71	2,132
High Performance New Construction	13,235	4	59	187	187	433	13	446
General Service > 50 kW								
Retrofit	3,967,734	772	-	2,818	2,835	5,653	152	5,805
Efficiency: Equipment Replacement	1,975,221	391	1,419	1,428	1,436	4,283	147	4,429
Direct Install Lighting	951,876	330	754	1,205	1,213	3,172	102	3,274
Demand Response 3 (Industrial program)	3,017	77	279	281	283	843	29	872
Efficiency: Equipment Replacement Incentive (C&I program)	317,769	56	205	206	207	618	21	639
Demand Response 3	2,318	99	72	361	363	796	23	819
Electricity Retrofit Incentive Program	1,267,102	227	822	827	832	2,480	85	2,565
High Performance New Construction	351,540	96	76	351	353	781	23	804
General Service > 1,000 kW								
Efficiency: Equipment Replacement	42,743	8	16	16	16	47	2	49
Direct Install Lighting	11,532	4	8	8	8	25	1	26
Demand Response 3 (Industrial program)	65	2	3	3	3	9	0	10
Efficiency: Equipment Replacement Incentive (C&I program)	6,876	1	2	2	2	7	0	7
Demand Response 3	25	0	1	1	1	2	0	2
Electricity Retrofit Incentive Program	27,420	5	9	9	9	27	1	28
High Performance New Construction	2,340	0	1	1	1	3	0	3
Total	12,739,828	4,046	39,064	61,734	61,918	162,716	5,245	167,961

Rate Classification	Lost Revenues ($)	Carrying Charges ($)	Total ($)	Billing Deteriminant	Forecasted kWh / kW	Proposed Rate Rider ($)
Residential	132,240	4,293	136,534	kWh	595,449,114	0.0002
General Service < 50 kW	11,728	366	12,095	kWh	158,508,292	0.0001
General Service > 50 kW	18,627	582	19,208	kW	1,589,641	0.0121
General Service > 1000 kW	120	4	124	kW	329,822	0.0004
Total	**162,716**	**5,245**	**167,961**			

9.2-Staff-53

Ref: Exhibit 2/Tab4/Schedule 1

Stranded Meters

On page 2 of this Exhibit, Oakville Hydro states that in 2006, developers were being charged for the costs of meters installed beyond the transformer in residential subdivisions. These meters were removed and replaced by Smart Meters. Therefore, Oakville Hydro has subtracted the depreciated value of the contributed capital from the net book value of the stranded meters.

a) By this, is Oakville Hydro stating that 100% of the costs of meters for new customers in new residential subdivision were funded through contributed capital?

RESPONSE:

Oakville Hydro is not stating that 100% of the costs of meters for new customers in new residential subdivision were funded through contributed capital. Oakville Hydro considers the electrical distribution system, up to and including the meter, for a new multi-unit subdivision an expansion of the Oakville Hydro system as defined in the Distribution System Code ("DSC"). In accordance with the DSC, Oakville Hydro performs an economic evaluation to determine the portion of the capital cost of the expansion that can be collected from the Developer of a new multi-unit subdivision. The balance of the capital cost is funded by Oakville Hydro.

b) How long has Oakville Hydro had this practice? Please explain Oakville Hydro's practice with reference to applicable sections of the Distribution System Code and how this complies with the DSC requirement to recover the cost of a basic service to residential customers as part of the revenue requirement.

RESPONSE:

Oakville Hydro has had the practice of considering the electrical distribution system, up to and including the meter, for a new multi-unit subdivision an expansion of the Oakville Hydro system as defined in the Distribution System Code ("DSC") from the time the DSC was first established. In accordance with Oakville Hydro's Conditions of Service, a multi-unit subdivision is considered a general service (non-residential) for connection purposes. Accordingly, recovering a basic connection as part of the revenue requirement is not applicable in a multi-unit subdivision.

c) Is this practice still ongoing? If not, when did Oakville Hydro cease this practice?

RESPONSE:

The practice of considering the electrical distribution system, up to and including the meter, for a new multi-unit subdivision an expansion of the Oakville Hydro system as defined in the DSC is still ongoing. Oakville Hydro ceased its practice of charging developers for meters installed in residential subdivisions, referred to above, when the Smart Meter conversion program was initiated.

d) How did Oakville Hydro treat the meter costs, including the portion funded through contributed capital in sheet I7.1 in its cost allocation model in previous applications?

RESPONSE:

In the cost allocation model submitted with its 2010 cost of service application (EB-2009-0271), Oakville Hydro entered the contributed capital associated with meters in sheet I4 BO Assets. In sheet I7.1, Oakville Hydro entered the total gross capital cost per meter installed (excluding the portion funded through contributed capital).

It is Oakville Hydro's understanding that the cost allocation model in use at the time of its 2010 cost of service application allocated the net book value of meter capital based upon the weighted average cost of meter capital for each rate class. Therefore, the contributed capital would have been allocated across all of the classes in based on the weighted average cost for each rate class.

e) In the current Application, assuming that no smart meters have been funded through contributed capital, the gross capital costs per meter should be reflected on sheet I7.1 and there should be no further impact on cost allocation with respect to meter capital costs.

Please confirm that there are no contributed capital costs factored into the costs in sheet I7.1. In the alternative, please explain.

RESPONSE:

Oakville Hydro confirms that the gross capital costs (with no capital contributions) per meter are reflected on sheet I7.1 and that there should be no further impact on cost allocation with respect to meter capital costs.

9.2-Staff-54

Ref: Exhibit 2/Tab4/Schedule 1

Stranded Meters

Oakville Hydro states that it has deducted depreciation recovered in rates to April 30, 2014. This would correspond with the four month "regulatory lag" of Oakville Hydro's rate year compared to the calendar Test (and fiscal) year on which the revenue requirement is set. Why is depreciation not stopped as of December 31, 2013 when the stranded conventional meters are effectively removed from rate base for regulatory rate-making purposes?

RESPONSE:

It is Oakville Hydro's understanding is that the depreciation of stranded meters forms part of Oakville Hydro's existing rates which will be effective until April 30, 2014, and these stranded meters are removed from rate base at that time. However, if Oakville Hydro's interpretation is incorrect, Oakville Hydro will make the appropriate adjustment based on the Boards staff's direction and update its evidence accordingly.

9.2-Staff-55

Ref: Exhibit 2/Tab6/Schedule 2/p. 2 Table 2-53

Smart Meter Model filed June 15, 2012 in Oakville Hydro's Smart Meter Cost Recovery Application EB-2012-0193

In its Smart Meter Cost Recovery application filed in 2012 and dealt with by the Board in EB-2012-0193, Oakville Hydro used a Typical Useful Life ("TUL") for smart meters of 15 years, as shown from the portion of Sheet 3 – Cost of Service Parameters from the Smart Meter Model Version 2.17 filed in that application:

Depreciation Rates
(expressed as expected useful life in years)

Smart Meters	- years	15	15	15	15	15	15	15
	- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware	- years	5	5	5	5	5	5	5
	- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software	- years	3	3	3	3	3	3	3
	- rate (%)	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
Tools & Equipment	- years	10	10	10	10	10	10	10
	- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment	- years	10	10	10	10	10	10	10
	- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Oakville Hydro states that it is now using a TUL of 10 years under the "New" (modified) CGAAP, as shown in Table 2-53.

a) Please provide further explanation for Oakville Hydro's change of the useful life of the smart meters from 15 to 10 years.

RESPONSE:

In 2013, Oakville Hydro reviewed its smart meter portfolio to determine the appropriate lifecycle of its meter assets. The assessment considered several factors that impacted on the durability, longevity and performance of smart meters. Unlike previous generations of meters that had a proven record of an extended lifecycle and were capable of being economically maintained and repaired, it was recognized that new electronic smart meters were basically non-serviceable. Although there are no moving parts and limited effects of wear and tear, a failure of any smart meter component results in disposal of the complete unit. Internal elements of smart meters consist primarily of circuit boards, processors, communication modules and liquid crystal displays. These electronic components are susceptible to a variety of external forces including environmental and power quality. With little to no protection from the voltage spikes and transients occurring in the distribution system, Oakville Hydro deemed that the failure rate of electronic meters could be significantly higher than their predecessors over an extended period of time. While it is reasonably early in the life cycle of the Smart Meters, failure rates indicate that the new smart meters lack the quality and durability of legacy meters and early performance indicators are confirming reduced reliability. Supporting evidence of this is becoming available from Ontario LDC's reporting a similar failure of smart meters related to the recent cold weather experienced throughout the province.

In addition, the assessment also concluded that smart meters would experience obsolescence at a rate many times higher than previous generation meters. Early generations of smart meters have limited functionality and expandability. Development of newer generations of meters available with increased functionality and upgrading capability is now occurring. It is expected that the development of these smart meters over the next several years, as they approach the required seal expiry date of 10 years, would result in outdated functionality and operability, thereby exceeding their useful lifespan. Accounting for the cost to replace and re-seal meters in 10 years, it is expected that replacing the old meters with future technology capable of supporting customer demands and expectations for value added services, new energy conservation technology and improved smart grid compatibility will be necessary.

Based on this assessment Oakville Hydro determined that reducing its smart meter lifecycle from 15 to 10 years is appropriate. The TUL of 10 years is within the range of useful lives within the Board's study of TUL by Kinetrics as shown in Exhibit 4, Tab 6, Schedule 3, Table 4-44.

b) Why does Oakville Hydro state that the TUL of Smart Meters under "Old" CGAAP was 25 years, when the utility used 15 years in its Smart Meter application for all years from 2006 to 2012?

RESPONSE:

Oakville Hydro made an incorrect statement. The TUL of 25 years is for all other meters excluding the smart meters.

Appendix 9 - A

DVA Work Form For 2014 Filers

Deferral/Variance Account Workform for 2014 Filers

Version 2.2

Utility Name	Oakville Hydro Electricity Distribution Inc.
Service Territory	*Town of Oakville*
Assigned EB Number	EB-2013-0159
Name of Contact and Title	Maryanne Wilson , Manager, Regulatory Affairs
Phone Number	905-825-4422
Email Address	mwilson@oakvillehydro.com

General Notes

1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

4. For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Deferral/Variance Account Workform for 2014 Filers

#	Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
	Group 1 Accounts											
1	LV Variance Account	1550					$0					$0
2	RSVA - Wholesale Market Service Charge	1580					$0					$0
3	RSVA - Retail Transmission Network Charge	1584					$0					$0
4	RSVA - Retail Transmission Connection Charge	1586					$0					$0
5	RSVA - Power (excluding Global Adjustment)	1588					$0					$0
6	RSVA - Global Adjustment	1589					$0					$0
7	Recovery of Regulatory Asset Balances	1590					$0					$0
8	Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$0					$0
9	Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0					$0
9	Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$0					$0
10	Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595					$0					$0
	Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Group 2 Accounts											
11	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$0					$0
12	Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$0					$0
13	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0					$0
14	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
15	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
16	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
17	Other Regulatory Assets - Sub-Account - Other [4]	1508					$0					$0
18	Retail Cost Variance Account - Retail	1518					$0					$0
19	Misc. Deferred Debits	1525					$0					$0
20	Renewable Generation Connection Capital Deferral Account	1531										
21	Renewable Generation Connection OM&A Deferral Account	1532										
22	Renewable Generation Connection Funding Adder Deferral Account	1533										
23	Smart Grid Capital Deferral Account	1534										
24	Smart Grid OM&A Deferral Account	1535										
25	Smart Grid Funding Adder Deferral Account	1536										
26	Retail Cost Variance Account - STR	1548					$0					$0
27	Board-Approved CDM Variance Account	1567										
28	Extra-Ordinary Event Costs	1572					$0					$0
29	Deferred Rate Impact Amounts	1574					$0					$0
30	RSVA - One-time	1582					$0					$0
31	Other Deferred Credits	2425					$0					$0
	Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Deferred Payments in Lieu of Taxes	1562					$0					$0
33	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0					$0
34	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0					$0
	Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
35	**LRAM Variance Account**	**1568**										
	Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555					$0					$0
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555					$0					$0
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555					$0					$0
39	Smart Meter OM&A Variance[10]	1556					$0					$0
40	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
41	Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
	The following is not included in the total claim but are included on a memo basis:											
42	Deferred PILs Contra Account [5]	1563					$0					$0
43	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$0					$0
44	Disposition and Recovery of Regulatory Balances[7]	1595					$0					$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

1A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

2 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

3 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

4 Please describe "other" components of 1508 and add more component lines if necessary.

5 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

6 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

7 Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

8 As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

9 The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Other Adjustments during Q4 2012" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in cell F39 from the relevant Chapter 2 Appendix (i.e. 2-EA, 2-EB or 2-EC). For Account 1576, please provide the value in cell F39 from the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

10 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531										
Renewable Generation Connection OM&A Deferral Account	1532										
Renewable Generation Connection Funding Adder Deferral Account	1533										
Smart Grid Capital Deferral Account	1534										
Smart Grid OM&A Deferral Account	1535										
Smart Grid Funding Adder Deferral Account	1536										
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account Descriptions	Account Number	2006									
		Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
LRAM Variance Account	**1568**										
Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2007									
		Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531										
Renewable Generation Connection OM&A Deferral Account	1532										
Renewable Generation Connection Funding Adder Deferral Account	1533										
Smart Grid Capital Deferral Account	1534										
Smart Grid OM&A Deferral Account	1535										
Smart Grid Funding Adder Deferral Account	1536										
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
LRAM Variance Account	**1568**										
Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0			-$52,781.84	-$52,782	$0			-$5,356.74	-$5,357
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531										
Renewable Generation Connection OM&A Deferral Account	1532										
Renewable Generation Connection Funding Adder Deferral Account	1533										
Smart Grid Capital Deferral Account	1534										
Smart Grid OM&A Deferral Account	1535										
Smart Grid Funding Adder Deferral Account	1536										
Retail Cost Variance Account - STR	1548	$0			-$896.00	-$896	$0				$0
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	-$53,678	-$53,678	$0	$0	$0	-$5,357	-$5,357
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0			-$206,335.99	-$206,336	$0			-$10,317.74	-$10,318
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	-$260,014	-$260,014	$0	$0	$0	-$15,674	-$15,674

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
LRAM Variance Account	**1568**										
Total including Account 1568		$0	$0	$0	-$260,014	-$260,014	$0	$0	$0	-$15,674	-$15,674
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0	$0.00			$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0	$0.00			$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0	$11,551.20			$11,551	$0	$0.00			$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$52,782	-$16,586.77			-$69,369	-$5,357	-$680.14			-$6,037
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531					$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532					$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0	$0				$0
Smart Grid OM&A Deferral Account	1535		$4,785.00			$4,785	$0	$0.00			$0
Smart Grid Funding Adder Deferral Account	1536					$0	$0				$0
Retail Cost Variance Account - STR	1548	-$896	-$537.50			-$1,434	$0	$0.00			$0
Board-Approved CDM Variance Account	1567										$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		-$53,678	-$788	$0	$0	-$54,466	-$5,357	-$680	$0	$0	-$6,037
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$206,336	$0.00			-$206,336	-$10,318	-$2,347.08			-$12,665
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$260,014	-$788	$0	$0	-$260,802	-$15,674	-$3,027	$0	$0	-$18,702

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
LRAM Variance Account	**1568**										
Total including Account 1568		-$260,014	-$788	$0	$0	-$260,802	-$15,674	-$3,027	$0	$0	-$18,702
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0	$0.00			$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$11,551	$ 5,123			$16,674	$0	$131.17			$131
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$69,369	-$ 17,790	-$ 52,782		-$34,377	-$6,037	-$357.99	-$6,054.00		-$341
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$4,785	$ 22,625			$27,410	$0	$74.48			$74
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	-$1,434	-$ 914	-$ 896		-$1,451	$0	-$11.45	-$12.00		$1
Board-Approved CDM Variance Account	1567					$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		-$54,466	$9,045	-$53,678	$0	$8,257	-$6,037	-$164	-$6,066	$0	-$135
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$206,336	$0.00			-$206,336	-$12,665	-$1,645.53			-$14,310
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$260,802	$9,045	-$53,678	$0	-$198,079	-$18,702	-$1,809	-$6,066	$0	-$14,445

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
LRAM Variance Account	**1568**					$0					$0
Total including Account 1568		-$260,802	$9,045	-$53,678	$0	-$198,079	-$18,702	-$1,809	-$6,066	$0	-$14,445
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0	$5,274,913.41			$5,274,913	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2011												
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012
Group 1 Accounts														
LV Variance Account	1550	$0			$ 460,427	$460,427	$0			$ 8,265	$8,265	$460,427	$ 211,236	
RSVA - Wholesale Market Service Charge	1580	$0			-$ 2,665,112	-$2,665,112	$0			-$ 410,557	-$410,557	-$2,665,112	-$ 1,940,613	
RSVA - Retail Transmission Network Charge	1584	$0			$ 2,988,244	$2,988,244	$0			-$ 204,092	-$204,092	$2,988,244	$ 322,379	
RSVA - Retail Transmission Connection Charge	1586	$0			$ 1,815,352	$1,815,352	$0			$ 84,858	$84,858	$1,815,352	$ 258,575	
RSVA - Power (excluding Global Adjustment)	1588	$0			-$ 1,061,333	-$1,061,333	$0			-$ 647,960	-$647,960	-$1,061,333	$ 736,308	
RSVA - Global Adjustment	1589	$0			$ 1,822,396	$1,822,396	$0			$ 494,370	$494,370	$1,822,396	-$ 1,132,427	
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0			-$2,961,310.94	-$2,961,311	$0			$610,690.20	$610,690	-$2,961,311	$1,426,638.72	
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$398,664	$398,664	$0	$0	$0	-$64,427	-$64,427	$398,664	-$117,903	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	-$1,423,732	-$1,423,732	$0	$0	$0	-$558,797	-$558,797	-$1,423,732	$1,014,524	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$1,822,396	$1,822,396	$0	$0	$0	$494,370	$494,370	$1,822,396	-$1,132,427	$0
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$16,674	$0.00			$16,674	$131	$245.16			$376	$16,674	$0.00	
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0	$0		
Retail Cost Variance Account - Retail	1518	-$34,377	-$15,666.26			-$50,043	-$341	-$624.68			-$966	-$50,043	-$8,875.61	
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0		
Renewable Generation Connection Capital Deferral Account	1531	$0				$0	$0				$0	$0		
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0	$0		
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0	$0		
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0		
Smart Grid OM&A Deferral Account	1535	$27,410	-$16,940.00			$10,470	$74	$225.79			$300	$10,470	$10,369.20	
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0		
Retail Cost Variance Account - STR	1548	-$1,451	-$660.75			-$2,112	$1	-$25.91			-$25	-$2,112	-$531.00	
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0		
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0		
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0		
RSVA - One-time	1582	$0				$0	$0				$0	$0		
Other Deferred Credits	2425	$0				$0	$0				$0	$0		
Group 2 Sub-Total		$8,257	-$33,267	$0	$0	-$25,010	-$135	-$180	$0	$0	-$314	-$25,010	$963	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$206,336	$0.00			-$206,336	-$14,310	-$3,033.12			-$17,343	-$206,336	$45,138.00	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0	$0		
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$198,079	-$33,267	$0	$398,664	$167,318	-$14,445	-$3,213	$0	-$64,427	-$82,084	$167,318	-$71,802	$0

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012
LRAM Variance Account	**1568**	$0				$0	$0				$0	$0		
Total including Account 1568		-$198,079	-$33,267	$0	$398,664	$167,318	-$14,445	-$3,213	$0	-$64,427	-$82,084	$167,318	-$71,802	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$5,274,913	$870,120.28			$6,145,034	$0				$0	$6,145,034	-$2,215,913.21	
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0	$0		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575													
Accounting Changes Under CGAAP Balance + Return Component[9]	1576													
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0	$0		
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0	$0		

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

		2012										2013			
Account Descriptions	**Account Number**	**Other [2] Adjustments during Q1 2012**	**Other [2] Adjustments during Q2 2012**	**Other [2] Adjustments during Q3 2012**	**Other [2] Adjustments during Q4 2012**	**Closing Principal Balance as of Dec-31-12**	**Opening Interest Amounts as of Jan-1-12**	**Interest Jan-1 to Dec-31-12**	**Board-Approved Disposition during 2012**	**Adjustments during 2012 - other [2]**	**Closing Interest Amounts as of Dec-31-12**	**Principal Disposition during 2013 - instructed by Board**	**Interest Disposition during 2013 - instructed by Board**	**Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013**	**Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013**
Group 1 Accounts															
LV Variance Account	1550					$671,663	$8,265	$ 8,130			$16,395	$ 460,427	$ 17,289	$211,236	-$894
RSVA - Wholesale Market Service Charge	1580					-$4,605,724	-$410,557	-$ 52,494			-$463,051	-$ 2,665,112	-$ 462,793	-$1,940,612	-$258
RSVA - Retail Transmission Network Charge	1584					$3,310,623	-$204,092	$ 48,292			-$155,800	$ 2,988,244	-$ 145,523	$322,379	-$10,277
RSVA - Retail Transmission Connection Charge	1586					$2,073,927	$84,858	$ 29,653			$114,511	$ 1,815,352	$ 120,439	$258,575	-$5,928
RSVA - Power (excluding Global Adjustment)	1588					-$325,025	-$647,960	-$ 17,577			-$665,537	-$ 1,061,333	-$ 668,762	$736,308	$3,225
RSVA - Global Adjustment	1589					$689,970	$494,370	$ 15,477			$509,847	$ 1,822,396	$ 530,089	-$1,132,426	-$20,242
Recovery of Regulatory Asset Balances	1590					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595					-$1,534,672	$610,690	-$51,188.18			$559,502			-$1,534,672	$559,502
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$280,761	-$64,427	-$19,707	$0	$0	-$84,134	$3,359,974	-$609,261	-$3,079,213	$525,127
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	-$409,208	-$558,797	-$35,184	$0	$0	-$593,981	$1,537,578	-$1,139,350	-$1,946,786	$545,369
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$689,970	$494,370	$15,477	$0	$0	$509,847	$1,822,396	$530,089	-$1,132,426	-$20,242
Group 2 Accounts															
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$16,674	$376	$245.16			$621			$16,674	$621
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Other [4]	1508					$0	$0				$0			$0	$0
Retail Cost Variance Account - Retail	1518					-$58,918	-$966	-$883.64			-$1,849			-$58,918	-$1,849
Misc. Deferred Debits	1525					$0	$0				$0			$0	$0
Renewable Generation Connection Capital Deferral Account	1531					$0	$0				$0			$0	$0
Renewable Generation Connection OM&A Deferral Account	1532					$0	$0				$0			$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0	$0				$0			$0	$0
Smart Grid Capital Deferral Account	1534					$0	$0				$0			$0	$0
Smart Grid OM&A Deferral Account	1535					$20,839	$300	$179.36			$480			$20,839	$480
Smart Grid Funding Adder Deferral Account	1536					$0	$0				$0			$0	$0
Retail Cost Variance Account - STR	1548					-$2,643	-$25	-$34.64			-$60			-$2,643	-$60
Board-Approved CDM Variance Account	1567					$0	$0				$0			$0	$0
Extra-Ordinary Event Costs	1572					$0	$0				$0			$0	$0
Deferred Rate Impact Amounts	1574					$0	$0				$0			$0	$0
RSVA - One-time	1582					$0	$0				$0			$0	$0
Other Deferred Credits	2425					$0	$0				$0			$0	$0
Group 2 Sub-Total		$0	$0	$0	$0	-$24,047	-$314	-$494	$0	$0	-$808	$0	$0	-$24,047	-$808
Deferred Payments in Lieu of Taxes	1562					$0	$0				$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					-$161,198	-$17,343	-$3,033.12			-$20,377			-$161,198	-$20,377
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0	$0				$0			$0	$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$95,516	-$82,084	-$23,234	$0	$0	-$105,318	$3,359,974	-$609,261	-$3,264,458	$503,943

		2012										2013			
Account Descriptions	Account Number	Other [2] Adjustments during Q1 2012	Other [2] Adjustments during Q2 2012	Other [2] Adjustments during Q3 2012	Other [2] Adjustments during Q4 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Adjustments during 2012 - other [2]	Closing Interest Amounts as of Dec-31-12	Principal Disposition during 2013 - instructed by Board	Interest Disposition during 2013 - instructed by Board	Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013	Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013
LRAM Variance Account	**1568**					$0	$0				$0			$0	$0
Total including Account 1568		$0	$0	$0	$0	$95,516	-$82,084	-$23,234	$0	$0	-$105,318	$3,359,974	-$609,261	-$3,264,458	$503,943
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555					$0	$0				$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555					$0	$0				$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555				-$597,315.10	$3,331,805	$0				$0			$3,331,805	$0
Smart Meter OM&A Variance[10]	1556					$0	$0				$0			$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575					$0	$0				$0			$0	$0
Accounting Changes Under CGAAP Balance + Return Component[9]	1576					$0	$0				$0			$0	$0
The following is not included in the total claim but are included on a memo basis:															
Deferred PILs Contra Account [5]	1563					$0	$0				$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$0	$0				$0			$0	$0
Disposition and Recovery of Regulatory Balances[7]	1595					$0	$0				$0			$0	$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs w

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

		Projected Interest on Dec-31-12 Balances			2.1.7 RRR	
Account Descriptions	Account Number	Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Total Claim	As of Dec 31-12	Variance RRR vs. 2012 Balance *(Principal + Interest)*
Group 1 Accounts						
LV Variance Account	1550	$ 3,105	$ 1,035	$214,482	$ 688,058	$0
RSVA - Wholesale Market Service Charge	1580	-$ 28,527	-$ 9,509	-$1,978,906	-$ 5,068,775	$0
RSVA - Retail Transmission Network Charge	1584	$ 4,739	$ 1,580	$318,420	$ 3,154,823	$0
RSVA - Retail Transmission Connection Charge	1586	$ 3,801	$ 1,267	$257,715	$ 2,188,438	$0
RSVA - Power (excluding Global Adjustment)	1588	$ 10,824	$ 3,608	$753,964	-$ 990,562	$0
RSVA - Global Adjustment	1589	-$ 16,647	-$ 5,549	-$1,174,863	$ 1,199,817	$0
Recovery of Regulatory Asset Balances	1590			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	-$ 22,560	-$ 7,520	-$1,005,250	-$975,170.20	$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$45,264	-$15,088	-$2,614,438	$196,628	-$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$28,618	-$9,539	-$1,439,574	-$1,003,189	-$0
RSVA - Global Adjustment	**1589**	-$16,647	-$5,549	-$1,174,863	$1,199,817	$0
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -	$0	$0.00	$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -	$0	$0.00	$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ -	$0	$ 650,737	$650,737
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 245	$ 82	$17,623	$ 17,296	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -	$ -	$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -	$ -	$0		$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -	$ -	$0		$0
Retail Cost Variance Account - Retail	1518	-$ 866	-$ 289	-$61,922	-$60,767.58	$0
Misc. Deferred Debits	1525	$ -	$ -	$0		$0
Renewable Generation Connection Capital Deferral Account	1531	$ -	$ -	$0		$0
Renewable Generation Connection OM&A Deferral Account	1532	$ -	$ -	$0		$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -	$ -	$0		$0
Smart Grid Capital Deferral Account	1534	$ -	$ -	$0		$0
Smart Grid OM&A Deferral Account	1535	$ 306	$ 102	$21,727	$21,318.83	$0
Smart Grid Funding Adder Deferral Account	1536	$ -	$ -	$0		$0
Retail Cost Variance Account - STR	1548	-$ 39	-$ 13	-$2,755	-$2,702.75	$0
Board-Approved CDM Variance Account	1567	$ -	$ -	$0		$0
Extra-Ordinary Event Costs	1572	$ -	$ -	$0		$0
Deferred Rate Impact Amounts	1574	$ -	$ -	$0		$0
RSVA - One-time	1582	$ -	$ -	$0		$0
Other Deferred Credits	2425	$ -	$ -	$0		$0
Group 2 Sub-Total		-$353	-$118	-$25,327	$625,881	$650,737
Deferred Payments in Lieu of Taxes	1562	$ -	$ -	$0		$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 2,370	-$ 790	-$184,734	-$181,574.58	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -	$ -	$0		$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$47,988	-$15,996	-$2,824,499	$640,934	$650,737

Account Descriptions	Account Number	Projected Interest on Dec-31-12 Balances: Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Total Claim	2.1.7 RRR: As of Dec 31-12	Variance RRR vs. 2012 Balance *(Principal + Interest)*
LRAM Variance Account	**1568**			$0		$0
Total including Account 1568		-$47,988	-$15,996	-$2,824,499	$640,934	$650,737
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555			$3,331,805	$3,929,120.48	$597,315
Smart Meter OM&A Variance[10]	1556			$0		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575			$0		$0
Accounting Changes Under CGAAP Balance + Return Component[9]	1576			$0		$0
The following is not included in the total claim but are included on a memo basis:						
Deferred PILs Contra Account [5]	1563			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$0		$0
Disposition and Recovery of Regulatory Balances[7]	1595			$0		$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ob

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fr
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In th
and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in
the relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Accounts that produced a variance on the 2014 continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

Account Descriptions	**Account Number**	**Variance RRR vs. 2012 Balance** ***(Principal + Interest)***	**Explanation**
Group 1 Accounts			
Group 2 Accounts			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$ 597,315.10	he difference of $597,311 is depreciation expense related to stranded meters which was not captured in the 2012 balance but which should have been.

Deferral/Variance Account Workform for 2014 Filers

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1595 Recovery Share Proportion (2011) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
Residential	kWh	58,286	602,407,699		29,968,136	-						12%	
General Service Less Than 50 kW	kWh	4,911	166,851,635		26,197,389	-						5%	
General Service 50 to 999 kW	kW	893	607,509,364	1,647,015	524,742,591	1,422,626						64%	
General Service Greater Than 1,000 kW	kW	16	150,201,768	332,469	150,201,768	332,469						19%	
Unmetered Scattered Load	kWh	676	3,696,824		26,438	-						0%	
Sentinel Lighting	kW	167	120,534	335	-	-						0%	
Street Lighting	kW	17,113	11,824,926	32,927	11,824,926	32,927						0%	
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
						-							
Total		**82,062**	**1,542,612,750**	**2,012,745**	**742,961,248**	**1,788,022**	**$ -**	**0%**	**0%**	**0%**	**0%**	**100%**	**$ -**
												Balance as per Sheet 2	$ -
												Variance	$ -

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

Deferral/Variance Account Workform for 2014 Filers

		Amounts from Sheet 2	Allocator	Residential	General Service Less Than 50 kW	General Service 50 to 999 kW	General Service Greater Than 1,000 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
LV Variance Account	1550	214,482	kWh	83,758	23,199	84,467	20,884	514	17	1,644
RSVA - Wholesale Market Service Charge	1580	(1,978,906)	kWh	(772,785)	(214,042)	(779,330)	(192,683)	(4,742)	(155)	(15,169)
RSVA - Retail Transmission Network Charge	1584	318,420	kWh	124,347	34,441	125,400	31,004	763	25	2,441
RSVA - Retail Transmission Connection Charge	1586	257,715	kWh	100,640	27,875	101,493	25,093	618	20	1,976
RSVA - Power (excluding Global Adjustment)	1588	753,964	kWh	294,432	81,550	296,925	73,412	1,807	59	5,780
RSVA - Global Adjustment	1589	(1,174,863)	Non-RPP kWh	(47,389)	(41,427)	(829,789)	(237,518)	(42)	0	(18,699)
Recovery of Regulatory Asset Balances	1590	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	(1,005,250)	kWh	(119,298)	(52,695)	(643,484)	(187,735)	(489)	(173)	(1,376)
Total of Group 1 Accounts (excluding 1589)		**(1,439,574)**		**(288,907)**	**(99,672)**	**(814,529)**	**(230,024)**	**(1,530)**	**(207)**	**(4,706)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	17,623	kWh	6,882	1,906	6,940	1,716	42	1	135
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(61,922)	# of Customers	(43,981)	(3,706)	(674)	(12)	(510)	(126)	(12,913)
Misc. Deferred Debits	1525	0		0	0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0	0	0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	21,727	kWh	8,485	2,350	8,557	2,116	52	2	167
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(2,755)	# of Customers	(1,956)	(165)	(30)	(1)	(23)	(6)	(574)
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0	0
RSVA - One-time	1582	0		0	0	0	0	0	0	0
Other Deferred Credits	2425	0		0	0	0	0	0	0	0
Total of Group 2 Accounts		**(25,327)**		**(30,571)**	**386**	**14,793**	**3,819**	**(438)**	**(129)**	**(13,186)**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(184,734)	kWh	(72,141)	(19,981)	(72,752)	(17,987)	(443)	(14)	(1,416)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0		0	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(184,734)**		**(72,141)**	**(19,981)**	**(72,752)**	**(17,987)**	**(443)**	**(14)**	**(1,416)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0								
(Account 1568 - total amount allocated to classes)		0								
Variance		0								
Total Balance Allocated to each class (excluding 1589)		**(1,649,635)**		**(391,619)**	**(119,268)**	**(872,488)**	**(244,193)**	**(2,411)**	**(350)**	**(19,308)**
Total Balance Allocated to each class from Account 1589		**(1,174,863)**		**(47,389)**	**(41,427)**	**(829,789)**	**(237,518)**	**(42)**	**0**	**(18,699)**
Total Balance Allocated to each class (including 1589)		**(2,824,499)**		**(439,008)**	**(160,694)**	**(1,702,276)**	**(481,710)**	**(2,453)**	**(350)**	**(38,007)**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Deferral/Variance Account for 2014 Filers

		Amounts from Sheet 2	Allocator						
LV Variance Account	1550	214,482	kWh	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(1,978,906)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	318,420	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	257,715	kWh	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	753,964	kWh	0	0	0	0	0	0
RSVA - Global Adjustment	1589	(1,174,863)	Non-RPP kWh	0	0	0	0	0	0
Recovery of Regulatory Asset Balances	1590	0		0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0		0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0		0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0		0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	(1,005,250)	kWh	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(1,439,574)**		**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	17,623	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(61,922)	# of Customers	0	0	0	0	0	0
Misc. Deferred Debits	1525	0		0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0	0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	21,727	kWh	0	0	0	0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(2,755)	# of Customers	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0
RSVA - One-time	1582	0		0	0	0	0	0	0
Other Deferred Credits	2425	0		0	0	0	0	0	0
Total of Group 2 Accounts		**(25,327)**		**0**	**0**	**0**	**0**	**0**	**0**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(184,734)	kWh	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0		0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(184,734)**		**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0							
(Account 1568 - total amount allocated to classes)		0							
Variance		0							
Total Balance Allocated to each class (excluding 1589)		**(1,649,635)**		**0**	**0**	**0**	**0**	**0**	**0**
Total Balance Allocated to each class from Account 1589		**(1,174,863)**		**0**	**0**	**0**	**0**	**0**	**0**
Total Balance Allocated to each class (including 1589)		**(2,824,499)**		**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**

		Amounts from Sheet 2	Allocator							
LV Variance Account	1550	214,482	kWh	0	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(1,978,906)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	318,420	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	257,715	kWh	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	753,964	kWh	0	0	0	0	0	0	0
RSVA - Global Adjustment	1589	(1,174,863)	Non-RPP kWh	0	0	0	0	0	0	0
Recovery of Regulatory Asset Balances	1590	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0		0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	(1,005,250)	kWh	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(1,439,574)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	17,623	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(61,922)	# of Customers	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	0		0	0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0	0	0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	21,727	kWh	0	0	0	0	0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(2,755)	# of Customers	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0	0
RSVA - One-time	1582	0		0	0	0	0	0	0	0
Other Deferred Credits	2425	0		0	0	0	0	0	0	0
Total of Group 2 Accounts		**(25,327)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(184,734)	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0		0	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(184,734)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0								
(Account 1568 - total amount allocated to classes)		0								
Variance		0								
Total Balance Allocated to each class (excluding 1589)		**(1,649,635)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Balance Allocated to each class from Account 1589		**(1,174,863)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Balance Allocated to each class (including 1589)		**(2,824,499)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Deferral/Variance Account Workform for 2014 Filers

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	602,407,699	-$ 391,619	- 0.0007	$/kWh
General Service Less Than 50 kW	kWh	166,851,635	-$ 119,268	- 0.0007	$/kWh
General Service 50 to 999 kW	kW	1,647,015	-$ 872,488	- 0.5297	$/kW
General Service Greater Than 1,000 kW	kW	332,469	-$ 244,193	- 0.7345	$/kW
Unmetered Scattered Load	kWh	3,696,824	-$ 2,411	- 0.0007	$/kWh
Sentinel Lighting	kW	335	-$ 350	- 1.0448	$/kW
Street Lighting	kW	32,927	-$ 19,308	- 0.5864	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 1,649,635**		

Appendix 9 - B

Final Verified Annual 2012 CDM Report_OHEDI

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

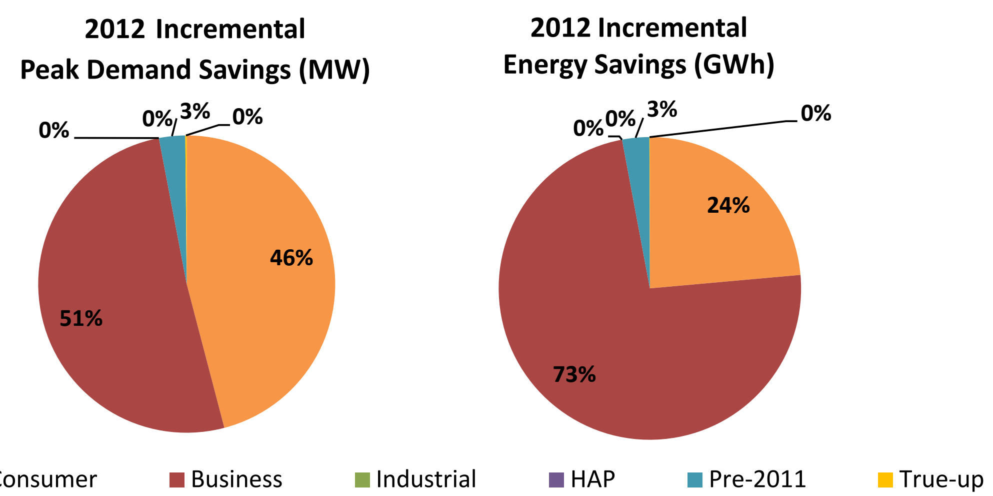
LDC: Oakville Hydro Electricity Distribution Inc.

FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	1.8	3.1	**14.8%**	**16.9%**
Net Energy Savings (GWh)	6.0	45.1	**60.9%**	**60.9%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

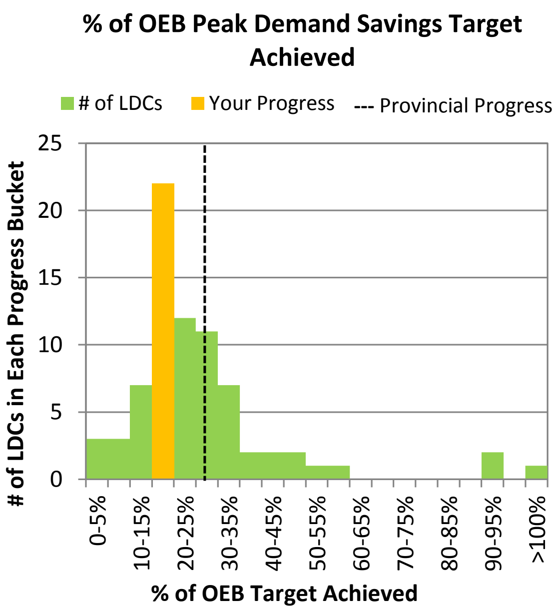
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

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



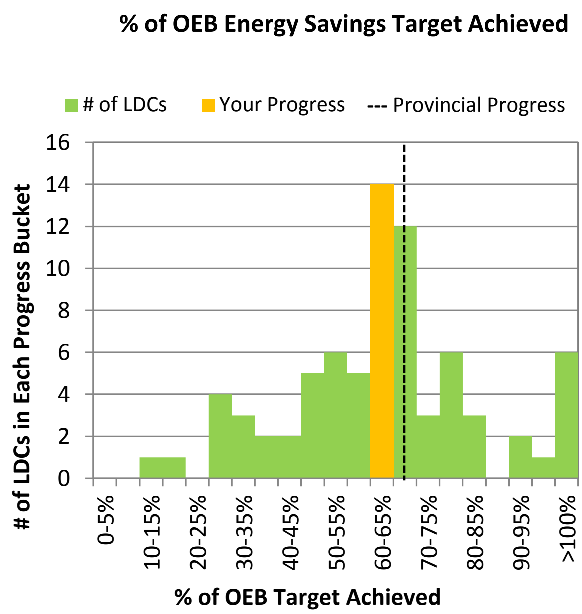


Table 1: **Oakville Hydro Electricity Distribution Inc.** Initiative and Program Level Savings by Year (Scenario 1)

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 Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	879	598			47	33			352,333	238,004			80	2,123,343
Appliance Exchange	Appliances	32	35			3	5			4,163	8,911			6	41,645
HVAC Incentives	Equipment	2,627	1,990			697	414			1,241,226	678,390			1,111	7,000,072
Conservation Instant Coupon Booklet	Items	7,394	452			17	3			276,221	20,458			20	1,166,259
Bi-Annual Retailer Event	Items	12,734	15,523			25	22			429,984	391,857			46	2,895,505
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	696	772			390	355			1,009	2,674			0	3,684
Residential Demand Response (IHD)	Devices	0	67			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**1,179**	**833**			**2,304,937**	**1,340,294**			**1,264**	**13,230,508**
Business Program															
Retrofit	Projects	39	99			415	755			2,093,673	3,837,793			1,154	19,829,140
Direct Install Lighting	Projects	183	112			220	89			564,846	336,964			282	3,183,276
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	1	1			82	82			3,198	1,194			0	4,392
Business Program Total						**717**	**926**			**2,661,717**	**4,175,952**			**1,436**	**23,016,809**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	5				60				336,825				60	1,347,300
Demand Response 3	Facilities	1	0			21	0			1,237	0			0	1,237
Industrial Program Total						**81**	**0**			**338,062**	**0**			**60**	**1,348,537**
Home Assistance Program															
Home Assistance Program	Homes	0	0			0	0			0	0			0	0
Home Assistance Program Total						**0**	**0**			**0**	**0**			**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	26	0			240	0			1,343,088	0			240	5,372,354
High Performance New Construction	Projects	1	1			22	52			114,603	164,845			74	952,949
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**262**	**52**			**1,457,692**	**164,845**			**314**	**6,325,303**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-3**				**296,333**			**-12**	**1,160,199**
Energy Efficiency Total						**1,746**	**1,373**			**6,756,963**	**5,677,222**			**3,074**	**43,911,844**
Demand Response Total (Scenario 1)						**493**	**438**			**5,444**	**3,869**			**0**	**9,313**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**2,239**	**1,808**			**6,762,407**	**5,977,423**			**3,062**	**45,081,356**
													Full OEB Target:	**20,700**	**74,060,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**14.8%**	**60.9%**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Oakville Hydro Electricity Distribution Inc.** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-448				-115				-203,098				-115	-812,392
Conservation Instant Coupon Booklet	Items	120				0				4,033				0	16,133
Bi-Annual Retailer Event	Items	1,197				2				31,946				2	127,785
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-113**				**-167,118**				**-113**	**-668,474**
Business Program															
Retrofit	Projects	5				46				278,114				46	1,112,458
Direct Install Lighting	Projects	25				38				97,670				29	365,551
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**85**				**375,785**				**76**	**1,478,008**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	1				26				87,666				26	350,665
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**26**				**87,666**				**26**	**350,665**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-3**				**296,333**				**-12**	**1,160,199**

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

Table 3: Oakville Hydro Electricity Distribution Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.47				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.94				0.78				1.10				0.78		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		n/a				n/a				n/a				n/a		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	2.2	1.7	1.7	1.7
2012 - Verified		1.8	1.4	1.3
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				3.1
Oakville Hydro Electricity Distribution Inc. 2014 Annual CDM Capacity Target				20.7
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				14.8%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	6.8	6.8	6.8	6.7	26.9
2012 - Verified		6.0	6.0	5.9	18.1
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					45.1
Oakville Hydro Electricity Distribution Inc. 2011-2014 Annual CDM Energy Target					74.1
Verified Portion of Cumulative Energy Target Achieved (%):					60.9%

*2011 energy adjustments included in cumulative energy savings.

Table 6: **Province-Wide** Initiatives 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 Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

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

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**237.2**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**17.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**3,906**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**65.1%**

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

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

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

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

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

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