Orangeville Hydro Limited

2014 Cost of Service

EB-2013-0160

Response to Interrogatories

Thursday, February 13, 2014

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

INTERROGATORIES
ORANGEVILLE HYDRO LIMITED (“OHL”)
2014 ELECTRICITY DISTRIBUTION COST OF SERVICE RATES

February 12, 2014

1. Foundation

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: E2/T5/S4 p. 1 – Overview of Distribution System Plan (“DSP”) (Adobe p. 247)

On page 1 of E1/T5/S4 in OHL overview over the DSP, OHL states that although no formal Asset Management Plan was included in OHL’s 2010 rebasing application, OHL provided the Hatch Asset Condition Report at that time. OHL further states that OHL applied the asset condition assessment report as well as existing Asset Management Practices to draft an Asset Management Plan prior to the issuance of the Renewed Regulatory Framework (“RRWF”). OHL also notes that its Asset Management Process has been developed within the renewed regulatory framework and the Chapter 5 filing requirements. Board staff notes that OHL has not provided a copy of the Asset Management Plan.

a. Please provide a copy of the Asset Management Plan or any other relevant documents of the ASI Asset Management Process.

OHL’s Response:

In E2/T5/S4, OHL incorrectly stated “OHL has developed an Asset Management Process within the framework specified in the Chapter 5 “Consolidated Distribution Plan Filing Requirements””. The statement was stating that OHL has developed a Distribution System Plan within the framework specified in the Chapter 5 “Consolidated Distribution Plan Filing Requirements”. The Distribution System Plan was filed in E2/T5/S5.

In regards to the draft Asset Management Plan, OHL does not have a completed copy to provide. The contents of the draft Asset Management Plan have been incorporated in the filed Distribution System Plan as this was OHL’s understanding of the Chapter 5 Requirements.

b. Please provide a copy of the most recent Asset Condition Assessment which forms the basis for assessments of equipment life, whether it is the Hatch report or a later report.

OHL's Response:

Please find attached a copy of the most recent Asset Condition Assessment .
Appendix A – Asset Condition Assessment - Final.

c. If the Hatch report is the latest, explain why OHL has not obtained an updated report.

OHL's Response:

OHL completed an Asset Condition Assessment (ACA) with Hatch in 2009. The ACA had a cost of $47,240 plus internal labour costs. OHL did not consider completing an additional ACA within the last 5 year period to be prudent. OHL's assets have not changed significantly within the 5 year time frame to warrant additional costs.

1.1-Staff-2

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

Please identify any impacts that the Applicant 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).

OHL's Response:

OHL had no significant impacts from the December 2013 ice storm. OHL staff assisted Hydro One and Centre Wellington Hydro throughout the storm.

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

OHL's Response:

OHL will not be updating its Application in light of the December 2013 ice storm.

1.1-Energy Probe-1

Ref: Exhibit 2, Tab 5, Schedule 5

a. The capital expenditures (net of contributions) appear to be significantly lower in 2015 through 2018 (Table 28) than the levels recorded in 2010 through 2013. Please explain.

OHL's Response:

The capital expenditures (net of contributions) appear to be lower in 2015 through 2018 than the recorded levels in 2010 through 2013 for various specific reasons. These reasons include:

- reduced expected capital meter expenses considering the majority of OHL's smart meter population was deployed throughout 2010-2012 and a significant portion of the capital expenditures was recorded in 2012
- reduced expected capital expenditures on station land considering the majority of expected costs associated with the site remediation project have been completed
- reduced expected capital expenditures on transportation equipment due to the life expectancy of the existing fleet vehicles
- reduced expected capital expenditures on system service and system renewal projects due to the specifics characteristics of the proposed projects and the expected reduced costs associated with external construction contractors
- expected reduced capital expenditures associated with computer software considering OHL deployed an new CIS and GIS throughout 2009-2013

b. What is the source of the 5% annual escalator used to increase the operating and maintenance expenses between 2014 and 2018 shown in Tables 29 and 30?

OHL's Response:

Please note the following historical **Operating Expenses** as submitted in the Rate Application:

DESCRIPTION	2009	2010	2011	2012	2013
TOTAL OPERATION EXPENSES	**$329,817**	**$392,746**	**$433,555**	**$458,597**	**$487,141**
Percent increase over previous		19.1%	10.4%	5.8%	6.2%

The Operating Expenses increased each year on average 10.4% annually (or an overall 47.7% increase)

77% of the 2013 Operating Expenses are from three categories:

- Miscellaneous Distribution Expense ($224,011)
- Meter Expenses ($91,171)
- Customer Premises – Operation Labour ($59,487)

Please note the following historical **Maintenance Expenses** as submitted in the Rate Application:

DESCRIPTION	2009	2010	2011	2012	2013
TOTAL MAINTENANCE EXPENSES	**$430,459**	**$425,049**	**$534,881**	**$465,329**	**$562,725**
Percent increase over previous		-1.3%	25.8%	-13.0%	20.9%

The Maintenance Expenses increased each year on average 8.1% annually (or an overall 30.7% increase)

78% of the 2013 Maintenance Expenses are from three categories:

- Maintenance Supervision and Engineering ($176,962)
- Overhead Distribution Lines and Feeders - Right of Way ($90,239)

- Maintenance of Underground Services ($87,188)
- Maintenance of Overhead Conductors and Devices ($86,379)

1.1-SEC-1

Please provide a copy of all documents that were provided to the Applicant's Board of Directors in approving this application and the associated Test Year budget.

OHL's Response:

Please find attached: Appendix B – 2014 Rate Application Board Budget
Appendix C – Rate App Docs

1.1-VECC-1

Ref: Exhibit 2, Tab 5, Schedule 5
Distribution System Plan, pg.26, Table 11

Please explain the spike in pole replacements in 2013 (59) and the low estimate for pole replacement in 2014 (12). What were the actual number of poles replaced in 2013?

OHL's Response:

The estimated number of pole replacements is dependent on the geographical location and type of planned capital projects. Therefore, the estimated number of poles will vary year to year depending on the existing infrastructure in the geographical location of the planned capital projects.

OHL replaced 28 poles in 2013.

1.1-VECC–2

Ref: Exhibit 2, Tab 5, Schedule 5 –
Distribution System Plan, pg.26, Table 18

Please show the Plan's estimated of the number of smart meter replacements for 2014 through 2018.

OHL's Response:

OHL expects to replace 40-70 meters per year due to various failure modes.

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

1.2-Staff-3

Ref: E1/T2/S1, pp. 1-2

On pages 1-2 of E1/T2/S1 of its Application OHL describes its customer engagement activities, especially its energy conservation efforts. Chapter 2 of the Filling Requirements states that "the RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations."

a. Please describe the difference between customer engagement conducted in preparation for the current application and previous customer engagement.

OHL's Response:

OHL has always engaged our customers in the past however nothing specific to this application. OHL recognizes that this is a transition year and that not all of the necessary processes are in place to support the Board's RRFE.

b. Please explain how customer engagement has been enhanced.

OHL's Response:

OHL plans to enhance our customer engagement by conducting a more comprehensive customer survey focusing on customer preferences in 2014, local newspaper communications, continually updating our website, customer connect, pre and post construction surveys, teleworks (notify customers of planned outages and special customer notifications) and OHL plans to cohesively work with Cornerstone Hydro Electric Concepts (CHEC) for further customer engagement initiatives in order to support the Board's RRFE requirements.

1.2-Staff-4

Ref: E1/T2/S1, pp. 1-2

On page 1 of E1/T2/S1 OHL mentions workshops/townhall meetings to explain smart meters to customers as well as workshops for manufacturers, commercial and institutional customers to help them understand and manage their bills.

OHL states that "since OHL is owned by municipal shareholders, ultimately the customers are engaged through the shareholders". 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."

a. Please explain how customers are engaged through the shareholders on electricity distribution issues specifically.

OHL's Response:

The Shareholders and the Town Councils are one in the same. The councilors are customers of OHL and are elected by the taxpayers who are mostly customers of OHL to represent their interests. One of the interests is ownership and stewardship of OHL. The members of council/shareholders include a retired electrician from one of Orangeville's large manufacturers, a school teacher, a business executive, 3 retirees, an environmentalist, a civil servant, a water-works employee, a salesman, and a contractor/property manager. OHL believes that this is a good cross-section of our customers. OHL meets with this group at least twice annually so that management can present the budget, business plans and discuss industry issues. The members of this group have asked questions about OHL's smart meter project, stranded assets, proposed capital projects, rate riders, and impacts on customer's rates. This group has also participated twice in day-long workshops to provide input into OHL's strategic plan and provided management with what they deem as the priorities for OHL. The president has also asked via e-mails and hand-written cards to each individual member if they have anything they would like to see OHL focus on or if they had any questions. The members were also given notice from the president via e-mail that the rate application had gone in and the impact on the customers. This group has also been invited to attend industry functions to learn more about current issues. By virtue of engaging the shareholder in this manner, OHL is of the opinion that they are engaging the customers. The shareholder has provided input into our mission statement. '*To provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders.....the citizens of Orangeville and Grand Valley.'*

b. What forms of outreach were employed to explain how the current application serves the needs and expectations of customers, beyond the smart meters costs included in this application?

OHL's Response:

Please see a. above.

c. If no further communication, specific to this application was employed, please explain why.

OHL's Response:

Please see a. above.

1.2-Energy Probe-2

Ref: Exhibit 1, Tab 2, Schedule 1

a. Please provide the dates of and any notes from meetings between the shareholders and residential ratepayers in each of 2012 and 2013.

OHL's Response:

There were no meetings between the shareholders and residential ratepayers in each 2012 and 2013.

b. Please provide the dates of and any notes from meetings between the shareholders and non-residential ratepayers in each of 2012 and 2013.

OHL's Response:

There were no meetings between the shareholders and non-residential ratepayers in each 2012 and 2013.

c. What feedback did the shareholders receive from residential customers in terms of capital budgets, OM&A budgets, etc.?

OHL's Response:

The shareholders did not receive feedback from residential customers in terms of capital budgets, OM&A budgets, etc.

d. What feedback did the shareholders receive from non-residential customers in terms of capital budgets, OM&A budgets, etc.?

OHL's Response:

The shareholders did not receive feedback from non-residential customers in terms of capital budgets, OM&A budgets, etc.

1.2-Energy Probe-3

Ref: Exhibit 1, Tab 2, Schedule 1

a. Please provide the dates of and any notes from meetings between the distributor and residential ratepayers in each of 2012 and 2013.

OHL's Response:

2012 EVENTS

		Segment
January - 6-9	Retrofit Photo Op	Business
30-Mar	Earth Hour Event	Home & Business
April	April 3,10,11, 17,18, 24– School presentations at St. Peters, Montgomery Village and St. Andrew School	Home & Business
April - 21-27	Earth Week Displays	Home & Business
April - 14-15	Spring Event (TSC / Home Depot)	Home & Business
4-May	Home Assistance Launch	Home
May - 22-23	Retrofit Photo Op	
26-May	Grand Valley Duck Race	Business
May	HAP mailout by County of Dufferin	Home
June - 16-17	Exchange Event	Home & Business
19-Jun	Sobeys Event	Home & Business
16-Aug	Retrofit Photo Op	Business
September 28 - 30	Home Show	Home & Business
October 6-7 Oct 13 - 14 October 20-21 October 27 - 28	Home Depot CDN Tire Home Hardware Home Depot	Home & Business
17-Oct	HAP Walk & Talk HAP Open House at DCAFS	Home
November	IESO Meeting	Business
November	Retrofit Photo Op	Business
November	Seniors Walk & Talk - Retailers	Residential
7-Nov	Breakfast Session - Understanding Your Bill 2012	Business
15-Nov	Calendar Contest Celebration	Home
20-Nov	Home Builders Association	Home & Business
16-Nov	Moonlight Magic & Tree Lighting Ceremony	Home & Business
24-Nov	Santa Parade - Grand Valley	Home & Business
13-Dec	Ecole Elementaire Des Quatre-Rivieres Fundraising bag event	Home & Business

2013 EVENTS		
		Segment
29-Jan	REM meeting with Fabricland	Business
30-Jan	REM meeting with Polyone	Business
31-Jan	REM meeting with Xogen	Business
February	REM Sign ups on Chamber site	Business
March 2 - 3	E-waste collection	Home
23-Mar	Earth Hour	Home & Business
March 23 - 24	Maple Syrup Festival	Home & Business
March 29 - April 29	Spring Event (available weekends only)	Home & Business
April 5 - 7	Spring Home Show	Home & Business
April 18 - 19	POWER of 1 Kids Fest	Home & Business
25-May	Grand Valley Duck Race	Home & Business
23-May	For Home & Business brochures for Public school conservation and electrical safety presentation at Credit Meadows Public School	Home & Business
June	HAP Brochure and LEAP Letter Mailout	Home
13-Jun	HAP Seniors Forum	Home
June 14-16	Exchange Event	Home & Business
25-Jun	Sobey's Event	Home & Business
3-Jul	REM meeting with Hofmann	Business
6-Jul	Town of Orangeville's 150 Year Celebration	Home & Business
29-Jul	DR3 / Retrofit to large cx mailout	Business
15-Aug	emailed letters out to Heating & Cooling contractors about the retrofit HVAC replacement program	Business
15-Aug	letters sent to large customers about the DR 3 / Retrofit program	Business
3-Sep	Open for Business - Retrofit - 1/2 page ad on a/c units	Business
Sept 14-15	Fall Exchange Event - CDN Tire	Home & Business
Sept 20 - 22	Grand Valley Fall Fair	Home & Business
Sept 27 - Oct 27	Fall Event (available weekends only)	Home & Business
Oct / Nov	Fall Exchange Event	Home & Business
November 2 - 3	Dufferin Home & Business Expo	Home & Business
22-Nov	Moonlight Magic and Tree Lighting Ceremony	Home & Business
28-Nov	Safety and Conservation Presentations at St. Peters School	Home & Business
28-Nov	Town Hall Meeting - Understanding Your Bill	Residential

b. Please provide the dates of and any notes from meetings between the distributor and non-residential ratepayers in each of 2012 and 2013.

OHL's Response:

Please refer to response in a.

c. What feedback did the distributor receive from residential customers in terms of capital budgets, OM&A budgets, etc.?

OHL's Response:

OHL did not receive any feedback from residential customers in terms of capital budgets, OM&A, etc.

d. What feedback did the distributor receive from non-residential customers in terms of capital budgets, OM&A budgets, etc.?

OHL's Response:

OHL did not receive any feedback from non-residential customers in terms of capital budgets, OM&A, etc.

1.2-SEC-2

Ref: Ex. 4/3/1, p. 8

Please provide a comparison of the applicant's formal vs. informal customer engagement activities both in the past year, and planned for the coming year, and the respective value of formal vs. informal activities in light of the size of the utility and its community.

OHL's Response:

Informally OHL has engaged our customers by the following activities;

- Been a member of the Orangeville Manufacturers Association
- Attended Service Clubs such as Lions and Optimists to speak about the industry
- Attended Greater Dufferin Homebuilders Association meetings
- Active member of the Greater Dufferin Chamber of Commerce
- Held workshops/town hall meetings to explain smart meters to customers
- Held workshops for manufacturers, commercial, and institutional customers to help them understand and manage their bills
- Website – When customers first enter OHL's website they are provided the opportunity to ask questions regarding their bill and hydro in general. It also asks the customer to provide suggestions on future information sessions that are to be held by OHL.
- Participate in local events. Most recently the Town of Orangeville's 150th Birthday Celebration.
- Other events include Christmas Moonlight Magic & Tree Lighting.
- KIDS FEST - Kids festival focuses on conservation, electrical safety, water conservation, renewable generation, waste reduction, and environmental stewardship for grade 5 & 6 students

- LOCAL EVENTS - Orangeville Hydro promotes saveonenergy incentive programs and ways to conserve at local events within the community for both HOME & BUSINESS
- EARTH HOUR - Hosted by Orangeville Hydro, this event brings awareness to climate change and promotes saveonenergy programs
- FUNDRAISING FOR CHARITIES - Orangeville Hydro raises funds for local charities through auctions and funds collected from staff
- LED LIGHT EXCHANGE - Orangeville Hydro held an event 1 allowing customers to exchange their old incandescent Christmas lights for LED lights as a way of helping our customers better manage their electricity costs over the holidays
- CALENDAR CONTEST - Orangeville Hydro educated students on conservation and saveonenergy programs through a calendar contest where grade 1 - 6 students drew pictures about how to save electricity
- HOME AUDIT KITS - Orangeville Hydro developed a program to help its customers identify energy leaks in their home and better manage their electricity costs. The kits are loaned out for 2 months for free.
- SCHOOL PROGRAMS - Orangeville Hydro conducts school presentations and walking tours on electrical safety and energy conservation to help foster a culture of conservation within our communities to students from JK - Grade 8
- SITE VISITS - Orangeville Hydro conducts free energy assessments for our local businesses and helps them to identify opportunities and offer incentive based programs to become energy efficient
- COMMUNITY ENERGY PLANNING - Orangeville Hydro is working with the Town of Orangeville to identify energy opportunities for their Green Energy Plan due July 1, 2014

OHL plans to enhance our customer engagement by conducting a more comprehensive customer survey focusing on customer preferences in 2014, local newspaper communications, continually updating our website, customer connect, pre and post construction surveys, teleworks (notify customers of planned outages and special customer notifications) and OHL plans to cohesively work with Cornerstone Hydro Electric Concepts (CHEC) for further customer engagement initiatives in order to support the Board's RRFE requirements.

1.2-SEC-3

Ref: Ex. 4/3/1, p. 8

Please provide an estimate of the incremental annual cost of complying with the Board's new customer engagement requirements.

OHL's Response:

OHL is performing a more comprehensive survey budgeted at $14,000 in 2014 to engage the customers as to their preferences. OHL did not include the cost of this survey in our 2014 OM&A costs. OHL is also planning to notify and inform customers in the newspapers on a frequent basis informing them of potential larger-scale projects that are being planned. Currently OHL is considering the notices will cost around $12,000 per year and have not included in this rate submission. OHL is also investigating transactional type surveys such as pre and post construction surveys and customer feedback through bill inserts. These surveys would be performed at no or little additional costs.

1.2-VECC-3

Ref: Exhibit 2, Tab 5, Schedule 5

Customer Surveys:

a. What customer survey(s), if any, had OHL undertaken between 2009 and 2012? Please provide the results of these surveys.

OHL's Response:

OHL did not undertake any customer surveys between 2009 and 2012.

b. At page 7 of the OHL Distribution System plan it states that OHL participated in a Utility Pulse Survey. Please provide the results of that survey.

OHL's Response:

Please see attached Appendix D – CHEC Utility Pulse Report June 2013.

c. Does OHL undertake transactional surveys (i.e. after engagement with a customer)? If so please provide a summary of these. If not, please explain why not.

OHL's Response:

OHL plans to enhance our customer engagement by conducting pre and post construction surveys.

1.2–VECC–4

Ref: Exhibit 1, Tab 2

Please explain how OHL communicates the availability of LEAP assistance.

OHL's Response:

OHLs work directly with Dufferin County Community Services to assist Low-income Energy customers (LEAP). In 2012, the program assisted 15 qualifying customers by paying their hydro bill in order to prevent interruption of their service. On average the program allocated $340 per customer. In 2013, the program assisted 18 qualifying customers by paying their hydro bill in order to prevent interruption of their service. On average the program allocated $283.90 per customer. We communicate the availability of the LEAP assistance program on our reminder and disconnect notice bill stock. We also communicate LEAP verbally to our customers and advise them to contact Dufferin County Community Services. We have a direct contact with the County who we send our customers to as once the OHL LEAP funds are exhausted the County has other programs that they tap into to assist those in need.

1.2–VECC–5

Ref: Exhibit 1, Tab 2, Schedule 1

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

OHL's Response:

Yes, OHL tracks and categorizes customer enquiries and complaints. We log calls directly to the customer's account when customers call in. We also have a general email account that customers can send email enquiries or complaints. Please see table below for a summary of the annual results for 2010 through 2013.

Enquiry Type	2010	2011	2012	2013
Account History	3	127	107	17
Address Change	62	28	66	91
Appointment	10	30	1	4
Appointment AM	6	10		
Appointment PM	3	14		
Appointment Trench Inspection		1		
Balance Inquiry	1,425	2,715	2,521	2,951
Bill History	96	117	21	115
Bill Reprint	27	138	133	125
Billing High	106	49	56	66
Billing Hydro	208	179	62	98
Billing Sewer	128	4		1
Billing Water	93	161	134	146
Change Bank	4	1	1	
Continuous Service Agreement	1		15	19
Continuous Service Agreement Landlord	1		15	19
Customer Complaint	7	15	9	6
Deposit Refund	5	16	5	17
Disconnect Inquiry	549	599	599	553
Disconnect Service	549	599	599	552
Electric Meter Change	496	202	67	113
Electric Retrofit ERIP	1	1		
Equal Billing Enquiry	33	36	47	63
General Inquiries	20,231	11,954	10,602	8,585
Lawyers Letter		102	97	75
Limiter			14	38
Meter Read	31	21	41	77
Move Inquiry	87	577	770	1,210
Move In	1,865	1,607	1,641	1,686
Move Out	1,892	1,608	1,694	1,692
Name Change	76	34	29	28
New Electric Meter	168	124	179	162
Notice Inquiry	58	148	119	131
Outgoing Calls Disconnects	228	1,922	813	19
Outgoing General Calls	123	1,154	1,166	1,873
PAP Inquiry	102	143	228	181
Payment Arrangement	1,637	4,200	5,298	4,936
Peaksaver	4	1	1	2
Penalty Inquiry	2	2	4	3
Post Dated Cheques	4	1		
Power Outage	7	28	23	29
Power Savings Blitz				1
Reactivate Service	7		1	
Reconnect Service	293	304	313	339
Reference Letter	17	97	59	79
Refridgerator Roundup	1	1		
Re-read Hydro Meter	190	138	122	155
Reschedule Appointment	1			
Retailer Enquiry	20	55	55	50
Service Removal	37	33	33	25
Service Upgrade		1		
Streetlight Enquiry	4	1	1	1
Time of Use Enquiry		61	12	14
Water Meter Change	2			
Water Meter Check Read	46	93	33	20
Water/Sewer Enquiry			10	29
Grand Total:	30,946	29,452	27,816	26,396

2. Performance Measures

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-5

Ref: E2/T5/S4, p.1 – DSP, Service Quality and Reliability Performance (Adobe p. 465) and 2006 Electricity Distribution Rate Handbook, p. 141, s15.2

OHL shows SAIDI (excluding supply losses) 4 year average of 1.015 and a 2012 value of 1.08. The target indices for 2014 indicate a SAIDI of 1.5 (excluding loss of supply). The Board generally expects LDCs to maintain or improve upon the 3 year average.

a. Please explain why OHL has not been able to maintain or improve its 3 year average.

OHL's Response:

OHL changed our recording practices in 2010 and 2011 after OEB staff visited our office and reviewed our historical data. Therefore, the low outage statistics of 2009 are not an appropriate representation of OHL's system reliability expectations. Also, due to significant foreign interference and weather events that occurred in 2013 prior to our rate filing OHL felt that the SAIDI of 1.5 was a realistic target.

b. Why is OHL anticipating higher outage rate during the 2014 rate year versus the 2012.

OHL's Response:

Please refer to our response to a. in this question.

c. What steps have been or will be taken to improve OHL's reliability statistics.

OHL's Response:

OHL has and will take the following steps to mitigate or minimize power interruptions:

- Continued tree trimming activities
- Adding additional fusing for radial feeds
- Acquiring an additional feeder which will reduce the number of customers per feeder and additional switching capabilities
- Continued infra-red and patrols
- Continued use of live line techniques

2.1-Energy Probe-4

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.

OHL's Response:

OHL does not have a list of Board-approved plans from the most recent cost of service decision because in prior years it was neither a requirement nor an outcome of the 2010 rate application process. However as this provision will be requirement in the Renewed Regulatory Framework OHL will have this process in place.

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

OHL's Response:

Please see OHL's response to a.

2.1-Energy Probe-5

Ref: All Exhibits

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

OHL's Response:

There are no references to any performance efficiency benchmarking undertaken by OHL. Please also refer to OHL's response to 3.1-Staff-7 a.

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.

OHL's Response:

Please refer to OHL's response to 3.1-Staff-7 a.

2.1-Energy Probe-6

Ref: Exhibit 2, Tab 1, Schedule 2

a. Please provide more details on the reduction in capital expenditures of $573,017 from the Board approved level, including a breakdown of this amount into the projects noted on page 1.

OHL's Response:

Please see table below for details.

Category	Project Description	Total Project	Contributed Capital	Completed
Jobs Approved by not completed in 2010				
System Access	Edgewood Valley	$ 52,277.04	$ (5,620.00)	2011
System Access	Broadway Grande	$ 239,029.45	$ (32,893.00)	2011
System Access	Mono Development Ph 4	$ 211,889.10	$ (81,622.00)	2012
System Renewal	Misc Pole Replacement	$ 24,990.41		2012
System Renewal	King St Rebuilds	$ 26,780.21		2012
System Renewal	Fault Indicators Replacement	$ 55,696.80		2012
System Service	Remove Old 4 kV Rear Lot	$ 34,782.80		2012
System Service	Remote Sensors	$ 50,601.02		2012
System Renewal	Broadway Removal Old Circuit	$ 84,633.84		Project has been deferred
General Plant	Scada System	$ 15,000.00		Project has been deferred
System Service	Optimization Study	$ 62,252.55		Replaced by GIS initiative and DSP
General Plant	Load Management	$ 22,000.00		Replaced by OPA Programs
Jobs not Budgeted				
System Access	C LINE ROAD WIDENING	$ 3,238.31		
System Access	SARAH ST RECONSTRUCTION	$ 7,253.71		
System Service	Land Rights	$ 9,667.78		
System Access	PME Replacement/Inventory	$ 20,018.72		
System Access	Bell Building Conversion	$ 28,462.72		
System Access	Transformer Replacement/Inven	$ 95,397.47		
		$ 715,894.51	$ (120,135.00)	
		$ 595,759.51		

b. Please provide the amount of approved capital expenditures in 2010 that were carried forward to 2011.

OHL's Response:

Please see OHL's response to a.

2.1-SEC-4

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

OHL's Response:

Please see OHL's response to 2.1-Energy Probe-5.

2.1-SEC-5

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

Please provide details of networking with other utilities, and specific examples of sharing of best practices.

OHL's Response:

OHL networks with other utilities by being a member of Utility Collaborative Services Inc. (UCS) since 2008. Utility Collaborative Services Inc. (UCS), an Ontario based organization that has now grown to 9 provincial Local Distribution Companies (LDCs) serving 102,387 customers. We continue to see the benefits of reliable cost-competitive long term software and service solutions in an increasingly complex and resource intensive market place. The members are continuing to support and work cooperatively on standardization of our systems leading to major cost savings for each other. We continue to negotiate preferential agreements with vendors and can see cost savings through shared resources. The Ontario marketplace is challenging and as a UCS member we pride ourselves on our industry knowledge, thorough negotiating skills, and our visionary leadership. All of our members are working hard to shape the changes that confront our industry, and to continue to deliver the highest level of customer service. We believe our model of LDCs coming together and sharing industry expertise and leading edge solutions is the best way for LDCs to face these challenges. UCS has monthly conference calls and quarterly face-to-face meetings.

Some of the best practices within UCS include:

- Standardized billing set-ups and processes
- CIS Training
- Smart Meter billing efficiencies
- Share Sync Operator
- Share CIS Analyst
- UCS Standards committee meets monthly via WebEx to discuss best practices and required changes in billing, collecting and reporting
- Share testing scripts
- Made a collaborative submission to the Sector Panel Review

OHL is also a member of Cornerstone Hydro Electric Concepts Inc (CHEC).

The Cornerstone Hydro Electric Concepts Association (CHEC) developed out of the Organized Power Group that was formed as de-regulation came to the province of Ontario. CHEC, an association of 13 local distribution companies (LDCs) is modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry and provide a high standard of locally supplied customer service.

CHEC is governed by a Board of directors who are responsible for ensuring that CHEC achieves its objectives, is financially accountable, and is in compliance with all relevant laws, regulations and by-laws.

CHEC has allowed members to exchange ideas on a variety of issues facing utilities, to initiate combined solutions and to share insights on what worked and what did not. The cooperative format allowed a “think tank” environment to be created between members..

The CHEC Operations staff meets two or three times per year.

The CHEC Finance/Regulatory staff meet together monthly either face-to-face or via WebEx.

The CHEC Collections staff meets twice a year.

The CHEC CDM staff meets quarterly.

Some of the best practices within CHEC include:

- Conditions of Service
- Development of Economic Evaluation Model
- Review and simplification of rate application process
- Review of IESO settlement processes
- Review of Net-metering set-ups
- Compilation and submission of annual CDM report
- Review and standardization of Policies and Procedures
- Safety and training sessions including Book 7 Traffic Control, equipment experiences, industry injury reviews and health and safety best practices
- During the Smart Meter deployment and TOU rate implementation worked together to share experiences with the new technologies, requirements and processes.
- Knowledge sharing
- Review OEB accounting changes and public policy responsiveness implementation
- Training and workshops for example customer service, regulatory, IESO, OEB
- CHEC – Customer Survey. In 2013 we participated in a Customer Survey collaboratively with CHEC and OHL plans to participate in another Survey in 2014.
- The CHEC CEO’s meet quarterly to discuss industry issues and what might be done collectively. From this the board is working on a strategic plan.
- Made a collaborative submission to the Sector Panel Review and participated in face-to-face panel discussions

As members of the EDA, OHL has members of our staff that participate on EDA councils such as Finance, Operations and Regulatory and OHL has one staff member who is a director on the EDA Board representing Georgian Bay District.

2.1-SEC-6

Please advise whether the Applicant has compared its OM&A cost per customer, OM&A cost per FTE, and customer per FTE metrics with other LDCs? If not, please explain? If such comparisons have been made for internal purposes, and the comparisons have not been included in response to other questions, please provide them.

OHL's Response:

Please refer to 3.1-Staff-7(a).

2.1-SEC-7

Ref: Ex.2/5/5, p. 63]

Please advise what steps, if any, the Applicant has taken to make the Outage Management System they developed available to other distributors.

OHL's Response:

The Outage Monitoring System is hosted and owned by our Operational Data Storage provider. The OMS is readily available to any other distributor that uses the same ODS and AMI provider.

OHL has contacted other CHEC members that utilize the same ODS provider and provided information about our experience.

2.1–VECC–6

Ref: Exhibit 2, Tab 5, Schedule 5, pg. 12
Tab 8, Schedule 1, pg.1

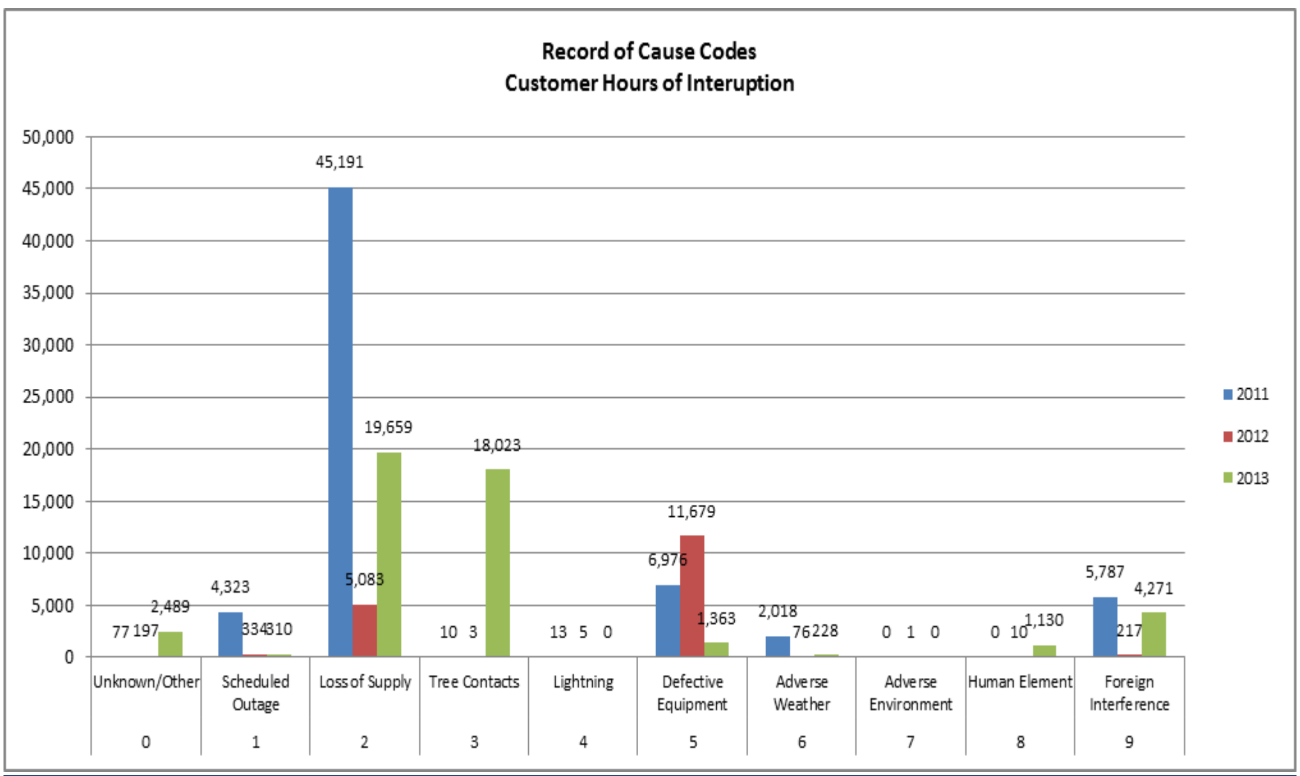
Please provide a breakdown of the service reliability performance metrics into the different category of reasons for the outage (excluding supply loss Code 2 outages). The table below provides an example format.

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				

OHL's Response:

The below Table states the Customer Hours of Interruption by the Cause Categories stated in the Electricity Reporting and Record Keeping Requirements.

Code	Cause Description	2011	2012	2013
		Hours	Hours	Hours
0	Unknown/Other	77	197	2,489
1	Scheduled Outage	4,323	334	310
2	Loss of Supply	45,191	5,083	19,659
3	Tree Contacts	10	3	18,023
4	Lightning	13	5	0
5	Defective Equipment	6,976	11,679	1,363
6	Adverse Weather	2,018	76	228
7	Adverse Environment	0	1	0
8	Human Element	0	10	1,130
9	Foreign Interference	5,787	217	4,271
Total Hours of Outages		**64,395**	**17,605**	**47,473**



3. Customer Focus

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

3.1-Staff-6

Ref: E2/T5/S4, DSP, p.4; section 2.6, p. 20 (Adobe p. 270) and section 5.0, p. 27

Chapter 5 of the Filing Requirements states, "A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences."

OHL has various projects that relate to the conversion from OHL's 4.16kV system to a 27.6kV distribution system. Board staff notes that this often includes the conversion from an overhead system to an underground system.

a. Please explain how these projects are responsive to customer preferences identified through customer engagement.

OHL's Response:

OHL would like to clarify that conversion projects are not often from an overhead system to an underground system. OHL primarily uses the term conversion when describing primary voltage conversions which change existing 4kV assets to new 27.6 kV assets. These voltage conversion projects include existing overhead and underground distribution systems. OHL can identify only two projects within the historical DSP horizon that include conversions from overhead to underground however they were municipally driven.

OHL feels these projects are responsive to customer preferences however they were not identified through direct customer engagement. OHL's main focus is on a safe, reliable and cost effective distribution system as per our mission statement. As mentioned throughout these responses, OHL will engage the customers as to their preferences.

b. Please state the role of the shareholder in this decision-making process.

OHL's Response:

OHL's strategic plan was developed with the shareholder's input. The shareholder also adopts OHL's budget and business plan in principle.

c. Please state what other options OHL has considered to provide a cost efficient distribution system.

OHL's Response:

OHL attempts to coordinate and schedule projects to align with the municipalities' road and civil reconstruction projects. Coordination efforts occur as a result of the Town's published budget as well as through periodic Technical Review Committee meetings. Furthermore, OHL provides a cost efficient distribution system through line loss reductions, equipment standardization and design standardization.

d. Please state the bill impact for a typical customer of the cost of this project and relate it to the additional value a typical customer will receive as a result of it.

OHL's Response:

OHL feels the bill impact is lower due to the advantages of 27.6kV distribution system. The typical customer will receive additional value due to the following:

- eliminated the need for building new distribution stations
- reduces line construction costs in that 44kV circuits do not have to be built along with the regular distribution circuits,
- allowed OHL to raise the transformation limits beyond the then 300 KVA, and would match the system of the then two neighboring systems
- the aging distribution stations can be eliminated and at the same time the distribution lines are upgraded or rebuilt giving new life to the distribution system
- reduces line losses
- it was consistent with the then Ontario Hydro's long range plans as outlined in the report *Implementation of Higher Distribution Voltage Levels,*

In the late-1980's the then Orangeville Hydro Electric Commission (HEC) began an ambitious plan to convert the entire 4.16 kV distribution system to a higher system voltage of 27.6kV. At this time, the 4.16kV was supplied through a number of distribution substations that were aging and feeders that were approaching capacity during winter peak periods. Furthermore, the single 44kV feeder was approaching its capacity limit and had limited backup capability due to loading. Therefore, the Orangeville HEC was provided an express 27.6kV feeder from the then Ontario Hydro to increase system capacity and improve overall system reliability.

Since that time, all new developments have been connected to the 27.6kV system and renewal projects have included converting end of life assets from 4.16kV to 27.6kV. The 27.6kV distribution system now covers the entire perimeter of the Town of Orangeville leaving the older core and underground residential subdivisions remaining on the 4.16kV system. OHL continues with the voltage conversion projects each year.

3.1-Staff-7

Ref: E4/T2/S1, pp. 1-3, Appendix 2-L

In Appendix 2-L, OHL shows OM&A costs of $237 per customer, which is an increase of 27% over 2010 Board-approved amount and 10.5% over 2012 actuals. OHL is proposing an increase in total OM&A expenses of 32.4% over 2010 board-approved and 12.8% over 2012 actuals.

a. Please state how OHL compares to other similar utilities.

OHL has revised the cost per customer to $299.71 in relation to the interrogatory 6.2-SEC-30.

OHL chose similar utilities that were approved for 2013 rates to compare the costs per customer. As shown in the table below, OHL's 2014 Test Year OM&A costs per customer are lower compared to these similar utilities in their 2013 test years. OHL's OM&A cost per customer is 1.7% higher than Cambridge, who is also applying for 2014 rates.

OM&A/Customer

Cohort	Utility	Status	COS Test	2009 BA	2010 BA	2011 Actuals	2012 Actuals	2014 Test	Increase from 2009 BA	Increase from 2010 BA	Increase from 2012 Actuals	2013 Test	Increase from 2009 BA	Increase from 2011 Actuals
Group III	Orangeville	filed	2014		$ 234.48		$ 272.05	$ 299.71		27.8%	10.2%			
Group III	Cambridge	filed	2014		$ 198.46		$ 264.47	$ 294.65		48.5%	11.4%			
Group III	NOTL	filed	2014	$ 233.02			$ 263.10	$ 262.62	12.7%		-0.2%		12.7%	
Group III	Innisfil	approved	2013	$ 270.47		$ 284.61						$ 323.11	19.5%	13.5%
Group III	Centre Wellington	approved	2013	$ 271.25		$ 305.49						$ 317.66	17.1%	4.0%
Group IV	Midland	approved	2013	$ 301.48		$ 258.26						$ 326.85	8.4%	26.6%

OHL's Response:

b. Please discuss the drivers for this increase in further detail, with reference to the Board's inflation factor of 1.7% and its labour/capital composition.

OHL's Response:

OHL has examined the drivers further to determine the factors of the increase of 32.4% from the 2010 board-approved costs over the 2014 test year costs. The total compound annual growth between 2010 board-approved and the 2014 test year compares at 5.6%. OHL performed a comparison of the total costs included in the 2010 cost of service application over the 2014 costs and found cost increases amounting to $529,509 over and above any usual inflation type costs.

OHL referred to EB-2010-0379, the Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors to adjust these costs. OHL determined that were two costs that were affected by the inflation factors and were adjusted to coincide with the

OHL deducted the "new or incremental" costs from the total OM&A costs for the 2014 test year amounting to $3,495,183, deducted the or incremental cost increase to come up with the total of $2,965,674. OHL calculated the compounded annual growth amounting to 2.2% which is slightly higher than the Board's inflation factor of 1.7%, a difference of .5%. However the increase in OM&A would be comparable to the range for the Reports' 3 year moving average in 2010 is 2.0%, in 2011, 1.8% and in 2012, 1.9%.

Cost Analysis	2010 Board Approved	2014 Test	Inflation Measure	Variance	Compounded Annual Growth
Insurance Costs/Cyber/Credit/Liability	65,393	88,387		22,994	
IT costs	20,000	50,000		30,000	
CIS costs	73,835	75,473		1,638	
Records Management - File Nexus	-	38,400		38,400	
Bad Debts	20,000	35,000		15,000	
EDA Fee Increase	25,800	31,100		5,300	
Audit	31,000	38,000		7,000	
Safety general admin cost	-	63,587		63,587	
Rate App	8,000	24,000		16,000	
Succession-Related Training	40,714	75,274		34,560	
Succession Salary Grade Increases	-	67,816		67,816	
ITM AS2 License	-	2,130		2,130	
Web Presentment/Customer Connect	-	23,807		23,807	
Sync Operator	-	31,858		31,858	
Security Framework Components Project	-	7,000		7,000	
Meter Point Reverifications	-	16,478		16,478	
GIS/USF	16,200	18,363		2,163	
Easements	-	4,950		4,950	
Benefits Increase	357,863	468,590	(33,771)	76,956	
Incentive Bonus	29,500	46,816	(2,784)	14,532	
Apprentice	-	47,340		47,340	
Total	**688,305**	**1,254,369**		**529,509**	
Total OM&A	**2,659,015**			**3,495,183**	**5.6%**
Total cost Increases				**529,509**	
Comparable Amounts	**2,659,015**			**2,965,674**	**2.2%**

c. Please outline the outcomes and higher level of services that OHL customers will receive for the relatively higher rates they are paying.

OHL's Response:

Customer Survey – 15th Annual Electric Utility Customer Satisfaction Survey completed in June 2013 in collaboration with Cornerstone Hydro Electric Concepts (CHEC). By knowing our customer's preferences we will be able to make more informed decisions going forward, in order to provide a higher level of customer service. The primary Objective of the survey is to provide information to support discussions about improving customer care at every level in our utility.

FileNexus Document Management System - gives us the ability to capture virtually any type of document from any source (i.e. paper records, such as maps, drawings, manuals, electronic files such as generated reports, client statement streams, IVR recordings, etc.) index and compress them for secure archival and future recall-providing a single cohesive repository for all document management, workflow and retention needs. Some examples of how we will use FileNexus throughout the organization are as follows:

Finance

- Automate accounts payable /receivable processes
- Capture and archive virtually all financial information
- Handle payment dispute resolutions efficiently
- Automatically burst and distribute financial reports

- Efficiently comply with all audit and regulatory requirements

Customer Service

- Securely capture and archive customer information
- dramatically streamline new customer sign-up process
- manage customer complaints process
- automate virtually any workflow requirement
- automatically link service orders to customer files

Engineering

- capture and archive virtually all engineering information
- link entire project file with all associated documents
- easily add supporting documents
- view completion notes
- change order process
- access records from anywhere
- add notes and approvals
- quicker response and improved accuracy on customer premise locate and easement requests

Human Resources

- capture and archive virtually all HR information
- capture and distribute data electronically

Purchasing

- automatically capture, track and manage all purchasing records
- elimination of all paper filing

Teleworks – Customers receive an automated message regarding disconnects thereby freeing up the time of the CSR's to provide better customer service directly with the customer. It is also used to communicate important messages to our customers for example planned outages.

Customer Connect – OHL did not include the most recent postage rate increase which sees rates going from $0.70 to $1.00. OHL will be offering e-billing to our customers that will give OHL the ability to save on postage and paper in the future. Customer Connect will provide the necessary solution to engage with our customers at a completely different level. This will be done by enabling OHL's customers to gain access to high value consumption data, to better understand their usage patterns, to educate themselves on rates and what affects them and to transact more effectively with the Utility. The ability to access this information will be available 24/7 and the customer will be able to customize setup email and SMS texts notifications specific to their account.

Cyber insurance – It mitigates our financial risk in the event of a security breach. The protection of the personal information of our customers (including names, addresses, banking or payment details; corporate data including financial records etc.) is a priority for our utility. The loss or breach of this information, either accidental or intentional, may be costly from a financial, business continuity and a reputational standpoint. Privacy and the protection of the personal information of our customers should be a priority not only from a legal requirement, but also from that of a "responsible and good" corporate citizen. Our customers trust and rely on us to protect their personal information. Within our organization, privacy is essential to establishing and maintaining trust. If customers, clients or employees believe that their personal information will be handled respectfully, in an open and transparent manner, with strong, reasonable safeguards, and made accessible to them at their request, this fosters trust and a continued positive relationship can be expected. If customers are considered our utility's' greatest asset, then their personal information must be considered as such as well. An accountable organization can demonstrate to customers, employees, shareholders, regulators, and competitors that it values privacy, not only for compliance reasons, but also because privacy makes good business sense.

Succession Planning – is necessary to achieve our objectives to maintain a seamless transition of knowledge management while considering upcoming retirements of staff. Succession Planning is necessary due to the length of time to fully train competent personnel. By protecting the business we are protecting our customers. Customers benefit from OHL being proactive not reactive.

Outsourcing IT Support is considerably less than hiring an FTE to manage our systems. The cost currently identified as IT support is not a direct representation of day to day user support requirements. Evaluating the last few years of the IT budget, it is very clear that base user support requirements that an FTE could reasonably be expected to fulfil is a very small part (~18hrs/month) of the overall budget. The increase in costs generated, often require specific expertise, are the various business based enhancements, initiatives and capabilities the departments require, system protection and information security, and digital customer interactions:

- Business initiatives where various departmental enhancements require assistance:
  A few examples in this area were external connectivity requirements to support metering changes, onsite redesign of LAN capabilities to support applications such as Filenexus, enhancing hardware capabilities to meet software upgrade paths, WAN design changes at the virtual local area network level to support offsite software requirements, infrastructure change requests on-site, and associated operating system upgrades to support these. None of the above can be considered as a day to day support requirement, as they each require a specific expertise to successfully implement, and would require 3rd party support.
- Increased system protection and information security to meet increasingly specific government and auditing guidelines:
  This very exact knowledge requirement is a career on to itself, as the need to ensure our systems and data are protected is essential to the successful, continuing operation of our systems. This is an area that has shown an increase in cost, and that cost is to provide the essential automated systems monitoring and patching, for protection and system stability. The implementation of this necessary business requirement has been designed to ensure we have a fully protected and sustainable IT infrastructure, and requires expertise. Further, the legislation specific to system protection, policies and procedures, has grown substantially in the last few years. To meet this requirement, specific expertise and contracts must be in place to fulfil these regulations.
- Enhancing customer interactions via web based information and exchange. This area is included in the overall IT budget. As another area of expertise, the support and design of our customer facing digital environment, from website to hosted exchange platform, requires outside support.

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

OHL's Response:

Please refer to OHL's response to 1.2-Staff-3 b.

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

OHL's Response:

OHL does not have a documented analysis to assess whether planning decisions reflect best practices of Ontario distributors, although OHL believes that our best practices reflect the industry standard. OHL is part of the Utilities Standards Form, Utility Collaborative Services, Electricity Distributors Association and CHEC where collaboration takes place to determine best practices. OHL participates in the yearly UPMS survey which compares us to other 'like' participating utilities. OHL also refers to the OEB yearbook to analyze costs compared to other 'like' utilities.

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.

OHL's Response:

Examples of initiatives that OHL performs are:

- Yearly preventative maintenance on sub-stations to avoid large capital replacement or repair costs,
- Line patrols and equipment inspections to ensure proper operation and determine maintenance requirements,
- Infrared testing on the distribution system to identify 'hot spots' prior to equipment failure or other issues,
- Tree trimming to prevent the line contacts and power outages.
- Analysis preformed on e-billing versus regular billing

The benefits of the maintenance activities is to reduce the quantity of unplanned outages as well as extend the life of the existing assets to reduce the quantity of required capital replacements

Customer Connect/E-billing - The analysis performed on e-billing versus regular billing as illustrated in the table below.

Hard copy VS ebilling Cost					
Total number of customers	**11605**				
Per Month for bills					
	# of bills	**Unit price**	**Annually**	**Monthly cost**	**Unit cost**
Envelopes with indicia	11605	$ 0.04	$ 5,266.81	$ 438.90	$ 0.04
Postage	11605	$ 0.70	$ 97,482.00	$ 8,123.50	$ 0.70
Bill Stock	11605	$ 0.03	$ 4,595.58	$ 382.97	$ 0.03
		$ 0.77	$ 107,344.39	$ 8,945.37	$ 0.77
Operational Cost	**Monthly**	**Unit price**	**Annually**	**Montly cost**	**Unit cost**
time of CSR	2	$ 25.00	$ 2,500.00	$ 208.33	$ 0.02
Ink	4	$ 130.00	$ 520.00	$ 43.33	$ 0.00
Maintenance of Maxmailer	1	$ 4,949.91	$ 4,949.91	$ 412.49	$ 0.04
Total		$ 5,104.91	$ 7,969.91	$ 664.16	$ 0.06
Summary					
Cost per bill	$ 0.83				
Total per month	$ 9,609.53				
Total per year	$ 115,314.30				
eBilling					
There is no direct associated costs for ebilling.					
We will be maximizing current and updated					
software to offer ebilling to our customers.					
Based on 25% of Customers signing up					
Per month	$ 2,402.38				
Per year	$ 28,828.58				
Savings of					
Hard copy - ebilling	**$ 28,828.58**				

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. The applicant was assigned to Group III out of five groups. Please provide details on any initiatives undertaken to improve the applicant's assignment in future years.

OHL's Response:

OHL plans to improve our assignment in future years by;

- reducing staff through attrition
- further review of our procurement processes
- investigating future outsourcing opportunities
- promoting e-billing to our customers

- further sub-station elimination
- training internal staff to reduce contractor costs
- utilizing our external cooperatives to reduce costs

OHL is diligent in reviewing cost reduction possibilities on an on-going basis

3.1-Staff-8

Ref: E4/T2/S1, pp. 1-3, Appendix 2JA

In Appendix 2-JA Orangeville Hydro shows OM&A expenses growing at a compounded annual growth rate of 5.8% with percentage change year over year from 12% (2011), 5% (2012), 4% (2013) and 9% (2014).

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2009 BA – 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2009 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Bridge Year	Variance 2013 Bridge vs. 2012 Actuals	2014 Test Year	Variance 2014 Test vs. 2013 Bridge
Operations	$ 378,946	$ 392,746	-$ 13,800	$ 433,555	$ 40,809	$ 458,597	$ 25,042	$ 487,141	$ 28,544	$ 507,835	$ 20,694
Maintenance	$ 492,423	$ 425,049	$ 67,374	$ 534,881	$ 109,833	$ 465,329	-$ 69,552	$ 562,725	$ 97,396	$ 616,413	$ 53,688
Billing and Collecting	$ 549,953	$ 523,585	$ 26,369	$ 628,892	$ 105,307	$ 739,649	$ 110,757	$ 712,500	-$ 27,148	$ 741,719	$ 29,218
Community Relations	$ 20,862	$ 18,084	$ 2,778	$ 26,560	$ 8,476	$ 28,170	$ 1,610	$ 21,254	-$ 6,917	$ 17,278	-$ 3,976
Administrative and General	$ 1,216,832	$ 1,280,256	-$ 63,425	$ 1,332,083	$ 51,826	$ 1,407,416	$ 75,333	$ 1,437,088	$ 29,672	$ 1,611,938	$ 174,850
Total OM&A Expenses	$ 2,659,015	$ 2,639,719	$ 19,296	$ 2,955,971	$ 316,252	$ 3,099,161	$ 143,189	$ 3,220,707	$ 121,547	$ 3,495,183	$ 274,476
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 2,659,015	$ 2,639,719	$ 19,296	$ 2,955,971	$ 316,252	$ 3,099,161	$ 143,189	$ 3,220,707	$ 121,547	$ 3,495,183	$ 274,476
Variance from previous year				$ 316,252		$ 143,189		$ 121,547		$ 274,476	
Percent change (year over year)				12%		5%		4%		9%	
Percent Change: Test year vs. Most Current Actual						12.78%					
Simple average of % variance for all years						32.41%					7%
Compound Annual Growth Rate for all years											5.8%
Compound Growth Rate (2012 Actuals vs. 2009 Actuals)						5.49%					

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 at about 1.5 times the annual rate experienced over the 2010-2013 period.

OHL's Response:

Please OHL's response to 3.1-Staff-7 c.

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, explain why not.

OHL's Response:

The benefits noted in the previous response are listed below and indicate if and how OHL communicated with our customers.

Customer Survey – 15th Annual Electric Utility Customer Satisfaction Survey completed in June 2013 in collaboration with Cornerstone Hydro Electric Concepts (CHEC). A Random sample of OHL customers were contacted by Utility Pulse Survey by telephone.

FileNexus – The benefits were not communicated directly with the customer as this was an internal process improvement giving customer service and other staff the ability to source information in a more efficient manner.

Teleworks – The benefits were not communicated directly with the customer as this requirement was due to the implementation of the new customer service rules. However, we have utilized this product in order to communicate scheduled outages and other important information to our customers.

Customer Connect – We communicated via bill messages, company website and verbally to the customer the benefits of using Customer Connect to gain access to high value consumption data, to better understand their usage patterns, to educate themselves on rates and what affects them and to transact more effectively with the Utility.

Cyber Insurance – The benefits were not communicated directly with the customer as this was an internal process. The protection of the personal information of our customers (including names, addresses, banking or payment details; corporate data including financial records etc.) is a priority for our utility.

Succession Planning - The benefits were not communicated directly with the customer.

Outsourcing IT Support - The benefits were not communicated directly with the customer. However, OHL provides our customers with accurate TOU readings and a timely monthly invoice for consumption of electricity used.

OHL did not communicate all of the benefits directly to our customers prior to our submission of our 2014 Cost of Service application. OHL recognizes that this is a transition year and will develop processes to support the Board's RRFE in the future.

3.1-Energy Probe-7

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.

OHL's Response:

OHL does not have any formal customer feedback from residential customers in the bridge and test years with respect to capital expenditures.

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

OHL's Response:

OHL does not have any formal customer feedback from non-residential customers in the bridge and test years with respect to capital expenditures.

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

OHL's Response:

OHL does not have any formal customer feedback from residential customers in the bridge and test years 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.

OHL's Response:

OHL does not have any formal customer feedback from non-residential customers in the bridge and test years with respect to OM&A expenses.

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.

OHL's Response:

OHL did not ask the customers (residential or non-residential) for feedback and preferences on employee compensation, including, but not limited to salary levels, salary increases, benefits and pensions.

OHL's Response:

3.1-SEC-8

Ref: Ex.1/1/5/p.1

Please confirm that the Applicant serves eighteen schools belonging to two school boards. Please advise how many schools are in each of the GS<50 and GS>50 rate classes. Please advise how many schools have more than one account associated with a single school (e.g. for portables, etc.).

OHL's Response:

Schools Total	13
Schools Multiply Accounts	9
GS>50kW	12
GS<50kW	1
Generation	8

3.1-SEC-9

Ref: Ex.1/2/1/p.3

Please provide an estimate of the percentage of the Applicant's annual revenues that comes from customers that are not municipal taxpayers of Orangeville or Grand Valley.

OHL's Response:

OHL has compared the total revenue historically from 2010 to the 2014 test year. The total revenue amount includes from account pertaining retailer revenues, accounts 4082 and 4084. In 2010 the total revenue OHL removed the SPC charges revenues of $64,281 in order to achieve a better comparison. In 2012, the revenue percentage is higher due to the smart meter carrying charges revenue that is included in the revenues due to the accounting instructions for the smart meter disposition. Please see table below that gives the percentage of the revenue that is generated from non-municipal taxpayers.

	2010	2011	2012	2013 Bridge	2014 Test
Other Revenue	561,139	551,069	385,577	454,662	465,962
Revenue Non-Municipal Taxpayer	126,024	144,530	208,040	136,778	129,999
Percentage	22%	26%	54%	30%	28%

3.1-SEC-10

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

a. Capital expenditures

OHL's Response:

Please see OHL's response to 3.1-Energy Probe-7 a. and b.

b. OM&A expenses

OHL's Response:

Please see OHL's response to 3.1-Energy Probe-7 c. and d.

3.1-SEC-11

Please provide a copy of any surveys, questionnaires or other methods that the Applicant used to collect customer feedback and preferences in respect of this Application. Please provide full results for any survey or questionnaire undertaken.

OHL's Response:

Please see OHL's response to 1.2-VECC-3 b.

4. Operational Effectiveness

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 associated level of revenue requirement requested by the applicant?

4.1-Staff-9

Ref: E2/T5/S4, DSP section 2.6, p. 20 (Adobe p. 270) and section 5.0, p. 27 (Adobe p.

On page 27, OHL states that new construction in both communities (Town of Orangeville and Village of Grand Valley) is mostly underground and notes that this practice began in Orangeville in the 1970's on the 4.16kV system. Board staff notes that this is generally more expensive than using overhead distribution.

a. Please provide any assessment that compared and contrasted the cost of 27.6kV overhead distribution system with a similarly rated underground ducted 27.6kV distribution and provide relevant business cases.

OHL's Response:

The statement on Page 27 is referring to new developments on undeveloped lands. It is common practice within southern Ontario for new developments to have the electrical distribution systems located underground. With that said, the majority of OHL's main feeder lines are overhead. This statement is referring to the fact that the majority of underground assets are located within the commercial and residential developments.

b. Please state what assessments were done to assist in the decision to install an underground system and state if OHL has been mandated by the municipality to convert to an underground system. Please provide any relevant documentation.

OHL's Response:

As mentioned in a), the statement on Page 27 is referring to new developments on undeveloped lands and not the relocation of existing infrastructure. OHL has not been mandated to convert existing overhead infrastructure to an underground system.

OHL would like to mention that during planned 4.16kV to 27.6kV voltage conversion projects, OHL does an assessment of the existing location of the primary voltage infrastructure. OHL looks to improve our distribution system in ways such as removing rear lot/backyard primary overhead lines. OHL feels strongly that primary 27.6kV voltage lines and transformers should not be located in residential backyards. During the planning process, OHL looks to locate the primary 27.6kV assets in accessible and acceptable locations for safety, reliability and maintenance purposes.

c. Please provide a detailed description of how ratepayers/consumers have been consulted in making this choice.

OHL's Response:

OHL allows all private developers to provide a preliminary design for the electrical supply of their development. Therefore, the developers are fully involved in the design and planning of the distribution system within their development. This process is also extended to individual construction projects and infill developments. The design process also involves municipal staff and other infrastructure owners such as telecoms and the gas company.

3.1–VECC–7

Ref: Exhibit 2, Tab 5, Schedule 5 Distribution System Plan

What customer concerns regarding service plant has OHL identified and addressed in this application? Please explain how these customer issues were identified.

OHL's Response:

OHL has always taken a strong customer service approach to customer concerns regarding OHL's infrastructure. All customer concerns are forwarded to Operations and Engineering staff. The Operations and Engineering department directs the field staff to respond to the customer concerns based on the severity and immediacy of the matter. Customer concerns are identified through direct contact from the customers through meetings, telephone calls and emails.

4.1-Staff-10

Ref: E2/T1/S2 p.1 and E2/T5/S4, p.62, s11.4 (Adobe p. 312)

In the first reference OHL noted that OHL underspend on capital projects in 2010 actual vs. board-approved and that this was partially due to OHL finding a "virtual no-cost remedy and In-home controls that are part of the OPA Peaksaver program" instead of SCADA development. In the second reference OHL concludes that the investment in a SCADA system has been deferred and that the existing system in place provides "near real time visual notification of all Power Fails, Power Restores, Voltage Dips and Meter Tampers that are reported by the smart meters". While the Smart Meter provides data, it does not allow for control of facilities, and hence the potential advantages of having the data may not be able to be realized.

a. Please describe what, if any, remote control facilities are in place for 44, 27.6 and 4kV distribution system equipment.

OHL's Response:

44kV: Hydro One owns and operates the M5 breaker at the Orangeville TS. OHL is able to contact the Hydro One OGCC 24/7 control room for remote monitoring and control of the M5 breaker.

27.6kV: Hydro One owns and operates the M25 and M26 breakers at the Orangeville TS. OHL is able to contact the Hydro One OGCC 24/7 control room for remote monitoring and control of the M25 and M26 breaker.

4kV: There are no remote control facilities in place for the 4kV feeders. Since OHL is has been reducing the 4kV infrastructure since the late 1980's, OHL did not feel it would be prudent to invest in remote control facilities on the 4kV infrastructure.

b. What sectionalizing facilities are available on the 27.6kV loops to gain advantage in reducing outages?

OHL's Response:

OHL's sectionalizing facilities include:

- Gang operated load break switches
- Inline switches
- Fused inline switches
- Solid blade cutouts
- Fused cutouts
- Underground primary switching cubicles
- Load break elbows
- Load break switches within pad mounted transformers

c. What kinds of projects were judged to be higher priority than the development of a SCADA system and why?

OHL's Response:

As stated in the DSP, OHL has utilized the Sensus AMI and the Savage Data ODS to build an Outage Monitoring System at no additional cost from either party. OHL staff receives near real time visual notification of all Power Fails, Power Restores, Voltage Dips and Meter Tampers that are reported by the smart meters. This has been utilized to decrease the lag between the start of an outage and OHL's awareness of the outage. This decrease in lag reduces the length of outages experienced by customers. The OMS also provides additional information to help determine the scale outages, and whether a problem is on the customer's side of the demarcation point. In some cases OHL is able to restore power to customers prior to the customer becoming aware of the event. The OMS has deferred further investment in other systems such as other outage management systems, "smart" technologies and a SCADA system.

Furthermore, OHL considers it prudent to allow the existing distribution level SCADA and smart grid technologies to mature in the coming years. OHL is not in a position to "test" new technologies or risk the costs of needing to replace or upgrade failed technologies. OHL considers it prudent to learn from the best practices that are currently being formed in the Ontario energy sector. OHL looks forward to working with other LDC's and learning from their experiences to ensure that a mature and reliable solution is utilized.

4.1-Staff-11

Ref: E2/T5/S6, Appendix A – OPA Letter of Comment and E2/T5/S4, p. 23, Tables 8 and 9

The OPA suggests that there is 190kW of FIT contracts as recently as July 3 2013, but this doesn't seem to explain the large difference between OPA and OHL in the kW of projects. The following table represents the OHL and OPA reports on Fit and MicroFIT projects:

MicroFit and FIT Contracts

	MicroFIT		FIT	
	Quantity	kW	Quantity	kW
OHL MicroFIT connected	14	109kW	1	250kW
OHL plans to connect	2	12kW	2	322kW
TOTAL	16	121kW	3	572kW
Per OPA	16	122kW	6	815kW

Please reconcile the difference in FIT and MicroFit projects between OPA and OHL.

OHL's Response:

The difference between the OPA and OHL states values was caused by projects that have applied to the OPA but had not contacted OHL. Please note that since the July 3, 2013, OHL has connected projects, additional projects have applied to OHL and the OPA has terminated two applications.

OHL is providing an updated list of MicroFIT and FIT as of February 5th, 2014:

Status	MicroFIT		FIT	
	Quantity	kW	Quantity	kW
Connected	16	117	1	250
OHL plans to connect	1	8	4	515
Proponent has not applied to OHL	0	0	1	50
Total	17	125	6	815

Projects that are under the status "OHL plans to connect" include projects that are under construction, considering the Offer to Connect or in the process of completing a CIA.

4.1-Staff-12

Ref: E2/T5/S4 – DSP, Project Number B78-2013: First St. – Fifth Avenue 27.6kV Conversion (Adobe p. 380)

In the above reference, under "Coordination" OHL states: "OHL is coordinating this pole work with third party attached to ensure clearances are appropriate and their needs are met."

a. Please identify this third party.

OHL's Response:

The third party attacher(s) involved in this project are Rogers Cable and the Town of Orangeville.

b. Please explain what is meant in this context by "attached".

OHL's Response:

This sentence should have stated "OHL is coordinating this pole work with two third party attachers to ensure clearances are appropriate and their needs are met." OHL considers joint use attachments as third party attachers and uses the terms interchangeably.

4.1-Staff-13

Ref: E2/T5/S4 – DSP, Project Number B79-2013: Parkview Heights Transformer Replacement (Adobe p. 382)

OHL has included capital cost of $85K for the replacement of existing transformer assets with 12 new pad mount transformers. OHL stated that these transformer assets have come to the end of life due to exterior corrosion and need to be replaced in 2013 & 2014. Included in this capital expenditure are excavation costs and new concrete vaults.

a. Please explain why completely new excavation and vaults are required for these transformers. Perhaps photographs would help to explain this.

OHL's Response:

The existing concrete foundations do not have the required surface area to support the current standard size of transformers.

b. Please explain how and why the decision was made to locate the pad mount transformers in underground vaults rather than above ground.

OHL's Response:

To clarify, OHL does not plan to install submersible transformers. OHL does not own any submersible transformers. OHL's standard is to install pad mounted transformers above grade. The pad mounted transformers rest on a concrete structure that is called a foundation or a "vault".

c. Please provide the results of the asset condition assessment which justifies replacing all of the transformers.

OHL's Response:

OHL would like to clarify that OHL is not replacing all of the transformers within the Parkview Heights subdivision. This specific subdivision contains approximately 35 pad mounted transformers that were installed in the early 1970s.

Here is a scanned image of a Padmount Transformer Inspection Form:

* Replace

ORANGEVILLE HYDRO

Padmount Transformer Inspection Form

Location #: 362

Phase: RED WHITE BLUE 3 PHASE

Address: Parkview

Condition of Transformer:

Rust	☑ Yes	☐ No	☐ If yes then repaint
Graffiti	☐ Yes	☑ No	☐ If yes then repaint
Holes, Dents, Broken Seams	☑ Yes	☑ No	
Door Open or Lock Missing	☐ Yes	☑ No	
Oil Leaking	☐ Yes	☑ No	
Objects blocking access to transformer or door	☐ Yes	☑ No	
Possible vehicle contact	☐ Yes	☑ No	
Possible sidewalk plow contact	☐ Yes	☑ No	☐ If yes then place transformer marker
Transformer crooked on concrete vault	☐ Yes	☑ No	
Location #, phase marker, & safety sticker not visible	☐ Yes	☑ No	☐ If yes then replace

Condition of Concrete Vault:

Unlevel	☐ Yes	☑ No	
Vault sits too high out of ground (over 12")	☐ Yes	☑ No	
Vault sits too low in ground (not visible)	☐ Yes	☑ No	
Needs dirt around vault	☐ Yes	☑ No	

Date Completed: 29/07/11

By: Colton Horan

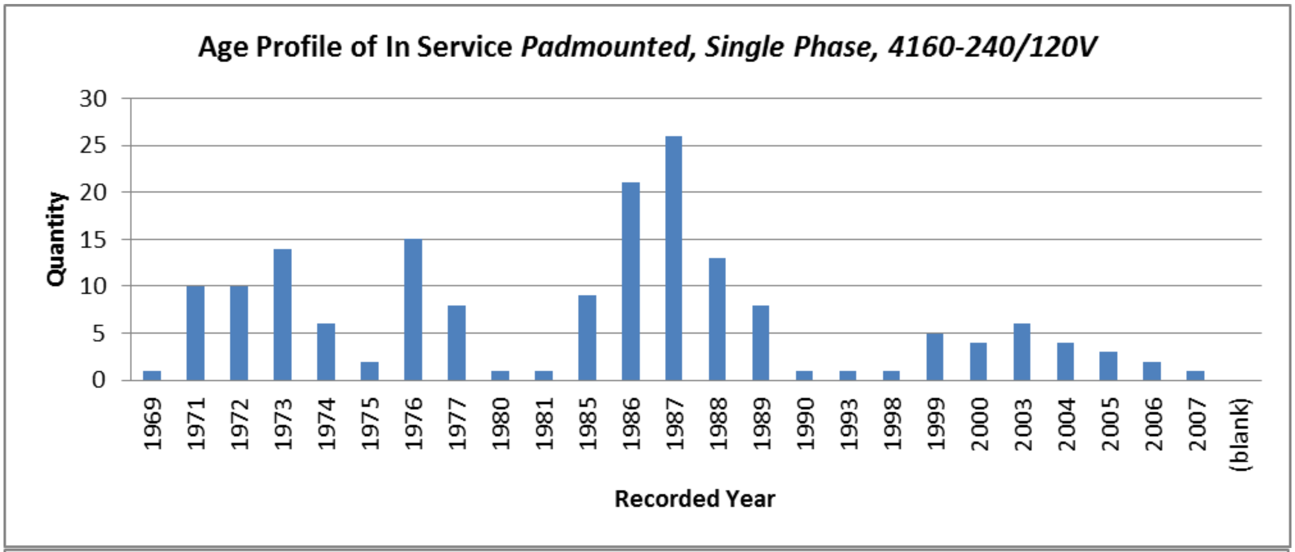
PO Box 400, 400 'C' Line, Orangeville, Ontario L9W 2Z7 (519) 942-8000 FAX (519) 941-6061

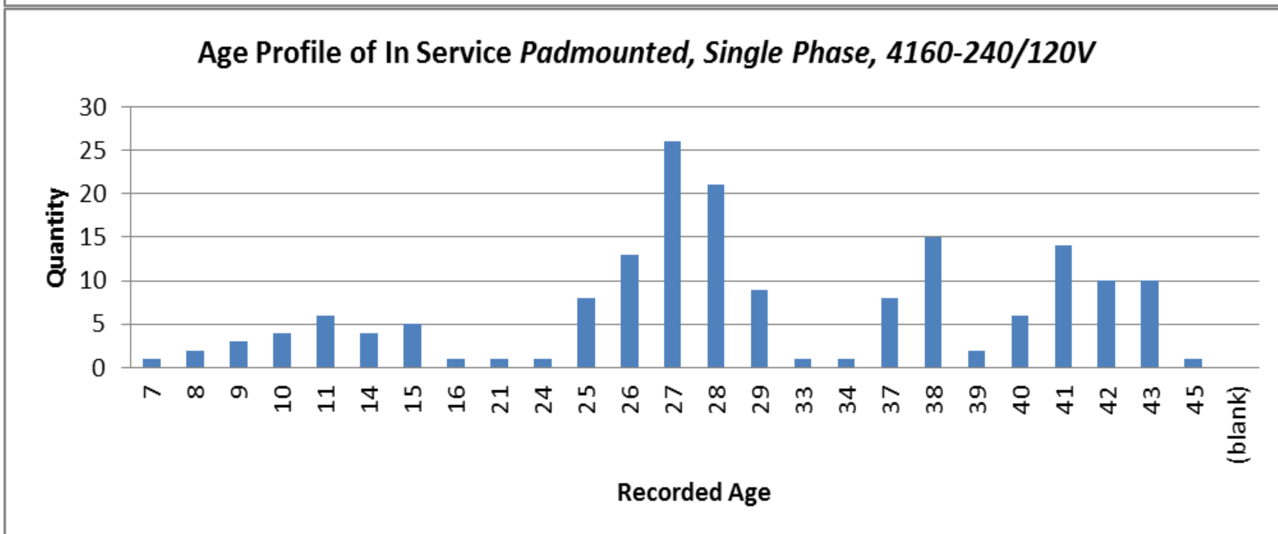
d. Please indicate how many transformers of the same specification exist in the OHL system and their ages.

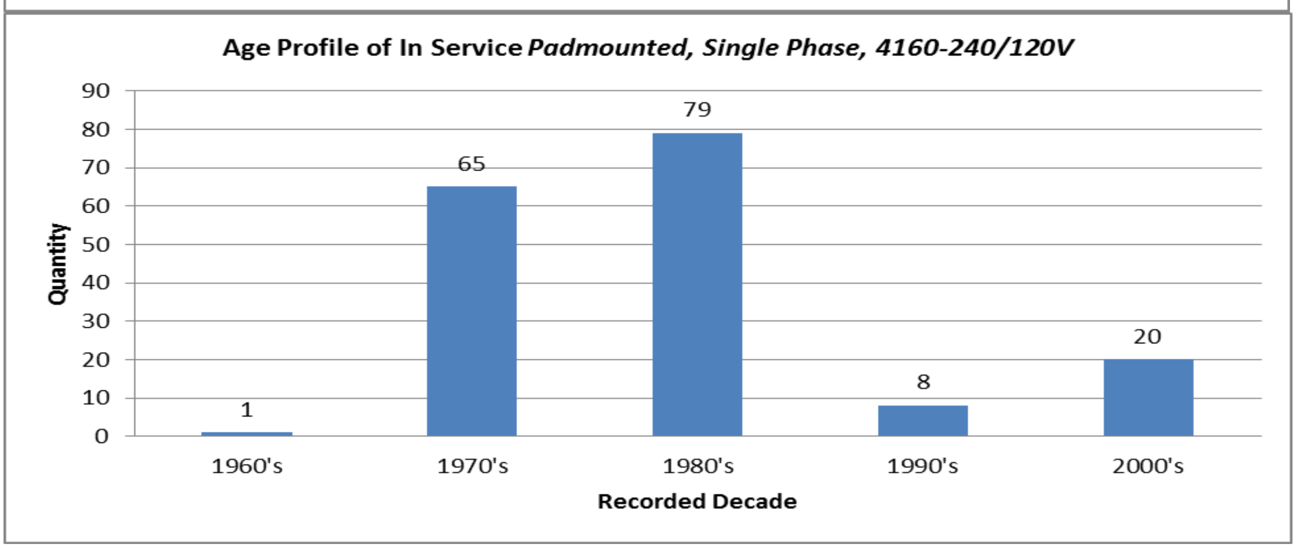
OHL's Response:

OHL assumes that by "the same specification" the Board staff is referring to in service transformers of the same Type, Phase, Primary Voltage and Secondary Voltage. Therefore, OHL will provide the details of transformers that are *Padmounted, Single Phase, 4160/2400V-240/120V*. OHL has 173 *Padmounted, Single Phase, 4160/2400V-240/120V* transformers. The recorded age of the 173 transformers ranges from 7 to 45 years. OHL is providing three charts to state the age profile of transformers of the same specification that exist in OHL's system.

The age profiles show that the Orangeville Hydro Electric Commission began installing padmounted transformers in the early 1970's.







e. Please provide a clear colour photograph of a transformer showing exterior corrosion and holes that pose a risk to the public.

OHL's Response:

Due to the recent snow fall in the Orangeville area, these transformers are covered by a significant of snow.

f. Please provide a reliability history of these transformers.

OHL's Response:

OHL records outage statistics as required by the Electricity Reporting & Record Keeping Requirements. OHL does not record outage statistics based on specific transformers.

g. Please indicate if the new pad mount transformers were or will be acquired through competitive bidding, or through alternate procedures, and explain.

OHL's Response:

OHL will be using existing transformers that are in stock. These transformers were repainted in 2013 and are acceptable for reuse.

4.1-Staff-14

Ref: E2/T5/S4 – DSP, Project Number B80-2013: Emma and Douglas Street Pole Line Replacement (Adobe p. 383)

In section C OHL states that "Due to the age and condition of these assets OHL has decided to replace this pole line." The total project cost is $58K.

Please provide a cost-benefit study that supports this project's capital expenditure.

OHL's Response:

OHL does not have a formal cost-benefit study available to support this projects capital expenditure. With that said, there were a number of factors to determine that this pole line required replacement. The village of Grand Valley has not had poles replaced since the tornado in the mid-1980's. The pole line is one of two trunk lines that exit the existing substation and this circuit is the main trunk line to service the northern half of Grand Valley. Therefore, this pole line is one of the most important pole lines in this area. OHL decided to start with this section of poles due to the following reasons:

- the poles were installed in the side of the asphalt road way and near private driveways without curbing which allowed snow removal vehicles and private vehicles to damage the base of the poles
- the private trees were encroaching and towering over the primary conductors
- the pole line contained legacy porcelain insulators and cross-arms

- the street light and joint use attachment assets did not have enough clearance to energized equipment
- the pole heights were shorter and contained longer spans lengths than required to meet the current construction standards
- the pole line location is nearest the existing substation

Due to the mentioned factors, OHL decided to replace these 15 poles out of our approximately 1,754 poles.

4.1-Staff-15

Ref: E2/T5/S4 – DSP, Project Number B82-2013: Cooper-George-Parkview-Main St. South Pole Line (Adobe p. 386)

OHL requested a total capital expenditure of $75K for the installation of 22 new wood poles, hardware, and new secondary bus as well as to complete a primary loop.

a. OHL stated that "OHL's annual inspections and staff reports have identified aged assets as well as inadequate clearances and undersized conductors". Please provide the asset condition assessment highlighting these deficiencies.

OHL's Response:

OHL's 2009 Asset Condition Assessment referred to this area in Appendix G: Sections 3.1.12-3.1.15. The staff reports have been visual and verbal.

b. Under Safety OHL states "the open bus small conductor will be replaced with the appropriate sized insulated conductor". Please explain that statement.

OHL's Response:

Open wire bus consists of two or more phase conductors and a bare neutral that are separated vertically in air. Open wire bus is no longer a standard installation at OHL.

For overhead secondary, OHL's standard is to install neutral supported triplex manufactured to CSA type designations as either NS75 or NS75.

4.1-Staff-16

Ref: E2/T5/S4 – DSP, Project Number B80-2013: Emma and Douglas Street Pole Line Replacement (Adobe p. 383) and Project Number B50-2011 (Adobe p. 352)

In the first reference OHL refers, in section C to "pole line is difficult to access for maintenance and repair." This relates to a project to replace 4kV distribution lines which cross the backyards, with underground 27.6kV cables.

a. Please expand upon the difficulties mentioned and how removal of backyard pole lines is likely to reduce maintenance and repair.

OHL's Response:

OHL would like to clarify that the *B80-2013: Emma and Douglas Street Pole Line Replacement* project does not involve any backyard pole line or voltage conversion.

OHL would like to clarify that the *B50-2011: Faulkner/Elizabeth St Conversion* project does not involve any backyard pole lines.

As mentioned in the response to 4.1-Staff-9 b) and in regards to backyard primary pole lines:

OHL would like to mention that during planned 4.16kV to 27.6kV voltage conversion projects, OHL does an assessment of the existing location of the primary voltage infrastructure. OHL looks to improve our distribution system in ways such as removing rear lot/backyard primary overhead lines. OHL feels strongly that primary 27.6kV voltage lines and transformers should not be located in residential backyards. During the planning process, OHL looks to locate the primary 27.6kV assets in accessible and acceptable locations for safety, reliability and maintenance purposes.

Additionally, the removal of rear lot/backyard primary overhead lines reduces OHL's future tree trimming requirements in those specific areas and reduces the expected repair and maintenance costs due to the relocation of the assets to more accessible and acceptable locations.

b. Please indicate in regard to removal of the backyard pole lines whether this is in response to customer consultation and preferences, and whether that consultation included awareness of the cost of the activity. Please provide details of customer consultations and methods.

OHL's Response:

OHL did not formally consult the customers for the mentioned projects.

c. Indicate how reduced maintenance and repair costs are reflected in the Operational costs.

OHL's Response:

Please refer to OHL's response to a.

4.1-Staff-17

Ref: E4/T5/S1, p. 1

OHL states that the 2012 capital cost for its new File Nexus system (total $38,400) has been shared with the municipalities. OHL further notes that it has increased the rate charged to the municipalities over a three year period to recover this capital cost.

a. Please state the amount that is being recovered from the municipalities.

OHL's Response:

The amount being recovered from the municipalities is $10,281.

b. Please explain how OHL customers are better served by this program and detail any savings due to efficiencies.

OHL's Response:

Customer Service

- Securely capture and archive customer information
- dramatically streamline new customer application process
- manage customer inquiries efficiently
- automate virtually any workflow requirement
- automatically link service orders to customer files

Savings due to efficiencies;

- time efficiency – allowing staff to spend more time on customer's needs
- reduce paper costs
- reduce purging costs
- reduce storage costs
- reduce environmental impact

c. Please state how customer feedback was incorporated in the decision to purchase the File Nexus system.

OHL's Response:

Customer feedback was not incorporated in the decision to purchase the FileNexus system as this was an internal process improvement giving customer service and other staff the ability to source information in a more efficient manner.

4.1-Energy Probe-8

Ref: Exhibit 2, Tab 5, Schedule 5

a. Does the distributor agree that system reliability has to be attained, or does it have to be maintained? Please explain fully.

OHL's Response:

OHL's mission is to provide safe, reliable, efficient delivery of electrical energy within the Town of Orangeville and the Town of Grand Valley while being accountable to our shareholders.....the citizens of Orangeville and Grand Valley. Therefore, OHL considers reliability a priority throughout all operational and planning processes.

b. How has the distributor determined that its distribution system plan will result in continuous improvement in productivity? Please explain fully.

OHL's Response:

- Continuation of best practices, conversion practices effective in providing sustainable and reliable, continuous improvement.
- Plan has been working
- Capital investment is decreasing as shown in the DSP
- Third party assessments agreed that OHL's planning process is acceptable

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?

OHL's Response:

OHL's mission is to provide safe, reliable, efficient delivery of electrical energy within the Town of Orangeville and the Town of Grand Valley while being accountable to our shareholders.....the citizens of Orangeville and Grand Valley. Therefore, OHL considers reliability a priority throughout all operational and planning processes. OHL believes that its current level of system reliability and quality is already high but is always striving to improve.

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?

OHL's Response:

4.1-SEC-12

Ref: Ex. 2

Does the Applicant expect that its proposed Test Year capital additions will result in continuous improvements in productivity? If so, can the Applicant quantify the improvements in productivity such as a reduction in current or future OM&A costs?

OHL's Response:

4.16kV – 27.6kV Voltage Conversion Projects:

OHL considers our long term 4.16kV – 27.6kV Voltage Conversion Program to result in long term continuous improvements in productivity. The conversion to a higher distribution voltage allows

OHL to provide our customers with the same amount of kWh consumption but with a decrease in line losses. This results in a long term continuous improvement in productivity. Also, the conversion to a higher voltage allows OHL to service more customers per asset. The higher distribution voltage allows OHL to reduce the required amount of individual distribution feeders, required conductor sizes and lengths, and the required pole heights to service the same amount of customers. Furthermore, the higher distribution voltage allows OHL to eliminate the requirement for distribution class substations. Therefore, our long term Voltage Conversion Program improves productivity because it allows OHL to serve our customers with less infrastructure and less assets.

Construction and Equipment/Inventory Standardization:

All of OHL's capital additions are constructed to the current construction standards and use OHL's standardized equipment. OHL will be able to reduce our inventory requirements as OHL eliminates non-standard installations, non-standard distribution equipment, non-standard metering equipment, 4.16kV equipment and our distribution substations for from our distribution system. The elimination of the mentioned items will allow OHL to reduce the quantity of unique inventory items. The reduction in inventory items will reduce OHL's inventory carrying costs as well as labour costs to manage the additional inventory items. Therefore, OHL's efforts regarding Construction and Equipment/Inventory Standardization will result in long term continuous improvements in productivity.

Please refer to IR 3.1-Staff-7 for improvements in productivity with the proposed capital additions for the General Plant.

OHL has not quantified the effects of the mention improvements.

4.1-SEC-13

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

Please provide an explanation of the phrase "reduce response requirements".

OHL's Response:

OHL works with the CHEC group to provide a single response on behalf of all group members to entities such as the OEB and EDA. This allows multiple utilities to share the regulatory costs and labour associated with regulatory activities.

4.1-SEC-14

Ref: Ex.1/3/1/C, p. 24

Please provide details of the lawsuit in Note 8.

OHL's Response:

Title of Proceedings: *72-74 Centennial Development Ltd. et al. v. Orangeville Hydro Limited*

In this suit, the three plaintiffs claim $800,000 in damages for unfair business practices, slander, malicious or injurious falsehood, intentional interference with economic relations, negligence, damages to business reputation, and inconvenience. The plaintiffs, which are commercial landlords, also seek several declarations related to Orangeville Hydro's ability to transfer accounts from commercial tenants to landlords and the connection and disconnection of electricity service.

The parties have completed discoveries, and the current status of the matter is that it is set for trial in June of 2014.

4.1–VECC–8

Ref: Exhibit 2, Tab 5, Schedule 5 – Distribution System Plan

Please explain what metrics (reliability targets etc.) or other objectives that OHL is using to assess the success of business 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.

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-18

Ref: E2/T5/S4, pp. 42-45, tables 20 and 21 (Adobe p. 292-295) and 53-56, tables 29 and 30 (Adobe 303-306)

OHL's DSP shows a significant conversion of OHL's distribution system from overhead to an underground system. OHL states that one of the drivers for this conversion is the reduction of maintenance costs and increased reliability.

On pages 42-45 and 53-56 of the DSP, OHL provides tables 20, 21, 29 and 30 which show historical (2009-2013) and forecast (2014-2018) operating and maintenance expenses. The table below is derived from excerpts of those O&M tables (rows 6-8 of table 20 and 29 and rows 7-9 in tables 21 and 30) and calculates the changes in operational expenditures over the historic and forecast period. Board staff notes increases in both the historic and forecasted period.

Operation and Maintenance expenses

	2009	2013	2009-2013 % increase	2014	2018	2014-2018 % Increase	2013-2014 % Increase
Overhead Operating	10,971	16,236	48	19,577	23,796	22	21
Overhead Maintenance	187,815	234,679	25	265,044	322,162	22	13
Overhead O&M	198,786	250,915	26	250,915	284,621	22	13
Underground Operating	1,276	9,280	627	9,965	12,113	22	7
Underground Maintenance	65,113	97,094	50	118,608	144,169	22	22
Underground O&M	66,389	106,374	60	128,573	156282	22	21

a. How was the projection of expenditures for the next five years arrived at?

OHL's Response:

These specific expenditure projections were arrived at through reviewing the 2009-2013 expenditures and applying a simple linear projection.

b. Please provide the rationale for the increase in underground O&M and overhead O&M.

OHL's Response:

As mentioned in OHL's response to question a OHL applied a simple linear projection to provide the five year outlook.

c. Please list operational efficiencies achieved through the conversion project and explain why overhead O&M continues to increase rather than showing a decline as OHL continues to convert its system an underground distribution system.

OHL's Response:

OHL is concerned about the Staff's opinion that "*OHL's DSP shows a significant conversion of OHL's distribution system from overhead to an underground system.*"

OHL would like to clarify that the majority of the "conversion projects" refer to the conversion of our legacy 4.16kV system to the 27.6kV system. OHL does not have intentions to convert our entire overhead distribution system to an underground distribution system. OHL apologizes if the DSP or Project descriptions provide the impression that OHL is actively completing projects for the sole purpose of an overhead to underground conversion.

OHL also explained this topic in our response to 4.1-Staff-9 b).

d. Please provide a detailed explanation of the increases of overhead and underground O&M from the 2013 bridge to the 2014 test year, as shown in the right hand column.

OHL's Response:

As mentioned in question a), OHL applied a simple linear projection to provide the five year outlook.

e. Please provide these costs on a unitized basis (i.e. per km).

OHL's Response:

Based on the above table, the unit costs are broken out by km per line in the table below:

	2009	2009 Unit Cost per KM	Cost per KM	2013	2013 Unit Cost per KM	Cost per KM	2014	2014 Unit Cost per KM	Cost per KM	2018	2014 Unit Cost per KM	Cost per KM
Total Overhead O&M	198,786	102	$1,949	250,915	80	$3,136	250,915	80	$3,136	284,621	82	$3,471
Total Underground O&M	66,389	71	$935	106,374	124	$858	128,573	126	$1,020	156,282	136	$1,149

4.2-Staff-19

Ref: E4/T4/S1, Appendix 2-K

The applicant has proposed an approx. 5% increases in headcount and 8% in employee compensation for the Test year relative to the 2012 actual levels.

What objectives has the applicant established for its operations? Please provide more specific information on why the proposed cost increases are necessary for the applicant to achieve the objectives that the applicant has targeted in the capital and operating expenditures sections of tis application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed headcount and compensation increases.

OHL's Response:

OHL's main objective for its operations as stated in our mission statement is 'To continually provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders.....the citizens of Orangeville and Grand Valley.' The proposed cost increases are necessary to achieve our objectives to maintain a seamless transition of knowledge management while considering upcoming retirements of staff. Succession Planning is necessary due to the length of time to fully train competent personnel. An alternative method seriously considered was a merge with a neighbouring utility that would have reduced operating costs. This alternative was rejected by our shareholder. The merger discussions took place over the span of two years which resulted in OHL delaying the necessary increase in our staff complement.

4.2-Staff-20

With respect to Appendix 2-K, please explain the applicant's compensation strategy. Please explain why this strategy has resulted in a 19% increase in management and 24% increase in non-management compensation since last rebasing and how these increases are fundamental to the delivery of OHL's plans.

OHL's Response:

OHL has summarized the increases in management and non-management compensation and the components that attributed to the increase in the table below. Overall categories in the table below indicate the major driver of the compensation levels is the increase in benefits from 2010. As salaries increase, certain benefit premiums are based on salary which contributes to an increase in benefits. As part of the MEARIE Group's Employee Benefit Program in 2011 we saw a significant increase in life insurance premiums. The renewal premium is determined each year based on the actual experience of the reciprocal portfolio. An analysis is conducted using an experience-rating model which captures the premiums and claims results for the most recent 7.5 years. Over the past few years there has been an increase in claims activity under the program-driven by the underlying cost pressures associated with an aging industry workforce, coupled with an aging retiree portfolio. On an overall basis, the premium under the Basic Term Life plan increased 11%. This result reflects the average renewal requirement for the plan at-large. The actual premium increase for OHL taking into consideration our demographic risk profile was 20.2%. Extended Health Care also had a significant increase of 19%. OHL's plan experience was adverse. The utilization of our group was significantly in excess of other small groups within the MERAIE Group's portfolio. A review of OHL results shows a paid loss ratio – excluding expenses – of 109.2% for health benefits. Given these results, premium rate leaves for OHL increased 19% for health. While significant, this rate increase is well below the calculated increase that would be required based solely on our own results (57.9%) if we were not part of the MEARIE Group's Employee Benefit Program. While the rate changes vary by benefit, the total premium increase for 2012 for OHL was 9.5%. Overall, the renewal premiums levels were favourable and competitive based on the financial experience and prevailing trends in benefit-related expenditures. In the Management compensation category, there was an increase in salary based on the CPI that averaged 2.44% over the 4 year period, an increase in salary to coincide with progression of a management salary range level and an increase pertaining a taxable benefit for personal use of company vehicles that should not have been included in the compensation amount. OHL removed the taxable benefit amount from Appendix 2-K. The non-management category consists of non-union and union components. The non-union category main driver is the salary progression in harmony with OHL's plan to maintain knowledge management and prepare for succession. These increases are fundamental to the delivery of OHL's plans for succession planning to remain competitive with other utilities, in order to retain staff for the long term, and to prepare and mentor the non-management staff.

Union wage increases as part of the collective agreement negotiations are relative to other utilities and benefit OHL by a healthy working relationship and connect with OHL's strategies within our workplace. The addition of the apprentice lineman also contributes to OHL's strategy to maintain trained staff prior to the retirement of a lineman that will potentially retire in 2015 and preserve a safe working environment. Union salary grade progressions increased due to 2009 and 2010 new hires that progressed up to their levels in the collective agreement framework. Employee morale and motivation are key to success as studies have shown that increases in job stress and low morale lead to higher rates of absenteeism and turnover as well as lower productivity. Maintaining a positive relationship with any workforce will provide benefits for both the employee and the company.

	2010 Board Approved	2014 Test Year	Variance	Variance %
Total Management Compensation	$ 557,850	$ 666,354	$ 108,504	19%
Salary Increases per CPI	**433,041**	$ 474,092	$ 41,051	7%
Incentive Bonuses	29,500	46,816	17,316	3%
Taxable Benefit Personal Vehicle		12,898	12,898	2%
VP Salary Grade Progression		$ 8,078	$ 8,078	1%
Benefits	$ 95,309	$ 124,470	$ 29,161	5%
Total		$ 666,354	$ 108,504	19%
Total Non-Management Compensation	$ 1,282,518	$ 1,591,534	$ 309,016	24%
Salary Increases per CPI	248,410	275,798	27,388	2%
Salary Grade Progression		$ 39,549	$ 39,549	3%
Wage Increases per Union Contract	$ 771,553	$ 864,539	$ 92,986	7%
Staff Addition Apprentice		47,340	47,340	4%
Progression of Salary Grades		$ 20,189	$ 20,189	2%
Benefits	$ 262,554	$ 344,120	$ 81,566	6%
Total	1,282,518	1,591,534	$ 309,016	24%

As referred to above, OHL removed the taxable benefit for personal use of vehicles included in the compensation total, therefore we have revised Appendix K below:

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	4.0	4.0	4.0	4.0	4.0	4.0
Non-Management (union and non-union)	16.0	15.5	16.0	16.0	17.0	17.0
Total	20.0	19.5	20.0	20.0	21.0	21.0
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 462,541	$ 459,928	$ 484,753	$ 502,111	$ 514,172	$ 528,987
Non-Management (union and non-union)	$ 1,019,964	$ 1,013,402	$ 1,101,787	$ 1,180,393	$ 1,210,685	$ 1,247,414
Total	$ 1,482,505	$ 1,473,330	$ 1,586,540	$ 1,682,504	$ 1,724,857	$ 1,776,401
Total Benefits (Current + Accrued)						
Management (including executive)	$ 95,309	$ 91,677	$ 100,793	$ 114,248	$ 122,101	$ 124,470
Non-Management (union and non-union)	$ 262,554	$ 221,628	$ 241,187	$ 285,902	$ 327,380	$ 344,120
Total	$ 357,863	$ 313,305	$ 341,980	$ 400,150	$ 449,481	$ 468,590
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 557,850	$ 551,605	$ 585,546	$ 616,359	$ 636,273	$ 653,456
Non-Management (union and non-union)	$ 1,282,518	$ 1,235,030	$ 1,342,974	$ 1,466,295	$ 1,538,066	$ 1,591,534
Total	$ 1,840,368	$ 1,786,635	$ 1,928,520	$ 2,082,655	$ 2,174,338	$ 2,244,990

4.2-Staff-21

Ref: E4/T2/S1, pp. 1-2

On page 1, OHL states that in 2005 it implemented a new Management Performance & Compensation Plan for all salaried employees. OHL noted that the plan was developed with the assistance of an outside consulting firm, Pearson & Associates and that pay market data was collected from Ontario's LDC's.

a. Please describe the external comparators in more detail.

OHL's Response:

Pearson & Associates compared 12 utilities of similar size and OHL used the average.

b. Has OHL updated this data since 2005? If yes, please state how this data has impacted on what is proposed in the application. If not, please explain why not.

OHL's Response:

OHL has not updated this data, however OHL does keep abreast of the MEARIE Survey and continues to compare compensation levels from the survey.

4.2-Staff-22

Ref: E4/T2/S1, Appendix 2-JB

For the 2013 bridge year OHL shows a cost driver of $159,096 titled Change in cost of Materials/Supplies, which is 5% of the overall OM&A budget and a 177% increase since 2012 actual. Please provide a breakdown of this expense. Please provide the rationale for this increase and state how OHL customers are better served by this expenditure. For any unit cost increases, please explain OHL's costs with reference to the capital portion of the industry specific inflation index. Please explain the procurement practices that Orangeville employs for these materials and their relation to the expense increase, including expected economies of purchasing at scale.

OHL's Response:

The cost driver, "Change in Materials/Supplies" included costs not only materials and supplies but also administration costs. OHL has broken out these costs and are shown in the table below with the total change in each category. The prepaid expenses were grouped in the Miscellaneous Cost driver category and OHL moved these expenses into another subaccount in 2013 and were included in the "Change in Materials/Supplies". Please note that there is a decrease in the Miscellaneous Costs cost driver, which offsets the increase to the change in materials/supplies costs. Other drivers in this category were training and conferences that were budgeted at a higher amount than actuals, due to succession planning and knowledge management. In the employee engagement category there is miscellaneous safety costs included in budgeted costs, which were not in actuals. The school programs are budgeted within the administration category and some of the actual costs were included within the contractor cost driver category, which is the reason for the difference. Safety equipment was budgeted for in 2013, but was not included in 2012 actual costs. There was an overall inflationary increase in the general business expenses, which included costs such as postage, communications, meals, mileage, stationary, etc. The expected future employee benefits costs increased in 2013 over 2012.
The amount of $52,820 was actually the increase in materials and supplies forecasted for 2013. As explained above, the cost driver amount in this category does not specifically have anything to do with our procurement practices.

Category	Total Change
Prepaids	55,420.03
Training and Conferences	18,478.30
Vehicle Costs	10,695.00
Employee Engagement	7,779.52
School Programs	3,967.62
Safety Equipment	3,631.36
General Business Expenses	3,436.22
Employee Future Benefits	2,867.50
Total	**106,275.55**
Change in cost of materials and suppli	52,820.83

4.2-Staff-23

Ref: E4/T3/S1, pp 9-10 and 14, Appendix 2-JC

In Appendix 2-JC, OHL shows a significant increase of 22.8% in Administrative Expenses, mainly in Labor and Benefits and Administration over 2012 actual. This accounts for a $263,060 or 66.4% of total OM&A increases over 2012 actual and 41.7% of total OM&A increases over 2010 board-approved.

a. Please provide the rationale for this increase and how OHL's customers are better served by this increase in administrative costs.

OHL's Response:

Cost Driver	How Customers are better served
Labour and Benefits/Training and Conferences	Increases relating to labour and benefits are the result of succession planning and retaining our future knowledge base. The increased training and conference costs are necessary to ensure staff are qualified to meet the customers needs. Customers benefit by the utility being managed through a reliable and organized structure.
Safety Labour Costs/Safety Costs	These costs were the result of the transition to new accounting policies, by removing general overheads from capital.
File Nexus	This software allows employees to quickly archive and retrieve customer information, providing them with additional time to provide exceptional customer service.
Cyber Insurance/Insurance Increases	Cyber Insurance mitigates the risk of loss due to security attacks and cyber breaches. The customer benefits by OHL being prudent as it reduces the risk of financial loss.

b. What factors were taken into consideration which leads to the increase in this program?

OHL's Response:

Cost Driver	Factors
Labour and Benefits/Training and Conferences	OHL needs to replace three executive management positions due to upcoming retirements. The costs to hire experienced executives outweigh the costs to train and mentor existing staff. OHL strives to maintain well trained and knowledgeable staff.
Safety Labour Costs/Safety Costs	Safety costs were a change in accounting policy, therefore no factors were considered.
File Nexus	To improve customer service response time and increase staff productivity by retrieving information instantaneously. A reduction in paper resulting in lower paper and printing costs.
Cyber Insurance/Insurance Increases	Higher use of technology creates increased vulnerability to cyber security threats. This can result in a security breach creating losses in the millions of dollars. Productivity would be reduced, as time and effort would take place to fix the cause, as well as legal expenses.

c. What alternatives were examined to deliver on these goals? Please explain this increase and how it exemplifies continuous improvement in productivity.

OHL's Response:

Cost Driver	Alternatives
Labour and Benefits/Training and Conferences	OHL considered hiring experienced external personnel with utility background. This would potentially increase costs. Long term staff create continuity to ensure a seamless transition over the longer term.
Safety Labour Costs/Safety Costs	Safety costs were a change in accounting policy, therefore no alternatives were considered.
File Nexus	Implementing the software without the collaboration of UCS would have increased overall costs to the customer.
Cyber Insurance/Insurance Increases	OHL felt that there were no alternatives, as this cost was necessary to reduce our risk exposure.

4.2-Staff-24

Ref: E4/T1/S1, pp. 2-3

On page 4 OHL states that Billing and Collecting, Community Relations, Administrative and

General increases account for 18% of the total increase of 30%. OHL further noted that it has implemented a File Nexus filing system.

a. Please identify the billing frequency that the applicant is planning on using for the test period and beyond. Please explain how the File Nexus filing system has impacted OHL's billing system.

OHL's Response:

OHL's billing frequency is monthly. The File Nexus "Document Management System" has only affected OHL's billing system by serving mission critical document management, workflow, archival and business continuity needs. No paper, no microfilm, no logging into multiple applications – everything instantly available with the click of a mouse. This allows for efficiencies when accessing information relating directly to a customer's account. It enables staff to search for documentation, reports, that are tied to specific criteria set up as identifiers, i.e. address, customer account, customer number.

b. If the applicant is planning to implement monthly billing, please refer to parts c) through g) below. If not, please explain why not.

OHL's Response:

OHL's billing frequency is monthly.

c. Please identify any impacts that the implementation of monthly billing has had on billing and collection expenses or any other OM&A category.

OHL's Response:

Please refer to OHL's response to **4.2-Staff-24 a. and b.**

d. Please identify the percentage of customers on e-billing as of December 31, 2013.

OHL's Response:

As of December 31, 2013, OHL has zero percentage of customers on e-billing.

e. Please describe the Applicant's efforts to promote e-billing to its customers.

OHL's Response:

Currently OHL is unable to offer e-billing to our customers and therefore we currently are not promoting e-billing to our customers.

f. Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

OHL's Response:

Please refer to OHL's response to **4.2-Staff-24 a. and b.**

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?

OHL's Response:

Please refer to OHL's response to **4.2-Staff-24 a. and b.**

4.2-Energy Probe-9

Ref: Exhibit 4, Tab 2, Schedule 1

Please explain how the changes shown in Appendix2-L for each of the following illustrates continuous improvement in cost performance between actual 2010 and forecast 2014:

a. OM&A cost per customer;

OHL's Response:

Please refer to 3.1-Staff-7 and 3.1-Staff-8.

b. customers per FTE; and

OHL's Response:

Please refer to 3.1-Staff-7 and 3.1-Staff-8.

c. OM&A cost per FTE.

OHL's Response:

Please refer to 3.1-Staff-7 and 3.1-Staff-8.

4.2-Energy Probe-10

Ref: Exhibit 4, Tab 4, Schedule 1

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.

OHL's Response:

	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Actual Bonus Payments	29,885	43,412	53,028	52,097	46,816

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.

OHL's Response:

	2010 Potential	2011 Potential	2012 Potential	2013 Potential	2014 Potential
Potential Bonus Payments	29,500	38,916	40,206	41,097	46,816

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.

OHL's Response:

	2010	2011	2012	2013	2014
Ratio of Actual to Potential	1%	10%	24%	21%	0%

4.2-Energy Probe-11

Ref: Exhibit 4, Tab 4, Schedules 1 & 3

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 4.2 that shows the distributors contributions to OMERS in one line and the contribution of all employees in aggregate to OMERS in a separate line.

OHL's Response:

Yes, the premiums paid by the distributor to OMERS equal to the employee contributions to OMERS.

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.

OHL's Response:

No, there have not been any changes in post-retirement benefits since the 2010 cost of service application.

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.

OHL's Response:

No, there have not been any changes in the benefits provided to employees since the 2010 cost of service application.

4.2-Energy Probe-12

Ref: Exhibit 4, Tab 1, Schedule 1

The current collective agreement expired on September 30, 2013. Has a new collective agreement been reached? If yes, please provide details and compare the new agreement with the forecast assumptions used in forecasting the 2014 wages, salaries and benefit costs.

OHL's Response:

The current collective agreement expires on September 30, 2014.

4.2-Energy Probe-13

Ref: Exhibit 4, Tab 1, Schedule 1

a. What inflation rate did OHL use for the general OM&A expenses?

OHL's Response:

OHL used 2% inflation rate on certain general OM&A expenses that were expected to increase on this basis.

b. What is the dollar impact in 2014 of the 3% assumption used for union wages?

OHL's Response:

The dollar impact of the 3% assumption used for union wages in 2014 is $23,029.

c. What CPI assumption did OHL use for the 2013 and 2014 forecast of management increases?

OHL's Response:

OHL used an average of 3% for 2013 and 2014 management salary increases. OHL used an average of 6% for 2013 non-union salary increases, and an average of 5% for 2013 non-union salary increases.

d. What is the corresponding dollar impact in each of 2013 and 2014 of the CPI forecasts used in (c) above?

OHL's Response:

The total dollar impact for 2013 is $31,895 and for 2014 is $30,402.

e. When did the Board of Directors approve the forecasts included in the cost of service application?

OHL's Response:

The OHL Board of Directors approved the budget for the purpose of the 2014 rate application on July 15, 2013.

f. When is the upcoming retirement, noted on page 2 at line 22, expected to occur?

OHL's Response:

One lineman is eligible to retire in 2015.

4.2-Energy Probe-14

Ref: Exhibit 4, Tab 1, Schedule 1

a. In addition to the meter reading and billing cost changes associated with smart meters, what are the operations and maintenance costs changes associated with the smart meters between 2010 and 2014? Please provide a table similar to Table 4.1 that shows the operations and maintenance costs changes due to smart meters.

OHL's Response:

	2010	2011	2012	2013
Incremental Labour due to smart meters	32,620	26,320	21,224	29,761
Smart Meter 1556 costs	-	-	21,471	-
Total	**32,620**	**26,320**	**42,695**	**29,761**

OHL analyzed the meter, operations and maintenance costs and found that incremental increases in costs were mainly due to the role that Engineering now has with regards to monitoring the smart meter system.

b. Prior to the beginning of the changeover to smart meters, what was the average annual cost associated with the repair, operation and maintenance of meters?

OHL's Response:

The average annual cost associated with the repair, operation and maintenance of meters over the previous 5 historical years was $86,035.

4.2-Energy Probe-15

Ref: Exhibit 4, Tab 2, Schedule 1

a. Please update Appendix 2-JA to reflect the most recent year-to-date information in 2013 available along with a forecast for the remaining months in 2013, if necessary.

OHL's Response:

OHL has updated Appendix-2-JA with total OM&A costs of $3,276,365. Please see OHL's response in 4.2-Staff-25 for the updated appendix. OHL is confident that this amount will be very close to actual amount for 2013.

b. Please provide a table in the same level of detail as shown in Appendix 2-JA that shows the most recent year-to-date actuals for 2013 as are currently available, along with the corresponding figures for the same period in 2012.

OHL's Response:

4.2-Energy Probe-16

Ref: Exhibit 4, Tab 2, Schedule 3 &
Exhibit 4, Tab 2, Schedule 1

a. Are the one-time costs for 2013 shown in Appendix 2-M that total $21,317 included in the 2013 forecast of costs shown in Appendix 2-JA?

OHL's Response:

No, these one-time costs were not included in the 2013 forecast of costs shown in Appendix2-JA. The costs shown in Appendix 2-M for 2013 were strictly for the 2014 rate application costs and were not included in the 2010 revenue requirement.

b. If the response to part (a) is yes, why isn't this double counting of this component of the one-time cost in 2013 and one-fifth of it in 2014?

OHL's Response:

N/A.

c. Please reconcile the figures in Appendix 2-M (One Time Costs) and the 5 year amortization of the costs with the figures shown in the 2014 column of Appendix 2-M (Regulatory Cost Schedule) for each of the costs shown in the One Time Costs table.

OHL's Response:

OHL has revised Appendix 2-M (one Time costs) as shown below.

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2010 Board Approved)	Most Current Actuals Year 2012	2013 Bridge Year	Annual % Change	2014 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	H) = [(G)-(F)]/(F	(I)	J) = [(I)-(G)]/(G
1	OEB Annual Assessment	5655	$ 46,429	On-Going	$ 32,897	$ 31,106	$ 36,000	15.73%	$ 33,660	-6.50%
2	OEB Section 30 Costs (Applicant-originated)			On-Going						
3	OEB Section 30 Costs (OEB-initiated)	5655	$ 46,429	On-Going	$ 1,955	$ 14	$ 1,955	13834.43%	$ 1,994	2.00%
4	Expert Witness costs for regulatory matters			One-Time	$ 5,000	$ -				
5	Legal costs for regulatory matters			On-Going					$ 6,000	
6	Legal costs for rate application	5630	$ 206,111	One-Time	$ 10,000	$ 53,965		-100.00%	$ 5,600	
7	Consultants' costs for regulatory matters	5630	$ 206,111	One-Time	$ 50,000	$ 2,638		-100.00%	$ 10,400	
8	Operating expenses associated with staff resources allocated to regulatory matters	5615		On-Going	$ 100,000	$ 92,849	$ 99,623	7.30%	$ 102,130	2.52%
9	Operating expenses associated with other resources allocated to regulatory matters [1]	5655	$ 46,429	On-Going		$ 3,429		-100.00%		
10	Other regulatory agency fees or assessments	5655	$ 46,429	On-Going		$ 6,508		-100.00%		
11	Any other costs for regulatory matters (please define)	5610		On-Going		$ 25,619	$ 26,799	4.61%	$ 27,543	2.78%
12	Intervenor costs	5655	$ 46,429	One-Time	$ 48,045	$ 5,372		-100.00%	$ 8,000	
13	Sub-total - Ongoing Costs		$ 185,715		$ 134,852	$ 159,524	$ 164,377	3.04%	$ 171,327	4.23%
14	Sub-total - One-time Costs [4]		$ 458,651		$ 113,045	$ 61,974	$ -	-100.00%	$ 24,000	
15	Total		$ 644,366		$ 247,897	$ 221,499	$ 164,377	-25.79%	$ 195,327	18.83%

4.2-Energy Probe-17

Ref: Exhibit 4, Tab 3, Schedule 2

The evidence on pages 5-6 indicate that some of the 2012 increase in smart meter related costs were the result of the transfer of account 1556 balances to the appropriate OM&A accounts.

a. Please confirm that this transfer was the result of the Board's decision in the smart meter disposition application in EB-2012-0039.

OHL's Response:

Yes, OHL confirms that this transfer was the result of the Board's decision in the smart meter disposition application in EB-2012-0039.

b. Please provide the amount transferred from account 1556 to the OM&A accounts in 2012.

OHL's Response:

The total amount transferred from account 1556 to the OM&A accounts in 2012 was $52,265.

c. Please disaggregate the amount in part (b) into the amount incurred in each of 2009, 2010, 2011 and 2012.

OHL's Response:

Please see table below noting the expenses as at May 30, 2012 that were transferred to the OM&A accounts. There were additional smart meter expenses incurred in 2012 after the transfer was completed of $71,041 that are not included in the total below.

Smart meter OM&A expenses transferred		
Year		Amount
2009	$	2,458
2010	$	40,979
2011	$	79,145
2012	$	52,265
	$	174,847

4.2-Energy Probe-18

Ref: Exhibit 4, Tab 3, Schedule 1, page 8

The evidence indicates that the distributor bills all customers monthly and issues approximately 140,000 bills annually. Please provide the average number of customers (not connections) by rate class in each of 2012, 2013 and 2014, based on the most recent information available for 2013.

OHL's Response:

	Residential	GS < 50 kW	GS > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2012	10,085	1,108	127	5	40	32	11,397
2013	10,202	1,127	125	5	37	32	11,528
2014	10,322	1,144	123	5	36	32	11,663

4.2-SEC-15

Ref: Ex. 1/1/7, p. 1

Please reconcile the "Payroll & Benefits" cost increase on the second table with the figures in Appendix 2-K [Ex. 4/4/1, p. 2]. If the sole reason for the difference is employees allocated to capital projects, please add a line to the 2-K showing the portion of total compensation allocated to capital for each year.

OHL's Response:

SEC is correct stating that the sole reason for the difference "Payroll & Benefits" cost increase on the second table with the figures in Appendix 2-K and Exhibit 1, Tab 1, Schedule 7 is due to employees allocated to capital projects. OHL has revised Appendix 2-K for the portion of total compensation allocated to capital each year.

Appendix 2-K Employee Costs						
	Last Rebasing Year - 2010 - Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	4.0	4.0	4.0	4.0	4.0	4.0
Non-Management (union and non-union)	16.0	15.5	16.0	16.0	17.0	17.0
Total	20.0	19.5	20.0	20.0	21.0	21.0
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 462,541	$ 466,637	$ 493,825	$ 511,026	$ 523,087	$ 541,884
Non-Management (union and non-union)	$ 1,019,964	$ 1,013,402	$ 1,101,787	$ 1,180,393	$ 1,210,685	$ 1,247,414
Total	$ 1,482,505	$ 1,480,039	$ 1,595,612	$ 1,691,419	$ 1,733,772	$ 1,789,298
Total Benefits (Current + Accrued)						
Management (including executive)	$ 95,309	$ 91,677	$ 100,793	$ 114,248	$ 122,101	$ 124,470
Non-Management (union and non-union)	$ 262,554	$ 221,628	$ 241,187	$ 285,902	$ 327,380	$ 344,120
Total	$ 357,863	$ 313,305	$ 341,980	$ 400,150	$ 449,481	$ 468,590
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 557,850	$ 558,314	$ 594,618	$ 625,274	$ 645,188	$ 666,354
Non-Management (union and non-union)	$ 1,282,518	$ 1,235,030	$ 1,342,974	$ 1,466,295	$ 1,538,066	$ 1,591,534
Total	$ 1,840,368	$ 1,793,344	$ 1,937,592	$ 2,091,569	$ 2,183,253	$ 2,257,888
Capital labour	$123,648	$189,863	$156,158	$185,720	$94,568	$101,292
Total Compensation Less Capital	$ 1,716,720	$ 1,603,480	$ 1,781,434	$ 1,905,849	$ 2,088,685	$ 2,156,596
Difference between 2010 BA & 2014 Test						$ 439,876

	Total in Exhibit 1, Tab 1, Schedule 7	Total Per Interrogatory
Payroll & Benefits	388,028	362,899
Apprentice	63,614	63,614
Total	451,642	426,513
Difference between 2010 BA & 2014 Test	**417,520**	**439,876**

The amount used in the Exhibit 1, Tab 1, Schedule 7 should have been lower.

4.2-SEC-16

Please detail the objectives has the Applicant set for its OM&A activities.

OHL's Response:

Please refer to 4.2-Staff-19

4.2-SEC-17

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

Please provide a copy of the current collective agreement, together with a brief summary of its key terms.

OHL's Response:

Please refer to: Appendix E – 2010 – 2014 Collective Agreement
Appendix F – 2010 – 2014 Collective Agreement Summary.

4.2-SEC-18

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

Please confirm that employees who achieve a professional designation are promoted to the level of manager whether or not their duties will involve management or supervision of others, or even whether or not their duties will change at all.

OHL's Response:

OHL does not confirm that employees who achieve a professional designation are promoted to the level of manager. However those who are promoted to a manager level have some changes in duties and responsibilities as they achieve more expertise. The duties of these employees do involve management or supervision of others.

4.2-SEC-19

Ref: Ex.4/1/1/p.3

Please advise whether four years is a typical length of time to progress to the top level for a position. If it is not, please estimate the typical length of time.

OHL's Response:

Every position is different and the progress rate would depend on the position and upon the individual's performance.

4.2–VECC–9

Ref: Exhibit 1, Tab 1, Schedule 7, pg. 2.

Please identify the incremental expenses since 2010 for infrared patrolling that were previously capitalized.

OHL's Response:

OHL would like to clarify that infrared patrolling expenses were not capitalized since 2010.

4.2–VECC–10

Ref: Exhibit 4, Tab 1, Schedule 1, pg.3

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.

OHL's Response:

Please see table below for cost components of Billing and Collection accounts, 5305, 5310, 5315, 5320, and 5335. OHL does not budget for accounts 5325 and 5340, nor are the balances in these accounts significant.

5305 By Cost Element	**2010 Board Approved**	**2010 Actual**	**2014 Forecast**	**2010 Board Approved to 2014 Forecast**	**Variance**
Labour & Benefits	26,093	23,874	40,992	14,900	57%
5310 By Cost Element	**2010 Board Approved**	**2010 Actual**	**2014 Forecast**	**2010 Board Approved to 2014 Forecast**	
Labour & Benefits	6,984	7,121	1,846	(5,138)	-74%
Vehicles	1,920	1,555	480	(1,440)	-75%
Meter Reading	101,150	82,572	44,569	(56,581)	-56%
CIS Operating Costs	4,922	3,707	3,917	(1,006)	-20%
ODS	-	-	20,808	20,808	100%
Security Audit	-	-	7,000	7,000	100%
TGB	-	-	67,320	67,320	100%
Total	**114,976**	**94,956**	**145,940**	**30,963**	**27%**
5315 By Cost Element	**2010 Board Approved**	**2010 Actual**	**2014 Forecast**	**2010 Board Approved to 2014 Forecast**	**Variance**
Labour & Benefits	99,833	113,203	134,666	34,833	35%
Retailer Settlement	20,505	25,149	18,665	(1,839)	-9%
Postage	38,160	46,784	49,266	11,106	29%
Training & Conferences	8,726	5,552	11,699	2,973	34%
Stationery & Supplies	9,191	8,615	4,774	(4,417)	-48%
CIS Hosting Services		5,827	6,371	6,371	100%
Customer Connect			23,807	23,807	100%
Sync Operator			31,858	31,858	100%
CIS Security Framework			7,000	7,000	100%
Automailer	2,054	2,404	2,379	325	16%
CIS Operating Costs	49,943	28,516	51,864	1,921	4%
Legal		1,761		-	
Total	**228,412**	**237,811**	**342,350**	**113,937**	**50%**
5320 By Cost Element	**2010 Board Approved**	**2010 Actual**	**2014 Forecast**	**2010 Board Approved to 2014 Forecast**	**Variance**
Labour & Benefits	97,992	94,338	113,565	15,572	16%
Vehicles	14,340	6,141	11,860	(2,480)	-17%
Postage	9,933	10,494	12,531	2,598	26%
Stationery	912	2,239	2,687	1,775	195%
Training	900	1,289	1,677	777	86%
Bank Charges	7,283	6,694	8,647	1,364	19%
Legal costs	3,000	4,943	5,100	2,100	70%
Notice Delivery	10,294	6,736	12,240	1,946	19%
Automailer	351	363	433	82	23%
CIS Operating Costs	15,467	10,543	11,826	(3,641)	-24%
Total	**160,472**	**143,781**	**180,565**	**20,093**	**13%**
5335 By Cost Element	**2010 Board Approved**	**2010 Actual**	**2014 Forecast**	**2010 Board Approved to 2014 Forecast**	**Variance**
Bad Debt Write Offs	20,000	22,545	35,000	15,000	75%

b. Please compare and contrast the components of actuals 5315 Billing for 2010 actuals as compared to 2014 forecast costs.

OHL's Response:

5315 By Cost Element	2010 Board Approved	2010 Actual	2014 Forecast	2010 Actuals to 2014 Forecast	Variance
Labour & Benefits	99,833	113,203	134,666	21,463	19%
Retailer Settlement	20,505	25,149	18,665	(6,484)	-26%
Postage	38,160	46,784	49,266	2,482	5%
Training & Conferences	8,726	5,552	11,699	6,148	111%
Stationery & Supplies	9,191	8,615	4,774	(3,841)	-45%
CIS Hosting Services		5,827	6,371	544	9%
Customer Connect			23,807	23,807	100%
Sync Operator			31,858	31,858	100%
CIS Security Framework			7,000	7,000	100%
Automailer	2,054	2,404	2,379	(25)	-1%
CIS Operating Costs	49,943	28,516	51,864	23,348	82%
Legal		1,761		(1,761)	-100%
Total	**228,412**	**237,811**	**342,350**	**104,539**	**44%**

The main driver of the increases in account 5315 Billing between 2010 actuals to 2014 forecast costs are mainly due to regulatory requirements for Customer Connect/Web Presentment, Smart Meter Sync Operator, and CIS Security Framework. The CIS Operating costs have also increased, mainly due to the implementation of Teleworks, which was an automated calling tool that was required to comply with the regulation to call all customers in arrears prior to disconnection.

4.2–VECC-11

Ref: Exhibit 1, Tab 1, Schedule 6, pgs.1-2
Exhibit 4, Tab 1, Schedule 1

Please provide the annual CPI rates provided by MEARIE for 2010 through 2014.

OHL's Response:

The CPI rates provide by MEARIE are the same CPI rates provided by Stats Canada. MEARIE provides monthly updates and provides the updates usually a few months after the fact. Orangeville Hydro uses the Ontario CPI as provided. The closest 12 months that information is available for is used – not by calendar year.

CONSUMER PRICE INDEX (Canada))Monthy & Yearly Change: Time Base: 2002=100

MONTH	2010	Increase for Month		Increase over 2009		2009	Increase for Month		Increase over 2008		2008
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	115.1	0.3	0.3	2.1	1.9	113	-0.3	-0.3	1.2	1.1	111.8
February	115.6	0.5	0.4	1.8	1.6	113.8	0.8	0.7	1.6	1.4	112.2
March	115.6	0	0	1.6	1.4	114	0.2	0.2	1.4	1.2	112.6
April	116	0.4	0.3	2.1	1.8	113.9	-0.1	-0.1	0.4	0.4	113.5
May	116.3	0.3	0.3	1.6	1.4	114.7	0.8	0.7	0.1	0.1	114.6
June	116.2	-0.1	-0.1	1.1	1	115.1	0.4	0.3	-0.3	-0.3	115.4
July	116.8	0.6	0.5	2.1	1.8	114.7	-0.4	-0.3	-1.1	-0.9	115.8
August	116.7	-0.1	-0.1	2	1.7	114.7	0	0	-0.9	-0.8	115.6
September	116.9	0.2	0.2	2.2	1.9	114.7	0	0	1	-0.9	115.7
October	117.4	0.5	0.4	2.8	2.4	114.6	-0.1	-0.1	0.1	0.1	114.5
November	117.5	0.1	0.1	2.3	2	115.2	0.6	0.5	1.1	1	114.1
December	117.5	0	0	2.7	2.4	114.8	-0.4	-0.3	1.5	1.3	113.3
Annual Average	**116.5**					**114.4**					**114.1**

CONSUMER PRICE INDEX (Ontario)Monthy & Yearly Change: Time Base: 2002=100

MONTH	2010	Increase for Month		Increase over 2009		2009	Increase for Month		Increase over 2008		2008
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	114.5	0.4	0.4	2.1	1.9	112.4	-0.4	-0.4	1.5	1.4	110.9
February	115.1	0.6	0.5	2	1.8	113.1	0.7	0.6	1.7	1.5	111.4
March	115.3	0.2	0.2	1.6	1.4	113.7	0.6	0.5	2	1.8	111.7
April	115.7	0.4	0.3	2.5	2.2	113.2	-0.5	-0.4	0.7	0.6	112.5
May	116.2	0.5	0.4	2.2	1.9	114	0.8	0.7	0.4	0.4	113.6
June	116	-0.2	-0.2	1.8	1.6	114.2	0.2	0.2	0	0	114.2
July	117	1	0.9	3.3	2.9	113.7	-0.5	-0.4	-1.4	-1.2	115.1
August	117	0	0	3.3	2.9	113.7	0	0	-1.1	-1	114.8
September	117.1	0.1	0.1	3.3	2.9	113.8	0.1	0.1	-1.3	-1.1	115.1
October	117.8	0.7	0.6	3.9	3.4	113.9	0.1	0.1	0.2	0.2	113.7
November	118	0.2	0.2	3.4	3	114.6	0.7	0.6	1.1	1	113.5
December	117.9	-0.1	-0.1	3.8	3.3	114.1	-0.5	-0.4	1.3	1.2	112.8
Annual Average	**116.5**					**113.7**					**113.3**

CONSUMER PRICE INDEX (Toronto)Monthy & Yearly Change: Time Base: 2002=100

MONTH	2010	Increase for Month		Increase over 2009		2009	Increase for Month		Increase over 2008		2008
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	114.5	0.6	0.5	2	1.8	112.5	-0.5	-0.4	1.8	1.6	110.7
February	115.1	0.6	0.5	1.9	1.7	113.2	0.7	0.6	1.9	1.7	111.3
March	115.3	0.2	0.2	1.5	1.3	113.8	0.6	0.5	2.3	2.1	111.5
April	115.8	0.5	0.4	2.7	2.4	113.1	-0.7	-0.6	0.9	0.8	112.2
May	116.3	0.5	0.4	2.4	2.1	113.9	0.8	0.7	0.6	0.5	113.3
June	116.1	-0.1	-0.2	2.1	1.8	114	0.1	0.1	0.2	0.2	113.8
July	117.1	1	0.9	3.5	3.1	113.6	-0.4	-0.4	-1.3	-1.1	114.9
August	117.1	0	0	3.5	3.1	113.6	0	0	-1.1	-1	114.7
September	117.3	0.2	0.2	3.6	3.2	113.7	0.1	0.1	-1.2	-1	114.9
October	117.7	0.4	0.3	3.7	3.2	114	0.3	0.3	0.3	0.3	113.7
November	117.8	0.1	0.1	3.4	3	114.4	0.4	0.4	0.9	0.8	113.5
December	117.6	-0.2	-0.2	3.7	3.2	113.9	-0.5	-0.4	0.9	0.8	113
Annual Average	**116.5**					**113.6**					**113.1**

PRIVATE TRANSPORTATION INDEX (Canada)Monthy & Yearly Change: Time Base: 2002=100

MONTH	2010	Increase for Month		Increase over 2009		2009	Increase for Month		Increase over 2008		2008
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	116.9	1.5	1.3	9.3	8.6	107.6	-1.3	-1.2	-10.3	-8.7	117.9
February	116.7	-0.2	-0.2	7.5	6.9	109.2	1.6	1.5	-8	-6.8	117.2
March	117.1	0.4	0.3	7.9	7.2	109.2	0	0	-8.8	-7.5	118
April	117.2	0.1	0.1	8	7.3	109.2	0	0	-11.1	-9.2	120.3
May	117.8	0.6	0.5	5.5	4.9	112.3	3.1	2.8	-11.5	-9.3	123.8
June	116.6	-1.2	-1	1.7	1.5	114.9	2.6	2.3	-10.8	-8.6	125.7
July	116.6	0	0	3.5	3.1	113.1	-1.8	-1.6	-12.3	-9.8	125.4
August	116.5	-0.1	-0.1	2.8	2.5	113.7	0.6	0.5	-8.9	-7.3	122.6
September	116.3	-0.2	-0.2	3.9	3.5	112.4	-1.3	-1.1	-10.2	-8.3	122.6
October	118.2	1.9	1.6	5.9	5.3	112.3	-0.1	-0.1	-4.1	-3.5	116.4
November	120.6	2.4	2	5.2	4.5	115.4	3.1	2.8	3	2.7	112.4
December	121.2	0.6	0.5	5.8	5	115.4	0	0	6.5	6	108.9
Annual Average	**117.6**					**112.1**					**119.3**

CONSUMER PRICE INDEX (Canada) Monthly & Yearly Change: Time Base: 1992=100

MONTH	2011	Increase for Month		Increase over 2010		2010	Increase for Month		Increase over 2009		2009
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	140.2	0.3	0.2	3.2	2.3	137	0.4	0.3	2.2	1.9	134.5
February	140.6	0.4	0.3	3	2.2	137.6	0.6	0.4	2.2	1.6	135.4
March	142.1	1.5	1.1	4.4	3.2	137.7	0.1	0.1	2	1.5	135.7
April	142.7	0.6	0.4	4.6	3.3	138.1	0.4	0.3	2.6	1.9	135.5
May	143.5	0.8	0.6	5	3.6	138.5	0.4	0.3	1.9	1.4	136.6
June	142.6	-0.9	-0.6	4.3	3.1	138.3	-0.2	-0.1	1.3	0.9	137
July	142.9	0.3	0.2	3.8	2.7	139.1	0.8	0.6	2.6	1.9	136.5
August	143.2	0.3	0.2	4.2	3	139	-0.1	-0.1	2.4	1.8	136.6
September	143.6	0.4	0.3	4.5	3.2	139.1	0.1	0.1	2.6	1.9	136.5
October	143.8	0.2	0.1	4.1	2.9	139.7	0.6	0.4	3.3	2.4	136.4
November	143.9	0.1	0.1	4	2.9	139.9	0.2	0.1	2.7	2	137.2
December	143	-0.9	-0.6	3.1	2.2	139.9	0	0	3.3	2.4	136.6
Annual Average	**142.7**					**138.7**					**136.2**

CONSUMER PRICE INDEX (Ontario) Monthly & Yearly Change: Time Base: 1992=100

MONTH	2011	Increase for Month		Increase over 2010		2010	Increase for Month		Increase over 2009		2009
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	141.5	-0.1	-0.1	4	2.9	137.5	0.5	0.4	2.5	1.9	135
February	141.7	0.2	0.1	3.5	2.5	138.2	0.7	0.5	2.3	1.7	135.9
March	143.5	1.8	1.3	5	3.6	138.5	0.3	0.2	2	1.5	136.5
April	144.1	0.6	0.4	5.1	3.7	139	0.5	0.4	3	2.2	136
May	145.2	1.1	0.8	5.6	4	139.6	0.6	0.4	2.7	2	136.9
June	144.4	-0.8	-0.6	5.1	3.7	139.3	-0.3	-0.2	2.2	1.6	137.1
July	144.7	0.3	0.2	4.1	2.9	140.6	1.3	0.9	4	2.9	136.6
August	144.8	0.1	0.1	4.3	3.1	140.5	-0.1	-0.1	4	2.9	136.5
September	145.5	0.7	0.5	4.8	3.4	140.7	0.2	0.1	4	2.9	136.7
October	145.4	-0.1	-0.1	4	2.8	141.4	0.7	0.5	4.6	3.4	136.8
November	145.3	-0.1	-0.1	3.6	2.5	141.7	0.3	0.2	4.1	3	137.6
December	144.5	-0.8	-0.6	2.9	2	141.6	-0.1	-0.1	4.6	3.4	137
Annual Average	**144.2**					**139.9**					**136.6**

CONSUMER PRICE INDEX (Toronto) Monthly & Yearly Change: Time Base: 1992=100

MONTH	2011	Increase for Month		Increase over 2010		2010	Increase for Month		Increase over 2009		2009
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	141.7	-0.1	-0.1	3.7	2.7	138	0.7	0.5	2.4	1.8	135.6
February	142.1	0.4	0.3	3.3	2.4	138.8	0.8	0.6	2.3	1.7	136.5
March	144	1.9	1.3	5	3.6	139	0.2	0.1	1.9	1.4	137.1
April	144.4	0.4	0.3	4.8	3.4	139.6	0.6	0.4	3.2	2.3	136.4
May	145.6	1.2	0.8	5.4	3.9	140.2	0.6	0.4	2.9	2.1	137.3
June	144.8	-0.8	-0.5	4.9	3.5	139.9	-0.3	-0.2	2.5	1.8	137.4
July	145.2	0.4	0.3	4.1	2.9	141.1	1.2	0.9	4.2	3.1	136.9
August	145.2	0	0	4	2.8	141.2	0.1	0.1	4.3	3.1	136.9
September	146.1	0.9	0.6	4.7	3.3	141.4	0.2	0.1	4.4	3.2	137
October	145.9	-0.2	-0.1	4	2.8	141.9	0.5	0.4	4.5	3.3	137.4
November	145.8	-0.1	-0.1	3.8	2.7	142	0.1	0.1	4.1	3	137.9
December	144.9	-0.9	-0.6	3.1	2.2	141.8	-0.2	-0.1	4.5	3.3	137.3
Annual Average	**144.6**					**140.4**					**137.0**

PRIVATE TRANSPORTATION INDEX (Canada) Monthly & Yearly Change: Time Base: 1992=100

MONTH	2011	Increase for Month		Increase over 2010		2010	Increase for Month		Increase over 2009		2009
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January											
February											
March											
April											
May		**No longer available**					**No longer available**				
June											
July											
August											
September											
October											
November											
December											
Annual Average											

CONSUMER PRICE INDEX (Canada) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2012	Increase for Month		Increase over 2011		2011	Increase for Month		Increase over 2010		2010
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	120.7	0.5	0.4	2.9	2.5	117.8	0.3	0.3	2.7	2.3	115.1
February	121.2	0.5	0.4	3.1	2.6	118.1	0.3	0.3	2.5	2.2	115.6
March	121.7	0.5	0.4	2.3	1.9	119.4	1.3	1.1	3.8	3.3	115.6
April	122.2	0.5	0.4	2.4	2	119.8	0.4	0.3	3.8	3.3	116
May	122.1	-0.1	-0.1	1.5	1.2	120.6	0.8	0.7	4.3	3.7	116.3
June	121.6	-0.5	-0.4	1.8	1.5	119.8	-0.8	0.7	3.6	3.1	116.2
July	121.5	-0.1	-0.1	1.5	1.3	120	0.2	0.2	3.2	2.7	116.8
August	121.8	0.3	0.2	1.5	1.2	120.3	0.3	0.3	3.6	3.1	116.7
September	122	0.2	0.2	1.4	1.2	120.6	0.3	0.2	3.7	3.2	116.9
October	122.2	0.2	0.2	1.4	1.2	120.8	0.2	0.2	3.4	2.9	117.4
November	121.9	-0.3	-0.2	1	0.8	120.9	0.1	0.1	3.4	2.9	117.5
December	121.2	-0.7	-0.6	1	0.8	120.2	-0.7	-0.6	2.7	2.3	117.5
Annual Average	**121.7**					**119.9**					**116.5**

CONSUMER PRICE INDEX (Ontario) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2012	Increase for Month		Increase over 2011		2011	Increase for Month		Increase over 2010		2010
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	120.6	0.3	0.2	2.8	2.4	117.8	-0.1	-0.1	3.3	2.9	114.5
February	121.4	0.8	0.7	3.4	2.9	118	0.2	0.2	2.9	2.5	115.1
March	122	0.6	0.5	2.6	2.2	119.4	1.4	1.2	4.1	3.6	115.3
April	122.4	0.4	0.3	2.5	2.1	119.9	0.5	0.4	4.2	3.6	115.7
May	122.4	0	0	1.5	1.2	120.9	1	0.8	4.7	4	116.2
June	121.6	-0.8	-0.7	1.4	1.2	120.2	-0.7	-0.6	4.2	3.6	116
July	121.4	-0.2	-0.2	0.9	0.8	120.5	0.3	0.2	3.5	3	117
August	121.8	0.4	0.3	1.2	1	120.6	0.1	0.1	3.6	3.1	117
September	122	0.2	0.2	0.9	0.7	121.1	0.5	0.4	4	3.4	117.1
October	122.2	0.2	0.2	1.2	1	121	-0.1	-0.1	3.2	2.7	117.8
November	121.9	-0.3	-0.2	0.9	0.7	121	0	0	3	2.5	118
December	121.3	-0.6	-0.5	1	0.8	120.3	-0.7	-0.6	2.4	2	117.9
Annual Average	**121.8**					**120.1**					**116.5**

CONSUMER PRICE INDEX (Toronto) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2012	Increase for Month		Increase over 2011		2011	Increase for Month		Increase over 2010		2010
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	120.7	0.5	0.4	3.2	2.7	117.5	-0.1	-0.1	3	2.6	114.5
February	121.5	0.8	0.7	3.6	3.1	117.9	0.4	0.3	2.8	2.4	115.1
March	122	0.5	0.4	2.6	2.2	119.4	1.5	1.3	4.1	3.6	115.3
April	122.4	0.4	0.3	2.6	2.2	119.8	0.4	0.3	4	3.5	115.8
May	122.4	0	0	1.6	1.3	120.8	1	0.8	4.5	3.9	116.3
June	121.7	-0.7	-0.6	1.5	1.2	120.2	-0.6	-0.5	4.1	3.5	116.1
July	121.6	-0.1	-0.1	1.2	1	120.4	0.2	0.2	3.3	2.8	117.1
August	121.8	0.2	0.2	1.3	1.1	120.5	0.1	0.1	3.4	2.9	117.1
September	122.1	0.3	0.2	0.9	0.7	121.2	0.7	0.6	3.9	3.3	117.3
October	122.3	0.2	0.2	1.2	1	121.1	-0.1	-0.1	3.4	2.9	117.7
November	122	-0.3	-0.2	1.1	0.9	120.9	-0.2	-0.2	3.1	2.6	117.8
December	121.4	-0.6	-0.5	1.2	1	120.2	-0.7	-0.6	2.6	2.2	117.6
Annual Average	**121.8**					**120.0**					**116.5**

PRIVATE TRANSPORTATION INDEX (Canada) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2012	Increase for Month		Increase over 2011		2011	Increase for Month		Increase over 2010		2010
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	127.1	2	1.6	4.4	3.6	122.7	1.5	1.2	5.8	5	116.9
February	127.5	0.4	0.3	5.1	4.2	122.4	-0.3	-0.2	5.7	4.9	116.7
March	129.2	1.7	1.3	4.7	3.8	124.5	2.1	1.7	7.4	6.3	117.1
April	131.2	2	1.5	4.1	3.2	127.1	2.6	2.1	9.9	8.4	117.2
May	129.6	-1.6	-1.2	0.7	0.5	128.9	1.8	1.4	11.1	9.4	117.8
June	127	-2.6	-2	2	1.6	125	-3.9	-3	8.4	7.2	116.6
July	125.9	-1.1	-0.9	1.3	1	124.6	-0.4	-0.3	8	6.9	116.6
August	127.4	1.5	1.2	2.5	2	124.9	0.3	0.2	8.4	7.2	116.5
September	128.2	0.8	0.6	2.4	1.9	125.8	0.9	0.7	9.5	8.2	116.3
October	128.4	0.2	0.2	1.6	1.7	126.8	1	0.4	8.6	6.9	118.2
November	127	-1.4	-1.1	-0.4	-0.3	127.4	0.6	0.5	6.8	5.6	120.6
December	125	-1.5	-1.2	0.4	0.3	125.1	-2.3	-1.8	3.9	3.2	121.2
Annual Average	**127.8**					**125.4**					**117.6**

CONSUMER PRICE INDEX (Canada) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2013	Increase for Month		Increase over 2012		2012	Increase for Month		Increase over 2011		2011
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	121.3	0.1	0.1	0.6	0.5	120.7	0.5	0.4	2.9	2.5	117.8
February	122.7	1.4	1.2	1.5	1.2	121.2	0.5	0.4	3.1	2.6	118.1
March	122.9	0.2	0.2	1.2	1	121.7	0.5	0.4	2.3	1.9	119.4
April	122.7	-0.2	-0.2	0.5	0.4	122.2	0.5	0.4	2.4	2	119.8
May	123	0.3	0.2	0.9	0.7	122.1	-0.1	-0.1	1.5	1.2	120.6
June	123	0	0	1.4	1.2	121.6	-0.5	-0.4	1.8	1.5	119.8
July	123.1	0.1	0.1	1.6	1.3	121.5	-0.1	-0.1	1.5	1.3	120
August	123.1	0	0	1.3	1.1	121.8	0.3	0.2	1.5	1.2	120.3
September	123.3	0.2	0.2	1.3	1.1	122	0.2	0.2	1.4	1.2	120.6
October	123	-0.3	-0.2	0.8	0.7	122.2	0.2	0.2	1.4	1.2	120.8
November	123	0	0	1.1	0.9	121.9	-0.3	-0.2	1	0.8	120.9
December	122.7	-0.3	-0.2	1.5	1.2	121.2	-0.7	-0.6	1	0.8	120.2
Annual Average	**122.8**					**121.7**					**119.9**

CONSUMER PRICE INDEX (Ontario) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2013	Increase for Month		Increase over 2012		2012	Increase for Month		Increase over 2011		2011
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	121.3	0.1	0.1	0.6	0.5	120.6	0.3	0.2	2.8	2.4	117.8
February	122.8	1.5	1.2	1.4	1.2	121.4	0.8	0.7	3.4	2.9	118
March	123.2	0.4	0.3	1.2	1	122	0.6	0.5	2.6	2.2	119.4
April	122.9	-0.3	-0.2	0.5	0.4	122.4	0.4	0.3	2.5	2.1	119.9
May	123	0.1	0.1	0.6	0.5	122.4	0	0	1.5	1.2	120.9
June	123.2	0.2	0.2	1.6	1.3	121.6	-0.8	-0.7	1.4	1.2	120.2
July	123.4	0.2	0.2	2	1.6	121.4	-0.2	-0.2	0.9	0.8	120.5
August	123.4	0	0	1.6	1.3	121.8	0.4	0.3	1.2	1	120.6
September	123.5	0.1	0.1	1.5	1.2	122	0.2	0.2	0.9	0.7	121.1
October	123.3	-0.2	-0.2	1.1	0.9	122.2	0.2	0.2	1.2	1	121
November	123.3	0	0	1.4	1.1	121.9	-0.3	-0.2	0.9	0.7	121
December	123.1	-0.2	-0.2	1.8	1.5	121.3	-0.6	-0.5	1	0.8	120.3
Annual Average	**123.0**					**121.8**					**120.1**

CONSUMER PRICE INDEX (Toronto) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2013	Increase for Month		Increase over 2012		2012	Increase for Month		Increase over 2011		2011
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	121.5	0.1	0.1	0.8	0.7	120.7	0.5	0.4	3.2	2.7	117.5
February	122.9	1.4	1.2	1.4	1.2	121.5	0.8	0.7	3.6	3.1	117.9
March	123.3	0.4	0.3	1.3	1.1	122	0.5	0.4	2.6	2.2	119.4
April	123.1	-0.2	-0.2	0.7	0.6	122.4	0.4	0.3	2.6	2.2	119.8
May	123.2	0.1	0.1	0.8	0.7	122.4	0	0	1.6	1.3	120.8
June	123.4	0.2	0.2	1.7	1.4	121.7	-0.7	-0.6	1.5	1.2	120.2
July	123.6	0.2	0.2	2	1.6	121.6	-0.1	-0.1	1.2	1	120.4
August	123.7	0.1	0.1	1.9	1.6	121.8	0.2	0.2	1.3	1.1	120.5
September	123.8	0.1	0.1	1.7	1.4	122.1	0.3	0.2	0.9	0.7	121.2
October	123.7	-0.1	-0.1	1.4	1.1	122.3	0.2	0.2	1.2	1	121.1
November	123.6	-0.1	-0.1	1.6	1.3	122	-0.3	-0.2	1.1	0.9	120.9
December	123.4	-0.2	-0.2	2	1.6	121.4	-0.6	-0.5	1.2	1	120.2
Annual Average	**123.3**					**121.8**					**120.0**

PRIVATE TRANSPORTATION INDEX (Canada) Monthly & Yearly Change: Time Base: 2002=100

MONTH	2013	Increase for Month		Increase over 2012		2012	Increase for Month		Increase over 2011		2011
	Points	pts	%	pts	%	Points	pts	%	pts	%	Points
January	126.3	0.8	0.6	-0.8	-0.6	127.1	2	1.6	4.4	3.6	122.7
February	130.2	3.9	3.1	2.7	2.1	127.5	0.4	0.3	5.1	4.2	122.4
March	129.5	-0.7	-0.5	0.3	0.2	129.2	1.7	1.3	4.7	3.8	124.5
April	128.3	-1.2	-0.9	-2.9	-2.2	131.2	2	1.5	4.1	3.2	127.1
May	128.6	0.3	0.2	-1	-0.8	129.6	-1.6	-1.2	0.7	0.5	128.9
June	129.6	1	0.8	2.6	2	127	-2.6	-2	2	1.6	125
July	129	-0.6	-0.5	3.1	2.5	125.9	-1.1	-0.9	1.3	1	124.6
August	128.4	-0.6	-0.5	1	0.8	127.4	1.5	1.2	2.5	2	124.9
September	128.8	0.4	0.3	0.6	0.5	128.2	0.8	0.6	2.4	1.9	125.8
October	127.9	-0.9	-0.7	-0.5	-0.4	128.4	0.2	0.2	1.6	1.7	126.8
November	127.5	-0.4	-0.3	0.5	0.4	127	-1.4	-1.1	-0.4	-0.3	127.4
December	128.2	0.7	0.5	2.7	2.2	125.5	-1.5	-1.2	0.4	0.3	125.1
Annual Average	**128.5**					**127.8**					**125.4**

4.2–VECC– 12

Ref: Exhibit 1, Tab 5, Schedule 11, pg.2

OHL explains that there are a number of savings related to the ODS system and other aspects of the smart meter program. Has OHL quantified these savings? If so please provide the estimates.

OHL's Response:

OHL has not quantified these savings per se, as these aspects of the smart meter program allowed for increased efficiencies. There were no incremental savings, as the staff levels remained the same, but these efficiencies allowed staff to shift workload to other projects.
The outage management system (OMS) allows prior investigation into outages before sending a staff member out to the property, often allowing for the problem to be corrected by the customer.
The ODS allows customer service to convey information more quickly to the customer, so that they could resolve some high bill complaints quickly and reduce the time spent by customer service staff explaining consumption patterns.
Smart meters also provide less human error with the ability for electronically transmitted as opposed to manual reads, which leads to more accurate bills, less billing estimation and less time spent on re-reading the meters.
By creating more efficiency it allows staff to move to other projects, including maintenance and capital work. With a growing customer base, this has also allowed OHL to avoid additional staff that may otherwise have been necessary.

4.2–VECC–13

Ref: Exhibit 4, Tab 1, Schedule 1, pg. 2
Tab 4, Schedule 2, pgs. 1-3

OHL has noted that is has budgeted for a lines apprentice in anticipation of a future retirement.

a. In what year is this retirement expected?

OHL's Response:

Please refer to 4.2-Energy Probe-13 (f).

b. Has OHL budgeted for a full year salary for the new lines apprentice in 2014?

OHL's Response:

Yes, OHL budgeted for a full year salary for the new lines apprentice in 2014.

c. Is this the only position added since 2010?

OHL's Response:

Yes, this is the only position added since 2010.

4.2–VECC–14

Ref: Exhibit 4, Tab 1/2, Schedule 1, pg. 4

Using the categories shown in the table Appendix 2-JA, please identify the adjustment to 2013 and 2014 OM&A (separately) for changes to capitalization policy.

OHL's Response:

The table below shows the safety costs separately and removed from the Administrative and General Expenses.

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$ 378,946	$ 392,746	$ 433,555	$ 458,597	$ 487,141	$ 507,835
Maintenance	$ 492,423	$ 425,049	$ 534,881	$ 465,329	$ 562,725	$ 616,413
SubTotal	**$ 871,369**	**$ 817,795**	**$ 968,437**	**$ 923,926**	**$1,049,866**	**$1,124,248**
%Change (year over year)			18.4%	-4.6%	13.6%	7.1%
%Change (Test Year vs Last Rebasing Year - Actual)						37.5%
Billing and Collecting	$ 549,953	$ 523,585	$ 628,892	$ 739,649	$ 712,500	$ 741,719
Community Relations	$ 20,862	$ 18,084	$ 26,560	$ 28,170	$ 21,254	$ 17,278
Administrative and General	$ 1,216,832	$1,280,256	$1,332,083	$1,407,416	$1,386,462	$1,548,351
Safety Costs					$ 50,625	$ 63,587
SubTotal	**$ 1,787,647**	**$1,821,925**	**$1,987,535**	**$2,175,234**	**$2,170,842**	**$2,370,935**
%Change (year over year)			9.1%	9.4%	-0.2%	9.2%
%Change (Test Year vs Last Rebasing Year - Actual)						30.1%
Total	**$ 2,659,015**	**$2,639,719**	**$2,955,971**	**$3,099,161**	**$3,220,707**	**$3,495,183**
%Change (year over year)			12.0%	4.8%	3.9%	8.5%

4.2–VECC–15

Ref: Exhibit 4, Tab 3, Schedule 2, pg.4

Please provide all training, conference and travel costs for each year 2010 through 2014.

OHL's Response:

The increase in the 2014 test year was mainly due to the inclusion of the safety training costs for the new apprentice that was hired in November 2013. OHL included the 2013 actual costs in the comparison below.

	Training, Conference and Travel Costs					
	2010 Actual	**2011 Actual**	**2012 Actual**	**2013 Actual**	**2014 Test**	**Grand Total**
Total	56,504	53,051	51,303	46,708	77,478	285,044

4.2–VECC–16

Ref: Exhibit 4, Tab 3, Schedule 1, pg. 13

Please update Appendix 2-JC for 2013 actual OM&A (unaudited).

OHL's Response:

OHL has updated Appendix 2-JC with the 2013 Actual OM&A below:

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Distribution Stations								
1 Labour & Benefits	2,853	244	400	262	2,587	11,940	11,678	9,088
2 Vehicles	720	-47	130	80	319	240	160	-480
3 Inventory	673	1,729	0	768	0	700	-68	28
4 Materials	0	0	3,362	0	0	0	0	0
5 Administration	15,391	15,496	15,772	16,494	17,839	16,824	330	1,434
6 Contractors	49,078	41,719	41,124	35,260	56,649	44,640	9,380	-4,437
Sub-Total	**68,714**	**59,141**	**60,788**	**52,865**	**77,394**	**74,345**	**21,481**	**5,631**
Overhead Operations								
1 Labour & Benefits	6,775	5,713	9,103	20,072	8,844	16,449	-3,623	9,674
2 Vehicles	1,620	1,397	2,423	3,398	1,559	1,720	-1,678	100
3 Inventory	0	451	169	0	286	0	0	0
4 Materials	0	0	0	45	0	0	-45	0
6 Contractors	6,325	7,563	8,843	7,602	10,236	9,142	1,541	2,817
Sub-Total	**14,720**	**15,124**	**20,539**	**31,116**	**20,925**	**27,312**	**-3,804**	**12,591**
Underground Operations								
1 Labour & Benefits	2,007	270	1,186	400	0	8,485	8,085	6,479
2 Vehicles	450	77	158	57	0	1,480	1,423	1,030
3 Inventory	0	0	0	0	0	0	0	0
4 Materials	0	842	0	5	0	0	-5	0
6 Contractors	0	0	0	4,550	0	0	-4,550	0
Sub-Total	**2,457**	**1,189**	**1,344**	**5,012**	**0**	**9,965**	**4,954**	**7,509**
Metering								
1 Labour & Benefits	42,783	83,461	71,447	45,712	58,019	75,699	29,986	32,915
2 Vehicles	4,170	9,810	6,778	1,906	4,808	7,900	5,994	3,730
3 Inventory	0	2,303	1,242	79	78	0	-79	0
4 Materials	1,009	3,084	13,565	5,863	4,414	2,264	-3,600	1,255
5 Administration	0	0	0	0	0	0	0	0
6 Contractors	35,970	34,978	33,860	53,731	28,576	31,710	-22,021	-4,260
Sub-Total	**83,932**	**133,635**	**126,893**	**107,292**	**95,896**	**117,572**	**10,280**	**33,641**
Cable Locates								
1 Labour & Benefits	44,701	44,128	42,598	58,350	73,595	55,334	-3,016	10,632
2 Vehicles	13,980	9,876	12,212	16,390	19,676	19,120	2,730	5,140
4 Materials	409	1,274	901	2,088	2,384	1,766	-322	1,356
6 Contractors	5,116	4,617	2,368	1,415	4,801	2,081	666	-3,035
Sub-Total	**64,207**	**59,895**	**58,080**	**78,243**	**100,456**	**78,300**	**57**	**14,094**
Engineering Expenses								
1 Labour & Benefits	125,933	115,548	143,669	160,695	206,528	162,174	1,479	36,241
2 Vehicles	7,560	5,715	6,675	6,760	6,526	14,844	8,084	7,284
4 Materials	0	620	643	114	558	0	-114	0
5 Administration	5,555	8,174	940	9,565	21,845	15,561	5,996	10,007
6 Contractors	17,215	7,949	24,773	22,271	9,905	25,891	3,619	8,675
Sub-Total	**156,263**	**138,007**	**176,700**	**199,406**	**245,362**	**218,470**	**19,064**	**62,207**
Maintenance Supervision								
1 Labour & Benefits	117,015	121,329	126,237	135,014	173,362	152,531	17,517	35,515
2 Vehicles	9,360	6,995	8,276	9,380	3,467	0	-9,380	-9,360
5 Administration	2,195	6,163	3,584	1,348	2,478	6,916	5,568	4,721
6 Contractors	0	0	0	78	0	510	432	510
Sub-Total	**128,570**	**134,487**	**138,097**	**145,820**	**179,306**	**159,957**	**14,137**	**31,387**

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Overhead Maintenance								
1 Labour & Benefits	71,668	81,424	101,049	91,239	101,346	123,131	31,893	51,463
2 Vehicles	26,370	19,355	26,083	12,237	15,471	19,440	7,203	-6,930
3 Inventory	8,951	4,878	23,317	3,318	4,924	20,534	17,216	11,583
4 Materials	1,620	15	304	1,051	924	0	-1,051	-1,620
5 Administration	0	0	0	807	2,178	1,296	489	1,296
6 Contractors	3,070	1,968	1,345	3,181	2,141	1,511	-1,670	-1,559
Sub-Total	**111,679**	**107,640**	**152,098**	**111,834**	**126,984**	**165,912**	**54,078**	**54,233**
Vegetation Management								
1 Labour & Benefits	70,669	54,448	71,142	68,400	53,526	77,069	8,669	6,400
2 Vehicles	33,120	15,191	22,376	10,334	8,577	21,600	11,266	-11,520
4 Materials	307	528	222	153	28	313	160	6
3 Inventory					371			
6 Contractors	150	106	0	120	3,371	150	30	0
Sub-Total	**104,245**	**70,274**	**93,740**	**79,007**	**65,873**	**99,132**	**20,125**	**-5,114**
Underground Maintenance								
1 Labour & Benefits	65,059	45,881	61,127	62,608	53,364	86,263	23,654	21,203
2 Vehicles	17,580	11,687	15,801	8,746	10,685	12,300	3,554	-5,280
3 Inventory	3,639	3,438	3,256	2,243	1,257	7,650	5,407	4,011
4 Materials	2,391	1,357	2,503	3,114	2,464	3,740	626	1,349
6 Contractors	2,500	4,034	11,603	8,640	11,711	8,656	16	6,156
Sub-Total	**91,169**	**66,397**	**94,291**	**85,352**	**79,480**	**118,608**	**33,256**	**27,439**
Transformer Maintenance								
1 Labour & Benefits	26,321	15,747	23,760	20,555	18,510	35,253	14,698	8,932
2 Vehicles	8,820	7,831	6,669	2,990	317	5,880	2,890	-2,940
3 Inventory	1,650	3,569	12,422	2,046	3,389	9,308	7,262	7,658
4 Materials	2,344	3,611	831	1,001	276	1,821	820	-523
6 Contractors	6,278	1,247	2,185	1,389	3,755	2,412	1,023	-3,866
Sub-Total	**45,413**	**32,006**	**45,867**	**27,980**	**26,247**	**54,674**	**26,693**	**9,261**
Billing/ Collecting/Meter Reading								
1 Labour & Benefits	230,902	238,537	243,941	273,828	258,492	287,942	14,113	57,040
2 Vehicles	16,260	7,658	9,158	4,857	7,358	11,920	7,063	-4,340
5 Administration	87,051	95,792	187,134	91,685	94,689	117,307	25,622	30,257
6 Contractors	215,741	181,597	188,660	144,862	131,561	164,627	19,765	-51,114
Sub-Total	**549,953**	**523,585**	**628,892**	**515,232**	**492,100**	**581,796**	**66,564**	**31,842**
Conservation & Community								
1 Labour & Benefits	5,594	4,968	7,480	8,799	5,869	5,935	-2,864	341
2 Vehicles	540	1,427	2,120	1,084	1,136	720	-364	180
5 Administration	14,728	9,488	15,460	16,688	20,669	10,467	-6,221	-4,261
6 Contractors	0	2,200	1,500	1,600	410	0	-1,600	0
Sub-Total	**20,862**	**18,084**	**26,560**	**28,170**	**28,085**	**17,122**	**-11,048**	**-3,740**
Administrative Expenses								
1 Labour & Benefits	754,662	694,066	739,931	800,787	870,190	937,577	136,790	182,915
2 Vehicles	390	64	105	75	55	520	445	130
4 Materials	0	125	658	492	2,996	1,836	1,344	1,836
5 Administration	228,925	227,517	234,440	236,901	345,100	347,342	110,442	118,418
6 Contractors	84,454	102,192	101,806	115,444	71,562	129,483	14,039	45,028
Sub-Total	**1,068,431**	**1,023,964**	**1,076,940**	**1,153,698**	**1,289,903**	**1,416,758**	**263,060**	**348,327**
Outside Services Employed								
6 Contractors	71,329	115,085	213,772	206,111	262,862	143,388	-62,723	72,059
Sub-Total	**71,329**	**115,085**	**213,772**	**206,111**	**262,862**	**143,388**	**-62,723**	**72,059**
Regulatory Expenses								
Regulatory	77,072	141,208	41,370	47,607	42,299	51,949	4,342	-25,123
Sub-Total	**77,072**	**141,208**	**41,370**	**47,607**	**42,299**	**51,949**	**4,342**	**-25,123**
Smart Meters								
Metering				0		0	0	0
Meter Reading				165,378	111,177	95,128	-70,250	95,128
Billing				59,039	32,015	64,795	5,756	64,795
Sub-Total	**0**	**0**	**0**	**224,417**	**143,192**	**159,923**	**-64,494**	**159,923**
Miscellaneous							0	0
Total	**2,659,015**	**2,639,719**	**2,955,971**	**3,099,161**	**3,276,365**	**3,495,183**	**396,023**	**836,168**

4.2–VECC–17

Ref: Exhibit 4, Tab 6

For each year in the period 2010 through 2014 please provide the amounts for:

a. EDA Fees

OHL's Response:

	2010	2011	2012	2013	2014
a) EDA Fees	26,100	26,950	28,450	29,800	31,100
b) MEARIE Insurance	15,318	20,625	26,868	36,135	37,638
c) MEARIE Actuarial Services		6,940			1,388

b. MEARIE insurance premiums

OHL's Response:

Please refer to OHL's response to a.

c. MEARIE Actuarial Services

OHL's Response:

Please refer to OHL's response to a.

4.2–VECC–18

Ref: Exhibit 4, Tab 4

For all MEARIE purchased services please explain if these services were competitively tendered and if not why not. If they were not tendered please explain what due diligence is undertaken to ensure the services are purchased competitively priced.

OHL's Response:

OHL did not tender the MEARIE purchased services.

OHL is a member of The MEARIE Group. MEARIE is an Insurance Reciprocal, created in 1987. MEARIE offers a full range of insurance solutions including legal, actuarial services, comprehensive general liability, property, vehicle insurance and group benefits. Subscribers include electrical utilities, municipalities, small hydro and gas generation, telecommunications, fiber optics and water distribution.
The MEARIE Group is progressive, innovative and dedicated to providing comprehensive, superior insurance, financial and business solutions to the energy sector. MEARIE's focus on the energy sector drives the development of products, coverages and stable pricing that are highly distinctive and responsive to the needs of our Subscribers.
The MEARIE Group is the only Canadian insurance supplier dedicated to the electricity sector. Since reciprocals are "owned" by their members "OHL", they are solely motivated to serve the needs of their members.
MEARIE's successful long-term strategic alliances with some of Canada's leading firms has brought together the resources, expertise and best practices to deliver exceptional results.

4.3 Are the applicant's proposed operating and capital expenditures appropriately paced and prioritized to result in reasonable rate increases for customers, or is any additional rate mitigation required?

4.3-Staff-25

Ref: E2/T5/S2, pp. 1-6

Please provide the year-to-date actual 2013 capital expenditures available, along with a forecast for the remaining month, to the same level of detail as Appendix 2-JA. Please provide a comparison of year-to-date actuals for 2013 with the corresponding time period in 2012.

OHL's Response:

Please see Appendix 2-JA below updated with the year-to-date actual 2013 OM&A costs amounting to $3,276,365. OHL has not provided the corresponding time period from 2012, as OHL expects that the costs give are final costs for the end of the 2013 year.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$ 378,946	$ 392,746	$ 433,555	$ 458,597	$ 511,969	$ 507,835
Maintenance	$ 492,423	$ 425,049	$ 534,881	$ 465,329	$ 505,954	$ 616,413
SubTotal	$ 871,369	$ 817,795	$ 968,437	$ 923,926	$ 1,017,923	$ 1,124,248
% Change (year over year)			18.4%	-4.6%	10.2%	10.4%
% Change (Test Year vs Last Rebasing Year - Actual)						37.5%
Billing and Collecting	$ 549,953	$ 523,585	$ 628,892	$ 739,649	$ 635,292	$ 741,719
Community Relations	$ 20,862	$ 18,084	$ 26,560	$ 28,170	$ 28,085	$ 17,278
Administrative and General	$ 1,216,832	$ 1,280,256	$ 1,332,083	$ 1,407,416	$ 1,595,065	$ 1,611,938
SubTotal	$ 1,787,647	$ 1,821,925	$ 1,987,535	$ 2,175,234	$ 2,258,442	$ 2,370,935
% Change (year over year)			9.1%	9.4%	3.8%	5.0%
% Change (Test Year vs Last Rebasing Year - Actual)						30.1%
Total	$ 2,659,015	$ 2,639,719	$ 2,955,971	$ 3,099,161	$ 3,276,365	$ 3,495,183
% Change (year over year)			12.0%	4.8%	5.7%	6.7%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$ 378,946	$ 392,746	$ 433,555	$ 458,597	$ 511,969	$ 507,835
Maintenance	$ 492,423	$ 425,049	$ 534,881	$ 465,329	$ 505,954	$ 616,413
Billing and Collecting	$ 549,953	$ 523,585	$ 628,892	$ 739,649	$ 635,292	$ 741,719
Community Relations	$ 20,862	$ 18,084	$ 26,560	$ 28,170	$ 28,085	$ 17,278
Administrative and General	$ 1,216,832	$ 1,280,256	$ 1,332,083	$ 1,407,416	$ 1,595,065	$ 1,611,938
Total	$ 2,659,015	$ 2,639,719	$ 2,955,971	$ 3,099,161	$ 3,276,365	$ 3,495,183
% Change (year over year)			12.0%	4.8%	5.7%	6.7%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2009 BA – 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2009 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Bridge Year	Variance 2013 Bridge vs. 2012 Actuals	2014 Test Year	Variance 2014 Test vs. 2013 Bridge
Operations	$ 378,946	$ 392,746	-$ 13,800	$ 433,555	$ 40,809	$ 458,597	$ 25,042	$ 511,969	$ 53,373	$ 507,835	-$ 4,134
Maintenance	$ 492,423	$ 425,049	$ 67,374	$ 534,881	$ 109,833	$ 465,329	-$ 69,552	$ 505,954	$ 40,624	$ 616,413	$ 110,459
Billing and Collecting	$ 549,953	$ 523,585	$ 26,369	$ 628,892	$ 105,307	$ 739,649	$ 110,757	$ 635,292	-$ 104,356	$ 741,719	$ 106,426
Community Relations	$ 20,862	$ 18,084	$ 2,778	$ 26,560	$ 8,476	$ 28,170	$ 1,610	$ 28,085	-$ 85	$ 17,278	-$ 10,807
Administrative and General	$ 1,216,832	$ 1,280,256	-$ 63,425	$ 1,332,083	$ 51,826	$ 1,407,416	$ 75,333	$ 1,595,065	$ 187,649	$ 1,611,938	$ 16,873
Total OM&A Expenses	$ 2,659,015	$ 2,639,719	$ 19,296	$ 2,955,971	$ 316,252	$ 3,099,161	$ 143,189	$ 3,276,365	$ 177,204	$ 3,495,183	$ 218,818
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 2,659,015	$ 2,639,719	$ 19,296	$ 2,955,971	$ 316,252	$ 3,099,161	$ 143,189	$ 3,276,365	$ 177,204	$ 3,495,183	$ 218,818
Variance from previous year				$ 316,252		$ 143,189		$ 177,204		$ 218,818	
Percent change (year over year)				12%		5%		6%		7%	
Percent Change: Test year vs. Most Current Actual						12.78%					
Simple average of % variance for all years						32.41%					7%
Compound Annual Growth Rate for all years											5.8%
Compound Growth Rate (2012 Actuals vs. 2009 Actuals)						5.49%					

4.3-SEC-20

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

Please provide the current Board of Directors approved budget for the Applicant for 2014.

OHL's Response:

The current approved Board of Directors 2014 budget for the application can be found in Appendix J – OHL 2014 Budget.

4.3-SEC-21

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

Please provide two lists: one of the top three capital projects not approved for 2014, and the second the bottom three capital projects approved for 2014. Please provide any explanation available that will show why the three approved were prioritized to proceed, and the three not approved were given the lesser priority.

OHL's Response:

OHL does not understand the request for "the top three capital projects not approved for 2014." Each department manager is responsible for the identification and justification of projects related to their department, which are then discussed with executive management. After examining all recommended projects they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters.

OHL has filed a DSP that contains the planned capital projects for 2014. The evidence filed does not contain capital projects that were not approved for 2014.

4.3-SEC-22

Ref: Ex.2/5/4, p. 1

Please provide a copy of the "draft Asset Management Plan" referred to.

OHL's Response:

The details of the draft Asset Management Plan have been incorporated in the DSP. This was OHL's understanding of the Chapter 5 Filing requirements. The remaining Word and Excel files that were created for the draft Asset Management Plan are out of date, incomplete, unedited and have not been reviewed by OHL's management or board.

4.3-SEC-23

Ref: Ex.2/5/5

Please confirm that this plan, marked "Draft", is actually the final Distribution System Plan. If it is not, please provide the final plan. Please confirm that this plan has been approved by the Applicant's Board of Directors. Please provide the document that sets out the scope of work and other instructions for the engineering firm that prepared this document.

OHL's Response:

OHL confirms that the filed DSP is the final DSP. The Scope of Work was significantly outlined by the OEB's Chapter 5 "Consolidated Distribution System Plan Filing Requirements" dated March 28, 2013.

Please find attached two documents that set out the scope of work and other instructions for the engineering firm that prepared the DSP.

Appendix G – OHL006 Task 1 Signoff
Appendix H – OHL006 Task 2 Signoff

4.3-SEC-24

Ref: Ex.2/5/5, p. 37

Please advise the tree-trimming cycle used for each of the years 2000 through 2013. If the number of years in the cycle has changed during that period, please provide the reason for the change, and any cost analysis done at the time of the change or subsequently. Please provide any documents that deal with requirements by either of the municipal owners relative to the utility's tree-trimming activities.

OHL's Response:

OHL has a service area of 17 km^2. Therefore, OHL has the ability to effectively patrol our lines, interview field staff and listen to customers to determine the areas that require tree trimming.

4.3-SEC-25

Ref: Ex.2/5/5, p. 53-56

Please add five columns to each of Tables 28, 29 and 31 to include 2009-2012 actuals and 2013 actuals (or most recent 9+3 or 10+2 forecast if actuals are not yet available).

OHL's Response:

4.3-SEC-26

Ref: Ex.4/3/1, p. 1

Please provide a list of all categories of capital assets that are operated on a "run to failure" basis.

OHL's Response:

OHL operates in-line switches and fused cutouts on a run to failure basis since they do not represent safety concerns and live-line techniques can be used to replace these items.

4.3–VECC–19

Ref: Exhibit 2, Tab 2, Schedule 12
Tab 5, Schedule 3, pg.1

OHL states that it spent $357,017 less than Board approved in 2010. Gross fixed assets were $2,220,796 less than Board approved.

a. OHL notes that SCADA development and CIS upgrades were not completed as forecast in 2010. Are either of these projects forecast to be carried out over the next 5 years? In doing this specifically address the comments at page 62 of the Distribution System Plan which states that "*system control and operation will also become more complex and the supporting systems will need to be sophisticated enough to support these operational needs".* (Exhibit 2, Tab 5, Schedule 5, pg.63).

OHL's Response:

Scada development – OHL considers it prudent to allow the existing distribution level SCADA to mature in the coming years. OHL is not in a position to "test" new technologies or risk the costs of needing to replace or upgrade failed technologies. OHL considers it prudent to learn from the best practices that are currently being formed in the Ontario energy sector. OHL looks forward to working with other LDC's and learning from their experiences to ensure that a mature and reliable solution is utilized.

CIS Upgrades – OHL currently has no intention on upgrading the CIS for microFit. This process is currently being handled outside of the system at no additional cost to our customer.

b. At Table 2:9 it shows that in 2010 OHL significantly underspend on Line Transformers and services, IT assets, Office and Transportation and other equipment. Please explain the reason for these areas of underspending.

OHL's Response:

The under spend on the Line transformers is primarily due to accounting transactions. Prior to

2010, OHL recorded underground switchgear in account 1850 instead of 1845. In 2010 OHL made a correction by transferring all gross asset costs of $1,003,802 into 1845 that decreased the asset additions in 2010 for 1850 and increased the asset additions for 1845.

4.3–VECC–20

Ref: Exhibit 2, Tab 5, Schedule 2, Appendix 2-AA – Capital Projects Table

Please file an amended Appendix 2-AA which shows the 2010 Board Actuals. Please include in this table capital contributions for each year and remove all smart meter related additions.

OHL's Response:

Please see table below for the amended Appendix 2-AA which shows the 2010 Actuals and includes the capital contributions for each year and the smart meter related additions removed.

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
B05 - Townline Rebuild							
1830 Poles, Towers & Fixtures	58,682						
1835 Overhead Conductors & Devices	81,922						
1850 Line Transformers	29,686						
1855 Services (Overhead & Underground)	4,770						
Sub-Total	175,060	0	0	0	0	0	0
B11 - 2009 - Bredin Pkwy Conversion							
1830 Poles, Towers & Fixtures		-650					
1840 Underground Conduit	172,883	63,780					
1845 Underground Conductors & Devices	29,623	45,970					
1850 Line Transformers	148,883	94,120					
Sub-Total	351,389	203,219	0	0	0	0	0
B22-2010 - Browns Farm Conversion							
1830 Poles, Towers & Fixtures				217			
1835 Overhead Conductors & Devices				80,646			
1840 Underground Conduit			196,231	208,384	36,050		
1845 Underground Conductors & Devices			30,072	94,960	35,046		
1850 Line Transformers			4,750	143,791	79,123		
1855 Services (Overhead & Underground)				4,186	6,557		
Sub-Total	0	0	231,054	532,184	156,776	0	0
B24-2009 - 2009 COS Project - Hansen Blvd Reconstruction							
1830 Poles, Towers & Fixtures		23,407	460				
1835 Overhead Conductors & Devices		12,574	807				
1840 Underground Conduit		3,443	114,831				
1845 Underground Conductors & Devices		144,034					
1850 Line Transformers		102,036	918				
Sub-Total	0	285,494	117,015	0	0	0	0
B27-2010 - Rolling Hills Refurbishment							
1840 Underground Conduit			7,607				
1845 Underground Conductors & Devices			106,296				
1850 Line Transformers			302				
Sub-Total	0	0	114,205	0	0	0	0
B29-2009 - DS#1 Removal Mill St							
1830 Poles, Towers & Fixtures	11,968	17,647					
1835 Overhead Conductors & Devices	21,710	19,724					
1840 Underground Conduit	9,470						
1845 Underground Conductors & Devices	8,592						
1850 Line Transformers	32,536	20,426					
1855 Services (Overhead & Underground)		202					
Sub-Total	84,275	57,999	0	0	0	0	0
B34-2010 - Hydro One Make Ready - Emma St							
1830 Poles, Towers & Fixtures			72,291				
1835 Overhead Conductors & Devices			36,062				
1840 Underground Conduit			9,854				
1845 Underground Conductors & Devices			8,547				
1850 Line Transformers			18,096				
1855 Services (Overhead & Underground)			7,934				
1995 Capital Contribution			(154,433)				
Sub-Total	0	0	(1,649)	0	0	0	0
B35-2010 - Wholesale Meter M5 & M26							
1820 Distribution Station Equipment <50kV			111,496				
1830 Poles, Towers & Fixtures			6,538				
1835 Overhead Conductors & Devices			9,929				
Sub-Total	0	0	127,963	0	0	0	0
B36-2011 - ORANGEVILLE MALL CONVERSION							
1830 Poles, Towers & Fixtures				4,674			
1840 Underground Conduit				38,723			
1845 Underground Conductors & Devices				48,729			
1850 Line Transformers				76,001			
Sub-Total	0	0	0	168,127	0	0	0

B42-2012 - Water & William St U/G Conversion							
1840 Underground Conduit					61,595		
1845 Underground Conductors & Devices					19,973		
1850 Line Transformers					9,550		
1855 Services (Overhead & Underground)					34,068		
Sub-Total	0	0	0	0	125,186	0	0
B47-2011 - ARMSTRONG ST RECONSTRUCTION							
1830 Poles, Towers & Fixtures				8,103			
1835 Overhead Conductors & Devices				20,173			
1840 Underground Conduit				3,179			
1845 Underground Conductors & Devices				42,640			
1850 Line Transformers				19,452			
1855 Services (Overhead & Underground)				932			
Sub-Total	0	0	0	94,479	0	0	0
B48-2012 - Centre & Church St Conversion							
1830 Poles, Towers & Fixtures					3,376		
1835 Overhead Conductors & Devices					1,198		
1840 Underground Conduit					32,076		
1845 Underground Conductors & Devices					10,954		
1850 Line Transformers					13,314		
1855 Services (Overhead & Underground)					1,909		
Sub-Total	0	0	0	0	62,826	0	0
B50-2011 - FAULKNER/ELIZABETH ST CONVERSI							
1830 Poles, Towers & Fixtures				203			
1835 Overhead Conductors & Devices				155			
1840 Underground Conduit				83,976			
1845 Underground Conductors & Devices				60,408			
1850 Line Transformers				714			
1855 Services (Overhead & Underground)				7,065			
Sub-Total	0	0	0	152,521	0	0	0
B55-2011 - Centennial Dr Pole Replacement							
1830 Poles, Towers & Fixtures					22,071		
1835 Overhead Conductors & Devices					41,959		
Sub-Total	0	0	0	0	64,030	0	0
B76-2013 - Stoney Crescent 27.6kV Conversion							
1840 Underground Conduit						31,330	
1845 Underground Conductors & Devices						12,519	
1850 Line Transformers						12,159	
Sub-Total	0	0	0	0	0	56,008	0
B78-2013 - First St- Fifth Ave 27kV OH-UG Conversion							
1830 Poles, Towers & Fixtures						14,055	
1835 Overhead Conductors & Devices						9,401	
1840 Underground Conduit						54,080	64,956
1845 Underground Conductors & Devices						76,472	68,964
1850 Line Transformers							31,130
Sub-Total	0	0	0	0	0	154,007	165,051
B79-2013 - Parkview Heights- Transformer Replacement							
1850 Line Transformers						85,237	63,926
Sub-Total	0	0	0	0	0	85,237	63,926
B80-2013 - Emma & Douglas St- Pole line Replacement							
1830 Poles, Towers & Fixtures						35,547	
1835 Overhead Conductors & Devices						12,796	
1850 Line Transformers						3,664	
1855 Services (Overhead & Underground)						5,771	
Sub-Total	0	0	0	0	0	57,777	0
B81-2013 - West Broadway 27.6kV UG Conversion							
1830 Poles, Towers & Fixtures						5,297	
1835 Overhead Conductors & Devices						6,164	
1840 Underground Conduit						58,500	
1845 Underground Conductors & Devices						58,928	
1850 Line Transformers						15,621	
1855 Services (Overhead & Underground)						13,408	
Sub-Total	0	0	0	0	0	157,918	0
B82-2013 - Cooper-George-Parkview-Main St South Pole Line Replacement							
1830 Poles, Towers & Fixtures						45,976	
1835 Overhead Conductors & Devices						9,790	
1850 Line Transformers						8,130	
1855 Services (Overhead & Underground)						11,793	
Sub-Total	0	0	0	0	0	75,689	0
B83-2013 - Municipal Substation - Major Service							
1830 Poles, Towers & Fixtures						71,135	
Sub-Total	0	0	0	0	0	71,135	0

B85-2013 - Bythia-Victoria-Princess 27.6kV Conversion Phase 1							
1830 Poles, Towers & Fixtures						17,472	
1835 Overhead Conductors & Devices						4,021	
1840 Underground Conduit						78,200	152,466
1845 Underground Conductors & Devices						30,303	66,394
1850 Line Transformers						56,154	123,027
1855 Services (Overhead & Underground)						3,856	36,135
Sub-Total	0	0	0	0	0	190,006	378,022
2014 - B87-2014							
1820 Distribution Station Equipment <50kV							89,011
1835 Overhead Conductors & Devices							73,418
Sub-Total	0	0	0	0	0	0	162,429
B88-2014 - 10 Third Street 27.6kV Conversion							
1830 Poles, Towers & Fixtures							11,763
1840 Underground Conduit							14,633
1845 Underground Conductors & Devices							10,955
1850 Line Transformers							15,032
Sub-Total	0	0	0	0	0	0	52,383
C01- Various General Service New Services/Service Upgrades							
1830 Poles, Towers & Fixtures							
1835 Overhead Conductors & Devices							
1840 Underground Conduit							
1845 Underground Conductors & Devices	17,438						
1850 Line Transformers	33,863						
1855 Services (Overhead & Underground)							
1860 Meters							
1995 Capital Contribution	(6,760)						
Sub-Total	44,541	0	0	0	0	0	0
S01 - Edgewood Valley							
1840 Underground Conduit	135,094						
1845 Underground Conductors & Devices	35,742						
1850 Line Transformers	32,753						
1855 Services (Overhead & Underground)	25,184						
1995 Capital Contribution	(121,622)						
Sub-Total	107,151	0	0	0	0	0	0
S02 - 2009 - Orangeville Highlands							
1840 Underground Conduit		76,579					
1845 Underground Conductors & Devices		40,008					
1850 Line Transformers		60,777					
1855 Services (Overhead & Underground)		49,833					
1995 Capital Contribution		(91,456)					
Sub-Total	0	135,742	0	0	0	0	0
S03-2011 - EDGEWOOD VALLEY PHASE 1B							
1830 Poles, Towers & Fixtures				53			
1835 Overhead Conductors & Devices				71			
1840 Underground Conduit		36,522		39,781			
1845 Underground Conductors & Devices		13,044		7,505			
1850 Line Transformers		32,028		20,854			
1855 Services (Overhead & Underground)		15,652		8,708			
1995 Capital Contribution		(15,469)		(38,677)			
Sub-Total	0	81,777	0	38,295	0	0	0
S04-2011 - BROADWAY GRANDE TOWNHOUSES							
1840 Underground Conduit				23,752			
1845 Underground Conductors & Devices				20,164			
1850 Line Transformers				36,345			
1855 Services (Overhead & Underground)				404			
1995 Capital Contribution				(55,214)			
Sub-Total	0	0	0	25,451	0	0	0
S06-2011 - Mono Meadows PH4 Sarah Properties							
1845 Underground Conductors & Devices					192,610		
1850 Line Transformers					138,303		
1855 Services (Overhead & Underground)					42,351		
1995 Capital Contribution					(209,179)		
Sub-Total	0	0	0	0	164,085	0	0
S09-2012 - Sarah Properties Phase 2							
1840 Underground Conduit					56,673		
1845 Underground Conductors & Devices					13,561		
1850 Line Transformers					20,995		
1855 Services (Overhead & Underground)					26,800		
1995 Capital Contribution					(68,285)		
Sub-Total	0	0	0	0	49,744	0	0
Various Subdivisions							
1835 Overhead Conductors & Devices						200	
1840 Underground Conduit						222,463	62,070

1845 Underground Conductors & Devices						189,563	63,497
1850 Line Transformers						106,780	59,226
1855 Services (Overhead & Underground)						117,210	74,550
1860 Meters						9,375	27,000
1995 Capital Contribution						(434,796)	(175,710)
Sub-Total	0	0	0	0	0	210,795	110,632
Land							
1805 Land					125,868		
Sub-Total	0	0	0	0	125,868	0	0
Transformer Replacement/Movement							
1845 Underground Conductors & Devices			250				
1850 Transformers	96,336	(63,979)	95,147	(105,984)			
Sub-Total	96,336	(63,979)	95,397	(105,984)	0	0	0
GP -Land							
1905 Land	95,379			228,820			
Sub-Total	95,379	0	0	228,820	0	0	0
GP - Computer Hardware							
1920 Computer Hardware			0				77,200
Sub-Total	0	0	0	0	0	0	77,200
GP - Computer Software							
1925 Computer Software	50,753	154,708	134,774	62,467	160,843		
Sub-Total	50,753	154,708	134,774	62,467	160,843	0	0
GP - Vehicle Replacement							
1930 Transportation		129,496	73,582			275,000	
Sub-Total	0	129,496	73,582	0	0	275,000	0
Miscellaneous							
1805 Land			9,430				
1806 Land Rights - Easements		7,638	9,668				
1820 Distribution Station Equipment <50kV	12,969		11,157	4,788			30,596
1830 Poles, Towers & Fixtures	41,863	47,005	36,186	33,760	64,981	43,434	38,159
1835 Overhead Conductors & Devices	58,018	39,751	75,550	19,326	24,870	15,914	33,660
1840 Underground Conduit	89	19,061	18,153	43,580	4,345		14,000
1845 Underground Conductors & Devices	30,088	66,857	47,981	51,448	-20,148	11,965	16,353
1850 Line Transformers	212,772	128,964	164,922	111,056	135,245	30,943	93,513
1855 Services (Overhead & Underground)	1,481	12,088	15,146	24,735	24,037	117,481	22,000
1860 Meters	35,731	24,154	36,530	38,178	22,198	16,764	18,764
1905 Land	14,111	42,411	26,280	36,436	23,668	7,000	29,500
1915 Office Equipment	2,632	1,496	57,587	6,022	23,138	23,000	17,200
1920 Computer Hardware	8,778	17,934	47,118	12,844	22,016	37,000	
1925 Computer Software		5,006		0		30,500	42,000
1930 Transportation				48,474	36,069		35,000
1935 Stores Equipment	910	2,387			1,606	2,500	2,000
1940 Tools, Shop & Garage Equipment	4,235	9,431	1,404	9,231	1,133	6,800	5,000
1945 Measurement & Testing Equipment				5,972	499	6,000	5,000
1955 Communication Equipment						2,000	5,600
1960 Miscellaneous Equipment	11,876	14,081	1,399	10,662	3,648		
1995 Capital Contribution	(125,863)	(146,752)	(113,308)	(91,276)	(19,545)	(122,764)	(122,764)
Sub-Total	309,689	291,510	445,203	365,236	347,760	228,537	285,580
Total	**1,314,574**	**1,275,967**	**1,337,544**	**1,561,595**	**1,257,119**	**1,562,109**	**1,295,222**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							
Total	**1,314,574**	**1,275,967**	**1,337,544**	**1,561,595**	**1,257,119**	**1,562,109**	**1,295,222**

5. Public Policy Responsiveness

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-Energy Probe-19

Ref: Current Application

a. Please provide a list of the obligations mandated by government in 2010 through to the current time.

OHL's Response:

OHL does not specifically track any of the costs of meeting all new government and OEB obligations established since 2010.

As an Ontario business and licensed local distribution company, OHL has obligations to many Ontario Ministries including but not limited to:

- Ministry of Consumer Services
- Ministry of Energy
- Ministry of Environment
- Ministry of Finance
- Ministry of Labour
- Ministry of Natural Resources
- Ministry of Training, Colleges and Universities
- Ministry of Transportation

OHL ensures that all obligations, requirements and requests from the provincial and federal government as well as ministries and related agencies are met or exceeded.

Considering the number of obligations, requirements and requests from the provincial and federal government as well as ministries and related agencies OHL is unable to provide this list.

b. For each of the obligations noted in (a) above, please explain how the distributor has met those obligations.

OHL's Response:

OHL ensures that all obligations, requirements and requests from the provincial and federal government as well as ministries and related agencies are met or exceeded.

Considering the number of obligations, requirements and requests from the provincial and federal government as well as ministries and related agencies OHL is unable to provide this list.

5.1–VECC–21

Ref: ALL

Please provide OHL's estimate of the cost of meeting all new government and OEB obligations established since 2010. Please categorize by requirement.

OHL's Response:

Please refer to response provided for IR # 5.1-Energy Probe-19

6. Financial Performance

6.1 Do the applicant's proposed rates allow it to meet its obligations to its customers while maintaining its financial viability?

6.1-Energy Probe-20

Ref: Exhibit 1, Tab 5, Schedule 1

Please confirm that line 35 on page 2 should refer to May 1, 2014 rather than May 1, 2013.

OHL's Response:

OHL would like to confirm that line 35 on page 2 should refer to May 1, 2014 not May 1, 2013.

6.1-SEC-27

Ref: Ex.1/3/1/C, p. 28

Please explain the rationale behind the special $1.5 million dividend.

OHL's Response:

As owner of OHL, the municipality is within its rights to withdraw funds from the LDC. The Town needed money. As OHL pays down debt borrowing takes place to try to stay close to the 60 / 40 debt equity ratio guideline as set forth by the OEB. Providing a special dividend to the shareholder from time to time keeps OHL on track for the 60 / 40 debt equity ratio.

6.1-SEC-28

Ref: Ex.1/5/6, p. 1

Please provide the current Shareholders Agreement or Shareholders Declaration. If the current information on "the desired rate of return on its investment" is not completely contained within the Shareholders Agreement or Shareholders Declaration, please provide any additional documents in which the Shareholder's expected return is set out.

OHL's Response:

Please find attached a copy of OHL's dividend policy in Appendix I – OHL Dividend Policy**.**

6.1-SEC-29

Ref: Ex.1/3/4, p. 4 and 11

Please advise the reason for the amount of $3,253,312 in Account 2220 for each of 2013 and 2014.

OHL's Response:

The amount of $3,253,312 for each 2013 and 2014 pro-forma financial statements is an estimate of the accrued liabilities based on prior years.

6.2 Has the applicant adequately demonstrated that the savings resulting from its operational effectiveness initiatives are sustainable?

6.2-Energy Probe-21

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.

OHL's Response:

As the requirement of operational effectiveness initiatives are new to OHL as presented in the draft score card from the Board in Q3 – 2013, OHL has not been tracking the annual savings of initiatives. However, OHL participates in the yearly UPMS survey which compares us to other 'like' participating utilities. OHL also refers to the OEB yearbook to analyze costs compared to other 'like' utilities. In future, OHL will attempt to identify added benefits or any potential annual savings to our customers from each initiative.

b. Please show now these initiatives have, or will result in savings to ratepayers.

OHL's Response:

Please also refer to OHL's response to 3.1-Staff-7 g.

c. Please explain how the savings identified in part (b) above are sustainable.

OHL's Response:

Please refer to OHL's response in a.

6.2-SEC-30

Ref: Ex.4/2/1/p.3

Please restate Appendix 2-L using the customer numbers in the Board's annual Electricity Distribution Yearbook for 2010-2012, and consistently derived figures for 2013 and 2014.

OHL's Response:

Please find the restated Appendix 2-L with corrected customer numbers.

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	11,340	11,256	11,248	11,392	11,528	11,662
Total Recoverable OM&A from Appendix 2-JB	$ 2,659,015	$ 2,639,719	$ 2,955,971	$ 3,099,161	$ 3,220,707	$ 3,495,183
OM&A cost per customer	$ 234.48	$ 234.52	$ 262.80	$ 272.05	$ 279.38	$ 299.71
Number of FTEs	20.0	19.5	20.0	20.0	21.0	21.0
Customers/FTEs	567.00	577.23	562.40	569.60	548.95	555.33
OM&A Cost per FTE	132,950.77	135,370.22	147,798.56	154,958.03	153,367.00	166,437.27

6.2–VECC–22

Please identify all "operational effectiveness initiatives" undertaken since 2010 and the annual savings each initiative has and will result in.

OHL's Response:

Please refer to the response provided to IR # 6.2-Energy Probe-21.

7. Revenue Requirement

7.1 Is the proposed Test year rate base including the working capital allowance reasonable?

7.1-Staff-26

Ref: E2/T1/S2, p.3
E2/T2/S3

On page 3 OHL makes reference to table 2:7, which should show the variance in rate base between the 2012 rate year and 2013 bridge year under the old CGAAP. However, this table is missing.

a. Please file the table 2:7.

OHL's Response:

Table 2:7 2012 Actual to 2013 Actual			
CGAAP	**2012 Actual**	**2013 Bridge**	**Variance**
Gross Fixed Assets	33,227,644	34,583,565	1,355,921
Accumulated Depreciation	18,009,217	19,122,202	1,112,985
Net Book Value	15,218,427	15,461,363	242,936
Average Net Book Value	14,922,913	15,339,895	416,982
Working Capital Expenses	26,005,586	28,116,815	2,111,230
15% Working Capital Allowance	3,900,838	4,217,522	316,684
Rate Base	18,823,751	19,557,417	733,666

b. Please explain why capital addition for under the old and the new CGAAP for 2013 are the same at $1,562,109 although OHL implemented its new capitalization policy on January 1, 2013.

OHL's Response:

The capital additions under the old CGAAP for 2013 should have read $1,582,283, a difference of $20,174 as the line labour did not include the safety and training in the overhead costs.

7.1-Energy Probe-22

Ref: Exhibit 2, Tab 2, Schedule 3 &
Exhibit 2, Tab 1, Schedule 1

a. Please explain why the additions shown for 2013 in both old CGAAP and new CGAAP are both $1,562,109. In particular, because of the capitalization changes implemented effective January 1, 2013 (Exhibit 2, Tab 1, Schedule 1, page 1), please explain how the additions under the two versions of CGAAP can be identical.

OHL's Response:

Please see OHL's response to 7.1-Staff-26 b.

b. How many months of actual data are reflected in the 2013 continuity schedules?

OHL's Response:

OHL did not use actual data in the 2013 continuity schedule.

c. Please provide updated continuity schedules for 2012 in both old CGAAP and new CGAAP that reflect the most recent year-to-date information available for 2013, along with, if necessary, the estimate for the remainder of 2013.

OHL's Response:

Please find the updated continuity schedules for 2013 in both old CGAAP and new CGAAP that reflect the actual information for 2013.

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**OLD CGAAP Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	122,655	0	0	122,655	0	0	0	0	122,655
CEC	1806	Land Rights	51,123	7,153	0	58,275	16,115	2,188	0	18,303	39,972
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	(0)
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primary	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	904,696	26,164	0	930,860	525,221	19,352	0	544,573	386,287
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	4,267,835	113,964	0	4,381,799	2,859,243	131,749	0	2,990,992	1,390,807
47	1835	Overhead Conductors and Devices	3,856,558	55,970	0	3,912,528	2,296,817	123,925	0	2,420,742	1,491,786
47	1840	Underground Conduit	4,569,868	301,233	0	4,871,101	2,190,290	163,261	0	2,353,551	2,517,550
47	1845	Underground Conductors and Devices	5,585,919	376,695	0	5,962,614	2,663,761	204,475	0	2,868,237	3,094,378
47	1850	Line Transformers	7,876,856	185,836	0	8,062,692	4,114,819	285,219	0	4,400,038	3,662,654
47	1855	Services	2,463,423	86,234	0	2,549,657	1,553,178	80,412	0	1,633,589	916,068
47	1860	Meters	296,808	0	13,347	283,462	78,793	11,594	2,702	87,685	195,776
	1860	Meters (Smart Meters)	1,778,199	56,742	12,811	1,822,130	284,191	121,644	4,649	401,186	1,420,944
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	144,400	0	0	144,400	0	0	0	0	144,400
CEC	1906	Land Rights	4,938	0	0	4,938	4,938	0	0	4,938	0
47	1908	Buildings and Fixtures	2,826,518	5,167	5,000	2,826,685	946,742	48,927	300	995,368	1,831,316
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	209,909	15,501	2,435	222,975	121,171	14,706	2,402	133,475	89,500
10	1920	Computer Equipment - Hardware	175,808	12,119	52,186	135,741	118,901	22,359	51,134	90,125	45,616
12	1925	Computer Software	789,233	36,054	14,696	810,592	491,170	111,756	14,541	588,384	222,208
10	1930	Transportation Equipment	1,011,299	0	0	1,011,299	795,865	87,300	0	883,165	128,134
8	1935	Stores Equipment	33,294	1,299	0	34,593	27,210	1,172	0	28,381	6,212
8	1940	Tools, Shop and Garage Equipment	148,154	1,487	20,176	129,466	126,606	3,789	20,181	110,214	19,251
8	1945	Measurement and Testing Equipment	21,790	10,070	0	31,860	15,540	1,528	0	17,068	14,792
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	18,701	0	0	18,701	18,342	234	0	18,576	125
8	1960	Miscellaneous Equipment	159,668	2,551	0	162,220	27,032	15,645	0	42,678	119,542
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	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 and Grants	(4,090,008)	(384,755)	(384,755)	(4,090,008)	(1,266,726)	(172,006)	0	(1,438,732)	(2,651,276)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**33,227,644**	**909,485**	**(264,104)**	**34,401,234**	**18,009,217**	**1,279,230**	**95,910**	**19,192,537**	**15,208,697**
WIP		Work in Process	166,768			166,768	0			0	166,768
		Total after Work in Process	**33,394,412**	**909,485**	**(264,104)**	**34,568,002**	**18,009,217**	**1,279,230**	**95,910**	**19,192,537**	**15,375,465**
							Less: Fully Allocated Depreciatic				
							Transportation	87,300			(459,024)
							Communication	234			
							Stores	1,172			
							Tools,Shop	3,789			
							Testing Equip	1,528			
							Net Depreciatior	1,185,207			

			Cost				Accumulated Depreciation				
CCA Class	OEB	NEW CGAAP Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	122,655	0	0	122,655	0	0	0	0	122,655
CEC	1806	Land Rights	51,123	7,153	0	58,275	16,115	2,188	0	18,303	39,972
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	(0)
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primary	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	904,696	25,707	0	930,403	538,881	38,892	0	577,773	352,630
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	4,238,936	111,976	29,605	4,321,306	2,751,933	53,369	24,729	2,780,573	1,540,733
47	1835	Overhead Conductors and Devices	3,854,541	54,994	83,813	3,825,721	2,203,665	36,942	71,882	2,168,725	1,656,996
47	1840	Underground Conduit	4,569,868	295,976	0	4,865,845	2,091,164	63,777	0	2,154,940	2,710,904
47	1845	Underground Conductors and Devices	5,577,840	370,122	22,226	5,925,736	2,589,027	165,157	50,771	2,703,413	3,222,323
47	1850	Line Transformers	7,818,886	182,593	58,820	7,942,659	3,922,675	137,005	111,106	3,948,573	3,994,086
47	1855	Services	2,460,489	84,729	0	2,545,217	1,507,392	38,950	0	1,546,342	998,876
47	1860	Meters	264,005	0	13,347	250,659	65,814	24,715	2,702	87,827	162,832
	1860	Meters (Smart Meters	1,775,402	56,742	12,811	1,819,333	284,191	104,051	4,649	383,592	1,435,741
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	144,400	0	0	144,400	0	0	0	0	144,400
CEC	1906	Land Rights	4,938	0	0	4,938	4,938	0	0	4,938	0
47	1908	Buildings and Fixtures	2,826,518	5,167	5,000	2,826,685	974,064	76,090	300	1,049,853	1,776,831
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	209,909	15,501	2,435	222,975	121,132	14,413	2,402	133,143	89,832
10	1920	Computer Equipment - Hardware	175,808	12,119	52,186	135,741	121,479	21,158	51,134	91,504	44,238
12	1925	Computer Software	789,233	36,054	14,696	810,592	512,792	110,189	14,541	608,439	202,153
10	1930	Transportation Equipment	1,011,299	0	0	1,011,299	749,700	39,766	0	789,465	221,833
8	1935	Stores Equipment	33,294	1,299	0	34,593	27,210	1,172	0	28,381	6,212
8	1940	Tools, Shop and Garage Equipment	148,154	1,487	20,176	129,466	126,606	3,794	20,181	110,219	19,246
8	1945	Measurement and Testing Equipment	21,790	10,070	0	31,860	15,540	1,291	0	16,831	15,030
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	18,701	0	0	18,701	18,342	234	0	18,576	125
8	1960	Miscellaneous Equipment	159,668	2,551	0	162,220	47,900	15,645	0	63,546	98,674
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	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 and Grants	(4,090,008)	(384,755)	0	(4,474,763)	(1,193,757)	(92,406)	0	(1,286,162)	(3,188,601)
	2005					0	0	0	0	0	0
		Total before Work in Process	**33,092,145**	**889,485**	**315,115**	**33,666,515**	**17,496,801**	**856,392**	**354,398**	**17,998,795**	**15,667,721**
WIP		Work in Process	166,768	0	0	166,768	0	0	0	0	166,768
		MIFRS Total after Work in Process	**33,258,913**	**889,485**	**315,115**	**33,833,284**	**17,496,801**	**856,392**	**354,398**	**17,998,795**	**15,834,489**
					check total	33,666,515			check	(17,998,795)	
							Less: Fully Allocated Depreciatic				
							Transportation	39,766			
							Communication	234			
							Stores	1,172			
							Tools,Shop	3,794			
							Testing Equip	1,291			
							PP&E Adjustme	(459,024)			
							Net Depreciatior	810,135			

d. Please provide a revised continuity schedule for 2014 based on the response to part (c) above.

OHL's Response:

			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	122,655	0	0	122,655	0	0	0	0	122,655
CEC	1806	Land Rights	58,275	0	0	58,275	18,303	2,331	0	20,634	37,641
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	(0)
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primary	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	930,403	119,607	0	1,050,010	577,773	41,176	0	618,949	431,061
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	4,321,306	49,922	689	4,370,539	2,780,573	55,174	530	2,835,216	1,535,323
47	1835	Overhead Conductors and Devices	3,825,721	107,077	4,005	3,928,794	2,168,725	38,497	3,781	2,203,441	1,725,353
47	1840	Underground Conduit	4,865,845	308,124	0	5,173,969	2,154,940	69,799	0	2,224,739	2,949,230
47	1845	Underground Conductors and Devices	5,925,736	226,163	27,976	6,123,924	2,703,413	159,065	23,334	2,839,144	3,284,779
47	1850	Line Transformers	7,942,659	385,854	2,304	8,326,209	3,948,573	138,033	1,622	4,084,984	4,241,226
47	1855	Services	2,545,217	132,685	0	2,677,902	1,546,342	41,744	0	1,588,086	1,089,816
47	1860	Meters	250,659	0	0	250,659	87,827	0	0	87,827	162,832
	1860	Meters (Smart Meters	1,819,333	45,764	0	1,865,097	383,592	169,633	0	553,225	1,311,872
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	144,400	0	0	144,400	0	0	0	0	144,400
CEC	1906	Land Rights	4,938	0	0	4,938	4,938	0	0	4,938	0
47	1908	Buildings and Fixtures	2,826,685	29,500	0	2,856,184	1,049,853	76,498	0	1,126,351	1,729,833
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	222,975	17,200	0	240,175	133,143	15,800	0	148,943	91,231
10	1920	Computer Equipment - Hardware	135,741	77,200	0	212,941	91,504	28,264	0	119,768	93,173
12	1925	Computer Software	810,592	42,000	0	852,592	608,439	94,715	0	703,154	149,438
10	1930	Transportation Equipment	1,011,299	35,000	18,229	1,028,069	789,465	41,224	12,755	817,935	210,135
8	1935	Stores Equipment	34,593	2,000	0	36,593	28,381	1,238	0	29,620	6,974
8	1940	Tools, Shop and Garage Equipment	129,466	5,000	0	134,466	110,219	3,704	0	113,923	20,542
8	1945	Measurement and Testing Equipment	31,860	5,000	0	36,861	16,831	2,519	0	19,350	17,511
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	18,701	0	0	18,701	18,576	125	0	18,701	(0)
8	1960	Miscellaneous Equipment	162,220	5,600	0	167,820	63,546	16,053	0	79,599	88,221
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	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 and Grants	(4,474,763)	(298,474)	0	(4,773,238)	(1,286,162)	(101,425)	0	(1,387,587)	(3,385,651)
	2005				0	0	0	0	0	0	0
		Total before Work in Process	**33,666,515**	**1,295,222**	**53,203**	**34,908,534**	**17,998,795**	**894,166**	**42,022**	**18,850,939**	**16,057,596**
WIP		Work in Process	166,768	0	0	166,768	0	0	0	0	166,768
		MIFRS Total after Work in Process	**33,833,284**	**1,295,222**	**53,203**	**35,075,303**	**17,998,795**	**894,166**	**42,022**	**18,850,939**	**16,224,364**
					check total	34,908,534			check	(18,850,939)	
							Less: Fully Allocated Depreciation				
							Transportation	41,224			
							Communication	125			
							Stores	1,238			
							Tools,Shop	3,704			
							Testing Equip	2,519			
							Net Depreciation	845,356			

e. Please provide details on the disposal of land in 2012 in the amount of $270,589.

OHL's Response:

This amount was transferred to 1572 and included in the Z-factor claim.

f. Please explain the disposals associated with accumulated depreciation in 2014 where there is no corresponding disposal of asset costs.

OHL's Response:

The disposals associated with accumulated depreciation in 2014 were missing from the 2014 Continuity Schedule.

7.1-Energy Probe-23

Ref: Exhibit 2, Tab 2, Schedule 1

The continuity schedule for 2014 shows a reduction in the additions to accumulated depreciation of approximately $72,000 for a number of line items. Please provide a breakdown of how much of this amount has been capitalized and how much has been expensed and included in the OM&A forecast.

OHL's Response:

The table below shows how the fully allocated depreciation is distributed to OM&A, Capital and Chargeable Jobs.

Fully Allocated Depreciation Total	71,931
Amount Allocated to OM&A	30,835
Amount Allocated to Capital	37,309
Amount Allocated to Chargeable Jobs	3,787
Total	71,931

7.1-Energy Probe-24

Ref: Exhibit 2, Tab 3, Schedule 1

a. Please explain why the cost of power shown in Table 2:11 does not match the cost of power shown at the bottom of the table on page 4.

OHL's Response:

The cost of power shown in Table 2:11 does not match the cost of power shown at the bottom of the table on page 4 because the 4708-Smart Meter Entity Charge was missing from the total.

	2013
4705-Power Purchased	20,783,463
4708-Charges-WMS	1,121,833
4714-Charges-NW	1,795,781
4716-Charges-CN	917,041
4730-Rural Rate Assistance	305,954
4750-Low Voltage	379,363
4708-Smart meter entity charges	107,395
TOTAL	**25,410,830**

b. Please explain why the sum of the RPP and non-RPP volumes shown in the table on page 4 do not match the volumes shown in table on the top of page 2 for the GS > 50 and streetlighting classes.

OHL's Response:

The amounts for the GS > 50kW and Streetlight classes had incorrect volumes in the Electricity – Commodity Non-RPP section. Please see the revised tables below.

Electricity - Commodity RPP	**2014**	**2014 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2014**		
Residential	78,990,897	1.0481	82,790,359	$0.07932	$6,566,931
General Service < 50 kW	30,652,180	1.0481	32,126,550	$0.07932	$2,548,278
General Service > 50	7,988,220	1.0481	8,372,453	$0.07932	$664,103
Streetlights Connections	275,035	1.0481	288,264	$0.07932	$22,865
Sentinel Lights Connections	122,073	1.0481	127,945	$0.07932	$10,149
Unmetered Loads Connections	358,304	1.0481	375,539	$0.07932	$29,788
TOTAL	**118,386,710**		**124,081,111**		**$9,842,114**

Electricity - Commodity Non-RPP	**2014**	**2014 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2014**		
Residential	10,716,067	1.0481	11,231,510	$0.08001	$898,633
General Service < 50 kW	6,127,943	1.0481	6,422,697	$0.08001	$513,880
General Service > 50	112,042,914	1.0481	117,432,178	$0.08001	$9,395,749
Streetlights Connections	1,586,582	1.0481	1,662,897	$0.08001	$133,048
Sentinel Lights Connections	463	1.0481	485	$0.08001	$39
Unmetered Loads Connections	0	1.0481	0	$0.08001	$0
TOTAL	**130,473,969**		**136,749,767**		**$10,941,349**

7.1-Energy Probe-25

Ref: Exhibit 2, Tab 3, Schedule 1

Do the OM&A costs shown in Table 2:11 include any fully allocated depreciation expense? If yes, please quantify the amount included in the OM&A forecast for 2014.

OHL's Response:

Yes, there are fully allocated depreciation expenses in the OM&A costs amounting to $30,835 as shown in the table presented in the response to 7.1-Energy Probe-23.

7.1-Energy Probe-26

Ref: Exhibit 2, Tab 3, Schedule 1

a. Please explain how the RPP and non-RPP prices shown for 2014 in the table on page 4 have been calculated, including the source of the information used.

OHL's Response:

The RPP prices shown for 2014 in the table on page 4 have been calculated using the Average Supply Cost for RPP consumers of $79.32/MWH from the Regulated Price Plan: Price Report (November 2012 to October 2013) released by the OEB on October 17, 2012.

The non-RPP prices shown for 2014 in the table on page 4 have been calculated using the sum of the Forecast Wholesale Electricity price $20.65/MWH and the impact of the Global Adjustment $59.36/MWH from the Regulated Price Plan: Price Report (November 2012 to October 2013) released by the OEB on October 17, 2012.

b. Please update the 2014 cost of power table shown on page 4 to reflect any updates to the source of the information used, as identified in part (a) above, and show the calculations of the new figures used for the RPP and non-RPP prices.

OHL's Response:

The 2014 cost of power table shown on page 4 has been changed to reflect the updates to the Regulated Price Plan: Price Report (November 2013 – October 2014), as identified in part (a) above, and show the calculations of the new figures used for the RPP and non-RPP prices. Please note the Electricity – Commodity Non-RPP for General Service > 50kW and Streetlights has been changed to reflect OHL's response to **7.1-Energy Probe-24 b.**

2014 Load Foreacst	**kWh**	**kW**	**2012 %RPP**		
Residential	89,450,364		88%		
General Service < 50 kW	37,137,194		83%		
General Service > 50	120,882,796	291,672	7%		
Streetlights Connections	1,861,618	5,230	15%		
Sentinel Lights Connections	122,536	339	100%		
Unmetered Loads Connections	358,304		100%		
TOTAL	**249,812,812**	**297,241**			
	249,812,812	297,241			
Electricity - Commodity RPP	**2014**	**2014 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2014**		
Residential	78,764,950	1.0481	82,553,544	$0.08900	$7,347,265
General Service < 50 kW	30,949,759	1.0481	32,438,443	$0.08900	$2,887,021
General Service > 50	8,044,899	1.0481	8,431,859	$0.08900	$750,435
Streetlights Connections	275,035	1.0481	288,265	$0.08900	$25,656
Sentinel Lights Connections	122,073	1.0481	127,944	$0.08900	$11,387
Unmetered Loads Connections	358,304	1.0481	375,539	$0.08900	$33,423
TOTAL	**118,515,021**		**124,215,594**		**$11,055,188**
Electricity - Commodity Non-RPP	**2014**	**2014 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2014**		
Residential	10,685,414	1.0481	11,199,383	$0.08760	$981,066
General Service < 50 kW	6,187,434	1.0481	6,485,050	$0.08760	$568,090
General Service > 50	112,837,897	1.0481	118,265,400	$0.08760	$10,360,049
Streetlights Connections	1,586,582	1.0481	1,662,897	$0.08760	$145,670
Sentinel Lights Connections	463	1.0481	485	$0.08760	$43
Unmetered Loads Connections	0	1.0481	0	$0.08760	$0
TOTAL	**131,297,791**		**137,613,215**		**$12,054,918**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	93,752,927	$0.0069	$649,980
General Service < 50 kW		kWh	38,923,493	$0.0064	$249,095
General Service > 50		kW	291,672	$2.6187	$763,806
Streetlights Connections		kW	5,230	$1.9749	$10,329
Sentinel Lights Connections		kW	339	$1.9848	$673
Unmetered Loads Connections		kWh	375,539	$0.0064	$2,403
TOTAL					**$1,676,285**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	93,752,927	$0.0034	$319,408
General Service < 50 kW		kWh	38,923,493	$0.0031	$120,908
General Service > 50		kW	291,672	$1.2309	$359,018
Streetlights Connections		kW	5,230	$0.9514	$4,976
Sentinel Lights Connections		kW	339	$0.9716	$329
Unmetered Loads Connections		kWh	375,539	$0.0031	$1,167
TOTAL					**$805,807**

Wholesale Market Service		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	93,752,927	$0.0044	$412,513
General Service < 50 kW		kWh	38,923,493	$0.0044	$171,263
General Service > 50		kWh	120,882,796	$0.0044	$531,884
Streetlights Connections		kWh	1,861,618	$0.0044	$8,191
Sentinel Lights Connections		kWh	122,536	$0.0044	$539
Unmetered Loads Connections		kWh	375,539	$0.0044	$1,652
TOTAL				$0.0000	**$1,126,043**

Rural Rate Assistance		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	93,752,927	$0.0012	$112,504
General Service < 50 kW		kWh	38,923,493	$0.0012	$46,708
General Service > 50		kWh	120,882,796	$0.0012	$145,059
Streetlights Connections		kWh	1,861,618	$0.0012	$2,234
Sentinel Lights Connections		kWh	122,536	$0.0012	$147
Unmetered Loads Connections		kWh	375,539	$0.0012	$451
TOTAL					**$307,103**

LV		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	89,450,364	$ 0.0016	$147,173
General Service < 50 kW		kWh	37,137,194	$ 0.0015	$55,711
General Service > 50		kW	291,672	$ 0.5944	$173,381
Streetlights		kW	5,230	$ 0.4595	$2,403
Sentinel Lights		kW	339	$ 0.4692	$159
Unmetered Loads Connections		kWh	358,304	$ 0.0015	$538
TOTAL					**379,363**

IESO Smart Meter Entity Charrge					
Class per Load Forecast		Customers		2013	
Residential			10,204	0.79	96736.34538
GS<50			1,124	0.79	10658.40464
TOTAL					**$107,395**

	2013
4705-Power Purchased	23,110,105
4708-Charges-WMS	1,126,043
4714-Charges-NW	1,676,285
4716-Charges-CN	805,807
4730-Rural Rate Assistance	307,103
4750-Low Voltage	379,363
4708-Smart meter entity charges	107,395
TOTAL	**27,512,101**

7.1-Energy Probe-27

Ref: Exhibit 2, Tab 3, Schedule 1

For each of the components of the cost of power shown in the table on page 4, please indicate when OHL pays the corresponding invoices (i.e. on average how many days after the end of the month are the invoices paid).

OHL's Response:

Hydro One
Electricity Commodity RPP
Electricity Commodity Non-RPP
Transmission – Network
Transmission – Connection
LV

Hydro One invoices are due anywhere from 35 – 50 calendar days from the end of the month.

IESO
Wholesale Market Service
Rural Rate Assistance
IESO Smart Meter Entity Charge

IESO invoices are due on average 12 business days from the end of the month.

7.1-SEC-31

Ref: Ex. 2/5/1, p. 1

Please confirm that parts of a conversion project are considered complete for rate base purposes only when they are energized.

OHL's Response:

OHL confirms that parts of a conversion projects are considered complete only when they are energized.

7.1–VECC–23

Ref: Exhibit 2, Tab 3, Schedule 1

Has OHL changed its billing cycle since 2010?

OHL's Response:

OHL has not changed its billing cycle since 2010. OHL bills its customers monthly.

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-28

Ref: Exhibit 4, Tab 7, Schedule 1

Did OHL use the half year rule in the calculation of the depreciation expense in its last rebasing application for 2010 rates? If not, what methodology was used by OHL in that filing and decision?

OHL's Response:

OHL did use the half year rule in the calculation of the depreciation expense in its last rebasing application for 2010 rates.

7.2 –VECC–24
Ref: Exhibit 2, Tab 2, Schedule 4, pg.2

a. Please provide a table showing those assets which OHL has determined should not fall within the useful service life recommended in the Kinectrics Report.

OHL's Response:

All of the useful service life's fall within the useful service life's recommended in the Kinectrics Report as shown in the *Service Life of Assets Table* in Exhibit 2, Tab 2, Schedule 4.

b. Please provide an estimate of the revenue requirement impact of the cumulate departures shown in a).

OHL's Response:

There was no revenue requirement impact as OHL did not depart form the useful service life's recommended in the Kinectrics Report.

7.2–VECC–25
Ref: Exhibit 2, Tab 2, Schedule 2 / Appendix 2-BA

Please provide an amended Appendix 2-BA for 2010 showing only the Costs and Accumulated Depreciation of the Grand Valley acquisition.

OHL's Response:

Please see the amended Appendix 2-BA for 2010 showing only the Costs and Accumulated Depreciation of the Grand Valley acquisition.

Appendix 2-BA												
Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP												
				Year	2010							
			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)	$ 25,822		-$ 25,822	$ 0		15,696.39		-$ 15,696	$ -	$ 0
CEC	1612	Land Rights (Formally known as Account 1906)				$ -					$ -	$ -
N/A	1805	Land				$ -					$ -	$ -
47	1808	Buildings				$ -					$ -	$ -
13	1810	Leasehold Improvements				$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -					$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 41,899.60			$ 41,900		6,983.35			$ 6,983	$ 34,916
47	1825	Storage Battery Equipment				$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 247,481			$ 247,481		197,054.00			$ 197,054	$ 50,427
47	1835	Overhead Conductors & Devices	$ 151,056			$ 151,056		99,278.99			$ 99,279	$ 51,777
47	1840	Underground Conduit				$ -					$ -	$ -
47	1845	Underground Conductors & Devices	$ 244,895			$ 244,895		189,022.84			$ 189,023	$ 55,872
47	1850	Line Transformers	$ 295,300			$ 295,300		188,111.78			$ 188,112	$ 107,188
47	1855	Services (Overhead & Underground)	$ 56,489			$ 56,489		43,148.36			$ 43,148	$ 13,341
47	1860	Meters	$ 67,051			$ 67,051		50,678.48			$ 50,678	$ 16,373
47	1860	Meters (Smart Meters)				$ -					$ -	$ -
N/A	1905	Land				$ -					$ -	$ -
47	1908	Buildings & Fixtures				$ -					$ -	$ -
13	1910	Leasehold Improvements				$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 17,891		-$ 17,891	$ -		12,878.98		-$ 12,879	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ 20,154		-$ 17,891	$ 2,262		19,425.09		-$ 19,425	$ -	$ 2,262
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -					$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -					$ -	$ -
10	1930	Transportation Equipment				$ -					$ -	$ -
8	1935	Stores Equipment				$ -					$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -					$ -	$ -
8	1945	Measurement & Testing Equipment				$ -					$ -	$ -
8	1950	Power Operated Equipment				$ -					$ -	$ -
8	1955	Communications Equipment				$ -					$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -					$ -	$ -
8	1960	Miscellaneous Equipment				$ -					$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -					$ -	$ -
47	1980	System Supervisor Equipment				$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -					$ -	$ -
47	1990	Other Tangible Property				$ -					$ -	$ -
47	1995	Contributions & Grants				$ -					$ -	$ -
	etc.					$ -					$ -	$ -
						$ -					$ -	$ -
		Sub-Total	$ 1,168,040	$ -	-$ 61,606	$ -		822,278.26	$ -	-$ 48,000	$ 774,278	$ 332,156
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
		Total PP&E	$ 1,168,040	$ -	-$ 61,606	$ -		822,278.26	$ -	-$ 48,000	$ 774,278	$ 332,156

7.3 Are the proposed levels of taxes appropriate?

7.3-Staff-27

Ref: E4/T8/S1, p. 1

Has OHL received its 2012 tax assessment? If yes, please provide the tax assessment.

OHL's Response:

OHL has provided the 2012 tax assessment as Appendix K – 2012 PILS Notice of Assessment.

7.3-Staff-28

Ref: E4/T8/S1, p.1 and Appendix C – PILS Workform

OHL's PILS tax form indicates that OHL will not be claiming SRED credit for the test year. Please provide further explanations as to why not, given that OHL was able to claim SRED credits for the 2012 rate year.

OHL's Response:

OHL is currently implementing Customer Connect, which may fit the criteria for the SRED credit. OHL is not aware that any additional budgeted expenses will trigger a SRED credit at this time.

7.3-Staff-29

Ref: E4/T4/S2 and Appendix C – PILS Workform

In the first reference OHL stated that it had a union staff increased by one Apprentice Lineperson in 2013. Please explain why OHL did not reflect an Apprenticeship Training Tax Credit in its PILs calculation.

OHL's Response:

OHL has revised the PILS workform to include the Apprenticeship Training Tax Credit for two months of 2013 and the maximum credit for 2014. OHL did not hire the apprentice until November 2013.

7.3-Energy Probe-29

Ref: Exhibit 4, Tab 8, Schedule 1

a. Does OHL have any positions that qualify for the Ontario Co-operative Education Tax Credit?

OHL's Response:

OHL hires a summer students for assistance for most years and they qualify for the Ontario Co-operative Education Tax Credit.

b. Has OHL claimed any amounts associated with the Ontario Apprenticeship Training Tax Credit or the federal job creation tax credit associated with the apprentice lineman noted in Exhibit 4, Tab 1, Schedule 1? If not, why not?

OHL's Response:

Please refer to response in Board Staff 7.3-Staff-29.

7.3-Energy Probe-30

Ref: Exhibit 4, Tab 8, Schedule 1, Appendix C

a. Please explain why OHL has included capital expenditures related to computer equipment in both 2013 and 2014 to CCA Class 10 (with a rate of 30%) rather than to CCA Class 50 (with a rate of 55%).

OHL's Response:

OHL has changed the CCA continuity schedules in the OEB tax model to reflect CCA Class 50. This schedule will be the basis of any other changes throughout these interrogatories to determine the Income tax payable for 2014.

b. Please provide revised CCA schedules for 2013 and 2014 with the computer equipment added to CCA Class 50 instead of Class 10.

OHL's Response:

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	$ 10,548,001			$ 10,548,001	$ -	$ 10,548,001	4%	$ 421,920	$ 10,126,081
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 138,636	$ 30,909		$ 169,545	$ 15,454	$ 154,090	20%	$ 30,818	$ 138,727
10	Computer Hardware/ Vehicles	$ 163,416	$ -	-$ 1,052	$ 162,364	$ -	$ 162,364	30%	$ 48,709	$ 113,655
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 45,397	$ 36,054	-$ 154	$ 81,297	$ 17,950	$ 63,347	100%	$ 63,347	$ 17,950
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	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	$ 862			$ 862	$ -	$ 862	45%	$ 388	$ 474
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 7,027,959	$ 803,250		$ 7,831,209	$ 401,625	$ 7,429,584	8%	$ 594,367	$ 7,236,843
50	Data Network Infrastructure Equipment - post Mar 2007	$ 14,356	$ 12,119		$ 26,475	$ 6,060	$ 20,416	55%	$ 11,229	$ 15,247
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 17,938,627	$ 882,333	-$ 1,206	$ 18,819,754	$ 441,089	$ 18,378,665		$ 1,170,778	$ 17,648,976

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	$ 10,126,081			$ 10,126,081	$ -	$ 10,126,081	4%	$ 405,043	$ 9,721,038
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 138,727	34,800		$ 173,527	$ 17,400	$ 156,127	20%	$ 31,225	$ 142,301
10	Computer Hardware/ Vehicles	$ 113,655	35,000	-10,000	$ 138,655	$ 12,500	$ 126,155	30%	$ 37,847	$ 100,809
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 17,950	42,000		$ 59,950	$ 21,000	$ 38,950	100%	$ 38,950	$ 21,000
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Tha	$ -			$ -	$ -	$ -	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	$ 474			$ 474	$ -	$ 474	45%	$ 213	$ 261
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 7,236,843	1,106,222		$ 8,343,065	$ 553,111	$ 7,789,954	8%	$ 623,196	$ 7,719,869
50	Data Network Infrastructure Equipment - post Mar 2007	$ 15,247	77,200		$ 92,447	$ 38,600	$ 53,847	55%	$ 29,616	$ 62,831
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 17,648,976	$ 1,295,222	-$ 10,000	$ 18,934,198	$ 642,611	$ 18,291,587		$ 1,166,090	$ 17,768,108

c. What is the impact on the PILs payable based on the higher CCA deduction as calculated in part (b) above?

OHL's Response:

The impact on the PILs payable based on the higher CCA deduction is a change from $69,957 to $89,967.

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 490,468	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	B	$ 22,071	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D				
	Rate reduction	-7.00%	E	$ -	F = D * E		
Ontario Income tax						$ 22,071	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	K = J / A		
	Federal tax rate			11.00%	L		
	Combined tax rate					15.50%	M = K + L
Total Income Taxes						$ 76,022	N = A * M
Investment Tax Credits							O
Miscellaneous Tax Credits							P
Total Tax Credits						$ -	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						$ 76,022	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				84.50%	S = 1 - M	$ 13,945	T = R / S - R
Income Tax (grossed-up)						$ 89,967	U = R + T

7.4 Is the proposed allocation of shared services and corporate costs appropriate?

7.4-Energy Probe-31

Ref: Exhibit 4, Tab 5, Schedule 1

a. Do the labour costs include salary, wages, benefits, overtime, bonus or incentive payments, etc.?

OHL's Response:

The labour costs include wages and benefits.

b. Do the vehicle costs include depreciation expenses, operating and maintenance expenses and the cost of capital associated with the assets?

OHL's Response:

The vehicle costs include depreciation, operating and maintenance expenses.

c. Do the material and contractor costs include costs associated with hiring contractors or procuring materials?

OHL's Response:

The contractor costs include costs that are associated with hiring contractors, and the materials costs are the costs associated with procuring materials.

d. Is any of the return on capital associated with the materials included in the building costs?

OHL's Response:

The building maintenance costs do not include any materials; therefore there is no return on capital in the building costs.

e. Please confirm that the costs for the service are not recorded in OM&A accounts but rather included as offsetting costs in other revenues.

OHL's Response:

OHL confirms that the costs for the services are not recorded in OM&A accounts and are included as offsetting costs in other revenues.

f. Has OHL included in any costs such as deprecation, return on capital, operating and maintenance costs, etc., associated with the equipment used to read meters and process bills in the costs associated with water billing? If yes, please provide calculations showing the costs included.

OHL's Response:

Equipment	Total Cost	Allocation Percentage
Automailer Maintenance	$2,122	$2,122 x 40% = $849
Bill Printer Maintenance	$1,224	$1,224 x 40% = $490

7.4-Energy Probe-32

Ref: Exhibit 4, Tab 2, Schedule 1

Appendix 2-JB shows a cost driver of $38,400 for File Nexus costs in 2014. Please indicate the total File Nexus OM&A costs and the amount that has been allocated to the city and to other affiliates.

OHL's Response:

Please refer to response in Board Staff 4.1-Staff-17.

7.4-SEC-32

Ref: Ex.4/5/1, p. 6

Please confirm that billing and collecting costs have increased 41.7% over the last four years. Please explain why the allocations to the Town of Orangeville for Water Billing have not increased by a similar amount.

OHL's Response:

OHL confirms that the billing and collecting costs have increased 41.7% based on Appendix 2-JA submitted in our rate application. Billing and collecting to the Town of Orangeville for water billing did not increase by a similar amount due to the nature of the regulatory requirements referred to in 4.2-VECC-10. Please refer to the response. These costs did not affect the costs for water billing being solely energy related. OHL has not increased customer service staff that performs the billing and collecting activities and the weighted activity of the staff is proportioned as it focuses more effort on the complexity of billing associated M/DMR and collections due to the OEB collections policy.

7.4-SEC-33

Ex.4/5/1, p. 6

Please confirm that OM&A expenditures have increased 32.4% over the last four years. Please explain why the allocations to the Town of Orangeville for Streetlight Maintenance have not increased by a similar amount.

OHL's Response:

OHL confirms that the OM&A expenditures have increased 32.4% based on Appendix 2-JA within our application. The allocations have not increased to the Town of Orangeville for street light maintenance because the Town is billed based on the total labour for the work that is performed, any material handling, with a 10% markup. In any given year there may be more street light maintenance, therefore OHL used its' best estimate in determining the forecast. The street light work was estimated based on historical.

7.4–VECC–26

Ref: Exhibit 4, Tab 5, Schedule 1

OHL states it charges cost plus 10% for streetlighting services. To OHL's knowledge which streetlight services providers operate in the Orangeville area? Has OHL compared the result of these charges with existing service providers of streetlighting services such as Black and MacDonald.

OHL's Response:

The Corporation of the Town of Orangeville owns the street lighting assets within the Town of Orangeville. OHL has not completed a detailed investigation of streetlight service providers within the Orangeville area.

7.5 Are the proposed capital structure, rate of return on equity and short and long term debt costs appropriate?

7.5-Staff-30

Ref: E5

OHL states that the cost of capital should be updated to reflect the Cost of Capital parameters as updated and issued by the Board for 2014 distribution rates. On November 25, 2013, the Board issued updated Cost of Capital parameters for rates effective in 2014 and determined on the basis of costs of service rates applications. The letter can be obtained at http://www.ontarioenergyboard.ca/OEB/_Documents/2014EDR/OEB_Ltr_Cost_of_Capital_update_2014Jan01_20131125.pdf . The following are the Cost of Capital parameters for 2014 cost of service rates applications:

Cost of Capital Parameter	Parameter Value for 2014 Cost of Service Rates Applications
Return on Equity (ROE)	9.36%
Deemed Long-term debt rate	4.88%
Deemed Short-term debt rate	2.11%

a. Please provide updated versions of Appendices 2-OA and 2-OB for the 2014 test year reflected the updated Cost of Capital parameters, as applicable.

OHL's Response:

OHL has updated the Appendix 2-OA to reflect the updated Cost of Capital parameters.

Year: 2014 Test

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$11,342,808	3.48%	$395,234
2	Short-term Debt	4.00%	(1)	$810,201	2.11%	$17,095
3	**Total Debt**	60.0%		$12,153,008	3.39%	$412,329
	Equity					
4	Common Equity	40.00%		$8,102,005	9.36%	$758,348
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$8,102,005	9.36%	$758,348
7	**Total**	100.0%		$20,255,013	5.78%	$1,170,677

OHL did not update Appendix 2-OB as all our debt instruments are third party.

b. Please reflect the updated Cost of Capital parameters in the updated RRWF reflecting changes made as a result of responses to interrogatories.

OHL's Response:

OHL has updated the RRWF reflecting the changes made as a result of responses to interrogatories and have included it with our submission.

c. Please reflect the updated Cost of Capital parameters in the calculation of any rate riders, such as for Accounts 1575 or 1576 or for Green Energy Act initiatives where the weighted average cost of capital will affect the determination of the amounts and the rate riders to recover or refund the balances for disposition.

OHL's Response:

OHL has updated Appendix 2-ED to reflect the updated Cost of Capital parameters and made the changes to the EDDVAR continuity schedule to calculate the correct rate riders. The chapter 2 appendices will be submitted in excel format along with the responses to the interrogatories.

7.5-Energy Probe-33

Ref: Exhibit 5, Tab 1, Schedule 2

Please update the 2014 table on page 3 to reflect the cost of capital parameters applicable to 2014 cost of service applications, as issued by the Board on November 25, 2013.

OHL's Response:

Please see the updated 2014 table below to reflect the cost of capital parameters applicable to 2014 cost of service applications, as issued by the Board on November 25, 2013.

2014 - CGAAP		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	3.48%
Short-Tern Debt	4.00%	2.11%
Return On Equity	40.00%	9.36%
Weighted Debt Rate		3.39%
Regulated Rate of Return		5.78%

WORKING CAPITAL ALLOWANCE FOR 2014		
Distribution Expenses		
Distribution Expenses - Operation		507,835
Distribution Expenses - Maintenance		616,413
Billing and Collecting		741,719
Community Relations		17,278
Administrative and General Expenses		1,611,938
Taxes Other than Income Taxes		-
Total Eligible Distribution Expenses		**3,495,183**
Power Supply Expenses		27,522,218
Total Working Capital Expenses		31,017,401
Working Capital Allowance @	13.00%	4,032,262

RATE BASE CALCULATION FOR 2014	
Fixed Assets Opening Balance 2014	15,667,721
Fixed Assets Closing Balance 2014	16,057,596
Average Fixed Asset Balance for 2014	15,862,658
Working Capital Allowance	4,032,262
Rate Base	19,894,920
Regulated Rate of Return	5.78%
Regulated Return on Capital	1,149,865
Deemed Interest Expense	404,999
Deemed Return on Equity	744,866

7.5-Energy Probe-34

Ref: Exhibit 5, tab 1, Schedule 1

a. What is the status of the new term loan of $2,500,000 that is forecast to be available January 1, 2014?

OHL's Response:

OHL recently met with TD Bank personnel and decided that the borrowing of the $2,500,000 would be included with the renewal of the smart meter loan #2 that expires in April 2014.

b. Has OHL approached Infrastructure Ontario for either of the two new loans forecast for 2014? If not, why not?

OHL's Response:

No, OHL did not approach Infrastructure Ontario (IO) for the two new loans forecasted for 2014. OHL investigated borrowing through IO in the past and noted that TD Bank offers a competitive interest rate with minimal administrative requirements. OHL felt that IO was very restrictive in borrowing to meet OEB deemed debt to equity levels, and required more administrative work providing information on a project detail level. Additionally, IO will not refinance if a loan has already been financed through another financial institution.

7.5–VECC–27

Reference: Exhibit 5, Tab 1, Schedule 1, pgs.1-2, 7

OHL states that is currently paying 3.38% on $5,366,868 loan that was re-negotiated with the TD Bank in 2012 and is due in 2022. However, the accompanying table at page 7 (Appendix 2-OB) for 2014 shows a principal amount of $4,803,653 @ 3.38%. Please explain the discrepancy

OHL's Response:

OHL was referring to the current amount of the loan amounting to $5,366,868 because this was the amount of the loan as at January 1, 2013. The amount of $4,803,653 in Appendix 2-OB is the amount of the same loan as at December 31, 2014.

7.5–VECC–28

Ref: Exhibit 5, Tab 1, Schedule 1

The evidence states that OHL renegotiated a loan at 4.25% to 3.38% in 2012. OHL also negotiated another loan in the latter part of 2012 at 2.79%. Please explain why OHL believes it will be unable to secure a new loan in 2013 below 3.4%. In providing this explanation please provide the prime rate posted at the time when the prior two loans were negotiated . Please also provide the current prime rate.

OHL's Response:

OHL received an estimate from the TD Bank forecasting the interest rates into 2014. We used a 5 year term loan, amortized over 25 years to come up with the interest rate at 4%. OHL justifies the use of the rate at 4% because this rate is comparable to the deemed debt rate published in the 2013 Board cost of capital parameters at 4.12% and the 2014 Board cost of capital parameters at 4.88%. At the end of January, OHL met with the TD bank and they provided current rates for the same time period noted above and it is currently 3.4%. Upon answering these interrogatories, the current prime rate is 3%. OHL has decided that the borrowing of the additional $2.5 million will be rolled together with the expiring loan in April thereby standing by our justification to use the 4% rate in calculation of OHL's cost of capital.

7.6 Is the proposed forecast of other revenues including those from specific service charges appropriate?

7.6-Staff-31

Ref: E3/T3/S2, p. 3
E2/T5/S9, p. 2, Appendix 2-ED

In Appendix 2-ED, the total in the deferral account as at 2013 is $821,499 before the associated return. In Exhibit 3, Tab 3, Schedule 2, Page 3, the amount recorded in Account 4305 Regulatory Debit is $173,590 and $847,666 for 2012 and 2013, totalling $1,021,256. OHL has indicated "In 2012 the actual entry for accounting changes was incorrect but is corrected in the Board's Appendix 2-ED".

a. Please explain what the nature of the incorrect entry for accounting changes was.

OHL's Response:

OHL recorded the smart meter entries but did not record the depreciation expense that was transferred from Account 1556 in the Old CGAAP. OHL did record this entry in the New CGAAP books. The table below shows the net difference between the initial entry and the corrected entry:

	Additions	Amortization	Net
2012 Total Net Additions Recorded	222,908	(992,238)	(769,330)
2012 Total Net Additions Corrrected	222,908	(788,910)	(566,002)
Total Difference	0	(203,328)	(203,328)
Amount Recorded			(173,590)
Difference from Above			(203,328)
Total Net Book Value			**(376,918)**

The table below highlights in orange, the amounts that OHL recorded at the end of the year 2012.

		2012 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	628,390	160,843		789,233	389,264	101,906		491,170	298,063
CEC	1612	Land Rights	56,061	0		56,061	19,008	2,045		21,053	35,008
N/A	1805	Land	267,376	125,868	270,589	122,655	0	0		0	122,655
47	1808	Buildings and Fixtures	15,296	0	15,296	0	15,296	0	15,296	0	(0)
13	1810	Leasehold Improvements	0	0		0	0	0		0	0
47	1815	Transformer Station Equipment - Normally Primary	0	0		0	0	0		0	0
47	1820	Distribution Station Equipment - Normally Primary	904,696	0		904,696	500,257	24,964		525,221	379,476
47	1825	Storage Battery Equipment	0	0		0	0	0		0	0
47	1830	Poles, Towers and Fixtures	4,177,407	90,427		4,267,835	2,724,270	134,973		2,859,243	1,408,592
47	1835	Overhead Conductors and Devices	3,788,531	68,027		3,856,558	2,169,250	127,567		2,296,817	1,559,741
47	1840	Underground Conduit	4,379,130	190,738		4,569,868	2,032,079	158,211		2,190,290	2,379,578
47	1845	Underground Conductors and Devices	5,333,922	251,997		5,585,919	2,462,228	201,534		2,663,761	2,922,158
47	1850	Line Transformers	7,480,326	396,530		7,876,856	3,858,839	255,980		4,114,819	3,762,037
47	1855	Services	2,327,702	135,722		2,463,423	1,473,252	79,926		1,553,178	910,246
47	1860	Meters	1,852,099	25,605	1,533,380	344,325	1,151,894	11,796	1,122,675	41,016	303,309
	1860	Meters (Smart Meters)		1,730,682		1,730,682	0	118,640		118,640	1,612,042
N/A	1865	Other Installations on Customer's Premises	0	0		0	0	0		0	0
N/A	1905	Land	144,400	0		144,400	0	0		0	144,400
CEC	1906	Land Rights	4,938	0		4,938	4,938	0		4,938	0
47	1908	Buildings and Fixtures	2,802,850	23,668		2,826,518	898,128	48,614		946,742	1,879,777
13	1910	Leasehold Improvements	0	0		0	0	0		0	0
8	1915	Office Furniture and Equipment	189,627	23,138	2,857	209,909	110,523	13,505	2,857	121,171	88,737
10	1920	Computer Equipment - Hardware	158,861	22,016	5,069	175,808	103,546	19,666	4,311	118,901	56,907
10	1930	Transportation Equipment	1,010,019	36,069	34,789	1,011,299	746,881	83,774	34,789	795,865	215,433
8	1935	Stores Equipment	32,212	1,606	524	33,294	26,478	1,255	524	27,210	6,085
8	1940	Tools, Shop and Garage Equipment	147,021	1,133		148,154	122,847	3,759		126,606	21,548
8	1945	Measurement and Testing Equipment	21,291	499		21,790	14,778	762		15,540	6,250
8	1950	Power Operated Equipment	0	0		0	0	0		0	0
8	1955	Communication Equipment	18,701	0		18,701	17,397	945		18,342	359
8	1960	Miscellaneous Equipment	46,689	112,979		159,668	11,697	15,336		27,032	132,636
47	1970	Load Management Controls - Customer Premises	0	0		0	0	0		0	0
47	1975	Load Management Controls - Utility Premises	0	0		0	0	0		0	0
47	1980	System Supervisory Equipment	0	0		0	0	0		0	0
47	1985	Sentinel Lighting Rentals	0	0		0	0	0		0	0
47	1990	Other Tangible Property	0	0		0	0	0		0	0
47	1995	Contributions and Grants	(3,793,000)	(297,008)		(4,090,008)	(1,108,784)	(157,942)		(1,266,726)	(2,823,282)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**31,994,545**	**3,100,540**	**1,862,504**	**33,232,582**	**17,744,064**	**1,247,215**	**1,180,451**	**17,810,828**	**15,421,754**
							Less: Fully Allocated Depreciation				(173,590)
							Transportation	83,774			
							Communication	945			
							Stores	1,255			
							Tools,Shop	3,759			
							Testing Equip	762			
							Net Depreciation	1,156,720			

The table below highlights in orange, the amounts that should have been recorded and the amounts that OHL submitted in the for the Old CGAAP continuity schedule (Appendix 2-BA1):

Old Year **Old CGAAP2012**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 628,390	$ 160,843	$ -	$ 789,233	$ 389,264	$ 101,906	$ -	$ 491,170	$ 298,063
CEC	1612	Land Rights (Formally known as Account 1906)	$ 56,060			$ 56,060	$ 19,008	$ 2,045		$ 21,052	$ 35,008
N/A	1805	Land	$ 267,376	$ 125,868	-$ 270,589	$ 122,655	$ -	$ -		$ -	$ 122,655
47	1808	Buildings	$ 15,296	$ -	-$ 15,296	$ -	$ 15,296	$ -	-$ 15,296	$ 0	-$ 0
13	1810	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 904,696	$ -		$ 904,696	$ 500,257	$ 24,964		$ 525,221	$ 379,476
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,177,407	$ 90,427		$ 4,267,835	$ 2,724,270	$ 134,973		$ 2,859,243	$ 1,408,592
47	1835	Overhead Conductors & Devices	$ 3,788,531	$ 68,027		$ 3,856,558	$ 2,169,250	$ 127,567		$ 2,296,817	$ 1,559,741
47	1840	Underground Conduit	$ 4,379,130	$ 190,738		$ 4,569,868	$ 2,032,079	$ 158,211		$ 2,190,290	$ 2,379,578
47	1845	Underground Conductors & Devices	$ 5,333,922	$ 251,997		$ 5,585,919	$ 2,462,228	$ 201,534		$ 2,663,761	$ 2,922,158
47	1850	Line Transformers	$ 7,480,326	$ 396,530		$ 7,876,856	$ 3,858,839	$ 255,980		$ 4,114,819	$ 3,762,037
47	1855	Services (Overhead & Underground)	$ 2,327,702	$ 135,722		$ 2,463,423	$ 1,473,252	$ 79,926		$ 1,553,178	$ 910,246
47	1860	Meters	$ 1,852,099	$ 22,198	-$ 1,577,489	$ 296,808	$ 1,151,894	$ 12,359	-$ 1,085,461	$ 78,793	$ 218,015
47	1860	Meters (Smart Meters)	$ -	$ 1,778,199		$ 1,778,199	$ -	$ 284,191		$ 284,191	$ 1,494,008
N/A	1905	Land	$ 144,400			$ 144,400	$ -			$ -	$ 144,400
47	1908	Buildings & Fixtures	$ 2,802,850	$ 23,668		$ 2,826,518	$ 898,128	$ 48,614		$ 946,742	$ 1,879,777
13	1910	Leasehold Improvements	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 189,627	$ 23,138	-$ 2,857	$ 209,909	$ 110,523	$ 13,505	-$ 2,857	$ 121,171	$ 88,737
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 158,861	$ 22,016	-$ 5,069	$ 175,808	$ 103,546	$ 19,666	-$ 4,311	$ 118,901	$ 56,907
10	1930	Transportation Equipment	$ 1,010,019	$ 36,069	-$ 34,789	$ 1,011,299	$ 746,881	$ 83,774	-$ 34,789	$ 795,865	$ 215,433
8	1935	Stores Equipment	$ 32,212	$ 1,606	-$ 524	$ 33,294	$ 26,478	$ 1,255	-$ 524	$ 27,210	$ 6,085
8	1940	Tools, Shop & Garage Equipment	$ 147,021	$ 1,133		$ 148,154	$ 122,847	$ 3,759		$ 126,606	$ 21,548
8	1945	Measurement & Testing Equipment	$ 21,291	$ 499		$ 21,790	$ 14,778	$ 762		$ 15,540	$ 6,250
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 18,701	$ -		$ 18,701	$ 17,397	$ 945		$ 18,342	$ 359
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 46,689	$ 112,979		$ 159,668	$ 11,697	$ 15,336		$ 27,032	$ 132,636
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 3,793,000	-$ 297,008		-$ 4,090,008	-$ 1,108,784	-$ 157,942		-$ 1,266,726	-$ 2,823,282
	etc.					$ -				$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 31,989,607**	**$ 3,144,650**	**-$ 1,906,613**	**$ 33,227,644**	**$ 17,739,126**	**$ 1,413,329**	**-$ 1,143,237**	**$ 18,009,217**	**$ 15,218,427**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 31,989,607**	**$ 3,144,650**	**-$ 1,906,613**	**$ 33,227,644**	**$ 17,739,126**	**$ 1,413,329**	**-$ 1,143,237**	**$ 18,009,217**	**$ 15,218,427**
											15,218,427

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	$ 83,774
Stores Equipment	$ 1,255
Tools, Shop	$ 3,759
Meas/Testing	$ 762
Communication	$ 945
Net Depreciation	$ 1,322,834

b. Please indicate if the correct amount has been recorded in OHL's books.

OHL's Response:

The amount was discovered after the 2012 year-end was finished and found during the process of completing this cost of service application. The adjusting entry will be made in OHL's books with the 2013 year-end entries.

c. Please explain what the actual amount recorded in Account 4305 Regulatory Debits is for 2012 and 2013.

OHL's Response:

The actual amount recorded in 4305 for 2012 remains as per OHL's 2012 year-end is $173,590. The amount in 4305 is $647,909, (-$821,499 - $173,590) arising from the accounting policy changes and does not include the rate of return component.

d. Please reconcile this with the amount recorded in Account 1576, excluding the return as per Appendix 2-ED.

OHL's Response:

The amount recorded in Appendix 2-ED for the total difference in closing net PP&E for Account 1576 is -$821,499 and is correct as filed based on the explanations given above. The table below changes only due to the rate of return component that should not be included in 1576 and the offset 4305.

Account	Table 3-34: Regulatory Debits	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2012 Actual	2013 Bridge	2013 Bridge	2014 Test
	Reporting Basis				CGAAP	CGAAP-n	CGAAP	CGAAP-n	CGAAP
4305	Regulatory Debits		0	0	0	(173,590)	0	(647,909)	0

7.6-Staff-32

Ref: E3/T3/S1

Please provide the most recent year-to-date actuals for 2013 and any remaining forecast, if applicable. Please update Appendix 2-H for the most recent year-to-date figures and provide the comparable figures for 2012.

OHL's Response:

Please see below an updated Apendix 2-H for the actual year to date figures for 2013.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2013	2013	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4235	Specific Service Charges	$ 156,473	$ 196,110	$ 214,612	$ 214,612	$ 172,627	$ 172,627	$ 199,731
4225	Late Payment Charges	$ 38,019	$ 42,726	$ 35,758	$ 35,758	$ 34,152	$ 34,152	$ 37,958
4082	Retail Service Charges - Billing Fee	$ 23,683	$ 20,119	$ 17,445	$ 17,445	$ 14,815	$ 14,815	$ 20,596
4084	Retail Service Charges - STR's	$ 301	$ 285	$ 363	$ 363	$ 288	$ 288	$ 339
4086	SSS Admin Fees	$ 29,420	$ 27,747	$ 30,412	$ 30,412	$ 31,419	$ 31,419	$ 31,020
4210	Rent from Electric Property	$ 54,484	$ 66,388	$ 64,169	$ 64,169	$ 49,033	$ 49,033	$ 54,960
4305	Regulatory Debits	$ -	$ -	$ -	-$ 173,590	$ -	-$ 285,434	$ -
4355	Gain on Disposal	$ 3,595	$ 3,372	$ 16,821	$ 23,076	$ 3,488	$ 3,488	$ 10,000
4360	Loss on Disposal	-$ 21,863	-$ 2,943	-$ 930	-$ 37,367	$ -	-$ 53,440	-$ 5,707
4375	Revenue Non-Utililty Operations	$ 463,788	$ 493,103	$ 482,010	$ 482,010	$ 479,359	$ 479,359	$ 456,408
4380	Expenses Non Utility Operation	-$ 357,496	-$ 363,510	-$ 378,134	-$ 378,134	-$ 359,102	-$ 359,102	-$ 385,484
4390	Misc. Non Operating Income	$ 4,420	$ 17,335	$ 6,084	-$ 171			$ -
4405	Interest & Dividend Income	$ 37,768	$ 50,522	$ 106,994	$ 106,994	$ 41,356	$ 41,356	$ 44,000
4324	Special Purpose Charge	$ 64,281	$ -	$ -	$ -	$ -	$ -	$ -
Specific Service Charges		$ 156,473	$ 196,110	$ 214,612	$ 214,612	$ 172,627	$ 172,627	$ 199,731
Late Payment Charges		$ 38,019	$ 42,726	$ 35,758	$ 35,758	$ 34,152	$ 34,152	$ 37,958
Other Operating Revenues		$ 107,888	$ 114,539	$ 112,389	$ 112,389	$ 95,555	$ 95,555	$ 106,916
Other Income or Deductions		$ 194,493	$ 197,879	$ 232,845	$ 22,818	$ 165,101	-$ 173,773	$ 119,218
Total		$ 496,873	$ 551,254	$ 595,604	$ 385,577	$ 467,435	$ 128,561	$ 463,822
		496,873	551,253	385,577	385,577	(471,314)	(599,875)	463,822

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP		CGAAP	CGAAP	CGAAP
Short-term Investment Interest	$ 1,871						
Bank Deposit Interest	$ 24,397	$ 27,000	$ 32,438	$ 32,438	$ 41,356	$ 41,356	$ 44,000
Miscellaneous Interest Revenue	$ 4,106	$ 1,608	-$ 27,610	-$ 27,610			
SR&ED Credit			$ 90,521	$ 90,521			
Variance Account Carrying Charges	$ 7,394	$ 21,914	$ 11,645	$ 11,645			
Total	$ 37,768	$ 50,522	$ 106,994	$ 106,994	$ 41,356	$ 41,356	$ 44,000

7.6-Energy Probe-35

Ref: Exhibit 3, Tab 3, Schedule 1

a. Please update Appendix 2-H to reflect the most recent year-to-date actuals for 2013 along with a forecast for the remainder of the year.

OHL's Response:

Please refer to OHL's response to 7.6-Staff-32.

b. Please provide the most recent year-to-date figures for 2013 in the same level of detail as shown in Appendix 2-H. Please also provide the corresponding figures for the same period in 2012.

OHL's Response:

Please refer to OHL's response to 7.6-Staff-32.

7.6-Energy Probe-36

Ref: Exhibit 3, Tab 3, Schedule 4

The evidence states that OHL collected additional revenues from the Towns to pay for their portion of the capital investment of the new Harris CIS system in 2009 and for the File Nexus system purchase in 2012.

a. Does this mean that only the portion of these capital expenditures are included in the regulated rate base of OHL, given that the Towns paid for their portion of the capital investments? If not, please explain how the accounting was done from both an asset and revenue perspective.

OHL's Response:

Yes, only a portion of the capital investment of the new Harris CIS system in 2009 and for the File Nexus system purchased in 2012 are included in the regulated rate base.

b. If all of the capital investments associated with these types of projects have been included in the regulated rate base, please provide the average net book value of these assets in the 2014 test year.

OHL's Response:

The average net book value for the CIS system is $14,671, and for File Nexus is $28,786 .

c. What proportion of these assets was allocated to the Towns for each of these assets?

OHL's Response:

The proportion of these assets is 80/20 for hydro and water respectively. The ratio was calculated based on a weighting of the systems functionality.

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-33

Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF in 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.

OHL's Response:

OHL has provided an updated RRWF in Excel Format with any corrections or adjustments .

7.7-Staff-34

Updated Appendix 2-W, Bill Impacts

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 (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

OHL's Response:

Please see attached Appendix L – Revised Bill Impacts.

7.7-Energy Probe-37

Ref: Exhibit 6

a. Please update Table 6.1 and 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.

OHL's Response:

Please see the updated Table 6.1 below.

Orangeville Hydro Limited
CGAAP-Revenue Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test - Required Revenue
Revenue			
Revenue Deficiency			65,456
Distribution Revenue	5,564,090	5,051,092	5,051,092
Other Operating Revenue (Net)	128,561	463,822	463,822
Total Revenue	**5,692,651**	**5,514,914**	**5,580,371**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,618,133	2,370,935	2,370,935
Operation & Maintenance	1,023,020	1,124,248	1,124,248
Depreciation & Amortization	810,135	845,356	845,356
Property Taxes	0	0	0
Deemed Interest	392,561	404,999	404,999
Total Costs and Expenses	**4,843,849**	**4,745,537**	**4,745,537**
Utility Income Before Income Taxes	**848,802**	**769,377**	**834,833**
Income Taxes:			
Corporate Income Taxes	114,804	79,822	89,967
Total Income Taxes	**114,804**	**79,822**	**89,967**
Utility Net Income	**733,999**	**689,555**	**744,866**
Income Tax Expense Calculation:			
Accounting Income	848,802	769,377	834,833
Tax Adjustments to Accounting Income	(274,019)	(254,398)	(254,398)
Taxable Income	**574,784**	**514,979**	**580,435**
Income tax expense before credits	**117,318**	**79,822**	**89,967**
Credits	**2,514**	**0**	**0**
Income Tax Expense	114,804	79,822	89,967
Tax Rate Refecting Tax Credits	20.41%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	19,909,511	19,894,920	19,894,920
Interest Expense	392,561	404,999	404,999
Net Income	733,999	689,555	744,866
Total Actual Return on Rate Base	**1,126,559**	**1,094,554**	**1,149,865**
Actual Return on Rate Base	5.66%	5.50%	5.78%
Required Return on Rate Base:			
Rate Base	19,909,511	19,894,920	19,894,920
Return Rates:			
Return on Debt (Weighted)	3.29%	3.39%	3.39%
Return on Equity	8.98%	9.36%	9.36%
Deemed Interest Expense	392,561	404,999	404,999
Return On Equity	784,435	744,866	744,866
Total Return	**1,176,996**	**1,149,865**	**1,149,865**
Expected Return on Rate Base	5.91%	5.78%	5.78%
Revenue Deficiency After Tax	**50,436**	**55,311**	**0**
Revenue Deficiency Before Tax	**63,371**	**65,456**	**0**

Tax Exhibit			**2014**
Deemed Utility Income			744,866
Tax Adjustments to Accounting Income			(254,398)
Taxable Income prior to adjusting revenue to PILs			**490,468**
Tax Rate			15.50%
Total PILs before gross up before tax credits			**76,022**
Tax Credits			**0**
Total PILs before gross up after tax credits			**76,022**
Grossed up PILs			**89,967**

Please refer to OHL's response to 7.7-Staff-33.

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.

OHL's Response:

Please refer to OHL's response to 7.7-Staff-33.

7.7-Energy Probe-38

Ref: Exhibit 6, Tab 1, Schedule 1

Please confirm that the reference to the 2013 Test Year on line 4 of page 1 should be to the 2014 Test Year.

OHL's Response:

The reference to the 2013 Test Year on line 4 of page 1 should be to the 2014 Test Year.

7.7-SEC-34

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

Please restate Table 1.1 using the up to date cost of capital parameters applicable to the Applicant.

OHL's Response:

Please refer to 7.5-Staff-30

8. Load Forecast, Cost Allocation and Rate Design

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-35

Ref: E3/T2/S4, E8/T3/S7 and Appendix 2-I – Load Forecast CDM Adjustment

Appendix 2-I calculates and documents the amount for the 2013 and 2014 CDM program impacts assuming that the distributor will achieve the 4-year (2011-2014) CDM target savings that are a condition of its license, and also the corresponding amount for the persistence of CDM programs for 2012 to 2014 beyond what is determined in the base forecast using historical consumption and exogenous explanatory variables, on the 2014 consumption forecast.

a. OHL has used a regression model to estimate system purchased consumption. In cell B75 of Appendix 2-I, OHL has input a loss factor of 4.74%. In Exhibit 8/Tab 3/Schedule 7, OHL has a proposed TLF of 4.81%. Please explain the input loss factor in Appendix 2-I.

OHL's Response:

The input loss factor in Appendix 2-I should be 4.81%. OHL has updated Appendix 2-I to reflect the change and provided the updated version in working Microsoft Excel format.

b. In row 55 of Appendix 2-I, OHL has input weights of 1, 0.5, 1 and 0.5 for, respectively, 2011, 2012, 2013 and 2014. These weights correspond to the impact on 2014 consumption of CDM programs in these years beyond what is in the base forecast derived from the estimated regression model. The weights for 2012, 2013 and 2014 are logical. However, 2011 CDM programs would have a ½-year impact in 2011 and full year persistence on 2012, and thus is fully reflected in the historical data used for the system purchased regression model. Please explain why OHL has used a factor of "1" for 2011 to reflect persistence of 2011 CDM programs on 2014 consumption through the manual adjustment if it is already reflected through the regression model.

OHL's Response:

OHL used a factor of "1" for 2011 to reflect persistence of 2011 CDM programs on 2014 consumption in error, the factor should have been "0". OHL has updated Appendix 2-I to reflect the change and provided the updated version in working Microsoft Excel format.

c. If OHL makes changes or updates to Appendix 2-I, please provide an updated version in working Microsoft Excel format. Please also reflect any changes in the 2014 load forecast and in the determination of the LRAMVA threshold for 2014.

OHL's Response:

OHL has updated Appendix 2-I to reflect the changes and provided the updated version in working Microsoft Excel format.

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2014)

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B29 to E29. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C30 to E30. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013. Until that report is issued, the distributor should use the results from the preliminary 2012 CDM Report issued in the spring of 2013.

Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

		4 Year (2011-2014) kWh Target:			
		11,820,000			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	9.81%	9.56%	9.56%	9.48%	38.41%
2012 CDM Programs		8.46%	7.61%	7.61%	23.69%
2013 CDM Programs			12.63%	12.63%	25.27%
2014 CDM Programs				12.63%	12.63%
Total in Year	**9.81%**	**18.02%**	**29.81%**	**42.36%**	**100.00%**
		kWh			
2011 CDM Programs	1,160,000	1,130,000	1,130,000	1,120,000	4,540,000.00
2012 CDM Programs		1,000,000	900,000	900,000	2,800,000.00
2013 CDM Programs			1,493,333	1,493,333	2,986,666.67
2014 CDM Programs				1,493,333	1,493,333.33
Total in Year	**1,160,000.00**	**2,130,000.00**	**3,523,333.33**	**5,006,666.67**	**11,820,000.00**

From each of the 2006-2010 CDM Final Report, 2011 CDM Final Report, and the 2012 CDM Final Report, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis.

		Net-to-Gross Conversion		
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs	**16,402,218**	**9,965,810**	**6,436,409**	**0.392410863**
2011 CDM program	**5,120,585**	**3,065,643**	**2,054,942**	**0.401310067**
2012 CDM program	**4,972,773**	**3,002,781**	**1,969,993**	**0.396155727**
2006 to 2011 OPA CDM programs: Persistence to 2013	26495576.76	16034233.12	10461343.64	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.
These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

	Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast				
	2011	**2012**	**2013**	**2014**	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0.5**	**1**	**0.5**	Utility can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Persistence of 2011 CDM programs for the full year of 2012 means that all of 2011 CDM impact is assumed to be in the base forecast before the CDM Adjustment*	*50% of 2012 CDM impact is assumed reflected in base forecast based on 1/2 year rule.*	*Full year impact of 2013 CDM programs on adjustment for 2014 load forecast*	*Only 50% of 2014 CDM impact is used based on a half year rule*	

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2014 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner, for both the LRAMVA and for the load forecast adjustment.

	2011	**2012**	**2013** **kWh**	**2014**	**Total for 2014**
Amount used for CDM threshold for LRAMVA (2014)	1,120,000.00	900,000.00	1,493,333.33	1,493,333.33	5,006,666.67
Manual Adjustment for 2014 Load Forecast (billed basis)	-	450,000.00	1,493,333.33	746,666.67	2,690,000.00
Proposed Loss Factor (TLF)	4.81%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	-	471,633.99	1,565,126.14	782,563.07	2,819,323.21

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

8.1-Staff-36

Ref: E3/T2/S3 and Excel Load Forecast Model

On page 2 of this exhibit, OHL states:

> The multifactor regression model has determined drivers of year-over-year changes in OHL's load growth; these include weather, number of days in the month, population and an Intermediate class flag weather, number of days in month, Ontario employment data, population, and CDM activity. These factors are captured within the multifactor regression model.

On the following page and in the model estimates on sheet "Purchased_Power_Model", the estimated model is summarized as consumption in modelled on the following exogenous variables:

- Heating Degree Days and Cooling Degree Days (proxying weather, and based on the Orangeville weather station);
- Spring/Fall flag (with values of "0", "1/3", "2/3" and "1" depending on the percentage of days in the month that are "Spring" or "Fall";
- Number of calendar days in the month;
- Number of Peak Hours in the month;
- Employment for Ontario, from StatsCan matrix 282-0054; and
- CDM program impacts.

a. What are the population and Intermediate flag variables referenced on page 2 of the exhibit?

OHL's Response:

The population and Intermediate flag variables were referenced in error on page 2 of the exhibit. The exhibit should have read,

> The multifactor regression model has determined drivers of year-over-year changes in OHL's load growth; these include weather, Ontario employment data, number of days in the month, Spring/Fall flag, CDM activity and number of peak hours. These factors are captured within the multifactor regression model.
>
> The "OHL's Monthly Predicted kWh Purchases" table should have appeared as,

OHL's Monthly Predicted kWh Purchases	
= Heating Degree Days	6,173.1
+ Cooling Degree Days	36,588.4
+ Ontario Employment	2,736.4
+ Number of Days in Month	381,398.0
+ Spring Fall Flag	(439,414.0)
+ CDM Activity	(1.7)
+ Number of Peak Hours	10,997.1
+ Intercept	(10,515,517.8)

b. Please explain why both the number of calendar days and the number of Peak Hours in the month are variables that are appropriately included together in the regression model?

OHL's Response:

Both the T-stats for the number of calendar days and the number of Peak Hours in the month are above 2, indicating they are statistically significant. Also, number of calendar day differs from peak hours as the number of peak hours indicates number of business days in a month versus the number of calendar days.

c. Statistics Canada Matrix 282-0054 is the Labour Force Survey and reflects employment and unemployment statistics on a number of measures, for Canada, provinces and major regional areas within provinces, including Ontario. Please identify the specific series used, by title/descriptor and series number used for the Ontario employment measure.

OHL's Response:

OHL used the Labour Force Survey number 3701 for Ontario. Table 282-0054 Labour force survey estimates (LFS), by provinces and economic regions based on 2006 Census boundaries, 3-month moving average, unadjusted for seasonality, monthly (persons unless otherwise noted)(17,18,19)

d. The CDM variable has a constant value for every month in each year. As new CDM programs are rolled out and uptake of the programs will increase, there should be some changes, mostly increase over time. Please provide a detailed description and derivation of the CDM variable.

OHL's Response:

Please see table below illustrating the calculation used in determining the annual CDM variable in the Load Forecast Model. The Net MWh's is the persistence savings for the 2006 – 2010 programs in to 2011 – 2014 provided by the OPA in the 2006-2010 Final OPA CDM Results report. The 2011-2014 Programs kWh's is based on the Q4 2012 CDM Status Report from the OPA.

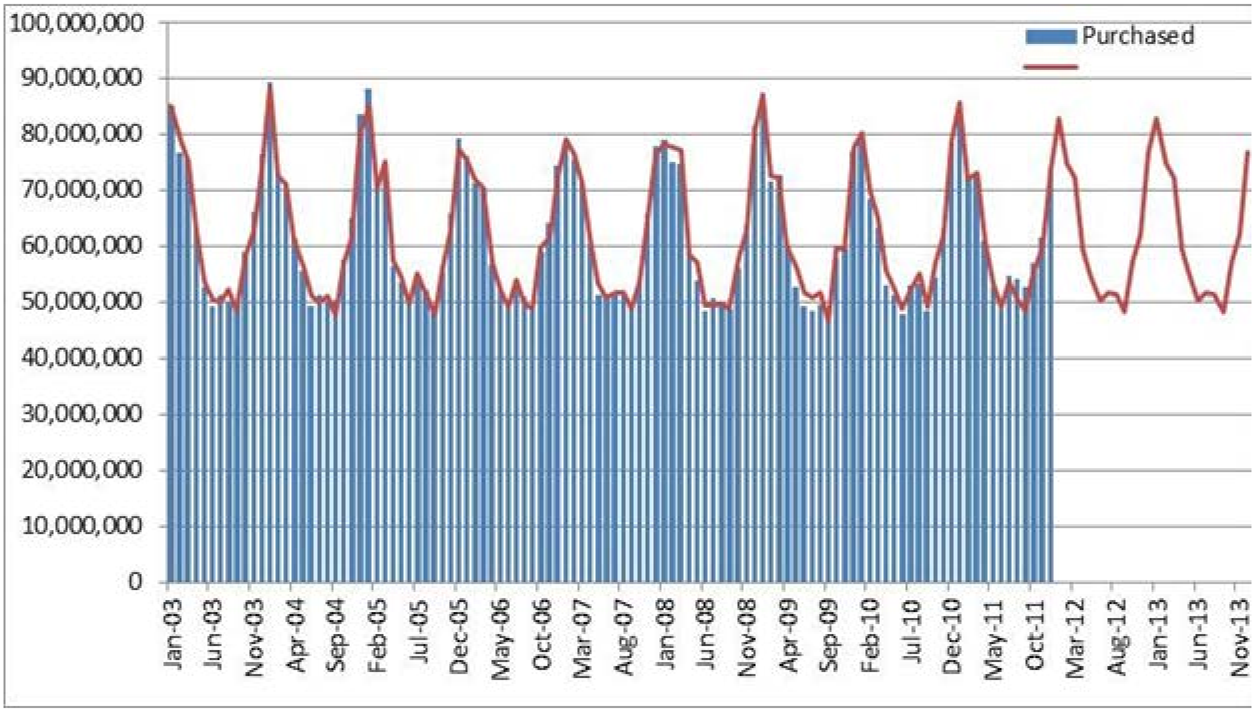
	Net MWh	2011-2014 Programs kWh	Total Annual Net kWh	Total Monthly kWh
2005				
2006	797.109		797,109	66,425.72
2007	1,393.096		1,393,096	116,091.34
2008	1,720.478		1,720,478	143,373.20
2009	2,687.127		2,687,127	223,927.27
2010	3,367.999		3,367,999	280,666.59
2011	3,065.643	1,160,000	4,225,643	352,136.90
2012	3,002.781	2,130,000	5,132,781	427,731.73
2013	2,978.413	2,030,000	5,008,413	417,367.78
2014	2,807.718	2,020,000	4,827,718	402,309.87
Total	21,820.365	7,340,000	29,160,365	

8.1-Staff-37

Ref: E3/T2/S3 – Load Forecast Model

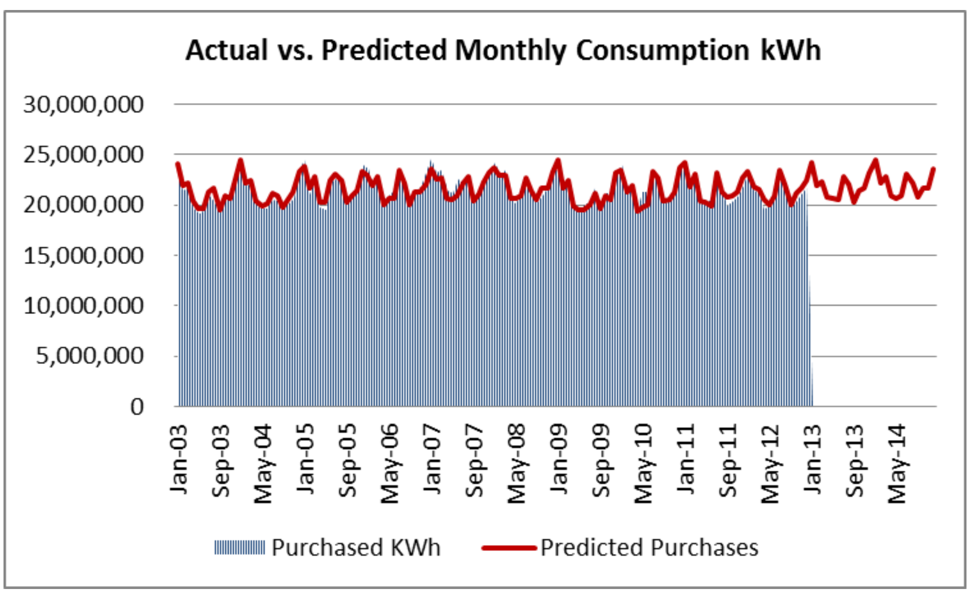
The estimated regression model is based on monthly statistics and so model diagnosis is appropriately based on monthly data.

Actual vs. Predicted Monthly Consumption kWh



a. Please provide a variation of the graph shown on page 5 of this exhibit, but based on the monthly actual and estimated values, similar to the format shown above. Please include the predicted values for the 2013 Bridge and 2014 Test years..

OHL's Response:



b. Please provide the Mean Absolute Percentage Error of the estimated load forecast regression model based on the monthly residuals.

OHL's Response:

The Mean Absolute Percentage Error of the estimated load forecast regression model based on the monthly residuals is 1.81%.

8.1-Energy Probe-39

Ref: Exhibit 3, Tab 1, Schedule 2

a. How many months of actual data are included in Table 3-27?

OHL's Response:

The data provided for the 2013 Bridge Year is all estimated in Table 3-27.

b. Please update Table 3-27 to reflect the most recent year-to-date information available for 2013 along with a forecast for the remaining months.

OHL's Response:

Please see the updated Table 3-27 below to reflect the most recent year-to-date information available for 2013.

Table 3-27: Comparison 2012 Actual to 2013 Actual								
	Customer/Connections			kWh		kW		
Billing Quantities	2012 Actual	2013 Actual	Difference	2012 Actual	2013 Actual	2012 Actual	2013 Actual	Volumetric Difference
Residential	10,143	10,261	118	85,673,643	86,211,195			537,552
GS < 50 kW	1,126	1,128	2	35,683,448	37,418,771			1,735,323
GS > 50 kW	123	127	4			295,004	288,829	-6,174
Streetlight	2,835	2,863	28			5,416	5,060	-356
Sentinel Light	156	153	-3			330	292	-38
Unmetered Scattered Load	104	104	0	413,791	387,032			-26,759
Total	**14,487**	**14,636**	**149**	**121,770,882**	**124,016,998**	**300,749**	**294,181**	**2,239,548**

c. Are the customer/connections shown year-end figures or averages for the year or mid-year figures?

OHL's Response:

The customer/connections shown are year-end figures.

8.1-Energy Probe-40

Ref: Exhibit 3, Tab 2, Schedule 2

a. Please provide the number of customers in the same level of detail as shown in Table 3-3, but based on the average number of customers where the average is calculated as the average number of customers in each month.

OHL's Response:

					Connections				Customers		
		Residential	GS<50	GS>50	Streetlights	Sentinel Lights	USL	Total	Streetlights	Sentinel Lights	USL
Number of Customers/Connections											
2010 Board Approved		10,045	1,081	133	2,724	170	151	14,304			
2010	January							-			
	February							-			
	March	9,857	1,149	129	2,769	167	153	14,224	5	46	35
	April	9,868	1,154	129	2,769	167	153	14,240	5	46	35
	May	9,883	1,154	129	2,769	167	153	14,255	5	46	35
	June	9,909	1,157	131	2,771	167	153	14,288	5	46	35
	July	9,921	1,159	131	2,771	167	153	14,302	5	46	35
	August	9,939	1,167	130	2,768	167	153	14,324	5	46	36
	September	9,950	1,167	130	2,778	167	157	14,349	5	46	36
	October	9,959	1,169	130	2,780	166	158	14,362	5	46	36
	November	9,964	1,170	130	2,781	165	158	14,368	5	46	36
	December	9,963	1,163	130	2,782	165	158	14,361	5	46	36
	Monthly Average:	9,921	1,161	130	2,774	167	155	14,307	5	46	36
2011	January	9,950	1,105	130	2,782	164	157	14,288	5	43	32
	February	9,949	1,104	130	2,782	160	157	14,282	5	42	32
	March	9,953	1,104	131	2,782	158	157	14,285	5	42	32
	April	9,955	1,104	132	2,783	158	157	14,289	5	41	32
	May	9,960	1,108	132	2,784	158	158	14,300	5	41	32
	June	9,959	1,106	133	2,785	158	158	14,299	5	41	32
	July	10,004	1,099	132	2,785	158	158	14,336	5	41	32
	August	10,004	1,099	132	2,785	158	158	14,336	5	41	32
	September	10,011	1,101	130	2,785	158	157	14,342	5	41	32
	October	10,009	1,088	131	2,785	158	157	14,328	5	41	32
	November	10,018	1,089	131	2,785	158	157	14,338	5	40	32
	December	10,027	1,090	131	2,785	158	157	14,348	5	40	32
	Monthly Average:	9,983	1,100	131	2,784	159	157	14,314	5	41	32
2012	January	10,036	1,095	130	2,785	158	157	14,361	5	40	32
	February	10,039	1,095	130	2,785	158	157	14,364	5	40	32
	March	10,060	1,096	130	2,785	158	157	14,386	5	40	32
	April	10,056	1,093	130	2,785	158	157	14,379	5	40	32
	May	10,068	1,094	130	2,835	158	107	14,392	5	39	32
	June	10,077	1,098	127	2,835	158	104	14,399	5	39	32
	July	10,092	1,102	125	2,835	158	104	14,416	5	39	32
	August	10,100	1,102	125	2,835	158	104	14,424	5	38	32
	September	10,101	1,113	124	2,835	156	104	14,433	5	38	32
	October	10,119	1,117	123	2,836	156	104	14,455	5	38	32
	November	10,133	1,122	123	2,836	156	104	14,474	5	38	32
	December	10,143	1,126	123	2,835	156	104	14,487	5	38	32
	Monthly Average:	10,085	1,104	127	2,819	157	122	14,414	5	39	32
2013	January	10,152	1,128	123	2,840	156	104	14,503	5	38	32
	February	10,156	1,123	124	2,845	156	104	14,508	5	38	32
	March	10,166	1,125	124	2,851	156	104	14,526	5	38	32
	April	10,185	1,123	124	2,851	156	104	14,543	5	38	32
	May	10,199	1,121	124	2,852	156	104	14,556	5	38	32
	June	10,211	1,121	124	2,855	156	101	14,568	5	38	32
	July	10,225	1,120	124	2,858	156	104	14,587	5	38	32
	August	10,233	1,118	125	2,858	156	104	14,594	5	38	32
	September	10,244	1,120	125	2,858	156	104	14,607	5	38	32
	October	10,250	1,121	126	2,858	156	104	14,615	5	38	32
	November	10,257	1,125	126	2,858	153	104	14,623	5	36	32
	December	10,261	1,128	127	2,863	153	104	14,636	5	36	32
	Monthly Average:	10,212	1,123	125	2,854	156	104	14,572	5	38	32

b. Please confirm that the average use figures shown in Table 3.4 are based on total consumption and mid-year customers/connections.

OHL's Response:

OHL confirms that the average use figures shown in Table 3.4 are based on total consumption and the average of the beginning and end year customer/connections.

c. Please provide a revised Table 3-4 that reflects total consumption divided by the average number of customers as calculated in part (a) above.

OHL's Response:

Please see revised Table 3-4 that reflects total consumption divided by the average number of customers as calculated in part a. above.

Table 3-4: Annual Usage per Customer/Connection by Rate Class - Revised with Monthly Averages							
Year		**Residential**	**GS<50**	**GS>50**	**Streetlights**	**Sentinels**	**USL**
Energy Usage per Customer/Connection (kWh per customer/connection)							
2010 Board Approved		8,536	35,766	927,348	656	759	2,480
2003 Actual		9,083	31,351	881,598	608	817	
2004 Actual		8,905	31,137	874,503	647	798	
2005 Actual		9,294	34,900	913,725	617	783	
2006 Actual		8,970	35,429	992,598	636	744	2,472
2007 Actual		9,000	35,993	1,007,805	641	748	2,595
2008 Actual		8,885	35,298	943,638	656	776	2,547
2009 Actual		8,672	32,067	930,966	660	747	2,423
2010 Actual		8,690	31,094	949,889	641	765	2,413
2011 Actual		8,605	32,611	927,293	640	625	2,149
2012 Actual		8,495	32,310	950,949	639	792	3,394
2013 Actual		**8,442**	**32,150**	**989,764**	**623**	**820**	**3,602**
2014 Test		**8,674**	**32,548**	**977,615**	**649**	**788**	**3,445**
Annual Growth Rate in Usage per Customer/Connection							
2010 Board App. Vs. 2010 Actual		0.5%	11.1%	(2.2%)	2.3%	(4.3%)	(21.8%)
2003 Actual							
2004 Actual		(1.9%)	(0.7%)	(0.8%)	6.4%	(2.3%)	
2005 Actual		4.4%	12.1%	4.5%	(4.6%)	(1.9%)	
2006 Actual		(3.5%)	1.5%	8.6%	3.1%	(5.0%)	
2007 Actual		0.3%	1.6%	1.5%	0.8%	0.6%	5.0%
2008 Actual		(1.3%)	(1.9%)	(6.4%)	2.3%	3.7%	(1.8%)
2009 Actual		(2.4%)	(9.2%)	(1.3%)	0.5%	(3.7%)	(4.9%)
2010 Actual		0.2%	(3.0%)	2.0%	(2.8%)	2.4%	(0.4%)
2011 Actual		(1.0%)	4.9%	(2.4%)	(0.1%)	(18.4%)	(10.9%)
2012 Actual		(1.3%)	(0.9%)	2.6%	(0.2%)	26.7%	57.9%
2013 Actual		**(0.6%)**	**(0.5%)**	**4.1%**	**(2.5%)**	**3.5%**	**6.1%**
2014 Test		**2.7%**	**1.2%**	**(1.2%)**	**4.2%**	**(3.8%)**	**(4.4%)**

8.1-Energy Probe-41

Ref: Exhibit 3, Tab 2, Schedule 3

a. On page 2, a number of variables are said to be included in the multifactor regression model including population and an Intermediate class flag weather (page 2, lines 18-21), whereas the table on page 3 does not include these variables. Please reconcile.

OHL's Response:

Please refer to OHL's response to 8.1-Staff-36.

b. The variables noted on page 2 and shown in the table on the top of page 3 are also not consistent with the variables included in Table 3-5. Please reconcile and provided corrected tables as necessary.

OHL's Response:

Please refer to OHL's response to 8.1-Staff-36.

8.1-Energy Probe-42

Ref: Exhibit 3, Tab 2, Schedule 3

a. What is the mean absolute percent error ("MAPE) based on the annual percentages shown in Table 3-6?

OHL's Response:

The mean absolute percent error ("MAPE") based on the annual percentages shown in Table 3-6 is 1.2%.

b. Please re-estimate the equation with the following two changes. First, add a trend variable that has a value of 1 in the first month and grows by 1 in each subsequent month. Second, split the spring fall variable into a spring variable and a fall variable. Please provide the regression coefficients (page 3), statistics (Table 3-5) and the resulting forecasts (Table 3-6).

OHL's Response:

Please see tables below for the regression coefficients (page 3), statistics (Table 3-5) and the resulting forecasts (Table 3-6).

	Coefficients
Intercept	-6095396.41
Heating Degree Days	5951.11
Cooling Degree Days	35814.97
Ontario Employment Numb	1694.65
Number of Days in Month	396508.66
Trend	28914.32
CDM Activity	-7.59
Spring	-516387.14
Fall	-688322.40
Number of Peak Hours	11036.83

Table 3-5: Statistcial Results	
Statistic	**Value**
R Square	88%
Adjusted R Square	87%
F Test	92.3
T-stats by Coefficient	
Intercept	(1.7)
Heating Degree Days	18.1
Cooling Degree Days	12.5
Ontario Employment Number	2.6
Number of Days in Month	6.3
Trend	3.9
CDM Activity	(5.1)
Spring	(2.9)

Table 3-6: Total System Purchases			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2003	249.9	250.0	0.0%
2004	252.9	254.8	0.8%
2005	261.5	264.8	1.3%
2006	263.1	259.5	(1.4%)
2007	268.6	263.0	(2.1%)
2008	261.6	264.5	1.1%
2009	254.5	255.4	0.3%
2010	261.2	259.5	(0.7%)
2011	257.8	258.7	0.3%
2012	255.3	256.3	0.4%
2013 Weather Normal		**263.3**	
2014 Weather Normal		**270.4**	
2014 Weather Normal - 10 year average		**270.4**	
2014 Weather Normal - 20 year trend		**270.0**	

c. What is the MAPE associated with the equation estimated in part (b)?

OHL's Response:

The MAPE associated with the equation estimated in part b is 0.8%

d. Based on the 2014 forecast that results from the equation requested in (b), and the methodology used by OHL to forecast billed kWh and kW, what is the impact on the revenue forecast based on existing rates (i.e. comparable to the $5,045,019 in the RRWF).

OHL's Response:

Please see table below.

Table 8.2 2014 Test Year Distribution Revenue at Existing Rates										
Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	91,877,841		123,899		2,014,599	1,286,290	3,300,889		3,300,889	64.64%
GS < 50 kW	38,175,438		13,690		455,472	385,572	841,044		841,044	16.47%
GS >50 to 4999 kW	122,929,675	296,611	1,484		276,429	650,378	926,807	79,731	847,076	16.59%
Sentinel Lights	122,536	339		1,866	6,195	4,387	10,582		10,582	0.21%
Street Lighting	1,861,618	5,230		34,436	51,998	43,702	95,701		95,701	1.87%
Unmetered and Scattered	358,304			1,248	7,912	3,189	11,101		11,101	0.22%
	255,325,412	**302,179**	**139,074**	**37,550**	**2,812,605**	**2,373,518**	**5,186,123**	**79,731**	**5,106,392**	**100%**

8.1-Energy Probe-43

Ref: Exhibit 3, Tab 2, Schedule 3

a. Please provide the average loss factor for 2003 through 2012 that would have been used had OHL included the 2003 figure in the calculation.

OHL's Response:

The average loss factor for 2003 through 2012 that would have been used had OHL included the 2003 figure in the calculation would have been 1.0465.

b. Does the exclusion of the 2003 loss factor, while using the 2003 actual purchases, bias the forecast downwards because the higher loss factor applied to the 2003 volumes results in a lower billed amount than actually took place in 2003?

OHL's Response:

The exclusion of the 2003 loss factor causes the average loss factor to be increased producing a lower load forecast, compared to if the 2003 loss factor was included.

8.1-Energy Probe-44

Ref: Exhibit 3, Tab 2, Schedule 3

a. Please update Table 3-7 to include the mid-year number of customers/connections by rate class for 2013.

OHL's Response:

Please see updated Table 3-7 to include the beginning year/end year averages by rate class for 2013.

Table 3-7: Historical Customer/Connection Data							
Year	Residential	GS<50	GS>50	Streetlights	Sentinels	USL	Total
Number of Customers/Connections							
2003	9,073	972	143	2,557	164	0	12,908
2004	9,278	983	146	2,622	168	0	13,196
2005	9,425	986	138	2,573	173	0	13,294
2006	9,483	994	130	2,506	175	151	13,438
2007	9,547	1,030	131	2,519	179	153	13,557
2008	9,619	1,061	132	2,643	177	154	13,784
2009	9,732	1,106	131	2,684	172	154	13,979
2010	9,889	1,156	130	2,698	166	156	14,194
2011	9,995	1,127	131	2,784	162	158	14,355
2012	10,085	1,108	127	2,810	157	131	14,418
2013	10,202	1,127	125	2,849	150	104	14,557

b. Did OHL reduce the actual energy purchases to reflect the loss of Plastiflex in its power purchases forecast? If not, how has OHL reflected the loss of this customer in the kWh and kW forecast?

OHL's Response:

OHL did not reduce the actual energy purchases to reflect the loss of Plastiflex in its power purchases forecast. The loss of this customer was reflected in the number of customers in the GS>50 class.

8.1-Energy Probe-45

Ref: Exhibit 3, Tab 2, Schedules 4 & 5

It appears that the total CDM adjustment made to the 2014 billed kWhs is 3,810,000 as shown in Table 3.29. In Appendix 2-I this figure includes 100% of the 2011 amount used for CDM, 50% of the 2012 amount, 100% of the 2013 amount and 50% of the 2014 amount. Given that the historical data used in the regression analysis included 2011 data, please explain why any 2011 adjustment should be included in the CDM adjustment proposed.

OHL's Response:

Please see OHL's response to 8.1-Staff-35.

8.1–VECC–29

Ref: Exhibit 3, Tab 2, Schedule 2, page 2
Exhibit 3, Tab 2, Schedule 3, page 3

What are the actual 2013 kWh Purchases?

OHL's Response:

Please see the table below with the actual 2013 kWh Purchases.

2013	Jan-13	22,831,960
2013	Feb-13	20,901,653
2013	Mar-13	21,755,248
2013	Apr-13	19,788,992
2013	May-13	19,550,083
2013	Jun-13	19,844,474
2013	Jul-13	21,753,618
2013	Aug-13	20,970,578
2013	Sep-13	19,014,719
2013	Oct-13	20,074,272
2013	Nov-13	21,058,077
2013	Dec-13	22,868,116
	Total:	250,411,790

B) Please provide a schedule that sets out:

i. The actual 2013 purchases
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 36,588.4
v. The difference between the Normal and Actual HDD values multiplied by 6,173.1
vi. The addition of items (i), (iv) and (v)

OHL's Response:

	Purchased KWh with Losses	Actual Heating Degree Days	Actual Cooling Degree Days	Assumed Heating Degree Days	Assumed Cooling Degree Days	Difference in HDD	Difference in CDD
Jan-13	22,831,960	805	0	785	0	122,906	-
Feb-13	20,901,653	719	0	705	0	87,535	-
Mar-13	21,755,248	628	0	594	0	210,935	-
Apr-13	19,788,992	397	1	373	0	149,578	31,100
May-13	19,550,083	203	10	200	7	18,211	111,595
Jun-13	19,844,474	74	28	57	38	102,597	(360,762)
Jul-13	21,753,618	26	59	15	74	66,608	(540,411)
Aug-13	20,970,578	38	46	26	52	73,090	(222,823)
Sep-13	19,014,719	135	14	110	12	155,562	81,958
Oct-13	20,074,272	318	0	303	1	94,325	(49,760)
Nov-13	21,058,077	493	0	456	0	226,059	-
Dec-13	22,868,116	700	0	666	0	212,663	-
	250,411,790	4,536	158	4,290	184	1,520,068	(949,103)

8.1–VECC–30

Ref: Exhibit 3, Tab 1, Schedule 2, page 7
Exhibit 3, Tab 2, Schedule 2, page 4

a. The 2012 actual customer counts by rate class differ as between Tables 3-27 and

3-3. Please reconcile.

OHL's Response:

The 2012 actual customer counts by rate class differ between Tables 3-27 and 3-3 because Table 3-27 is based on actual customer counts and Table 3-3 is based on average (beginning/end year) customer counts.

b. Based on this reconciliation are corrections required to any of the other Tables in Exhibit 3?

OHL's Response:

Corrections are not required to any of the other Tables in Exhibit 3.

8.1–VECC–31

Ref: Exhibit 3, Tab 2, Schedule 3, page 3

What is the source for the 2013 and 2013 Ontario Employment Numbers used in the load forecast?

OHL's Response:

Please see OHL's response to 8.1-Staff-36.

8.1–VECC–32

Ref: Exhibit 3, Tab 2, Schedule 3, page 8

a. Please confirm that the 2013 customer count for the GS>50 class was calculated by first applying the geometric mean growth of -1.3% to the 2012 count and then reducing the result further to allow for the loss of Plastiflex.

OHL's Response:

Yes, OHL confirms that the 2013 customer count for the GS>50 class was calculated by first applying the geometric mean growth of -1.3% to the 2012 count and then reducing the result further to allow for the loss of Plastiflex

b. If not, please explain how the 2013 customer count was derived.

OHL's Response:

N/A

c. If yes, why wasn't assumed that the loss of Plastiflex was already captured in the negative value for the geometric mean growth rate?

OHL's Response:

OHL agrees and has changed the model to reflect this.

d. Please provide both the 2012 and 2013 year end customer counts by customer class.

OHL's Response:

Please see table below.

Number of Year End Actuals Customers/Connections										
				Connections				Customers		
Year	Residential	GS<50	GS>50	Streetlights	Sentinels	USL	Total	Streetlights	Sentinels	USL
2012	10,143	1,126	123	2,835	156	104	104	5	38	32
2013	10,261	1,128	127	2,863	153	104	104	5	36	32

8.1–VECC–33

Ref: OHL's Excel Load Forecast Model

Please provide a working copy of model with the formulae and cell linkages intact.

OHL's Response:

OHL has provided a working copy of the original model with the formulae and cell linkages intact. Please note there were two small changes made to the model under the 2013 COP Forecast and 2014 COP Forecast. The Electricity – Commodity Non-RPP has been corrected and the total Power Purchased has been corrected to include the Smart Meter Entity charge.

8.1 – VECC – 34

Ref: Exhibit 3, Tab 2, Schedule 3, page 3
Exhibit 3, Tab 2, Schedule 5, page 1

a. Please confirm that for the monthly CDM activity variable OHL has used one-twelfth of the "annualized" CDM savings reported even for the first year a CDM program is in effect.

OHL's Response:

OHL confirms that the monthly CDM activity variable is one-twelfth of the "annualized" CDM savings reported even for the first year a CDM program is in effect.

b. Why is it reasonable to include ½ year of 2012 CDM savings in the manual adjustment when the regression model inputs for 2012 used the full "annualized" savings in 2012 – thereby fully account for all 2012 program impacts?

OHL's Response:

Since the ½ year rule has been used for the 2012 CDM savings in the manual adjustment, it would be reasonable to be use the ½ year rule as well in the regression model for 2012.

8.1–VECC–35

Ref: Exhibit 3, Tab 2, Schedule 5, page 1

a. Please provide any preliminary or interim reports that OHL has received from the OPA regarding the results of its 2013 CDM programs.

OHL's Response:

Please see attached Appendix M – Preliminary OPA 2013 CDM Report

b. What is OHL's current expectation as the "annualized" savings it will achieve in 2013 from 2013 CDM programs?

OHL's Response:

OHL's current expectation as the "annualized" savings it will achieve in 2013 is 8,760,000 kWh's and 1,750 kW's.

8.1–VECC–36

Ref: Exhibit 3, Tab 2, Schedule 5, page 2

a. Please confirm that the kWhs associated with OHL's proposed 2014 LRAMVA are 5,006,666.67.

OHL's Response:

OHL confirms that the kWhs proposed 2014 LRAMVA are 5,006,666.67

b. Please show how this value is allocated by customer class.

OHL's Response:

Please see LRAMVA calculations below.

LRAMVA Calculations

Per class allocation (kWh)	LF 2011	LF 2012	LF2013	LF 2014
Residential	85,903,538.00	85,673,643.00	88,880,994.00	89,706,964.00
General Service < 50 kW	35,863,634.00	35,683,448.00	37,014,298.00	36,780,123.00
General Service > 50 to 4999 kW	121,707,245.00	120,453,549.00	120,548,540.00	120,031,135.00
	243,474,417.00	241,810,640.00	246,443,832.00	246,518,222.00

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	2011/2012 Total	kWh's	kW's	
						5,006,666.67		
Residential	35%	35%	395,162.51	318,870.50	714,033.01	1,766,470.52		
General Service < 50 kW	15%	15%	164,975.32	132,810.96	297,786.28	737,478.96		
General Service > 50 to 4999 kW	50%	50%	559,862.17	448,318.54	1,008,180.71	2,502,717.18	6,038.67	0.00241285
USL			-	-	-			
	100%	100%	1,120,000	900,000	2,020,000			
KW			1,200	1,000	2,200		from OPA report	
			0.002143385	0.002230557	0.002182148			

LRAMVA Rate Rider	2011 Volumetric	2012 Volumetric	2011 LRAM	2012 LRAM	2011/2012 Total		Entry to 1568
Residential	0.0139	0.0140	$5,492.76	$4,464.19	9,956.95		9,957
General Service < 50 kW	0.0100	0.0101	$1,649.75	$1,341.39	2,991.14		2,991
General Service > 50 to 4999 kW	2.1632	2.1822	$2,595.84	$2,182.20	4,778.04		4,778
			$9,738.35	$7,987.78	$17,726.13		$17,726.13

Carrying Charges	Principal	Jan 1-Dec 31/13	Jan 1-Apr 30/14	Total Claim
Residential	9,957	146.37	48.79	**10,152**
General Service < 50 kW	2,991	43.97	14.66	**3,050**
General Service > 50 to 4999 kW	4,778	70.24	23.41	**4,872**
	$17,726.13	260.57	86.86	18,074

c. For the demand billed classes, please show how the allocated kWhs are converted to billing kW.

OHL's Response:

Please refer to response to b.

8.2 Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

8.2-Staff-38

Ref: E7/T1/S2, Table 7-2 and Cost Allocation model, worksheets 'I 5.2 Weighting Factors' and 'I 6.2 Customer Data'

Please confirm that the weighting factor of 21.8 for the Street Light class is applied to the number of bills to that class, not the number of connections as appears in Table 7-2.

OHL's Response:

OHL confirms that the weighting factor of 21.8 for the Street Light class is applied to the number of bills to that class, not the number of connection as appears in Table 7 -2. Please see the revised Table 7-2 below.

Table 7-2 Weighting Factors for Billing and Collecting		
Rate Class	Billing & Collecting Weighting Factors	OEB Default Weighting Factors
Residential	1.0	1
General Service < 50kW	1.0	2
General Service ≥ 50 kW	16.9	7
Street Light	21.8	1
Sentinel Light	1.3	0
Unmetered Scattered Load	1.1	5

8.2-Staff-39

Ref: E7/T1/S3, Table 7-7 Appendix 2-P; Appendix 2-W

Orangeville proposes to reduce the revenue to cost ratio for two classes (GS<50, USL) where the status quo ratio is substantially above 100%. To accommodate this adjustment, the Residential status quo revenue to cost ratio is being increased from 101.88% to 103.00%, but the ratio for three other classes remains unchanged despite the fact that they are all substantially below 100%. A result of this re-balancing proposal is that distribution rates for the Residential class would increase by 1.5% while those of all other classes will decrease or remain nearly unchanged.

Please explain the rationale for increasing the Residential revenue to cost ratio and distribution rates while leaving the rates unchanged for GS>50 kW, Street Lights, and Sentinel Lighting classes and their ratios below 100%.

OHL's Response:

Upon reflection OHL agrees that the Residential class should have remained status quo and the three classes that had ratios below 100% should have been adjusted. OHL has also adjusted the two rate classes that were at the high end of their ratios. Please see table below for the revised Revenue to Cost ratios.

Cost Allocation Based Calculations

Class	Revenue Requirement - 2014 Cost Allocation Model - Line 40 from O1 in CA	2014 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2014 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2014 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	3,561,724	3,309,239	311,715	3,620,955	101.7%	101.7%	101.7%	3,620,955	311,715	3,309,239	85%	115%
GS < 50 kW	778,126	841,321	59,430	900,751	115.8%	115.8%	109.0%	848,158	59,430	788,728	80%	120%
GS >50 to 4999 kW	1,091,192	847,083	78,434	925,518	84.8%	84.8%	89.4%	975,665	78,434	897,231	80%	120%
Sentinel Lights	15,266	10,719	1,579	12,298	80.6%	80.6%	89.4%	13,649	1,579	12,071	80%	120%
Street Lighting	123,474	96,941	11,415	108,356	87.8%	87.8%	89.4%	110,402	11,415	98,987	70%	120%
Unmetered and Scattered	10,589	11,245	1,249	12,494	118.0%	118.0%	109.0%	11,542	1,249	10,293	80%	120%
TOTAL	**5,580,371**	**5,116,548**	**463,822**	**5,580,371**				**5,580,371**	**463,822**	**5,116,548**		
	5,580,371									5,116,548		
	0									0		

8.2-Energy Probe-46

Ref: Exhibit 8, Tab 1, Schedule 3

Table 7.7 shows a column labelled "2014 Updated Cost Allocation Study", but the immediately preceding paragraph references an updated 2013 cost allocation study (line 7). Please confirm that Table 7.7 includes the 2014 updated cost allocation study results and not the 2013 updated cost allocation study.

OHL's Response:

OHL confirms that Table 7-7 includes the 2014 updated cost allocation study results and not the 2013 updated cost allocation.

8.2-Energy Probe-47

Ref: Exhibit 8, Tab 1, Schedule 3

All of the revenue to cost ratios shown in the 2014 updated cost allocation study shown in Table 7.7 are within the Board's approved ranges.

a. Please explain why OHL believes it is appropriate to adjust the ratios of any of the classes given that they are all within the approved ranges.

OHL's Response:

OHL would like to reduce the amount of cross subsidization by lowering the revenue to cost ratios for classes that are at the higher end of their range. Ideally OHL would like to have ratios all at the 100% level however we believe a revised cost allocation model is required in order to properly address this.

b. Please explain why OHL is proposing to increase the revenue to cost ratio for the residential class, which is already about 100%, while at the same time reducing the ratio for the GS<50 and USL classes, which are also over the 100% level.

OHL's Response:

Please refer to OHL's response to 8.2-Staff-39.

c. Please explain why OHL is proposing to reduce the street lighting ratio even though it is already below 100%.

OHL's Response:

Please refer to OHL's response to 8.2-Staff-39.

d. Doesn't the overall OHL proposal actually increase the level of cross- subsidization from the residential class?

OHL's Response:

Please refer to OHL's response to 8.2-Staff-39**.**

8.2-Energy Probe-48

Ref: Exhibit 7, Tab 1, Schedule 3 &
Exhibit 8, Tab 6, Schedule 1

Please provide the bill impacts shown in Appendix C to Exhibit 8, Tab 6, Schedule 1 under each of the following 2 scenarios. For each scenario, please keep the proposed fixed/variable revenue proportions unchanged, as proposed by OHL.

a. Using the revenue to cost ratios that are shown in Table 7.7 under the "2014 Updated Cost Allocation Study" column, with no adjustments; and

OHL's Response:

Please find attached Appendix N – Bill Impacts No Change.

b. Using revenue to cost ratios that are equal to 100% for all rate classes.

OHL's Response:

Please find attached Appendix O – 8.2-Energy Probe-48 – Bill Impacts 100% all Classes.

8.2–VECC–37

Ref: Exhibit 3, Tab 2, Schedule 1, page 2
Exhibit 7, Tab 1, Schedule 1, Appendix A, page 3

Street Light connections in the first reference are reported as 2,870 but as 1,524 in the second reference. Please reconcile.

OHL's Response:

The first reference reported as 2,870 is the Number of Devices and the second reference of 1,524 is the Number of Connections. The difference in the numbers reported is due to OHL having daisy chains for some of our streetlights.

8.2–VECC–38

Ref: Exhibit 7, Tab 1, Schedule 2, page 1

a. Please confirm that the customers in classes other than Residential and GS<50 own and are responsible for the maintenance/repair/replacement of service assets.

OHL's Response:

GS > 50kW customers typically own their own service wires going into their building. Streetlights, Sentinel Lights and Unmetered Scattered Load customer's service assets are very minimal.

b. If not confirmed, why are the weighting factors for these classes zero?

OHL's Response:

N/A

8.2–VECC–39

Ref: Exhibit 7, Tab 1, Schedule 1, page 2

Please explain how the 2014 demand values (Sheet I8) were derived based on the 2014 weather normalized load forecast.

OHL's Response:

On sheet I8, Demand data is based on the output of our load forecast model. The load profile from the 2004 data received from Hydro One, Run 2 and the weather normalized 2014 forecast data was used to calculate the 1 NCP, 4 NCP, 12 NCP, 1 CP, 4 CP and the 12CP demand data.

8.3 Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?

8.3-Staff-40

Ref: E3/T2/S1, Table 3-20; Rate Design Model worksheet 'Allocation Low Voltage costs' and RTSR model worksheet 'Forecast wholesale'

a. Please confirm that the LV costs are allocated in the Rate Design model using a forecast wholesale cost of $893,917, whereas the corresponding forecast in the RTSR model is $903,888.

OHL's Response:

OHL confirms that the LV costs are allocated in the Rate Design model using a forecast wholesale cost of $893,917, whereas the corresponding forecast in the RTSR model is $903,888

b. Please update one or both of the references if necessary, based on the response to the previous interrogatory as it concerns Orangeville's forecast of Transmission Connection cost.

OHL's Response:

The RTSR model uses loss adjusted kWh's to forecast where as OHL used unadjusted usage in the rate design to allocate to the classes.

c. Orangeville appears to be following the methodology for allocating LV costs that the Board has directed. Nevertheless, please comment on the plausibility of the methodology in Orangeville's case, in which over 45% of LV cost is allocated to the GS>50 kW class which is forecast to consume less than 15% of total kWh based on Orangeville's load forecast (i.e. 37 GWh of 249 total GWh)

OHL's Response:

OHL believes the methodology coincides with the results of the RTSR model that allocates 45.9% of the costs to the GS > 50kW class.

8.3–VECC–40

Ref: Exhibit 8, Tab 3, Schedule 5, page 1

a. Please update Table 8-11 for the actual 2013 LVDS kW.

OHL's Response:

Table 8.11 Hydro One Variance Analysis					
	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test
Hydro One Charges	249,234	369,696	366,951	385,508	379,363
Revenues	(281,799)	(251,467)	(250,090)	(249,779)	(379,363)
Variance	(32,565)	118,229	116,861	135,729	0
Average kW	490,806	484,754	486,521	493,338	493,338
Average kW LVDS	18,800	19,040	18,712	19,465	19,465

b. Please update Table 8-10 for the approved 2014 ST rates.

OHL's Response:

Table 8.10 Hydro One Test Year Forecast					
Hydro One LV Charges	**2014 ST Rates**		**Billing Determinent**	**Months**	**$**
Service Charge	298.89		48		14,347
Common ST Lines	0.6820		493,338	12	336,457
LVDS	1.9870		19,465		38,677
					389,481

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-Staff-41

Ref: E8/T3/S7, p. 1

The proposed Supply Facilities Loss Factor is 1.0141, which is the five-year average. The average SFLF for the most recent two years is 1.013.

a. Please provide the calculation of the SFLF for 2012, showing the amounts of electricity delivered from the grid system through the high voltage transmission system and from the host distributor, together with the loss factors associated with these two sources (which are expected to be 1.0045 and 1.034 respectively).

OHL's Response:

OHL is not connected to the high voltage transmission system.

b. Please confirm that the Total Loss Factor would be 1.0470 if the SFLF were based on the two recent years, whereas it is 1.0482 using the five-year average.

OHL's Response:

OHL confirms that the Total Loss Factor would be 1.0470 if the SFLF were based on the two recent years, whereas it is 1.0482 using the five-year average.

8.4-Staff-42

Ref: Appendix 2-W

The bill impact of line losses increases from $4.68 to $4.81 for all customer sizes in all classes in Appendix 2-W.

Please confirm that the cost of line losses should be proportional to the size of the customer's consumption in each class.

OHL's Response:

OHL would like to confirm that the cost of line losses should be proportional to the size of the customer's consumption in each class. The bill impact of losses showing increases from $4.68 to $4.81 for all customer sizes in all classes in Appendix 2-W was an done in error.

8.5 Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?

8.5-Staff-43

Ref: E8, Appendix A - RTSR model

The wholesale cost of Transmission consists entirely of electricity delivered through the IESO at the Uniform Transmission Service rates, for historical, current, and test years. As a partially embedded distributor, it would be expected that some proportion of the power is delivered through the host distributor Hydro One, with the cost determined by the Sub-Transmission class RTSRs.

a. Please provide the proportions of electricity that Orangeville receives directly from the transmission system (Hydro One T.S.) and from the host distributor's LV system (Common St Line).

OHL's Response:

OHL receives 100% of electricity directly from the transmission system (Hydro One T.S.).

b. Please update the RTSR model correspondingly with the host distributor's RTSR rates (which are already provided in worksheet 'UTRs and Sub-Transmission' but are apparently not used in subsequent worksheets).

OHL's Response:

OHL has updated the RTSR model to reflect the correct inputs into 6. Historical Wholesale.

8.5–VECC–41

Ref: Exhibit 8, Tab 3, Schedule 1, page 1

a. Please update the 2014 RTSR calculation to reflect the approved 2014 UTRs and HON ST Rates.

OHL's Response:

OHL has updated the 2014 RTSR calculation to reflect the approved 2014 HON ST Rates. The revised model has been filed with this submission.

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

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-Staff-44

Tariff of Rates and Charges

The 3rd paragraph in the "Application" section of the tariff sheet for each rate class reads as follows:

> *Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.*

Based on recent Tariff of Rates and Charges approved by the Board in 2013 rate applications, the above paragraph should be amended as follows:

> *Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.*

Please confirm whether the applicant has any concerns with the noted change to be applied to those classes for which the regulatory component applies,
and if so, why .

<u>OHL's Response:</u>

OHL has no concerns with the noted changed to be applied to those classes for which the regulatory component applies.

9. Accounting

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-45

Ref: E9/T4/S1 and Appendix 2-S – Stranded Meters

In Exhibit 9/Tab 4/Schedule 1, OHL provides its proposal for the Stranded Meter Rate Rider (SMRR). OHL has also provided Appendix 2-S to document the determination of the net book value of stranded meters to be recovered through the SMRR. Board staff has replicated Appendix 2-S below, and added a column that shows the depreciation expense being attributed to the stranded conventional meters in each year.

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value	Depreciation Expense in Year
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)	(G) = [(B) - (B) (previous year)]+[(A) - (A)(previous year)]
2006		$ 1,411,095	$ 766,748		$ 644,347		$ 644,347	
2007		$ 1,547,803	$ 841,807		$ 705,996		$ 705,996	$ 211,766
2008		$ 1,557,220	$ 897,709		$ 659,512		$ 659,512	$ 65,320
2009		$ 1,557,640	$ 937,558		$ 620,082		$ 620,082	$ 40,269
2010		$ 1,579,709	$ 999,961		$ 579,747		$ 579,747	$ 84,472
2011		$ 1,533,380	$ 1,080,009		$ 453,370		$ 453,370	$ 33,719
2012		$ 1,533,380	$ 1,122,675		$ 410,705		$ 410,705	$ 42,665
2013	(1)	$ 1,533,380	$ 1,159,981		$ 373,399		$ 373,399	$ 37,306

a. Please confirm the data and calculations.

OHL's Response:

The data and calculations are correct. OHL engaged BDO to perform an analysis of all assets based on the 2011 year-end figures to prepare for the new accounting policy under CGAAP. It was noted during the process that the GS >50 meters and the CT and PTs were contained in the same account with the stranded meters and should be removed. The following table demonstrates how the assets were identified into groups:

	Gross Assets	Acc Amort	GS>50 Gross	GS> Accum	CT/PT Gross	CT/PT Acc	Total Stranded Gross	Total Stranded Acc Amort	NBV Stranded
2006	1,565,933.89	822,914.40	120,276.92	34,780.97	34,562.17	21,385.14	1,411,094.81	766,748.30	644,346.51
2007	1,701,316.76	881,241.00	153,514.17	39,434.18	34,960.87	21,448.93	1,512,841.72	820,357.89	692,483.83
2008	1,736,865.21	940,278.45	179,644.88	42,569.87	35,359.57	21,512.72	1,521,860.76	876,195.86	645,664.90
2009	1,777,391.32	1,002,315.67	180,544.16	42,659.80	39,206.90	22,098.09	1,557,640.26	937,557.79	620,082.47
2010	1,813,921.23	1,065,587.00	195,005.61	43,527.48	39,206.90	22,098.09	1,579,708.72	999,961.43	579,747.30
2011	$1,807,989.54	$1,146,443.02	235,403.14	44,335.43	39,206.90	22,098.09	$1,533,379.50	$1,080,009.50	453,370.00

The following details how the assets were distributed:

Commercial Meters GS>50
Summary of Cost and Depreciation

	Total Devices	Total Allocated Cost (DM+DL+OH)		Year Installed	ACC%	Accumulated Depreciation
1985	6	$991.12		1985	80%	$793.59
1988	2	$1,282.20		1988	80%	$1,026.66
1989	2	$120.00		1989	80%	$96.08
1992	1	$1,402.77		1992	50%	$701.39
1994	1	$3,516.01		1994	46%	$1,617.37
1997	1	$587.25		1997	41%	$240.77
1999	1	$1,586.25		1999	37%	$586.91
2000	11	$22,563.42		2000	32%	$7,220.30
2001	24	$39,891.68		2001	30%	$11,847.85
2002	5	$6,266.80		2002	28%	$1,754.70
2003	11	$12,120.99		2003	26%	$3,151.46
2005	4	$8,829.38		2005	22%	$1,942.46
2006	11	$21,119.03		2006	18%	$3,801.42
2007	23	$33,237.25		2007	14%	$4,653.22
2008	15	$26,130.71		2008	12%	$3,135.69
2009	4	$899.28		2009	10%	$89.93
2010	13	$14,461.45		2010	6%	$867.69
2011	39	$40,397.53		2011	2%	$807.95
Grand Total	**174**	**$235,403.14**				**$44,335.43**
					Accumulated Depreciation	**$43,827.56**
					Difference	$507.87

Orangeville Hydro
CT and PT Analysis
Summary of Cost and Depreciation

	Total Devices	Total Allocated Cost (DM+DL+OH)		Vintages	ACC%	Accumulated Depreciation
1960s	54	$ 1,479.22		1960s	94%	$1,390.47
1970s	79	$ 2,683.88		1970s	94%	$2,522.85
1980s	142	$ 5,996.84		1980s	94%	$5,637.03
1990s	264	$ 13,676.42		1990s	59%	$8,080.76
2000 - 2004	165	$ 10,725.81		2000 - 2004	35%	$3,754.03
2005 - 2009	68	$ 4,342.69		2005 - 2009	16%	$694.83
2010	4	$ 302.05		2010	6%	$18.12
2011	0	$ -		2011	2%	$0.00
Grand Total	**776**	**$ 39,206.90**				**$22,098.09**
					Accumulated Depreciation	**$22,098.09**
					Difference	$0.00

b. Please explain the decrease in the gross book value of stranded meters from $1,579,709 in 2010 to $1,533,380 in 2011.

OHL's Response:

The decrease in the gross book value of the stranded meters was due to smart meter installations for new subdivisions that were installed from 2006 to 2010 that amounted to $36,329 and recorded in account 1860 while any transactions for the smart meter initiative were included in account 1555. OHL made the decision to install smart meters in new subdivisions instead of using conventional meters. The amount of $36,329 along with accumulated amortization of $5,451 was transferred to a sub-account for smart meters within 1860 after the Board approved smart meter disposition entries occurred. Therefore OHL included $36,329 in the 2012 additions as noted below:

Gross Asset	2011 Opening Balance	Additions	Disposal	2012 Balance	2012 YE Actual GL Balance	Difference
Smart Meters	1,730,456	47,743	(2,797)	1,775,402	$1,780,239	(4,836.76)
GS >50 kW	274,610	22,198	(32,803)	264,005	$259,168	4,836.77
Accumulated Amortization	**Opening Balance**	**Additions**	**Disposal**	**2012 Balance**	**2012 YE Actual GL Balance**	**Difference**
Smart Meters	166,201	117,990		284,191	284,191	-
GS >50 kW	65,814	620	12,359	66,434	66,434	-

Note: There is a small difference of $4,836 between our fixed asset system and the GL in both sub-accounts that has been corrected in 2013.

c. Please explain why the depreciation expense in each year varies from 2010 onwards. In particular, please explain why depreciation expense in each of 2011 to 2013 is no more than 50% of the depreciation expense in 2010.

OHL's Response:

The stranded asset account and the stranded accumulated amortization were adjusted accordingly:

Stranded Asset 2010 Opening Balance	1,579,709	Stranded Acc Amort 2010 Opening Balance	(999,961)
Move to Smart Meter Sub-account	(36,329)	Move to Smart Meter Sub-account	5,451
CT/PT Inventory to 1330	(7,780)	Correct Amortization	(28,227)
Unreconciled due to Analysis	(2,220)	Amortization for 2011	(46,724)
		Unreconciled due to Analysis	(10,548)
Total Stranded Asset	**1,533,380**	**Total Accumumlated Amortization**	**(1,080,009)**

The difference of $28,227 was added to the total amortization. Due to an unknown reason, from 1980 to 1985 the useful life of the meters was 35 years. When OHL completed the analysis of the stranded meters, we applied the remaining useful life to the amortization. Also in the difference, there were also some unreconciled differences performing the BDO asset analysis that was included in the total amortization.

9.1-Staff-46

Ref: E9/T2/S1, pp. 5-7 and E9/T2/S3, p. 2

The following differences are noted in OHL's request for disposition within its evidence

Account	Exhibit 9, Tab 2, Schedule 1, Page 5-7	Exhibit 9, Tab 2, Schedule 3, Page 2
1508 Other Regulatory Assets – Sub-account Incremental Capital Charges	$42,781	$9,554
1518 Retail Settlement Variance Account - Retail	$47,550	$42,781
1532 Renewable Connection Operation, Maintenance and Administration	($825)	$47,550
1548 Retail Settlement Variance Account – Service Transaction Request	($32,043)	($825)
1555 Smart Meter Capital & Recovery Offset Variance Sub-Account Stranded Meter Costs and 1566 Smart Meter OM&A Offset Variance Sub-Account Stranded Meter Costs	$373,399* *Per Exhibit 9, Tab 4, Schedule 1, Page 1 as well	$453,370 (=$410,705+$42,665)

Please clarify the amount OHL is requesting for disposition for the above noted accounts. Please update the evidence as necessary (e.g. rate rider allocation).

OHL's Response:

Table 9.4 in Exhibit 9, Tab 2, Schedule 3, Page 2 is correct except for the Stranded Meter amounts. OHL depreciated the 2012 stranded meter depreciation expense of $42,665 and recorded the amount in 1556 in error. The amount of $42,665 should have been expensed to 5705. The misstatement of the amounts in Exhibit 9, Tab 2, Schedule 1, Pages 5-7 did not affect the amounts of the rate rider dispositions as set out in this exhibit. OHL has made the following corrections to the Board's table included in interrogatory 9.1-Staff-46 as follows:

Account	Exhibit 9, Tab 2, Schedule 1, Page 5-7	Exhibit 9, Tab 2, Schedule 3, Page 2
1508 Other Regulatory Assets-Sub-account Incremental Capital Charges	9,554	9,554
1518 Retail Settlement Variance Account-Retail	42,781	42,781
1532 Renewable Connection Operation, Maintenance and Administration	47,550	47,550
1548 Retail Settlement Variance Account-Service Transaction Request	(825)	(825)
1555 Smart Meter Capital & Recovery Offset Variance Sub-account Stranded Meter Costs	373,999	373,999
1556 Smart Meter OM&A Offset Variance Sub-account Stranded Meter Costs	0	0

9.1-Staff-47

Ref: E9/T2/S1, pp. 10-11; E9/T2/S3, p. 2 and Filing Requirements for Electricity Distribution Rate Applications, July 17, 2013, Section 2.12.2

With regards to Account 1592 PILS and Tax Variance for 2006 and Subsequent Years – Sub- account HST/OVAT Input Tax Credits:

a. Please explain what amounts in the table on page 10 represent.

OHL's Response:

OHL has provided the details of the amounts in the table on page 10. The table below shows the calculation for the capital and OM&A components of the HST PILs and Tax Variance:

Account	PST	Purchase Net PST	Asset Recorded	Years	Depreciation			
					2010	2011	2012	2013
1830	2,909.14	36,364.19	39,273.33	25	116.37	232.73	349.10	465.46
1835	1,420.44	17,755.47	19,175.91	25	56.82	113.64	56.82	56.82
1840	3,276.71	40,958.82	44,235.53	25	131.07	262.14	393.20	524.27
1845	14,921.67	186,520.84	201,442.51	25	596.87	1,193.73	1,790.60	2,387.47
1850	18,237.33	227,966.63	246,203.96	25	729.49	1,458.99	2,188.48	2,917.97
1855	3,106.33	38,829.13	41,935.46	25	124.25	248.51	372.76	497.01
1860	528.98	6,612.30	7,141.28	25	21.16	42.32	63.48	84.64
1905	3,015.60	37,695.00	40,710.60	50	60.31	120.62	180.94	241.25
1915	110.82	1,385.24	1,496.06	15	7.39	14.78	22.16	29.55
1920	1,243.83	15,547.81	16,791.64	5	248.77	497.53	746.30	995.06
1925	11,289.04	141,113.03	152,402.07	5	2,257.81	4,515.62	6,773.43	9,031.23
1930	9,592.32	119,904.00	129,496.32	10	959.23	1,918.46	2,877.70	3,836.93
1935	176.82	2,210.28	2,387.10	10	17.68	35.36	53.05	70.73
1940	698.56	8,732.00	9,430.56	10	69.86	139.71	209.57	279.42
1960	1,043.01	13,037.68	14,080.69	10	104.30	208.60	312.90	417.21
1995	(8,245.38)	(103,067.28)	(111,312.66)	25	(329.82)	(659.63)	(989.45)	(1,319.26)
Total	63,325.21	791,565.15	854,890.36					
Capital		Total			$5,171.55	$10,343.11	$15,401.03	$20,515.76
OM&A		Total			13,519.21	13,519.21	13,519.21	13,519.21
		Grand Total			$18,690.76	$23,862.31	$28,920.23	$34,034.97
		Monthly Entry			$1,557.56	$1,988.53	$2,410.02	$2,836.25

b. Please explain why carrying charges are applied to the amounts in the table on page 10.

OHL's Response:

The carrying charges that were applied in the table on page 10 however the amounts are incorrectly shown. The APH accounting instructions indicate carrying charges apply to this account. OHL has provided the table below noting the correct carrying charges applied.

Year	Principal	Interest	Total
2010	(12,460.51)	(36.25)	(12,496.76)
2011	(34,598.97)	(357.33)	(34,956.30)
2012	(61,833.22)	(1,041.16)	(62,874.39)
2013	(94,163.28)	(2,159.58)	(96,322.86)
2014	(105,508.27)	(2,641.83)	(108,150.10)
		50% =	(54,075.05)

c. On Schedule 1 page 10, OHL states "the requested amount is a 50% credit of ($108,385) balance of outlined in the Board's Appendix 2-TB below". This is confirmed on page 11 where OHL states "OHL is thereby requesting disposition a credit $(54,193) for Account 1592. However, in Appendix 2-TB on page 11, the Total Annual PST savings is $62,888 (50% of this amount is $34,444). In Schedule 3, page 2, the total claim amount for Account 1592 is ($32,043). Please clarify what is the amount that OHL is requesting for disposition and provide the appropriate analysis on how these estimates are derived in accordance with the December 2010 FAQ #4 as per the Filing Requirements.

OHL's Response:

The numbers shown in Appendix 2-TB on page 11 that noted the annual PST saving is $62,888 was incorrect. OHL has provided a revised Appendix 2-TB below:

Summary of PST Savings from 2009 Historic Year Analysis

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal Jan-April 2014 [1]	Carrying Charges to April 30, 2014	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings	$ 9,013	$ 13,519	$ 13,519	$ 13,519	$ 4,506	$ -	$ 54,077
Capital Items PST Savings	$ 3,448	$ 8,619	$ 13,715	$ 18,811	$ 6,839	$ 2,642	$ 54,073
Total Annual PST Savings [2]	$ 12,461	$ 22,138	$ 27,234	$ 32,330	$ 11,345	$ 2,642	$ 108,150

9.1-Staff-48

Ref: E9/T6/S1, pp. 1 - 2, LRAM Recovery

OHL has requested the disposition of its LRAMVA – Account 1568, of a total amount of $18,074, which includes $348 in carrying charges through April 30, 2014.

OHL is requesting the disposition of the lost revenues related to its 2011 CDM savings in both 2011 and the persisting 2011 savings in 2012.

a. Please provide a table that includes all the appropriate OPA CDM Initiatives OHL participated in which produced net CDM savings used in OHL's LRAMVA calculations. For each rate class, please list all relevant CDM initiatives for the applicable year and provide the subsequent net CDM savings for each. An example is provided below:

OPA CDM Initiatives

Residential	2011 Net kWh	2011 Net kW	2012 Persisting Net kWh	2012 Persisting Net kWh
Initiative 1				
Initiative 2				
Initiative 3				
Total				
GS<50	**2011 Net kWh**	**2011 Net kW**	**2012 Persisting Net kWh**	**2012 Persisting Net kWh**
Initiative 1				
Initiative 2				
Initiative 3				
Total				
GS>50	**2011 Net kWh**	**2011 Net kW**	**2012 Persisting Net kWh**	**2012 Persisting Net kWh**
Initiative 1				
Initiative 2				
Initiative 3				
Total				

OHL's Response:

Please see table below.

OPA CDM Initiatives				
Residential	**2011 Net kWh**	**2011 Net kW**	**2012 Persisting Net kWh**	**2012 Persisting Net kW**
Appliance Retirement	39,565	5	38,547.48	5
Appliance Exchange	815	1	794.04	0
HVAC Incentives	154,791	80	150,810.12	80
Conservation Instant Coupon Booklet	41,018	3	39,963.11	3
Bi-Annual Retailer Event	62,306	4	60,703.63	4
Retailer Co-op	-	-		
Residential Demand Response (switch/pstat)	-	-		
Residential Demand Response (IHD)	-	-		
Residential New Construction	-	-	-	-
RESIDENTIAL TOTAL	**298,495**	**93**	**290,818**	**92**
Home Assistance Program	-	-		
HOME ASSISSTANCE TOTAL	**-**	**-**	**-**	**-**
GS <50	**2011 Net kWh**	**2011 Net kW**	**2012 Persisting Net kWh**	**2012 Persisting Net kW**
Retrofit	361,262	65	351,971.14	65
Direct Install Lighting	55,853	22	54,416.58	18
Demand Response 3	15,665	400	15,262.13	0
Building Commissioning	-	-	-	-
New Construction	-	-	-	-
Energy Audit	-	-	-	-

Small Commercial Demand Response	-	-	-	-
Small Commercial Demand Response (IHD)	-	-	-	-
Pre - 2011 Electricity Retrofit Incentive Program Completed in 2011	354,732	72	345,609.07	72
Pre - 2011 High Performance New Construction Program Completed in 2011 or 2012	688	-	670.31	
C&I TOTAL	**788,200**	**559**	**767,929**	**155**
GS >50	**2011 Net kWh**	**2011 Net kW**	**2012 Persisting Net kWh**	**2012 Persisting Net kW**
Retrofit	56,536	8	55,082.02	8
Demand Response 3	14,099	240	13,736.40	0
Process & System Upgrades	-	-	-	-
Monitoring & Targeting	-	-	-	-
Energy Manager	-	-	-	-
INDUSTRIAL TOTAL	**70,635**	**248**	**68,818**	**8**
OVERALL TOTAL	1,157,330	900	1,127,566	255

9.1-Staff-49

Ref: E9/T3/S1, pp. 1-4 and Appendix A – Z-factor Event

OHL is requesting the disposition of a total debit balance of $275,893 due to the remediation of a contaminated site of a dismantled distribution station. On page 2 OHL stated that in order to limit costs, based on the consultant's report, the site was entombed with a rubber membrane so nothing could leach into or out of OHL's property. On page 11, the Remediation Closure Report (Appendix A) noted in its conclusion that the contaminated soil left in place beneath the 0.90m depth contained concentration of arsenic, at all sampling locations, which exceed the MOE Table 8 Standard. A geotextile membrane denotes the boundary between contaminated soils left in place versus clean imported backfill.

a. How can OHL ensure that this cost is a one-time cost, given the contamination at deeper soil levels as well as the southeastern portion of the site remain?

OHL's Response:

OHL ensures that it is a one-time cost. OHL did consider further excavation to complete the remediation of the site due to additional cost involved. At the suggestion of the environmental consultants future excavation was stopped and the rubber membrane was installed complete the remediation with new granular fill.

b. How is OHL guaranteeing the public safety of this site in the future?

OHL's Response:

The above process now makes the site safe for future uses including parking lot or slab on grade building structures.

c. Please discuss any alternative solution considered by OHL, e.g. did OHL consider further excavation to complete the remediation of the site? If so, please provide cost estimates.

OHL's Response:

Please see above response to a.

d. OHL has deducted a property value of $100,000 from the total event cost of $370,589 excluding carrying charges. What are OHL's future plans for this property?

OHL's Response:

OHL does not have any future plans for the property at this time.

e. Does OHL expect any similar issues with other sites of dismantled distribution stations as the conversion project progresses?

OHL's Response:

OHL does not expect any similar issues with other sites as this particular site the contamination was a result of the type of fill that was imported into the area prior to hydro's usage.

9.1-Staff-50

Ref: E9/T3/S1, pp. 1-4 and Appendix A

OHL has elected to allocate the extraordinary event costs of $275,893 on a volumetric basis.

a. Please provide the rationale from a cost causality standpoint of proposing to use metered kWh to allocate the costs to OHL's customer rate classes.

OHL's Response:

OHL assumed that the kWh allocation was the most appropriate method to allocate to the customers classes and has no justification other than OHL treated the cost as an energy-related cost.

b. Did OHL consider allocating this amount on the same basis as transformer costs? If so, please explain the rationale for rejecting this approach. If not, please comment on OHLs view on whether this approach should be considered.

OHL's Response:

OHL did not consider allocating this amount on the same basis as transformer costs. OHL has no comments on whether this approach should be used.

c. Please provide a table that compares the costs allocated to each rate classes when using: (a) kWh as the allocator; and (b) using the allocation factor for transformer costs underpinning OHL's 2010 cost of service application.

OHL's Response:

OHL has provided the table below demonstrating the allocation of the extraordinary event cost based on the transformers costs underpinning OHL's 2010 cost of service application.

Allocation based on 2010 Cos Allocation Factor					
Customer Class	Retail Transmission Connection Rate		Basis for Allocation	Allocation	Allocated $
	per KWh	per kW	($)	Percentages	
Residential	0.0030		257,313	37.78%	104,223
GS < 50 kW	0.0027		104,754	15.38%	42,430
GS >50 kW		1.0652	313,586	46.04%	127,016
GS >50 kW - TOU-eliminate			0	0.00%	0
Sentinel Lights		0.8407	300	0.04%	122
Street Lighting		0.8234	4,173	0.61%	1,690
USL	0.0027		1,015	0.15%	411
TOTALS			681,142	100.00%	275,893

Comparison of Cost Allocation Methods								
	Total Amount Allocated	Allocator	Residential Service	General Service Less than 50kW	General Service 50 to 4,999 kW	Street Light	Sentinel Lighting	Unmetered Scattered Load
a)	275,893	kWh	94,615	42,645	136,105	1,972	142	413
b)	275,893	Tx CN	104,223	42,430	127,016	1,690	122	411

9.1-Energy Probe-49

Ref: Exhibit 1, Tab 1, Schedule 10 &
Exhibit 1, Tab 5, Schedule 2

OHL proposes a 2 year recovery period for the stranded meter costs in Exhibit 1, Tab 1, Schedule 10. OHL proposes a 1 year recovery period for the stranded meter costs in Exhibit 1, Tab 5, Schedule 2 (page 2). Please reconcile.

OHL's Response:

OHL is proposing a 2 year recovery period as indicated in Exhibit 9, Tab 4, Schedule 1, Page 2 as shown in Table 9.7 and as stated in Exhibit 1, Tab 1, Schedule 10. There was a typographical error in the statement made in Exhibit 1, Tab 5, Schedule 2.

9.1-Energy Probe-50

Ref: Exhibit 9, Tab 2, Schedule 4

a. Please explain why OHL has used 2010 test year data to allocate costs and calculate rate riders.

OHL's Response:

There were instructions in the OEB EDVARR model on the billing determinant sheet as follows: "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"

b. Please update all the tables in this schedule to reflect the allocation of costs and the calculation of the rate riders based on the 2014 test year data.

OHL's Response:

OHL followed the instructions according to the Board modelling. The Board did not instruct us to use the 2014 test year data, therefore OHL does not believe the tables should be updated to reflect 2014 test year data.

9.1-Energy Probe-51

Ref: Exhibit 9, Tab 3, Schedule 1

a. Has OHL sold the property in questions as of the current time? If yes, please provide details.

OHL's Response:

No, OHL has not sold the property.

b. Based on the continuity schedule for 2012, it appears that OHL has reduced rate base by the net cost of $270,589. Please confirm that this is correct.

OHL's Response:

OHL has reduced the rate base by the net cost of $270,589.

c. What has OHL done for financial reporting purposes related to these expenses incurred to remediate the site?

OHL's Response:

Information for financial reporting purposes was included in our 2011 and 2012 audited financial statements. These statements were included as part of our 2014 rate application however, we have provided the 2011 audited financial statements disclosure note: "The company owns a piece of land which formerly housed a transformer station, due to environmental requirements the company is legally required to remediate the land. When a reasonable estimate of the cost of rehabilitating the land can be made, the fair value of the liability should be recognized and the corresponding asset retirement cost capitalized. The estimated obligation for the property rehabilitation as at December 31, 2011 was $200,000 and the company has recorded an asset retirement obligation and the corresponding asset retirement cost has been capitalized as at that date. "In the 2012 audited financial statements, the following disclosure note was included: "The company owns a piece of land which formerly housed a transformer station. After remediation of the land the company had the land appraised. It was determined that the asset was impaired and as a result it was written down by $270,589. The company has applied to the OEB to recover this amount from customers as an extraordinary event outside management's control. As such, this amount has been set up as a regulatory asset, awaiting the OEB's decision. If the OEB disallows this recovery, it will be recorded as an expense in the statement of operations in the year of decision.

d. Did OHL investigate any other uses for the property, such as storage for its own use that would have involved lower mitigation costs?

OHL's Response:

No. The land abuts the main creek through Orangeville. Orangeville Hydro's main concern was for public health and safety and to mitigate any future liability.

e. What are the tax implications in the test year if the Board allows recovery of these expenses? Has OHL claimed tax reductions associated with the remediation expenses in 2013 or previous years? If yes, please quantify the reductions and the tax savings.

OHL's Response:

OHL has not claimed tax reductions associated with the remediation expenses in 2013 or previous years.

f. Who was the previous owner of the property? Was the previous owner related in any way to OHL or the city?

OHL's Response:

The information provided by our consultant in the phase 1 environmental assessment indicated that the Orangeville Hydro Electric Commission has owned the land since 1924. The report did not indicate who the previous owner was.

9.1-Energy Probe-52

Ref: Exhibit 9, Tab 4, Schedule 1

a. What did OHL do with the stranded meters? In particular, were any sold for use, or sold as scrap?

OHL's Response:

No, OHL did not sell any meters for use or scrap, as stated in Exhibit 9, Tab 4, Schedule 1.

b. If yes to either, please indicate where the proceeds were recorded and the year this took place.

OHL's Response:

Not applicable.

9.1–VECC–42

Ref: Exhibit 9, Tab 3, Schedule 1, pg.4

Orangeville Hydro Substation Remediation

a. Did OHL seek Board approval for the establishment of a deferral account for the remediation costs of the station site? If so please provide the order for that account.

OHL's Response:

OHL did not seek Board approval for the establishment of a deferral account for the remediation costs of the station site. OHL addressed a letter to the Board secretary the latter part of 2013 and this letter can be found in the rate application documents in RESS.

b. Please confirm that the site is adjacent to both a city parkette and a large apartment building.

OHL's Response:

Yes the site is adjacent to a town parkette and across the road from a large apartment building. The apartment building had a previous industrial use as Dod's Knitting Mill. The site also abuts Mill Creek which is the major creek flowing through Orangeville.

c. OHL has stated that the market value of the land is $100,000. Please provide the report on land valuation.

OHL's Response:

Please see the attached valuation in Appendix P – MS1 Valuation.

d. There appears to be a recently built building without a basement foundation across the street from the site (Dickinson + Hicks). Please confirm if this is correct. If so does OHL know when that building was built and at what value it sold?

OHL's Response:

The building across the road from the remediation site (Dickinson and Hicks) was built in 1964. It was purchased by Dickinson and Hicks in 1997 for approximately $145,000. The building <u>does</u> have a lower level under part of the building.

e. Has OHL attempted to sell the land? If not why not.

OHL's Response:

Please refer to 9.1-Staff-49

f. Has the value of this land been removed from OHL's regulated rate base. If not why not. If yes, please provide the value removed from rate base and in what year.

OHL's Response:

No, the value of the land is in the rate base. OHL will remove from the rate base once a decision is made to sell the land.

g. When and from whom did OHL acquire the property. If the property was acquired from the City please indicate what efforts were made to recover remediation costs.

OHL's Response:

Please refer to 9.1-Energy Probe-51(f)

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: E3, Appendix D, EDDVAR Continuity Schedule; E2/T5/S9, Page 2, Appendix 2-ED and E1/T3/S1, Appendix C, 2012 Audited Financial Statements (Note 6)

In the continuity schedule, a variance was noted for Account 1576 in the column showing the variance between RRR and the 2012 balance. The RRR balance agrees with OHL's 2012 financial statements. The 2012 balance agrees with the balance per Appendix 2-ED. The variance shown in the EDDVARR continuity schedule is as follows:

Account	RRR and Audited Financial Statements	2012 Balance Claimed for Disposition	Variance
1576 Accounting Changes Under CGAAP	-$173,590	-$1,052,590	$879,000

In Appendix A of the EDDVARR Continuity Schedule, OHL indicated that the variance is due to the 2013 difference and the rate the return calculation. Per Appendix 2-ED, the 2013 difference would be -$444,582 [-$821,499-(-$376,917)] and the rate of return is -$231,091, totalling - 675,673 and not -$879,000. Please reconcile the difference and update the evidence as necessary.

OHL's Response:

Please see 7.6-Staff-31 that provides an explanation of the corrections that were completed in 2012 to reconcile Appendix 2-ED to the amount recorded in 2012 of -$173,590 and the amount that should have been recorded of -$376,917. The variance of $879,000 is the correct variance between the 2012 RRR balance and the total amount to be claimed for disposition.

Rate of Return	231,091
1576 Accounting Policy Change	821,499
Total Amount claimed for Disposition	1,052,590
RRR & Finanical Statements	173,590
Variance	879,000

9.2-Staff-52

Licence: Distribution System Planning, issued June 16, 2009

In its Application OHL is requesting to dispose a debit balance of $47,550 in account 1532 related to the development of a GEA Plan for OHL's 2010 CoS application. OHL notes that it subsequently withdrew the GEA plan. See breakdown of the costs below:

Description	2009	2010	2011	2012	2013	2014	Total
Consultant - GEA Plan	16,378						16,378
Staff Training	2,913						2,913
GEA Education for Staff	5,114						5,114
GEA Education for Business/Community	1,180	7,302					8,482
Science Workshop		10,522					10,522
Website Modifications	-	797					797
Incremental Labour	648						648
Carrying Charges		294	862	659	659	220	2,694
Total	**26,234**	**18,915**	**862**	**659**	**659**	**220**	**47,550**

a. Please confirm that the balance for disposition is $47,550 rather than $825 as shown in line 25 of E9/T2/S1, p. 6.

OHL's Response:

The balance in account 1532 that OHL is applying for disposition is $47,550.

b. Please provide further details as to the reason for withdrawing the GEA plan from its 2010 application.

OHL's Response:

OHL withdrew the GEA plan in our 2010 rate application during the confidential settlement conference. Ontario Energy Board staff had previously directed Orangeville Hydro to include and merge the Green Energy Plan into the rate application. Ontario Energy Board staff members were summoned and were consulted during the settlement conference. All parties mutually agreed that the GEA plan should be withdrawn from our 2010 application.

c. Please describe if OHL's customers received any value from the planning process and if so what. Please describe whether, and how this plan was incorporated into this current application's DSP.

OHL's Response:

OHL attempted to establish a cohesive plan to engage our customers in Green Energy and be

prepared to assist and connect any of the >10 kW renewable generation proponents that were present in our service area. OHL retained a consultant to develop a plan that would meet the government's mandate and the Ontario Energy Board's release of the initial requirements under G-2009-0087 released June 16, 2009. OHL's plan was well in advance of the issuance of the Filing Requirements, Distribution System Plans – Filing under Deemed Conditions of License (EB-2009-0397). OHL drafted a basic GEA plan that in preparation for the purpose of our 2014 rate application and those requirements changed with the issuance of the Chapter 5 Filing Requirements (DSP), therefore included in the DSP.
OHL's customer's received value from the planning with the education of staff, giving them ability to answer any questions from proponents. The workshop benefits the ratepayers with greater community engagement, fostering the creation of greater awareness of the culture of conservation, which ultimately will move the ratepayer in the direction of choosing energy efficient products/services, thus saving money on their bill.

d. Account 1532 is established to record "incremental operating, maintenance, amortization and administrative expenses directly related to "renewable enabling improvements"…In addition, costs that can be recorded in this account also include expenses associated with preparing a Distribution System Plan pursuant to the planning guidelines set out in section IV of these Guidelines and expenses associated with changes to a distributor's CIS to enable the automated settlement of FIT contracts".

i. Please explain how Staff Training ($2,913), GEA Education for Staff ($5,114) and Businesses ($1,180 and $7,302) as well a science workshop ($10,522) qualify under the above account description.

OHL's Response:

OHL's administrative expenses directly related to renewable enabling costs as staff training dealt with the types of generation, solar, wind and community generation projects . GEA staff training involved conferences and workshops to educate the staff understanding the Minister's Directive and LDC involvement, MicroFit, and FIT projects and settlement processes. The science workshop targeted the schools and involved a series of hands-on 'stations' that provided education to kids (and some of their parents) with respect to phantom power, renewable energy, fossil fuels and the need for conservation. Students were provided with the tools, and set up the workshops, and focused on the OPA Grade 5 curriculum.

ii. Please provide a copy of the GEA plan, which was the basis of these expenditures.

OHL's Response:

Please find attached a copy of the GEA plan as Appendix Q – GEA Plan.

9.2-Energy Probe-53

Ref: Exhibit 9, Tab 5, Schedule 1

Please explain why the additions to gross assets are the same under both old and new CGAAP in both 2012 and 2013. In particular, why hasn't the change in capitalization implemented for January 1, 2013 resulted in different additions in the bridge year?

OHL's Response:

9.2-SEC-35

Ref: Ex.1/5/1, p. 1

Please provide a list of all ways in which the Application is inconsistent with the Filing Requirements.

OHL's Response:

OHL filed its 2014 Cost of Service according to the filing requirements and did not receive an incomplete from the Board. To OHL's knowledge the application is consistent with the filing requirements.

ORANGEVILLE HYDRO

Appendix A -

Asset Condition

Assessment

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Orangeville Hydro Limited
Orangeville, Ontario, Canada

Asset Condition Assessment

Final Report

H332547-ACA1-70-124-0001
Rev. 0

August 2009

Project Report

Aug 31, 2009

Orangeville Hydro Limited
Asset Condition Assessment

DISTRIBUTION
George Dick
Jan Howard
Bob Noble
Dick Carryer
Project File

Final Report

2009.Aug.31	0	Final	HZ	GR		
2009.Jul.27	C	Exec Summary	HZ	HZ		
2009.Jul.20	B	Addendum (2.1)	HZ	HZ		
2009.Jul.09	A	First draft	HZ	TT		
DATE	**REV.**	**STATUS**	**AUTHOR**	**CHECKED**	**APPROVED**	**APPROVED**
HATCH						**CLIENT**

Report Disclaimer

This report has been prepared by Hatch Limited (the “Engineer”) for the sole and exclusive use of Orangeville Hydro (the “Client”) for the purpose of assisting the management of the Client in making decisions with respect to the condition of assets owned by the Client; and shall not be (a) used for any other purpose, or (b) provided to, relied upon or used by any third party.

This report contains opinions, conclusions and recommendations made by the Engineer, using its professional judgment and reasonable care. Use of or reliance upon this report by the Client is subject to the following conditions:

(a) the report being read in the context of and subject to the terms of the signed proposal 09-0592 between the Engineer and the Client dated March 17th, 2009 (the “Agreement”), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions that were specified or agreed therein;

(b) the report being read as a whole, with sections or parts hereof read or relied upon in context;

(c) the conditions of the assets may change over time due to natural forces or human intervention, and the Engineer takes no responsibility for the impact that such changes may have on the accuracy or validity or the observations, conclusions and recommendations set out in this report; and

(d) The report is based on information made available to the Engineer by the Client or by certain third parties, and unless stated otherwise in the Agreement, the Engineer has not verified the accuracy, completeness or validity of such information, makes no representation regarding its accuracy and hereby disclaims any liability in connection therewith.

(e) The Executive Summary is written as a stand-alone report that can be published with the OEB Rate Application for Orangeville Hydro, for years 2010 and 2011. The full document is an internal working document as it describes the overall process/methodology, and expresses opinion on the process and data management practices within Orangeville Hydro.

Table of Contents

Executive Summary 4

1. Introduction and Methodology 8

1.1 Scope 8
1.2 What is ACA? 9
1.3 Orangeville Hydro Technical Overview 10
1.4 Overview Of This Report 12
1.5 Asset Condition Assessment Methodology 13

2. Overhead System 20

2.1 Distribution Line Sections 20
2.2 Load Break Switches 30
2.3 In-line Switches 34
2.4 Pole Mounted Transformer 38
2.5 Fault Indicators 44
2.6 Fuse Cutouts 47
2.7 Voltage Conversion Transformers (28/4kV) 50

3. Underground System 52

3.1 Underground Cable 52
3.2 Pad Mounted Switches 58
3.3 Pad Mounted Transformers 64
3.4 Duct Banks and Manholes 70

4. Substation Equipment 72

4.1 Substation Transformers (46-4kV) 73
4.2 Substation Switchgear 82
4.3 Substation Riser Cable (4kV) 87
4.4 Substation HV Structures 90
4.5 Substation Civil Infrastructure 93

5. Other Infrastructure 102

5.1 Metering Installations 102
5.2 Right of Way 104
5.3 Operating Spares 104
5.4 Other Assets Not Included 107

6. Observations, Conclusions and Recommendations 109

6.1 Observations 109
6.2 Conclusions 111
6.3 Recommendations 113
6.4 Possible Next Steps 117

Executive Summary

E.1 Introduction

Orangeville Hydro has completed an Asset Condition Assessment of its distribution assets, and summarized the results in this document. By using existing data, and supplementing it with additional data from field visits, it was possible to complete an objective appraisal of asset condition. In some cases, additional data will be required to achieve critical mass of asset condition data needed to effectively plan its sustainment work programs.

This report contains a review of the overall asset condition assessment process adopted by Orangeville Hydro, and documents the evaluated condition of the total population of Distribution assets, based on condition criteria and end-of-life criteria that are indicative of asset condition and consistent with industry practices.

The Distribution assets were grouped into 19 asset classes. Asset classes are further grouped into (a) Overhead, (b) underground, (c) substation, and (d) Other assets.

This report has been prepared by Hatch Ltd (Oakville, formerly Acres International Limited (Acres) of Oakville Ontario). The analysis and report has been prepared in consultation with Orangeville Hydro staff specialists, but the report and its conclusions are based on the findings of the consultant.

E.2 Process Review

In general, it has been found that Orangeville Hydro has undertaken a careful and thoughtful evaluation of condition assessment needs. Prior to the project resulting in this report, Orangeville Hydro has collected data on its major assets. During this project, additional data was collected to secure much of the information needed to assess the condition of its Distribution assets. The data collection methods, tools and technologies are generally appropriate to the task of measuring asset condition, providing the right data at an appropriate cost. The methods used by Orangeville Hydro have been found to be consistent with industry practices. The methods and procedures for data collection are documented for data collection practices by internal staff.

With a few exceptions, the identified data collection procedures have been executed according to specifications, and useable data has been collected and stored in databases.

Orangeville Hydro is using this data appropriately, having adopted condition criteria that form a rational basis for asset decision-making. Orangeville Hydro has adopted methods of analysis that are consistent with industry practices. With the adoption of composite Health Indices for each class of assets, as recommended by the consultant, Orangeville Hydro has established a coherent and rational basis for evaluating the overall condition of each Distribution asset owned by the company.

Tables E1 shows an overall evaluation of the quality of the processes adopted by Orangeville Hydro, and the quality of the data found in the various databases.

Category	Description	Count	UOM	Utility Comparison	Process Viability	Data Availability	Health Index Evaluated
Overhead							
	2.1 Distribution Line Sections	56.0	km	2	2	2	Y
	2.2 Load Break Switches	12.0	pc	3	2	3	Y
	2.3 In-Line Switches	312.0	pc	1	1	1	Y
	2.4 Pole Mounted Transformers	596.0	pc	1	1	3	Y
	2.5 Fault Indicators	30.0	pc	3	2	1	Y
	2.6 Fuse Cutouts	unknown		5	5	5	N
	2.7 Voltage Conversion Transformers	5.0	pc	1	1	1	Y
Underground							
	3.1 underground cable	381.0	pc	2	2	2	Y
	3.2 pad mounted switchgear	60.0	pc	2	2	3	Y
	3.3 pad mounted transformers	823.0	pc	1	1	3	Y
	3.4 duct banks and manholes	unknown		5	5	5	N
Substations							
	4.1 substation transformer (44-4kV)	8.0	pc	1	1	1	Y
	4.2 substation switchgear	11.0	pc	1	1	3	Y
	4.3 substation riser cable	33.0	pc	1	1	3	Y
	4.4 substation HV structure	4.0	pc	1	1	3	Y
	4.5 substation civil	4.0	pc	1	1	1	Y
Other Assets							
	5.1 Metering	N/A					N
	5.2 Right of Way	unknown		3	3	5	N
	5.3 Operating Spares	N/A		1	1		N
	5.4 Other Assets not Included	N/A					N

grey	not evaluated
green	1-2 very good - only minor gaps or problems
yellow	3 fair - some gaps or problems
pink	4-5 very poor - significant gaps or problems

Table E1 - Evaluation of Orangeville Hydro ACA Processes for P1 Assets

Orangeville Hydro is pursuing a program of asset condition assessment that is equivalent to programs executed in forward-thinking utilities around the world. The ACA processes of Orangeville Hydro have been demonstrated to be viable, in the sense that the data collected and the uses made of it are entirely appropriate to support the spending decisions that Orangeville Hydro must make.

Composite Health Indices have been recommended for Orangeville Hydro use by the consultant in every case. Health Indices provide a basis for assessing the overall health of an asset. Health Indices are based on identification of the modes of failure for the asset and its sub-systems, as well as functional obsolescence drivers, and then developing measures of generalized degradation or degradation of key sub-systems that can lead to end-of-life for the entire asset.

The data availability rankings require some clarification. The only assets ranked "POOR" on this aspect were for fuse cutouts, duct banks and Right of Way.

The most common way of managing fuse cutouts is on a run-to-failure basis and can be easily replaced. These fuse cutouts are understood as those that are not associated with transformers and not associated with cable risers. These devices are used for switching, isolation and feeder tap protection.

For Duct Banks and Right of Way, It is recommended that Orangeville Hydro review their process and data collection methods, both for demographics and for condition.

Most key performance indicators are in GOOD or VERY GOOD condition. Those flagged as FAIR can be improved with some changes to process and/or data collection practices.

E.3 Asset Condition Results

The condition of the Orangeville Hydro assets has been evaluated in all circumstances where viable condition criteria are in place and sufficient condition data exists. Health Indices have been calculated for every asset with a recommended Health Index formulation and sufficient condition data to satisfy the minimum requirements for application of that formulation.

The results of the asset condition assessments assets are presented in Tables E2, based on the Health Index formulations and the extrapolated test results.

Category	Description	Count	UOM	very poor	poor	fair	good	very good
Overhead								
2.1	Distribution Line Sections	56.0	km	8.2%	5.4%	38.6%	37.5%	10.2%
2.2	Load Break Switches	12.0	pc	8.3%	8.3%	16.7%	16.7%	50.0%
2.3	In-Line Switches	312.0	pc	54.2%	29.8%	5.4%	5.4%	5.1%
2.4	Pole Mounted Transformers	596.0	pc	2.0%	7.9%	15.8%	17.4%	56.9%
2.5	Fault Indicators	30.0	pc	66.7%	3.3%	3.3%	13.3%	13.3%
2.6	Fuse Cutouts	unknown		---	---	---	---	---
2.7	Voltage Conversion Transformers	5.0	pc	0.0%	0.0%	0.0%	40.0%	60.0%
Underground								
3.1	underground cable	381.0	pc	6.6%	3.1%	3.4%	49.6%	37.3%
3.2	pad mounted switchgear	60.0	pc	10.5%	5.3%	10.5%	26.3%	47.4%
3.3	pad mounted transformers	823.0	pc	2.6%	6.0%	9.4%	40.2%	41.9%
3.4	duct banks and manholes	unknown		---	---	---	---	---
Substations								
4.1	substation transformer (44-4kV)	8.0	pc	0.0%	12.5%	12.5%	50.0%	25.0%
4.2	substation switchgear	11.0	pc	0.0%	0.0%	9.1%	27.3%	63.6%
4.3	substation riser cable	33.0	pc	3.0%	3.0%	24.2%	45.5%	24.2%
4.4	substation HV structure	4.0	pc	0.0%	0.0%	25.0%	25.0%	50.0%
4.5	substation civil	4.0	pc	0.0%	0.0%	25.0%	25.0%	50.0%

assessment shading for "very poor" categories

(grey)	zero
(green)	≤5%
(yellow)	5 to 10%
(pink)	>10%

Table E2 – Summary of ACA Condition Results

For some assets, maintenance and condition data has been collected for virtually every asset owned by Orangeville Hydro. In other asset classes, a smaller proportion of the total asset base has been tested and/or inspected, and the size and nature of the samples taken is sufficient to extend the results to the balance of the assets in that class through statistically relevant sampling.

A consistent approach has been used in developing the Health Index formulations, so that the meaning of the categories is broadly consistent across most assets.

In general terms, a "VERY POOR" asset can be interpreted to be very close to end-of-life, requiring urgent attention in the form of a risk assessment potentially leading to asset replacement or a major overhaul. Assets in the "POOR" category can be interpreted as being close to end-of-life, requiring risk assessment potentially leading to replacement or significant maintenance expenditures in a 1 to 5 year time frame. Assets in "FAIR" condition have experienced significant deterioration, but may be able to survive for another 5-10 years with only modest maintenance and/or component replacements. Assets in the "GOOD" category can be considered to have at least 10 to 20 years of service left, given normal maintenance expenditures. Assets in the "VERY GOOD" category should survive for more than 20 years, given normal maintenance expenditures. This scale is based on assets that typically have a 20 – 40 year life span. Assets with a shorter lifespan, have shorter time periods for each.

As might be expected, the vast majority of the assets owned by Orangeville Hydro are ranked in "GOOD" or "VERY GOOD" condition, meaning that these assets are generally being managed effectively and are being maintained in a condition suitable for many more years of service. The same conclusion may be drawn from the relatively small proportion of assets found in "VERY POOR" or "POOR" condition.

In the Orangeville Hydro Fleet of Assets, the following assets have shown noticeably higher than average results (red colour) in the VERY POOR condition: in-line switches, fault indicators, and pad mount switchgear. In addition, higher than expected levels (yellow) were found in distribution line sections, load break switches and underground cable.

Regarding in-line switches, some of the data records were incomplete and it was unknown if the switch was operated successfully within the last 2 years; additional data collection is underway to refine results. Both fault indicators and pad mounted switchgear have particular manufacturers and/or other physical characteristics such that the devices are no longer suitable for operations environment at Orangeville Hydro; consequently, it has been decided that electrical equipment with these characteristics is functionally obsolete.

Concerns exist for distribution line sections, load break switches and underground cable. For load break switches, there was marginal volume of information available. It is recommended that a short term maintenance program be implemented to acquire all required condition data. Distribution line sections and underground cable both have circuit sections that have been identified for conversion from 4kV to 28kV. For Distribution line sections, there are several examples of older construction, which does not meet the present engineering standard. In the last 10 years, the engineering standard has changed to armless construction, with pole mounted equipment between phase wire and neutral. Upgrading these line sections, or replacing transformers presents Orangeville Hydro with some technical challenges, consequently, the line sections have been identified as functionally obsolete. Overall, both distribution line sections and underground cable are well managed.

1. Introduction and Methodology

Orangeville Hydro has requested Hatch to assist with an Asset Condition Assessment (ACA) of its electrical infrastructure (overhead and underground). Based on the proposal 09-0592, the following work was completed.

Asset Condition Assessment and Asset Management are evolving concepts for smaller distribution utilities and are generally being driven by regulatory requirements to include Asset Condition Assessment and Asset Management philosophies with rate submissions. While the concepts have been maturing in larger transmission utility planning for more than 5 years, the availability of system-wide condition data has made the distribution environment harder to implement using the same methods.

Orangeville Hydro is undertaking to supply an Asset Condition Assessment with their rate submission in the summer of 2009, and Hatch is undertaking to facilitate the process and ensure that a useful result is obtained.

This section summarizes the scope and methodology used for this project, as well as general information that affects the entire project:

1.1 Scope

1.2 What is ACA

1.3 Orangeville Hydro Technical Overview

1.4 Overview of this Report

1.5 ACA Process

1.1 Scope

The scope of this project is the development of an Asset Condition Assessment report using available data and interviews with the field and office staff. Orangeville Hydro resources may undertake field inspections of high priority assets to enhance condition information.

The Orangeville Hydro System supplies two geographic areas: Town of Orangeville and Grand Valley. The Town of Orangeville includes feeders at 46kV, 28kV, 4kV, and four municipal stations. The Grand Valley system consists of 12kV feeders, and no municipal substations. More details are available in section 1.3.2 and section 1.3.3. In general, Non-system related assets such as vehicles and buildings are not included in this project.

The general methodology is detailed in Figure below, outlining the major steps and activities; however the first element of the project will be to conduct a “Needs Assessment Meeting” which will develop the plan for ultimate project. It is a goal that the Asset Condition Assessment process be “Owned” by Orangeville Hydro, and as such, the project will incorporate as much interface time for the exchange of knowledge as possible.

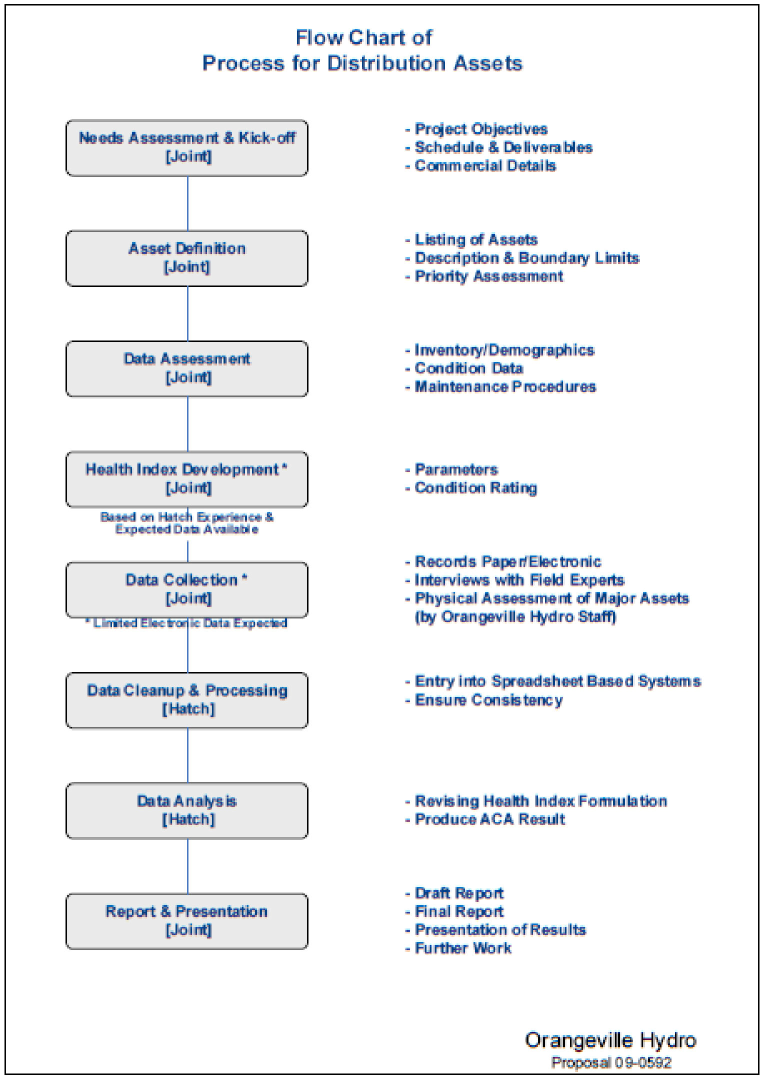


Figure – Process Overview

1.2 What is ACA?

Asset Condition Assessment or ACA, is a process whereby specific questions are asked of each asset in an asset class (a.k.a. condition information), and the results are summarized to provide a "50,000 ft" overview of the assets within a utility.

Many utilities have used this process as part of their asset management practices, including capital investment planning, optimization of the overall system, and in some cases risk managed asset management which takes asset condition, power grid configuration, asset location and other factors into account to manage reliability and total multi year capital cash flow.

This focus of this project is the assessment of distribution level assets, and to establish a first view for the utility of the fleet of assets, given that some traditional condition information is not available.

1.3 Orangeville Hydro Technical Overview

Orangeville Hydro services the following geographic areas: Orangeville Town (OT) and Grand Valley (GV) – pictures of area can be found in the following figures.

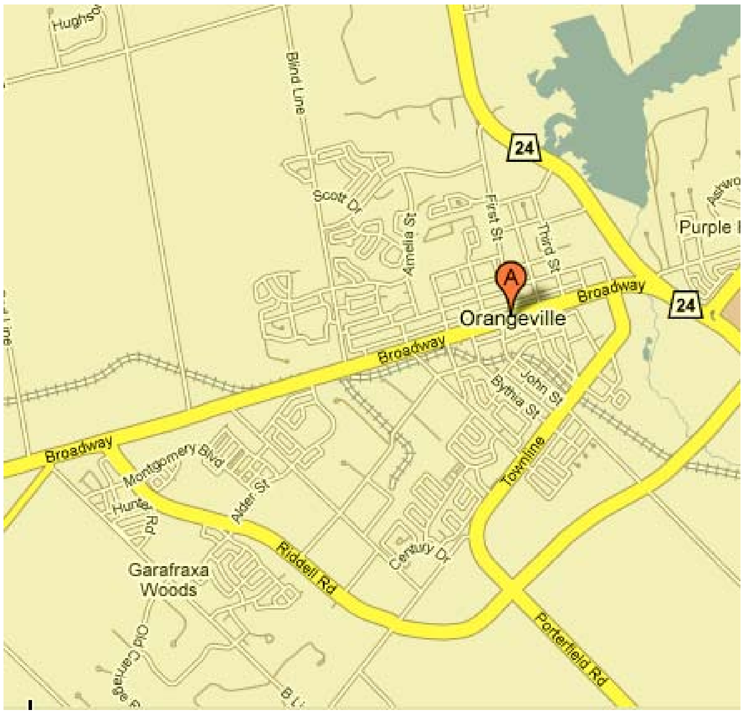


Figure - Orangeville Town Geographic Area

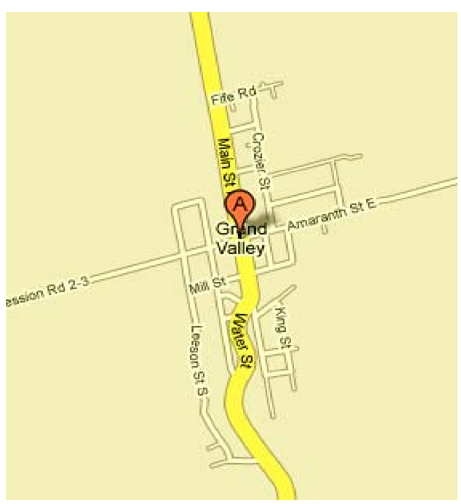


Figure - Grand Valley Geographic Area

1.3.1 Technical Notes on Terminology

Orangeville Hydro has several voltage systems it manages. The report uses the following general terminology for these voltage levels:

- 46kV = nominal 46.0kV, 3 phase, 3 wire. There is no neutral wire connected to the supply point. The single phase equivalent voltage is 25.5kV. This voltage is sometimes also referred to as 44kV.
- 28kV = nominal 27.6kV, 3 phase, 4 wire. The single phase equivalent voltage is 16.0kV. This voltage is sometimes also referred to as 27kV.
- 15kV = nominal 13.8kV, 3 phase, 4 wire. The single phase equivalent voltage is 8.0kV.
- 12kV = nominal 12.5kV, 3 phase, 4 wire. The single phase equivalent voltage is 7.2kV.
- 4kV = nominal 4.16kV, 3 phase, 4 wire. The single phase equivalent voltage is 2.4kV. Some utilities and suppliers refer to this voltage as 5kV.

1.3.2 General Infrastructure

Orangeville Hydro manages several voltages of infrastructure, both underground and overhead. The main distribution system is overhead, with a large portion of the residential neighborhood supply being underground. Most residential areas are now fed underground in direct bury joint use cable trenches or duct banks.

The overhead systems are supplied by Hydro One, as express feeders; therefore, the metering system and protection systems are located at the Hydro One substations, and are owned and maintained by Hydro One. The point of demarcation is typically a load break switch.

Orangeville Hydro also has several KABAR units. Over time, these units have started failing, either internal to the box they are in, or during operations. These units are deemed at end of life if there is not a suitable switching means on both sides of the KABAR unit.

1.3.3 Town of Orangeville

The Town of Orangeville, with a population[1] of approximately 28,000, and an area of 15.6 sq km, has a distribution system consisting of:

- one feeder from Hydro One at 46Kv
- two feeders from Hydro One at 28kV
- four municipal substations to transform 46kV to 4kV (MS#1 decommissioned July 2009)
- a 4kV distribution system, that is being slowly phased out
- approximately 9,000 customers, mostly residential, with some commercial, industrial and large user.
- approximately 30 large customers

The Town of Orangeville has been undergoing a voltage conversion process for approximately 18 years, from 4kV to 28kV. This is primarily driven by the following reasons:

- capacity issues regarding 4kV – not enough capacity
- reduction of the spare parts that purchasing and stores need to manage
- improved reliability of the higher voltage system
- lower operating costs after conversion.

Areas that have been flagged for conversion in the next 5 years are generally the oldest infrastructure, or areas that have been under-performing in some way. These flagged areas are presented in the health indices, and in the criteria "functional obsolescence" – namely, the asset item is no longer able to provide quality service, can no longer be adequately serviced or spare parts (replacements) are no longer technically available or cost wise reasonably available. New underground cable and switching units are being installed with 28kV insulation, but may be operated at 4kV during the transition period.

1.3.4 Grand Valley

The Town of Grand Valley, with a population[2] of approximately 1,000, and an area of 0.3 sq km, has a distribution system consisting of:

- town supply voltage is 12kV 3 phase (7.2kV 1 phase)
- one feeder from Hydro entering the town from the south, at 12kV 3 phase (7.2kV 1 phase)
- two feeders from a Hydro One MS (Grand Valley DS) , at 12kV 3 phase (7.2kV 1 phase)

The main distribution system is overhead, with a large portion of the residential neighbourhood supply being underground. Amaranth street (main east west street) is nicknamed "tornado alley"; it was hit by a tornado in 1985.

1.4 Overview Of This Report

The rest of the report will focus on the following general areas:

2.0	Overhead System
3.0	Underground System
4.0	Substation Equipment
5.0	Other Infrastructure
6.0	Observations, Conclusions and Recommendations

For each, a number of asset groups are listed (sections 2 – 5, not 6), and within each of the asset groups, the following sections can be found (where applicable):

X.Y.1 Description
X.Y.2 Demographics
X.Y.3 Asset Management Practice
X.Y.4 Health Index Formulation
X.Y.5 Health Index Results
X.Y.6 Observations

… where

X = section number by asset group
X.Y = Asset Number

The following appendices are attached to this report.

Ref.	Description	Contents
A	Demographic Data	MS Excel spreadsheets with Orangeville Hydro Data and extra columns to categorize data and interpret information
B	Health Index Parameter Guide	A table for each parameter of every Health Index to explain how to interpret the A, B, C, D letter codes.
C	Completed Survey Forms	Completed survey forms, in MS Excel format, as received by Hatch from Orangeville Hydro
D	Health Index Calculations	Calculation MS Excel spreadsheets using data from Appendix C, and the Health Index formulations found in this report
E	Blank Survey Forms	Blank forms in MS Excel format
F	Orangeville Hydro Reference Data	Reference Data provided by Orangeville Hydro
G	Site Visit Notes	Notes and pictures from site visit Jun 25th, as well as other supporting information

Table – List of Appendices and their Content

1.5 Asset Condition Assessment Methodology

The ACA methodology consists of the following steps:

1.5.1 Asset Definition

1.5.2 Demographic Information Collection

1.5.3 Summary of Asset Management Practices

1.5.4 Health Index Formulation

1.5.5 Health Index Calculation Results

1.5.6 Reporting of Results

1.5.1 *Asset Definition and Description*

The first step in this process is to clearly define the asset, what components are included and what is not. In other words, a dotted line is put around the asset. This process sometimes results in the identification of other assets that exist, but have not been given much attention in the past. For each asset, the asset is then described for later reference.

1.5.2 *Demographics (Asset Count)*

A Demographic is a statement of the number of assets based on some grouping within the asset class. Traditionally, age of the asset has been used. Information was received from Orangeville Hydro, in the following forms:

- maps – marked up with age and other information.
- MS excel tables
- reports from 3rd party service providers
- oil sample reports (appendix F)
- pole inventory project
- discussions with staff and crews.

1.5.3 *Summary of Asset Management Practices*

Every utility manages its assets in a slightly different manner. In this report, this section (X.Y.3) summarizes the key points of how Orangeville Hydro manages its assets. This information forms the basis for the Health Index formulation - the key measurables or parameters.

The focus on the parameters should be End of Life, with minimal contribution to items that can easily be corrected with maintenance, or are part of the regular maintenance practice for that particular asset; for example, an oil change on the car would not be part of a Health Index formulation as it does not measure end of life.

1.5.4 *Health Index Implementation*

The Health Index is a calculation, consisting of several inputs (parameters), which are weighted to form an intermediate score (points). This score is then adjusted by over-riding factors, like functional obsolescence, to arrive at the final Health Index score.

1.5.4.1 Health Index Formulation Formulation

1.5.4.2 Condition Data Collection

1.5.4.3 Data Validation

1.5.4.1 Health Index Formulation/Revision

Each parameter of Health Index identifies the data that comes from data records (DR) and those that come from visual inspections (VI). Data records include any tests or measurements of the equipment that need to be converted to ABCD values. Historically examples include

- DGA = dissolved gas analysis
- conductance measurements
- insulation measurement using a meggar
- polarization tests
- TTR = transformer turns ratio test
- standard oil tests
- number of operations in a given time period (switches, circuit breakers, etc).
- circuit breaker travel time.

The Health Index score is expressed as a percentage, where 100% is brand new condition (no indications of degradation in condition), and 0% is considered at end of life (all measureable condition indicators are at end of life).

Functional obsolescence is a special parameter of the Health Index, which adjusts the overall score downward (toward end of life), given various conditions. Functional obsolescence summarizes many aspects; for example, if a PILC cable can not be maintained, (i.e. no one available to splice, or no materials available to splice), then the asset is considered near end of life and needs to be replaced. Other aspects can include:

- equipment installed many years ago to a then acceptable standard, does not meet the present engineering standard any more
- management has decided not to use a particular type of equipment or manufacturer of equipment, for one or more reasons
- software to service equipment is no longer available
- people or the necessary skill sets are not available to service the equipment
- Existing equipment cannot be replaced one for one, with present standard equipment; for example, certain parts are not available anymore, or physical spacing requirements have changed.
- The area around the asset (i.e. pole, pad transformer, pad mounted switch) has changed over time to a point that standard maintenance practices can not restore general access and serviceability, or, today's normal operating practices can not be applied.
- Specifically, In the case of poles installed in backyard construction, the infrastructure can not be maintained (i.e. with built up back yards – it is not accessible 24/7/365).

For each of the defined parameters, a letter is assigned. Generally, the condition ratings as follows:

- A: new or near-new condition (also test pass in many cases)
- B: minor defects
- C: significant defects
- D: imminent failure expected (very short term) or, Not fit for service (also test fail)
- E: selected assets – parameter is not fit for service. If this parameter is used, then "D" remains imminent failure, but the part in question is fit for service. Some measurements may be below required minimum, but only by a small percentage.
- N: no data – the parameter in question does not exist in the particular asset in question. Consequently, it makes no contribution to the Health Index results. An entry of "N" recognizes that during the equipment inspection, a decision was reached that the parameter does not apply to the piece of equipment, or that no data is present (as per guide book). During the evaluation process, the parameter does not contribute to the maximum score (excluded)

1.5.4.2 Condition Data Collection

Once the Asset Management practices of the utility are defined, and the parameters of the Health Index are clear, it is necessary to collect information to evaluate.

Some data will be available in some form of data record (i.e. oil reports, test results, 3rd party inspection reports, past maintenance records, etc), whereas other data is available from visual inspections. Visual inspections, also known as field surveys, are a means to collect data from equipment, thru visual inspection. Some assets will not require an outage, whereas others may require an outage to complete this activity.

Should all assets in an asset class be inspected visually? No - sampling has the advantage that a percentage of the population can be evaluated, given a certain margin of error, and confidence level, without evaluating the entire population; for example, wood poles of which most utilities have several thousand, it would not be practical to evaluate all poles; consequently sampling is used.

Depending on the level of detail desired after the Health Index is calculated, assets may need to be split into sub-groups, and from there the minimum sample size determined. Also, the sample taken should be in proportion to the overall population – it makes no sense to sample all the 28kV pole mount transformers and expect to be able to say something about all transformers (including those of other voltage levels).

The condition assessment data collection process is based on achieving a minimum 80% confidence level with a measure of error of $\pm$ 16%. In general, the following table summarizes the sample size for the stated population:

Population	Sample	Percent
10	8	80.0
20	8	40.0
40	10	25.0
60	13	21.7
100	16	16.0
150	18	12.0
200	21	10.5
250	23	9.2
300	24	8.0
500	30	6.0
823	35	4.3

Table - Population and Sample Quantities

1.5.4.3 Data Validation

Once the data has been collected, the calculation process can begin. Calculations are performed in MS Excel where possible. Very large data sets are done using other programs.

The data for each record (row in MS Excel = 1 asset) is validated, meaning that the results from the field are compared to the parameter definitions (ABCDN). Missing data or not valid entries are rejected.

A maximum possible score is developed for each asset and compared to the maximum score. All parameters contribute the maximum score, but only parameters with valid data contribute to the maximum possible score.

- Maximum score = calculated from the weightings of each parameter, assuming that all parameters have an "A" value. This value is calculated for the asset class once.
- Maximum possible score = calculated from the weightings of each parameter, with VALID DATA, assuming that the parameter has an "A" value. This value is calculated for each asset in the asset class and can vary from one asset to another.

Note, if a parameter has an "N" for not applicable, then the parameter is not included in "maximum possible score" as well as "maximum score". The following ratio must be greater than 70% for a valid Health Index calculation:

$$\frac{(\text{Maximum possible score}) * 100\%}{(\text{maximum score})}$$

If this check were not included, then it is possible for one Health Index parameter to drive the results of the process. It also provides a gate, to help screen assets that have sufficient data from those that have in-sufficient data. An example is described in section 4.1.3.

The Health Index calculation then proceeds based on valid information only:

- Maximum score = see previous definition
- Accumulated points = weighted sum of points from each parameter, corrected by the functional obsolescence factor, as required.

$$\frac{\text{(accumulated points)} * 100\%}{\text{(maximum possible score)}}$$

1.5.5 *Health Index Calculation Results*

At this point, it has been determined that the Health Index calculation can be completed for a particular asset (row) in an asset class. The Health Index is calculated, and expressed as a percentage. Results are reported using the following sample results:

- Table summarizing the sample (if less than 100% sampling done)
- Table summarizing the population (extrapolated sample)
- Pie chart of the population results
- Bar chart of the population results

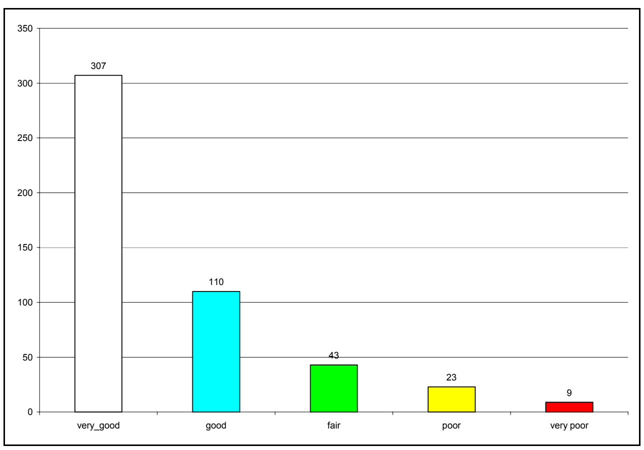


Figure – Sample Bar Chart

It should be noted, that based on the percent size of the sample (sample/population), there is always the possibility of having items in categories where the sample does not have any. Consider, if the sample has a count of zero in one of the categories (FAIR, POOR, VERY POOR), then this may be the result of rounding down a number near 0.5%. It is with this approach that it is possible to project the sample to the overall population.

At this point, it is possible to identify the count of items in FAIR, POOR and VERY POOR categories, but it is not possible to identify which specific item is in the category. This level of detail is sufficient for establishing budgets, further investigations, and general remediation plans.

Results are reported in a final project report (this document), together with the table below, which provides an interpretation of the five categories:

- VERY GOOD
- GOOD
- FAIR
- POOR
- VERY POOR

Each of the categories has the following typical interpretation. The following table is specific to transformers, with an average life of 40 years.

Health Index	Condition	Description	Remaining Life (years)	Requirements
85-100	VERY GOOD	Some aging or minor deterioration of a limited number of components	20 – 40 yrs	Normal maintenance
70-85	GOOD	Significant deterioration of some components	10 – 20 yrs	Normal maintenance
50-70	FAIR	Wide spread significant or serious deterioration of specific components	5 – 10 yrs	Increased diagnostic testing, possible remedial work, or replacement needed, depending on criticality
30-50	POOR	Wide spread serious deterioration	2 – 5 yrs	Start planning process to replace or rebuild considering risk and consequences of failure
0-30	VERY POOR	Extensive serious deterioration	0 - 2 yrs	At end of life, immediately assess risk, replace or rebuild depending on assessment

Table – Typical Health Index Scale

1.5.6 Observations

For each asset class, observations are provided, based on the population results. The percentage (or count) of assets in the 5 categories, will assist Orangeville Hydro in determining what level of effort is required and indirectly, the amount of operational (maintenance) and/or capital will need to be spent in each asset class.

2. Overhead System

The Overhead distribution system consists of all components installed above ground, on poles, outside of substations. Riser Cables connecting pad mounted equipment or substation switchgear are in either the Underground equipment category or substation category. Located in this section are:

2.1 Distribution Line Sections

2.2 Load-break Switches

2.3 In-line Switches

2.4 Pole Mounted Transformers

2.5 Fault Indicators

2.6 Fuse Cutouts

2.7 Voltage Conversion Transformers

2.1 Distribution Line Sections

Overhead distribution lines are constructed and managed as line sections, typically from dead-end to dead-end. A dead-end is a location where the phase wires are terminated on an angle or dead-end pole, which will include guys. Distribution poles, crossarms, insulators and guys are the mechanical elements that keep wires up in the air, off of the ground, and away from supporting elements, at the required clearances distances required for the given voltage level and land use as defined in CSA C22.3 No 1 – Overhead Standard.

At present, there is insufficient data to complete a pole evaluation on a pole by pole basis. Orangeville Hydro started a pole cataloguing program approximately 1 year ago, and has catalogued nearly 300 poles. Instead, an alternate approach is the use of line section evaluations as detailed below.

The following provides some definitions to clarify different levels of organization:

- A *line section* can be as short as 1 span, and as long as required to cover the distance required. A line section can be re-built without making changes to the neighbouring line section. The line section is self supporting, and not required to support a neighbouring section. A line section can have one or more circuit sections from different circuits, including different voltages. Most often, the higher voltage is higher off the ground.

  Each line section contains phase wire, poles, insulators, and other components. The line section may also contain the following based on the type of construction: cross arms, transformers, cable risers, fuses, capacitors, reclosers, communications wire, load break switches, and in-line switches. Since line sections may have more than one circuit present, the length of line sections measured in kilometres is always less than the length of circuit sections.

- A *circuit section* exists between deadends, consists of the same wire type, same number of phases. A feeder (or circuit) consists of one or more circuit sections.
- A *feeder* may be branched, from one supply point. Traditionally, distribution circuits operate radially, or looped with open points. A feeder consists of one or more circuit sections.
- The *phase wire* is part of the circuit section. It represents a single section of wire, which can be phase or neutral.

Field crews maintain and construct the power system based on line sections. Operations typically works on the feeder level or circuit section level. System studies and protection analysis are typically performed on the feeder or branch circuit level.

Line sections and circuit sections are typically defined with the following data:

- starting point
- end point
- same wire type thru out section for a given circuit
- same year of construction for majority of components
- circuit designation
- voltage

Since line sections may have more than one circuit present, the length of line sections measured in kilometres is always less than the total length of circuit sections.

The condition assessment was completed on line sections, which were converted to circuit sections, in order to compare with demographic information. Results are presented based on circuit sections, but can be interpreted for line sections, given the methods used. Future data collection and management activities should include more detailed asset inventory to facilitate the analysis of the base infrastructure (poles, guys, phase wire, insulators, etc), and harmonize the combination of the analysis method with the asset management practices.

2.1.1 Description

A description of the asset is summarized in the previous section. Excluded from the line section are the following items, as they are covered elsewhere in this document:

- pole mounted transformers and related primary protection
- HV switches (46kV, 28kV, 12kV, 4kV)
- (in-line) Isolation switches
- cable risers and related equipment

- fault indicators
- metering installations

There are many types of phase wire. Orangeville Hydro has the following in their system:

- Copper
- ACSR = aluminum conductor steel reinforced
- AAC = all aluminum conductor.

Orangeville Hydro uses predominantly wood poles but has some concrete poles installed in its system.

It should be noted that a pole may contain wires from feeders of different voltages, or multiple feeders of the same voltage or other equipment (see above list). Some line sections have poles by Hydro One, or circuits by Hydro One on the pole. In these cases, the following interpretations are provided on the data:

- poles by Hydro One – pole data item flagged as "N", implying no data, as Orangeville Hydro is not responsible for this component.
- circuits owned by Hydro One – circuit count and condition assessment only includes those circuits owned and managed by Orangeville Hydro.

2.1.2 Demographics

Phase wire consists of either a single phase or a 3 phase installation. Any 2 phase installations are considered as 3 phase installations (there is very little present). A neutral wire is present in most cases. This applies to each voltage level. At 46kV, all line sections consist of 3 phase installations.

The analysis of the line section and circuit section demographic data produces data tables, with overhead and underground information (one record for each circuit section, as read from the system maps; one per voltage level). Underground information is removed, for use in a separate section of this report. The results are summarized based on circuit section count, and circuit section length:

Age	4 kV			Grand Valley			27 kV			44 kV	GRAND	
	OH_1	OH_3	Total	OH_1	OH_3	Total	OH_1	OH_3	Total	OH_3	TOTAL	PRCT
0 - 9 yrs	1.0	8.5	9.5	1.0	8.5	9.5	0.5	8.0	8.6	3.1	30.6	34.4
10 - 19 yrs	0.6	4.3	4.9	0.6	4.3	4.9	0.4	12.3	12.6	7.8	30.3	34.0
19 - 29 yrs		1.5	1.5		1.5	1.5				4.3	7.3	8.2
30 - 39 yrs		0.9	0.9		0.9	0.9					1.8	2.0
40 - 49 yrs	2.8	3.6	6.4	2.8	3.6	6.4				1.3	14.1	15.9
50+ yrs		1.1	1.1		1.1	1.1					2.2	2.5
unkwn	0.4		0.4	0.4		0.4	1.7	0.3	1.9		2.7	3.1
Total	4.8	19.9	24.7	4.8	19.9	24.7	2.6	20.6	23.1	16.5	89.0	100.0

GRAND TOTAL	12.2	76.8	89.0

Table - Overhead Line Section Length (km)

Age	4 kV			Grand Valley			27 kV			44 kV	GRAND	
	OH_1	OH_3	Total	OH_1	OH_3	Total	OH_1	OH_3	Total	OH_3	TOTAL	PRCT
0 - 9 yrs	2	18	20		2	2	2	19	21	8	51	26.4
10 - 19 yrs	2	11	13				2	31	33	15	61	31.6
19 - 29 yrs		4	4	10	8	18				9	31	16.1
30 - 39 yrs		3	3	1	2	3					6	3.1
40 - 49 yrs	9	8	17		3	3				3	23	11.9
50+ yrs		2	2								2	1.0
unkwn	2		2	1		1	13	3	16		19	9.8
Total	15	46	61	12	15	27	17	53	70	35	193	100.0

GRAND TOTAL	44	149	193

Table - Overhead Line Section Count

To establish demographics of circuit sections, maps of the distribution system (appendix F) were analysed, and tabulated. From there, an audit was done to determine the number of poles in selected feeder section lengths. This sample was then used to estimate the number of poles in the overall system.

2.1.3 Asset Management Practices

Overhead line sections distribute electricity, and as such there are various technical aspects that must be met to distribute electricity within established standards. Given the wire size in use for 46kV and 28kV, load flow and voltage drop are not a concern in the next 10 years, unless there is a significant increase in load within the service area.

Under normal usage, phase wire can last from 25 to 100 years depending on the environment it is installed in. Heavy industrial environment may cause premature aging due to chemical actions. Orangeville Hydro practices a run to failure mode of operation, which is consistent with other LDCs in Ontario. Some transmission companies will sample a section of wire after 50 years of age and complete several tests including the twist test to determine if the strands have the required ability to support their own weight, within manufacturers and engineering specifications of the line.

There are several methods to assess the condition of poles. At present Orangeville Hydro does not perform condition assessment of poles via physical tests. Orangeville Hydro does do visual inspections of their poles, but does not record the outcome of the inspection.

Orangeville Hydro practice is to periodically review line sections (field visual inspections), as well as the overall system performance (reliability), to determine where improvements are required. Furthermore, there are several strategic plans underway, to convert areas of the town from 4kV to 28kV. This was initiated approximately 18 years ago, when a capacity constraint required the conversion to a higher voltage. As a consequence, MS#1 will be/has been decommissioned July 2009, with others following suite, as the load is transferred to 28kV.

It should be noted, that since the conversion process has started, capacity is no longer a concern for the near to medium future. Orangeville Hydro is continuing the decommissioning the 4kV infrastructure, in order to increase capacity for the future, and to be more cost effective regarding spares and general materials. Consequently, the condition of the phase wire (copper), and the existence of 4kV infrastructure, does contribute to the end of life decision, as it sets relative priorities for the conversion process.

The following parameters are considered in evaluating the condition of a line section:

Demographics

- number of poles
- number of circuits (sample picture or sketch)
- line section length

Condition Assessment

- type of insulators – porcelain, polymer
- framing – cross arm based, or armless
- age information – from engineering records, maps or stamps on poles
- type of phase conductor – aluminum/ACSR/copper
- typical pole condition based on group assessment (how many in each category; which one denominates; how probable is it for the line to fall down; how much of the line section would be affected by a catastrophic failure)
- functional obsolescence – see section 1.5.4

An overhead line section has various components that contribute to the obsolescence of the line section. These include:

- wire – presence of copper wire (typically #4, or #6)

- fuses – old style box fuses (i.e. 4kV system)
- framing – old style cross arm based framing that does not permit a transformer or other equipment to be installed between phase wire and neutral.
- pole line section located in backyards – these can be difficult to access, service, maintain, or upgrade, under all seasonal conditions
- 4kV line section that has been listed for voltage conversion.

2.1.4 Health Index Formulation – Distribution Line Section

There are two Health Indices proposed here. The final subsection here summaries the Health Index formulation application - the calculation process.

- Distribution Pole – this is proposed but can not be evaluated given the amount of data available.
- Distribution Line Section – this can be evaluated based on a sample of line sections.

2.1.4.1 Health Index Formulation – Distribution Pole

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Pole Condition	VI	10	A,B,C or D	3,2,1,0	30
2	Pole Age	DR	4	A,B,C or D	3,2,1,0	12
3	Insulator Type	VI	1	A,B,C or D	3,2,1,0	3
4	Framing (cross arm/Armless)	VI	1	A,B,C or D	3,2,1,0	3
5	Phase Conductor	VI	1	A,B,C or D	3,2,1,0	3
6	Foundation and Grounding	VI	1	A,B,C,D,N	3,2,1,0	3
7	Guying and Anchoring	VI	1	A,B,C,D,N	3,2,1,0	3
8	Overall Condition	VI	1	A,B,C or D	3,2,1,0	3
9	Functional Obsolescence	DR	—	—	—	—

Table - Health Index Formulation for Distribution Pole

Note: Where sufficient information exists for categories 3-8 inclusive, the age information should be ignored. Under all conditions, pole information is required, as the primary driver, with a minimum of 4 non age parameters, or age.

2.1.4.2 Health Index Formulation – Distribution Line Section

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Pole condition	VI	6	A,B,C or D	3,2,1,0	18
2	Phase Conductor	VI	2	A,B,C or D	3,2,1,0	6
3	Insulators	VI	3	A,B,C or D	3,2,1,0	9
4	Guy and anchors	VI	2	A,B,C or D	3,2,1,0	6
5	Trees	VI	4	A,B,C or D	3,2,1,0	12
6	Foundation and grounding	VI	3	A,B,C or D	3,2,1,0	9
7	Functional obsolescence	DR	—	—	—	—

Max Score = 60

HI = 100*Score/Max

Table - Health Index Formulation for Distribution Line Section

For Functional obsolescence, a value of "C" results in the total point count being divided by "2" and in the case of "D", divided by 4.

In addition to the parameters above, the following information should be identified for each line section:

- number of poles
- number of circuits (digital picture or sketch)
- age information (pole date stamps, or engineering records)
- description of start and end point (i.e. along street, from cross street1 to cross street2)
- line section length (from map)

This Health Index formulation permits the calculation of a Health Index result even if no pole information is available. This occurs in cases where Hydro One owns the pole, but Orangeville Hydro has circuits on the pole.

Where several conditions may exist in a line section, it is the one with the worst score that shall be applied; for example, if polymer insulators and porcelain insulators are present, then porcelain insulators will be used to determine the parameter for the Health Index Calculation.

2.1.4.3 Health Index Formulation Application

This Health Index is more difficult to apply than other health indices' in this report. Since the demographic data is only available as circuit sections, and the field assessment is completed in the form of line sections, it is necessary to convert the data from the field into circuit section data, for extrapolation purposes. Once the results have been extrapolated, the results can then be expressed as line section results, if so required.

The disadvantage of this approach is that if poles in general govern the Health Index results, then the conversion from line section to circuit section may represent the condition of the overall line sections in a condition closer to end of life than they actually are. In the future, it is recommended that the data management practices of poles and overhead line sections be reviewed so that a more accurate assessment of the infrastructure can be completed.

The application involves the following general steps:

1. Tabulation of field survey results by line section (table in appendix D).
2. Removal of all line sections with condition "unknown" – since there is insufficient information for these sections; they are excluded from further considerations.
3. Conversion of table of line sections to circuit sections. Here, the Health Index result is applied equally to all circuits in the line section, creating more records than existed with line sections.
4. Summary results of the circuit sections by voltage level and condition band (VERY GOOD, GOOD, FAIR, POOR, And VERY POOR). Single phase and three phase line sections are treated the same – each is one line section. The summary of results is presented as length of circuit section, not count of circuit sections.
5. Sample results are extrapolated to the population by each voltage level.
6. As with all extrapolations, a small error is included, to account for any rounding that may have occurred during the sample process.
7. The circuit sections are converted back to line sections based on the ratio of line section length to circuit section length found in the sample.
8. Results are presented for consideration.

2.1.5 Health Index Results

Line section evaluation looks at a portion of an overhead line, between dead ends or corners or similar poles, with constant number of circuits on a pole. Circuit sections allow for a more direct comparison between the field visit (Appendix G) and the line information made available by Orangeville Hydro.

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

CONDITION	LINE SECTION (KM)	PERCENT
VERY GOOD	3.39	22.8
GOOD	5.45	36.6
FAIR	4.30	28.8
POOR	0.62	4.2
VERY POOR	1.15	7.7
TOTAL	14.90	100.0

Table - Sample Results – Line Section Length (km)

	44kv	27kv	12kv	4kv	Total	Percent
VERY GOOD	29	3,358	17	28	3,432	14.5
GOOD	2,574	3,203	1,487	1,583	8,847	37.3
FAIR	2,872	2,244	738	3,440	9,294	39.2
POOR	29	44	616	28	718	3.0
VERY POOR	260	44	525	612	1,442	6.1
TOTAL	5,763	8,894	3,384	5,692	23,733	100.0

Table - Sample Results – Circuit Length (m)

When the sample is extracted to the population, the results can be found in the following table:

	44kv	27kv	12kv	4kv	Total	Percent
VERY GOOD	83	8,759	124	124	9,089	10.2
GOOD	7,370	8,354	10,856	6,868	33,447	37.5
FAIR	8,221	5,854	5,387	14,928	34,391	38.6
POOR	83	116	4,500	124	4,822	5.4
VERY POOR	744	116	3,834	2,657	7,351	8.2
TOTAL	16,500	23,200	24,700	24,700	89,100	100.0

Table – Population Results Circuit Length (m)

	Total	Percent
VERY GOOD	5,708	10.2
GOOD	21,005	37.5
FAIR	21,598	38.6
POOR	3,028	5.4
VERY POOR	4,616	8.2
TOTAL	55,954	100.0

Table – Population Results, Line Section Length (m)

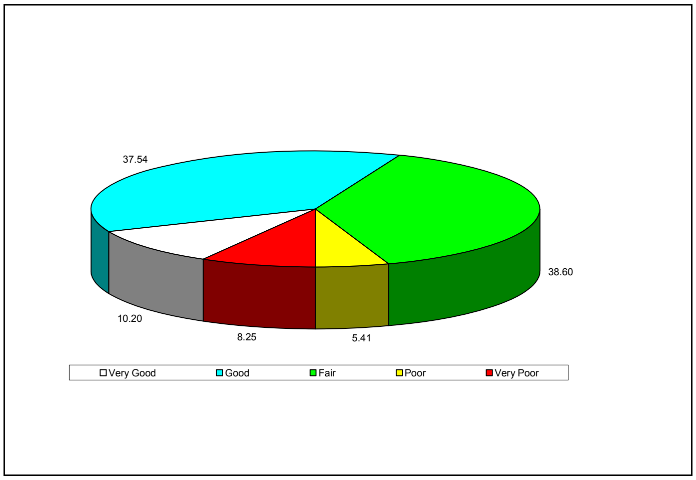


Figure – Pie Chart Population Results (percent)

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

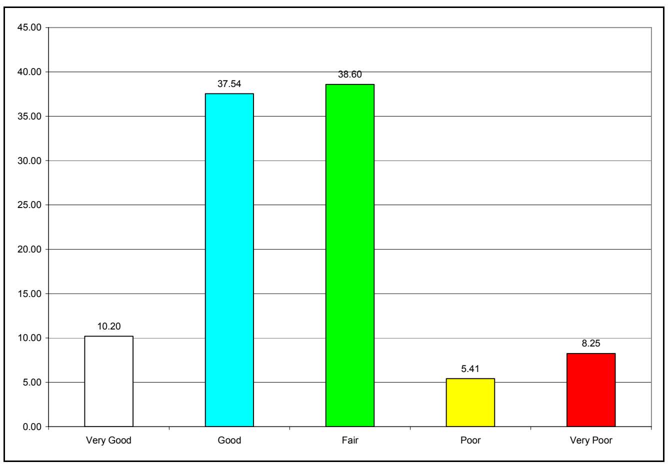


Figure – Bar Chart Population Results (percent)

2.1.6 Observations

Health Index Results

The Health Index results show that about 8.2% of the distribution line sections are near end of life or at end of life (see VERY POOR). Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 44.0% of the distribution line sections will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further (see POOR and FAIR).

The remaining 47.7% of the distribution line sections are in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

General Data Observations

For the sample of line sections visited, there is an average of 1.592 circuits per pole.

Given the sample of line sections, and the geographical information provided by Orangeville Hydro, the average span within the sample is 46.0 m.

Given the 55.95 km of line sections in Orangeville and Grand Valley, it appears there are approximately 1220 poles in the distribution system.

2.2 Load Break Switches

2.2.1 Description

Load break switches are three phase devices, typically installed in pole top arrangements, and used by utilities to perform feeder switching, sectionalizing or distribution grid re-configuration, to permit safe working conditions for utility field staff on a targeted overhead line section. Technically, this switch is capable of interrupting all loads current and some fault currents. It can also be used to pickup (energize) line sections and cable sections.

Picture: Pole Top Load Break Switch

Switches typically have a manual operator or automatic operator at ground level, which is connected to the switch with a pipe, running vertically down the pole. A load break switch can also be mounted on the side of the existing pole (side mount).

2.2.2 *Demographics*

Orangeville Hydro currently manages 12 load break switches, at different voltage levels, as shown in the table below. Age information (installation date) is not available for these devices.

VOLTAGE	TOTAL	PERCENT
27.6kV	4	33.3
44kV	8	66.7
TOTAL	12	100.0

Table - Demographics Load Break Switch

2.2.3 *Asset Management Practices*

Pole top Load break switches are devices used by utilities to redirect electrical power from one feeder section to another. The typical utility switching orders (OTO = orders to operate), involve "make before break" operations; hence the switch must be capable of all of the following:

- opening and closing on full load line current
- the pickup of line sections
- the pickup of transformers (especially cold units with high inrush current)
- withstanding thru fault currents
- providing visible break (isolation) for the operating voltage.

Many utilities have extensive programs for the maintenance of these switches, as they are a key component in the operations of a distribution system. As opposed to inline switches, which are relatively simple to install, the pole top load break switches are more difficult to install. Consequently their maintenance and continued operation on an as needed basis is paramount.

The asset management process involves evaluating both physical measurements as well as visual observations of the switch. This is consistent with activities of other utilities. Not all utilities in Ontario have such an involved process, which provides confidence in the switches ability to operate correctly when required.

A condition assessment process should include a review of the following components and measurements:

- condition of arc Interrupter
- physical Insulator Damage including copper wash

- mechanical deterioration of linkages
- rust/corrosion on metal parts, including moving parts
- measurement of contact resistance (indication of pitting or fusing)
- measurement of insulation (A-B in closed position, A-A in open position, A – frame in closed position, and all relevant permutations)
- any other activities suggested by the manufacturer
- recording of full name plate data.

2.2.4 Health Index Formulation – Load Break Switches

The following table summarizes the Health Index Formulation.

#	Condition Criteria	DR/VI	Weight	Condition Rating	Factors	Maximum Score
1	Arc Interrupter Condition	VI	2	A,B,C,D	3,2,1,0	6
2	Insulation Quality	DR	3	A,B,C,D	3,2,1,0	9
3	Contact Resistance	DR	3	A,B,C,D	3,2,1,0	9
4	Control/Mechanism Box	VI	2	A,B,C,D	3,2,1,0	6
5	Insulators	VI	2	A,B,C,D	3,2,1,0	6
6	Overall Switch Condition	VI	4	A,B,C,D	3,2,1,0	12

Max Score = 48
HI = 100*Score/Max

Table - Health Index Formulation for Load Break Switches

2.2.5 Health Index Results

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	27.6	44	TOTAL	PRCT
VERY GOOD	1	1	2	100.0
GOOD	0	0	0	0.0
FAIR	0	0	0	0.0
POOR	0	0	0	0.0
VERY POOR	0	0	0	0.0
TOTAL	1	1	2	100.0
PERCENT	50.0	50.0	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	27.6	44	TOTAL	PRCT
VERY GOOD	2	4	6	50.0
GOOD	1	1	2	16.7
FAIR	1	1	2	16.7
POOR		1	1	8.3
VERY POOR		1	1	8.3
TOTAL	4	8	12	100.0
PERCENT	33.3	66.7	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

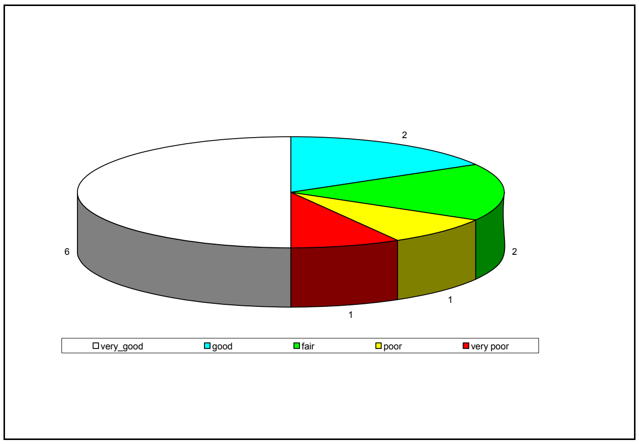


Figure – Pie Chart Population Results

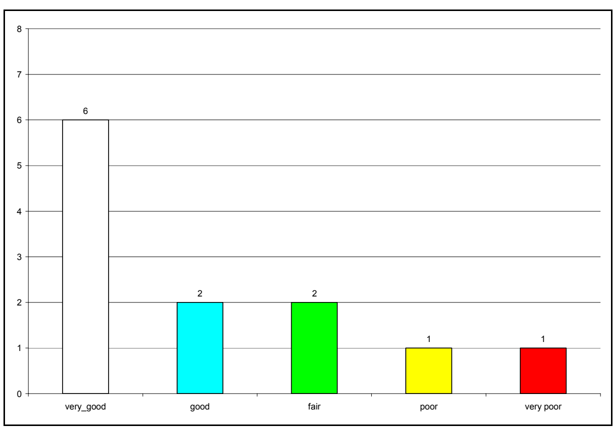


Figure – Bar Chart Population Results

2.2.6 *Observations*

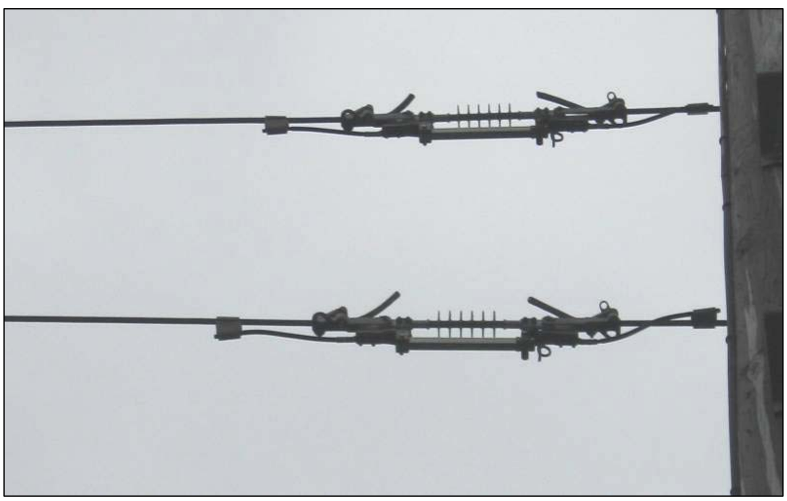
The load break switch asset class had too few valid parameters (amount of information) to reasonably calculate the Health Index. In the time available for this project, it was not possible to schedule the required outages to get the condition data required.

A most probable distribution is shown based on the experience of Hatch with other utilities.

2.3 In-line Switches

2.3.1 *Description*

In-line switches are single phase units, hook stick operated, that provide visible isolation for overhead line sections and some underground sections. They are installed on overhead bare conductor as the picture below shows.



Picture - Inline Switches

These switches have no current interrupting rating, but can be used to pick up short overhead and underground line sections. Using live line techniques, these devices can be removed or inserted as required. Consequently, these devices are given little maintenance attention.

All switches are type 46kV, no matter in which circuit or voltage level they are installed in.

2.3.2 *Demographics*

In-line switches are found in both service areas, Grand Valley (GV) and Orangeville (OV). There is no age information available:

Phase	Voltage	GV	OV	TOTAL	PERCENT
1	4.0		1	1	33.3
1	7.2	2		2	66.7
SUB TOTAL 1 PH		2	1	3	100.0

Phase	Voltage	GV	OV	TOTAL	
3	4.0		31	31	30.1
3	12.0	4		4	3.9
3	27.6		31	31	30.1
3	44.0		37	37	35.9
SUB TOTAL 3 PH		4	99	103	100.0
INSTALLATIONS		6	100	106	

1 PHASE UNIT COUNT	312	

Table - Demographics In-line Switches

With three switches at each 3 phase location, there are a total of 312 devices connected to the system. The vast majority of the in-line switches are three phase installations, and can be found in Orangeville.

2.3.3 Asset Management Practices

Orangeville Hydro completes visual inspection of devices on a periodic basis. Since these devices can be installed using live line techniques, the replacement of a Poorly functioning device can be completed quickly and efficiently as required. The date of last operation (open/close) is recorded and submitted to Engineering for review and archiving.

Generally, distribution utilities do not have replacement programs for these switches, and they are considered "run-to-failure" items. However, some utilities have had to replace in-line switches due to misalignment problems. Several utilities perform maintenance on a cyclic basis (e.g., every 5 years), but in most cases this is done on an as-needed basis. Maintenance involves cleaning, lubricating and adjusting switch contact alignments. Generally, no testing or electrical measurements are done.

These devices do not have an extensive ACA process to evaluate their condition. Since these devices can be installed using live line techniques, the replacement of a poorly functioning device can be completed quickly and efficiently as required.

The Health Index formulation for isolation switches is based on the date of last operation, to determine if the device requires attention. Obsolescence based on

- voltage rating of the switch relative to the operations voltage
- make/model of the isolation switch – certain types have had problems in the past.

If an obsolete switch is found, and is is required for switching or isolation purposes, it would be immediately replaced if it is not able to fulfill its function.

2.3.4 *Health Index Formulation – In-line Switches*

The following Health Index formulation is proposed.

#	Condition Criteria	VI/DR	Weight	Condition Rating	Factors	Maximum Score
1	Thermographic Scan	DR	1	A,B,C,D	3,2,1,0	3
2	Overall Switch Condition	VI	3	A,B,C,D	3,2,1,0	9
3	Functional Obsolescence	—	—	A,B,C,D	—	—

Max Score = 12
HI = 100*Score/Max

Table - Health Index Formulation for In-line Switches

For Functional obsolescence, a value of "C" results in the total point count being divided by "2" and in the case of "D", divided by 4.

If functional obsolescence is known, and no other information is available, the switch can be assumed to have 6 points, and then the remainder of the calculation can proceed as normal.

2.3.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	4kV	GV	27kV	44kV	TOTAL	PRCT
VERY GOOD					0	0.0
GOOD					0	0.0
FAIR					0	0.0
POOR			6	3	9	33.3
VERY POOR	6		6	6	18	66.7
TOTAL	6	0	12	9	27	100.0
PERCENT	22.2	0.0	44.4	33.3	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	GV	OV	TOTAL	PRCT
VERY GOOD	2	13	16	5.1
GOOD	3	13	17	5.4
FAIR	3	13	17	5.4
POOR	3	91	93	29.8
VERY POOR	3	168	169	54.2
TOTAL	14	298	312	100.0
PERCENT	4.5	95.5	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

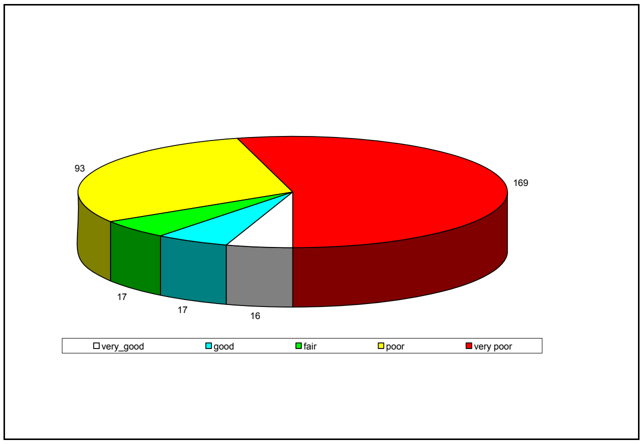


Figure – Pie Chart Population Results

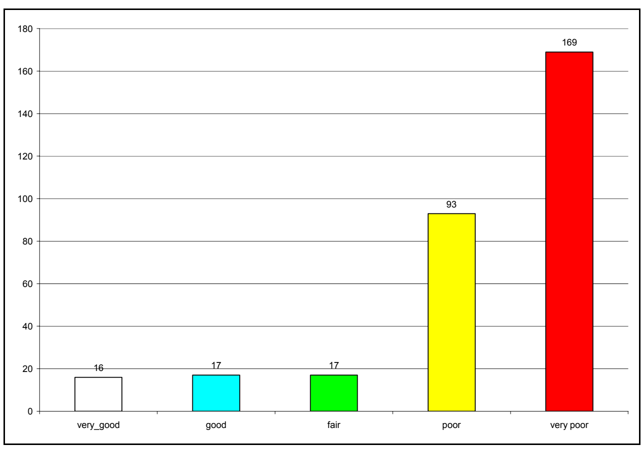


Figure – Bar Chart Population Results

2.3.6 *Observations*

In reviewing these results, it is evident that no switches were sampled in Grand Valley; hence the distribution of the population is flat across all five categories. Furthermore, it is noted that the sample from Orangeville contains POOR and VERY POOR values exclusively. After a review of specific results in the data table with field conditions, another survey should be completed to confirm that the results are as presented.

The Health Index results show that about 54.0% of the in-line switches are near or at end of life. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 35.0% of the in-line switches will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 11.0% of the in-line switches are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

2.4 Pole Mounted Transformer

2.4.1 Description

Pole mounted transformers are installed on selected poles, to provide one of several typical secondary voltages to customers. These voltages may include: 120/240, 120/208, and/or 347/600.

Picture - Pole Mounted Transformers

Pole mounted transformers are generally round, ranging in heights of up to 6.0 ft and diameters of up top 3.0 ft. They are attached to poles, and come in 1 phase and 3 phase units. 1 phase units are typically cylinders, and 3 phase units can be a cluster of cylinders or box shaped. Single phase transformers (cans) can be grouped into three units of 1 phase to create a 3 phase supply.

Installations are generally between the neutral (under the transformer), and the phase wire (over the transformer), including surge arrestor(s) and fuses. The surge arrestor is connected on the line side of the fuse.

Note: Orangeville Hydro has two other types of installations that use pole type transformers. These include:

- trans-pad – a metal enclosure, installed outside on the ground, with pole type transformers inside. These are legacy installations; they will be maintained, but no new installations will be made. These are included with PAD mounted transformers.
- vault installed pole transformers – these are now customer owned; therefore excluded

2.4.2 Demographics

The demographics for pad mounted transformers can be viewed in two ways:

- Age and Geographic Area
- PCB Levels

2.4.2.1 Age and Geographic Area

Pole mounted transformers are installed in Grand Valley (GV) and Orangeville; in Orangeville, they are installed on two voltage levels: 4kV and 28kV (OV-4, OV-28).

AGE	INSTALL AREA			TOTAL	PERCENT
	GV	OV-4	OV-28		
0-9 YR	7	53	256	316	53.0
10-19 YR	4	13	64	81	13.6
20-29 YR	16			16	2.7
30-39 YR	36			36	6.0
40-49 YR	6			6	1.0
50+ YR	1			1	0.2
UNKWN	27	113		140	23.5
TOTAL	97	179	320	596	100.0
PERCENT	16.3	30.0	53.7	100.0	

Table - Demographics Pole Top Transformers

It should be noted that voltage conversion transformers (28 – 4kV) have been included in the OV-28 category. Three phase transformer installations using pole mounted transformers have been counted as "3".

Transformers with unknown age, in Orangeville, on the 28kV system are assigned an age band (0-9 or 10-19) in proportion to the existing known data. The 28kV system was introduced in 1990, and given the fact that new transformers have been installed, the age and PCB information is known. For this same group of transformers, the PCB level has been set to <2 ppm, if there was no information provided in the database. All the 28kV transformers were purchased new, and it is recommended that all nameplate data be collected and archived.

In reviewing the available data, it is evident that approximately 23.5% of the transformers have an unknown age. The majority of the units are on the 4kV system, where, in the past, Orangeville Hydro has purchased used transformers. It is recommended that Orangeville Hydro

- review their records to update the age information, and
- review their data entry methods, to harmonize the various data entries.

2.4.2.2 *PCB Levels*

In addition to the above information, the following information on PCB content is available:

AGE	PCB LEVEL				TOTAL	PERCENT
	<2	LOW	HIGH	UNKWN		
0-9 YR	272	12	6	26	316	53.0
10-19 YR	71	3		7	81	13.6
20-29 YR	13			3	16	2.7
30-39 YR	3			33	36	6.0
40-49 YR				6	6	1.0
50+ YR	1				1	0.2
UNKWN	56	21	3	60	140	23.5
TOTAL	416	36	9	135	596	100.0
PERCENT	69.8	6.0	1.5	22.7	100.0	

Table - Demographics Pole Mounted Transformers

There are approximately 23% of transformers with no information on PCB level. Most of these transformers have an unknown age. They are installed in Grand Valley or on the 4kV system. It is recommended that more information be collected on this sub-group of transformers to determine the PCB level.

PCB LEVEL	INSTALL AREA				TOTAL	PERCENT
	<2	LOW	HIGH	UNKWN		
GV	38			59	97	16.3
OV-28	320				320	53.7
OV-4	58	36	9	76	179	30.0
TOTAL	416	36	9	135	596	100.0
PERCENT	69.8	6.0	1.5	22.7	100.0	

Table - Demographics Pole Mounted Transformers

There are 140 transformers (23.5%) with an unknown age. Orangeville Hydro has purchased used transformers in the past. It is recommended that additional efforts be made to identify the age of the transformers, either by searching old paper records (transformer purchases), or reviewing information in the field. Sometimes where a serial number and manufacturer exists, it is possible to engage the manufacturer in identifying more about the transformers.

There are approximately 23% of transformers with no information on PCB level. Most of these transformers have an unknown age and are installed in Grand Valley or on the 4kV system. It is evident that almost 70% of the transformers have non detectable levels of PCB's (less than 2 ppm).

2.4.3 Asset Management Practices

Most utilities typically operate pole-mounted transformers as run-to-failure items. Because of this, utilities seldom make any attempt to gather information about the duties or condition of these assets.

Line transformers generally receive basic visual inspections during line patrols. Some transformers have had their oil tested for PCB – in the past, Orangeville Hydro purchased used transformers, from other utilities. In some cases, the name plate is faded so badly that manufacture age is not available. For many of the older transformers, there are in-sufficient paper records to determine the transformer age, either by purchase date, or installation date.

Replacements would occur if very severe degradation (e.g., corrosion or oil leaks) or damage was observed, or if the equipment was obsolete or overloaded. Also, replacements are done for transformers with PCB levels greater than 50 ppm.

When utilities perform specific inspections on line transformers, they typically occur on a 3 to 6 year cycle. During such inspections, infrared and ultrasound evaluation is performed along with standard checks for leakage, oil levels, connections and general condition of the unit (corrosion and seals, etc.).

In summary the asset management process that Orangeville Hydro has implemented, measures the following parameters:

- PCB level in the transformers
- transformer name plate information
- purchase date, installation date, location
- condition of the bushings and Condition of transformer tank
- condition of oil leaks.

Functional obsolescence is a review of the installation, and if the transformer or the location is consistent with present engineering standards. In particular, the following items would lead to a conclusion that the transformer is at end of life and requires immediate attention:

- transformer is of CSP type
- transformer is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole
- transformer has PCB levels at 50 ppm or greater.

2.4.4 *Health Index Formulation – Pole Mounted Transformers*

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Tank Condition	VI	3	A,B,C or D	3,2,1,0	9
2	Tank Leaks	VI	2	A,B,C or D	3,2,1,0	6
3	Bushing condition	VI	1	A,B,C or D	3,2,1,0	3
4	Overall condition	VI	1	A,B,C or D	3,2,1,0	3
5	Functional obsolescence	DR	---	---	---	---

Max Score = 21

HI = 100*Score/Max

Table – Health Index Formulation for Pole Mounted Transformers

To calculate the total Health Index, divide the accumulated points by 21, and then multiply by 100. If functional obsolescence results in a "C", then divide score by 2, and if a "D" is present, divide score by 4.

2.4.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below. PCB information (functional obsolescence) has not been included in these calculations :

	VOLTAGE				
RESULT	4	7.2	27	TOTAL	PRCT
VERY GOOD	7	5	26	38	50.7
GOOD	11	2	4	17	22.7
FAIR	7	6		13	17.3
POOR	5	2		7	9.3
VERY POOR				0	0.0
TOTAL	30	15	30	75	100.0
PERCENT	40.0	20.0	40.0	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	VOLTAGE 4	7.2	27	TOTAL	PRCT
VERY GOOD	22	56	261	339	56.9
GOOD	34	26	44	104	17.4
FAIR	23	66	5	94	15.8
POOR	16	26	5	47	7.9
VERY POOR	2	5	5	12	2.0
TOTAL	97	179	320	596	100.0
PERCENT	16.3	30.0	53.7	100.0	

Table – Population Results

At this point, the contribution of PCB's has not been included. Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

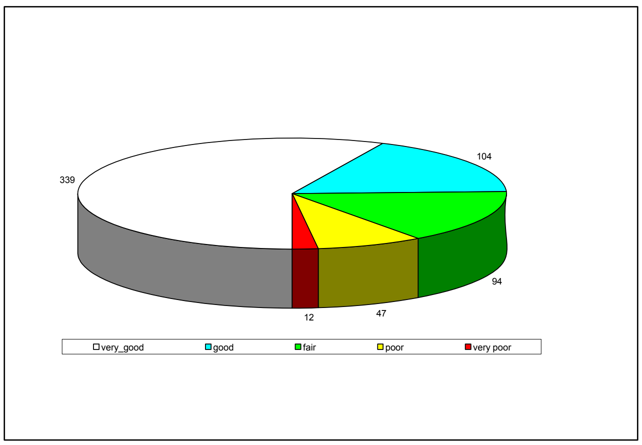


Figure – Pie Chart Population Results

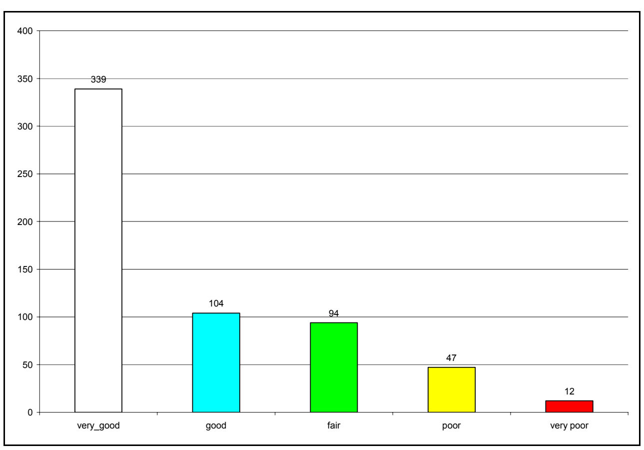


Figure – Bar Chart Population Results

2.4.6 *Observations*

In reviewing these results, it is evident that not enough transformers were sampled in Grand Valley (7.2kV) to make a general statements for that area. On the other hand for Orangeville there were more than required sampled, and the total sample is more than sufficient given the total population. For projections from sample to population, each of the sub-groups was used, to create the Health Index of the pole mounted transformer class. If a re-sample was done, the largest change would be in the 7.2kV transformer group, and they represent only 30% of the overall picture.

The Health Index results show that about 2.0% of the pole mounted transformers are near or at end of life. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 24.0% of the pole mounted transformers will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 74.0% of the pole mounted transformers are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

2.5 Fault Indicators

2.5.1 *Description*

Fault indicators are devices, attached to overhead phase wire, and indicate when a fault current passed the point of attachment. Units can be battery powered or, self powered (by the fault current passing the unit).

Picture[3] – Overhead Fault Indicator

2.5.2 *Demographics*

There are 10 fault indicator locations are found at 28kV voltage level in service areas Orangeville (OV). Each installation location has 3 units, one for each phase. There is no age information available. Grand Valley does not have fault indicators installed.

Some underground cable based fault indicators exist, but these are being removed from service, and hence are not counted here.

There are 30 fault indicator units installed in the Orangeville System.

2.5.3 *Asset Management Practices*

Fault indicators are tools to assist field crews in locating where a fault occurred. The principle is based on these units being able to detect a fault current and indicating in some way that a fault current has passed the location where the fault indicator is installed. By process of elimination, as well as information from other installation locations, the fault location in an overhead system can be localized relatively quickly.

Units come in two varieties:

- those with a power supply or battery
- those which are powered by the fault current.

Typically, these units are "run to failure". There are no moving parts, and the unit either works or it does not. These are not primary current carrying components (pole transformers, overhead line sections, etc.), or major components like poles and switching units, and as such their failure to operate properly does not constitute a significant risk to any number of stake holders.

Orangeville Hydro has both types of units installed in the system. That being said, it is the experience of Orangeville Hydro that battery powered units are un-reliable. Consequently there is a program in place to have these replaced. Battery powered units are functionally obsolete.

The overall condition is quite simple – it works or it does not. If the unit is installed but not visible from the road or from an easy access point, the purpose of the unit is not being met.

The application of units is a check as to whether all three phases have units installed, and/or locations identified by Orangeville Hydro, require units may or may not have them installed.

2.5.4 *Health Index Formulation – Fault Indicators*

The following table summarizes the Health Index formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Overall condition	VI	1	A,B,C or D	3,2,1,0	3
2	Application of units	DR	1	A,B,C or D	3,2,1,0	3
3	Functional obsolescence	DR	—	A or D	—	—

Max Score = 6

HI = 100*Score/Max

Table – Fault Indicator Health Index Formulation

To calculate the total Health Index, divide the accumulated points by 6, and then multiply by 100. If functional obsolescence results in a "D", divide score by 4.

Note, if only the functional obsolescence value is available, and the value is "D", it is permissible to assign the asset a total points of "1", as if the previous "divide by 4" has already occurred.

2.5.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	1	11.1
GOOD	1	11.1
FAIR	0	0.0
POOR	0	0.0
VERY POOR	7	77.8
TOTAL	9	100.0

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	4	13.3
GOOD	4	13.3
FAIR	1	3.3
POOR	1	3.3
VERY POOR	20	66.7
TOTAL	30	100.0
PERCENT	100.0	

Table – Population results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

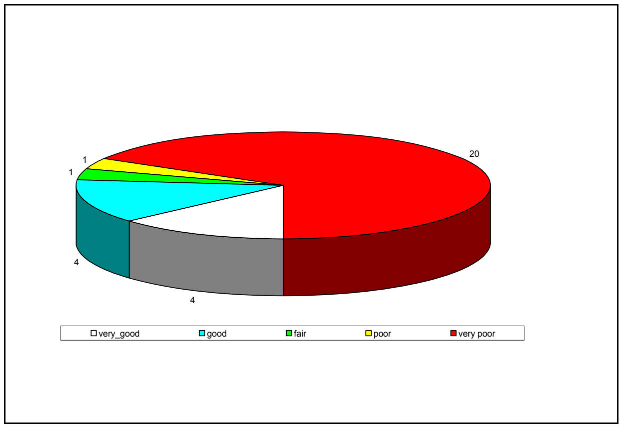


Figure – Pie Chart Population Results

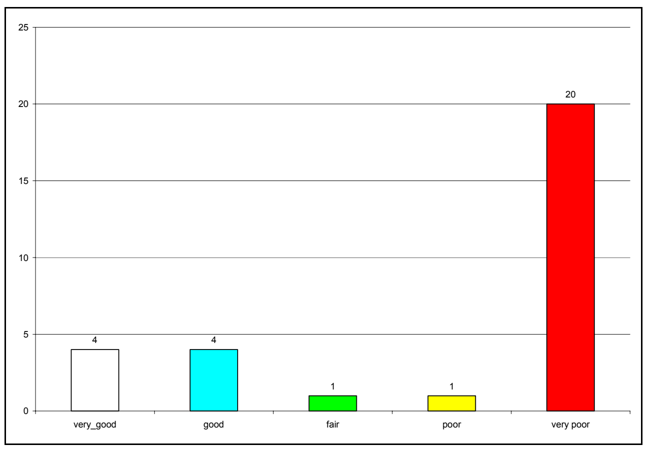


Figure – Bar Chart Population Results

2.5.6 Observations

The Health Index results show that about 70.0% of the fault indicators are near end of life. It is recommended that they be replaced in a short time frame. The remaining 30% are in GOOD or VERY GOOD condition, therefore fulfilling their designed purpose.

2.6 Fuse Cutouts

2.6.1 Description

Fused cutouts are devices with fuses that provide electrical protection against over currents. These can be applied in two very common applications:

- lines sections (taps),
- cable risers, and
- transformer protection.

Picture – Fuse Cutout

Fuse cutouts installed with other equipment is generally excluded; for example, transformers and cable risers, as they are part of the other asset class. Included here are the fuse cut outs for line sections.

2.6.2 Demographics

Demographics were not available at the time of writing this report.

Consequently, it was not possible to evaluate the condition of the fuse cutouts.

2.6.3 Asset Management Practices

The units can have a fuse or a solid switch blade installed. The installation is more involved than an inline switch, but less involved than a pole top switch. Fuse cutouts have two purposes:

- They provide some form of protection (fuse) for line sections and taps.
- They provide a switching means (i.e. hook stick operated).

In most cases, the jumper wire from the line side of the cutout to the actual supply line, may be solidly connected with wedge connectors, or with hot line clamps – the latter can be removed with live line tools and personal protective equipment (PPE), and as such the isolation of a cutout is relatively simple.

As the units age, there are various items to look for. Some are correctable, others are not:

- broken insulator body
- copper splash on the insulator body
- loose nuts and/or bolts and/or connection wires (crimp connections)
- mis-alignment of switch arm or fuse barrel
- loose connection between housing and supporting component (i.e. cross arm).

Orangeville Hydro has had some problems in its service territory with porcelain body units, and as such there is a program underway to replace these units. Any unit with a porcelain body are functionally obsolete, as they do not meet present engineering standards.

Similarly, each installation should have a surge arrestor attached on the line side of the fuse. Not having surge arrestors, or units that are not properly connected, is an indication of functional obsolescence.

2.6.4 Health Index Formulation – Fused Cutouts

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Overall Condition	VI	1	A,B,C,D,E	4,3,2,1,0	4
2	Functional Obsolescence	DR	—	—	—	—

Max Score = 4
HI = 100*Score/Max

Table – Health Index Formulation for Fused Cutouts

To calculate the total Health Index, divide the accumulated points by 4, and then multiply by 100. If functional obsolescence results in a "C", then divide score by 2, and if a "D" is present, divide score by 4.

If functional obsolescence is known, and no other information is available, the fuse cutout can be assumed to have 3 points, and then the remainder of the calculation can proceed as normal.

2.6.5 Health Index Results

As there are no demographics, a field survey could not be established to meet the required confidence level. There are no Health Index results.

2.7 Voltage Conversion Transformers (28/4kV)

2.7.1 Description

"Rabbits" are special transformers that are pole mounted to convert one voltage system to another voltage system. They look very similar to standard pole mounted transformers.

These are used, and re-used where required, to assist in voltage conversion processes to permit the utility to rebuild line sections on a year over year basis, while maintaining supply to those customers whose service has not been upgraded.

2.7.2 Demographics

There are 5 units owned by Orangeville Hydro. Age information is not available. PCB content is not available.

2.7.3 Asset Management Practices

These units are generally managed in the same way that pole mounted transformers are.

2.7.4 Health Index Formulation

These units use the same method as pole mounted transformers.

2.7.5 Health Index Results

The field survey data is reviewed and the Health Index is calculated. Since a 100% sample was used, the sample and population information is the same – only the population totals are presented here:

RESULT	TOTAL	PRCT
VERY GOOD	3	60.0
GOOD	2	40.0
FAIR	0	0.0
POOR	0	0.0
VERY POOR	0	0.0
TOTAL	5	100.0

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

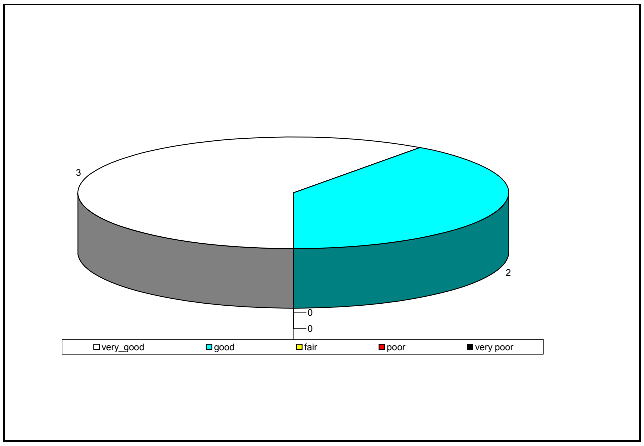


Figure – Pie Chart Population Results

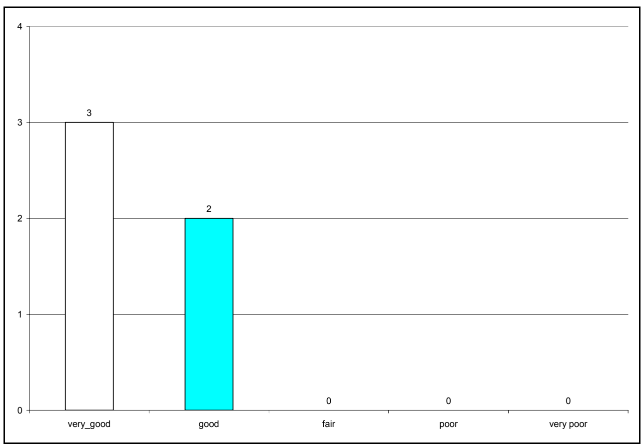


Figure – Bar Chart Population Results

2.7.6 Observations

The Health Index results show that all five (5) pole mounted voltage conversion transformers are in GOOD to VERY GOOD condition. It is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

3. Underground System

The Underground system consists of all infrastructure outside the substation used to convey electricity to the service entrance of a customer. It includes the riser cable, if the riser cable is located 100% outside the substation (i.e. both ends, with no taps). If an underground cable is tapped, then from the tap to each end (or next tap) is considered one cable section. The underground system chapter contains the following sections:

3.1 Buried Cable

3.2 Pad-mounted Switching Units

3.3 Pad-mounted Transformers

3.4 Duct Banks and Manholes

3.1 Underground Cable

3.1.1 Description

Underground (Buried) cable is one of the types of conductors that utilities use to distribute electrical power. Historically there have been numerous materials used (PILC, XLPE, EPR, …), as well as various configurations (single core, 3 core, …).

Orangeville Hydro uses XLPE single core cable (both copper and aluminum) to distribute voltage at 28kV and 4kV levels. There is no underground cable at 46kV.

Picture – XLPE Underground Cable

These cables exist outside of the substations, connecting either pad mounted equipment to each other, or via cable risers, providing a connection from the overhead system to pad mounted equipment.

The definitions of feeder, circuit section and phase conductor are very similar to the overhead system. Definitions include:

- An underground *line section* consists of one or more circuit sections, much like on a pole. The number of line sections will always be less than the total number of circuit sections.
- An underground *circuit section*, consists of one circuit, a set of cables (phase conductors). This can be 1 phase or 3 phase, but is required to be the same wire size, and same installation year. It may contain a splice, but Orangeville Hydro tends not to install splices. A circuit section is the basis of any electronic model of the power system for load flows and short circuit studies.
- A *Feeder* is a collection of circuit sections, which is supplied radially (one point), or configured in a looped system, operated with open points (radially)
- A *phase conductor*, is a 1 phase cable, complete with ground wire on the outside of the cable. This is very similar to the phase wire definition for the overhead system. To calculate the amount of cable in the system, a sum is made of three terms. Each term is (n*Ln), where "n" is the phase count in the circuit section and "Ln" is the length of the circuit section. Consequently, the amount of cable present will always be larger than the amount of circuit sections in the system.
- A *duct*, if used, is a single cylinder connecting two points in the underground system. Most utilities install a single phase cable in a duct. Some industry chooses to install three 1 phase cables in a duct. An alternate configuration is direct bury.
- A *duct bank* consists of one or more ducts. Each duct is usually surrounded by concrete, to provide extra protection to the ducts.
- An underground *right of way* (ROW) consists of land set aside for the direct bury of cable. In many jurisdictions, utilities and other asset owners have easements or other entries at land registry entities to remind people not to build on top of the asset.
- A *Joint Use Trench* (JUT) is a method of construction for underground direct buried assets, that combines several assets in one location. It simplifies construction, but makes maintenance or repair more difficult. Co-located can be gas, distribution electric, fiber, phone, low voltage electric, cable, and other services.

Orangeville Hydro direct buries its cable, with very little use of cable duct banks (road crossings are in cable duct banks). The practice is also to bond both ends of the cable to ground. Most cable is in either dedicated underground ROW's or in JUT's (i.e. residential neighbourhoods).

3.1.2 *Demographics*

Orangeville Hydro currently manages a system of distribution underground cables with a total circuit length of about 79.5 km operating at voltages of 46kV and lower. Alternatively, this is 107.1 km of buried cable.

The underground cables of Orangeville Hydro consist of about 80% Extruded Cross-Linked Polyethylene (XLPE) 20% Paper Insulated Lead Covered (PILC) and a very small percentage of Ethylene Propylene Rubber (EPR). Over 80% of the cable conductor is stranded aluminum and the rest is stranded copper. About 85% of the distribution underground cables are direct buried except when crossing roads and railways.

	4 kV			Grand Valley			27 kV			44 kV	GRAND	
Age	UG_1	UG_3	Total	UG_1	UG_3	Total	UG_1	UG_3	Total	UG_3	TOTAL	PRCT
0 - 9 yrs	5	10	15	0		0	14	16	30		45	20.3
10 - 19 yrs	9	6	15	0		0	51	22	73		88	39.6
19 - 29 yrs	16	12	28	3		3	0	0	0		31	14.0
30 - 39 yrs	19	3	22	1		1	0	0	0		23	10.4
40 - 49 yrs	17	7	24	0		0	0	0	0		24	10.8
50+ yrs	0	0	0	0		0	0	0	0		0	0.0
unkwn	1	2	3	0		0	5	3	8		11	5.0
Total	67	40	107	4	0	4	70	41	111	0	222	100.0

GRAND TOTAL	141	81	222

Table – Underground Cable Section Count

The underground section count is 222, whereas the number of underground cable pieces (1 phase) is 141 + 3*81 = 384.

	4 kV			Grand Valley			27 kV			44 kV	GRAND	
Age	UG_1	UG_3	Total	UG_1	UG_3	Total	UG_1	UG_3	Total	UG_3	TOTAL	PCNT
0 - 9 yrs	3.2	1.6	4.8				10.0	1.8	11.8		16.6	20.9
10 - 19 yrs	4.5	0.8	5.3				19.0	4.7	23.7		29.0	36.5
19 - 29 yrs	12.1	3.0	15.1	1.7		1.7					16.8	21.2
30 - 39 yrs	8.1	0.5	8.6	1.1		1.1					9.7	12.2
40 - 49 yrs	4.8	0.8	5.6								5.6	7.0
50+ yrs												
unkwn	0.2	0.2	0.4				1.0	0.3	1.4		1.8	2.2
Total	32.9	6.9	39.8	2.8		2.8	30.0	6.9	36.9		79.5	100.0

GRAND TOTAL	65.7	13.8	79.5

Table – Underground Circuit Section Length (km)

The underground section length is 79.5 km, whereas the length of underground single phase cable pieces (1 phase) is 65.7 + (3*13.8) = 107.1 km.

The average cable piece length is (107.1 km / 384) → 278.9 m.

3.1.3 *Asset Management Practices*

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Underground cables are relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems, do not suffer from weather induced faults and have better reliability records than overhead systems. Faults on underground cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable.

Thus, the standard approach to cable system management has been based on reliability rather than the balance between and repair and replacement costs. It is the practice of Orangeville Hydro not to have splices in underground cable. If a cable faults, the cable runs are relatively short, that the cable is replaced.

Periodically Orangeville Hydro commissions thermographic scans of the cable connections to verify that no overheating is present. Underground cable terminates either on a pole (cable riser, not station cable riser), or in a pad mounted switching unit, or a pad mounted transformer. Consequently, the ends of the cable are accessible for inspection.

The asset management program for underground cable includes the following measurables:

- Condition of Pothead/Connectors/Terminations – a failure of the termination of a cable does not permit the cable to operate as design
- Foundation/Supporting Steel – if required to support or train the cable
- Grounding – both ends are solidly grounded
- Number of Failures Per Unit Length of Installation – a measure of performance and/or reliability of the feeder, the type of cable, and other correlative measures
- Age of Cable – supports the asset management process as a screening method for other condition assessment practices
- Thermal Scan – review connections for over heating.

3.1.4 *Health Index Formulation – Underground Cables*

The following table summarizes the Health Index Formulation.

#	Condition Criteria	(VI/DR)	Weight	Condition Rating	Factors	Maximum Score
1	Pothead/Connectors/Terminations	VI	4	A,B,C,D	3,2,1,0	12
2	Foundation/Support Steel/Grounding	VI	2	A,B,C,D	3,2,1,0	6
3	Overall Cable Condition	VI	3	A,B,C,D	3,2,1,0	9
4	Thermograph Scan	DR	3	A,B,C,D	3,2,1,0	9

Max Score = 36

HI = 100*Score/Max

Table - Substation Cables and Terminations Health Index Formulation

3.1.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

	VOLTAGE			
RESULT	4	27	TOTAL	PRCT
VERY GOOD	6	5	11	40.7
GOOD	6	9	15	55.6
FAIR		0	0	0.0
POOR			0	0.0
VERY POOR	1		1	3.7
TOTAL	13	14	27	100.0
PERCENT	48.1	51.9	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

	VOLTAGE			
RESULT	4	27	TOTAL	PRCT
VERY GOOD	80	64	144	37.5
GOOD	79	111	190	49.5
FAIR	7	6	13	3.4
POOR	6	6	12	3.1
VERY POOR	19	6	25	6.5
TOTAL	191	193	384	100.0
PERCENT	49.7	50.3	100.0	

Table – Population results (phase wire)

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

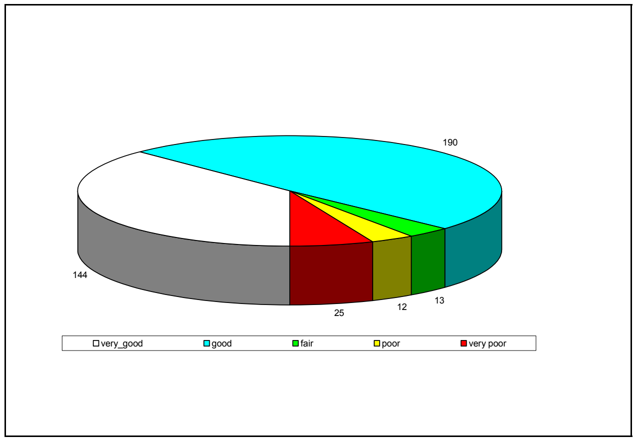


Figure – Pie Chart Population Results

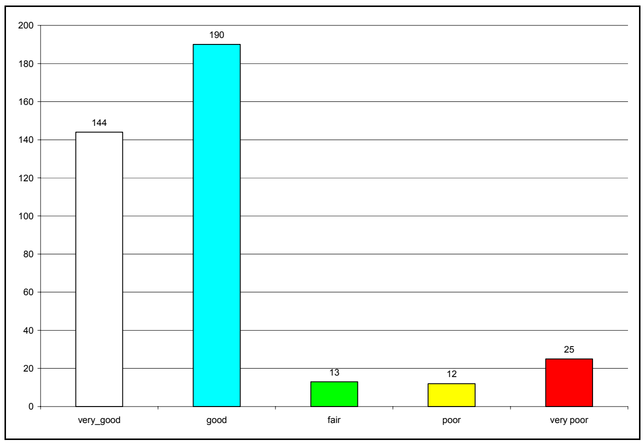


Figure – Bar Chart Population Results

3.1.6 Observations

The Health Index results show that about 6.5% of the underground cable sections are at or near to end of life, and refurbishment or replacement likely is required within the next two years to prevent imminent failure.

About 6.5% of the underground cable sections will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 87.0% of the underground cable sections are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

3.2 Pad Mounted Switches

3.2.1 Description

Pad mounted switching equipment provides a utility with a means to (a) switch power and isolate work zones in a safe manner and (b) to branch cables off in other directions.

These metal enclosed spaces sit on a concrete pad, and some form of walled underground formwork that provides a space under the equipment for the cable to bend, from a general horizontal orientation up to the connection points on the equipment. Common equipment type falling into this class is: PMH, KABAR units , PME, PMU.

Pad mounted switching units are of similar size to pad mounted transformers. They are connected to other electrical equipment via underground cable. They are mounted at ground level, often in industrial or residential neighbourhoods. Their presence at ground level makes them potential candidates for more rigorous periodic inspection and testing.

Picture[4] - KABAR Unit

Picture[5] – PMH Unit

Picture[6] – PME Unit

3.2.2 Demographics

The following summarizes the number of KABAR units in the system:

VOLTAGE	1_PHASE	3_PHASE	TOTAL
2.4	4		4
4		7	7
16	1		1
27.6		10	10
TOTAL	5	17	22

Table - Demographics KABAR Units

The following summarizes the number of PME units in the system:

Voltage	Total
27.6kV	30
4kV	8
TOTAL	38

Table - Demographics PME Units

3.2.3 Asset Management Practices

Pad mounted switches are used by utilities for several reasons:

- distribution point for power on underground cables
- switching location for a feeder (i.e. transition from 3 phase to 1 phase)
- automated load re-distribution for utilities with SCADA based units.

The general purpose of all pad mounted switching units is to provide an enclosed space, with controlled access to house electrical equipment. The controlled space prevents accidental contact of non qualified people with electrical components. A hole in the enclosure, depending on the size, may mean the device is at end of life.

The KABAR unit is perhaps the least complicated, in that it is a box, with Elastimold type 200A and 600A connectors. Orangeville Hydro has had some problems with these units, to the point, that today they are not used for switching, simply as end points of power cables. Because of these past problems, Orangeville Hydro is not installing new KABAR units. Consequently, KABAR units are defined as functionally obsolete.

Other units in the system are PME, PMH and some PMU. These are predominantly S & C product, but other manufacturers also exist. Although there are variations in the three listed, but basically it is a metal enclosed space, with places to connect underground cables. Some units have fuses and switches.

These units can also be classified as "dead front" and "live front". Live front units may become energized under some conditions. Equipment of this type is not longer acceptable for new installations in the Orangeville service territory. Existing equipment has been identified as functionally obsolete.

3.2.4 Health Index Formulation – Pad-mounted Switches

The following table summarizes the Health Index formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Enclosure Condition	VI	3	A,B,C or D	3,2,1,0	9
2	Bushing Condition	VI	1	A,B,C or D	3,2,1,0	3
3	Foundation & Grounding Condition	VI	1	A,B,C or D	3,2,1,0	3
4	Anti-collision bollards	VI	1	A,C,D or N	3,1,0	3
5	Overall Condition	VI	2	A,B,C or D	3,2,1,0	6
6	Thermograph Condition	DR	3	A,C,D or N	3,2,1,0	9
7	Functional Obsolescence	DR	—	—	—	—

Max Score = 33

HI = 100*Score/Max

Table – Pad-mounted Switches Health Index Formulation

To calculate the total Health Index, divide the accumulated points by 33, and then multiply by 100. If functional obsolescence has a C, then divide score by 2 and for a D, divide score by 4. Note the maximum score may need to be adjusted depending on the number of "N" entries.

3.2.5 Health Index Results

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	VOLTAGE 4	27	TOTAL	PRCT
VERY GOOD	2	7	9	47.4
GOOD	1	4	5	26.3
FAIR	2		2	10.5
POOR		1	1	5.3
VERY POOR		2	2	10.5
TOTAL	5	14	19	100.0
PERCENT	26.3	73.7	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	VOLTAGE 4	27	TOTAL	PRCT
VERY GOOD	6	18	24	40.0
GOOD	4	11	15	25.0
FAIR	7	1	8	13.3
POOR	1	4	5	8.3
VERY POOR	2	6	8	13.3
TOTAL	20	40	60	100.0
PERCENT	33.3	66.7	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

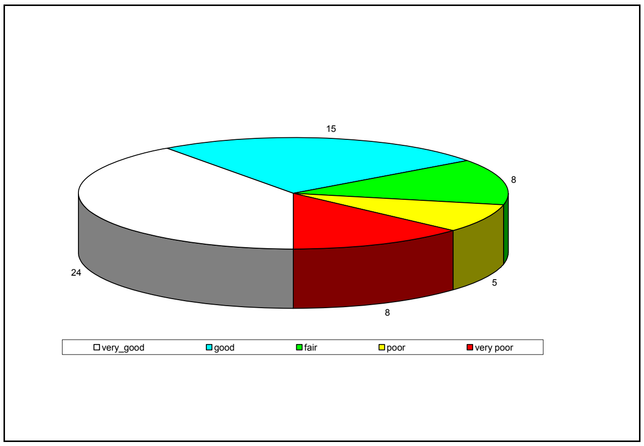


Figure – Pie Chart Population Results

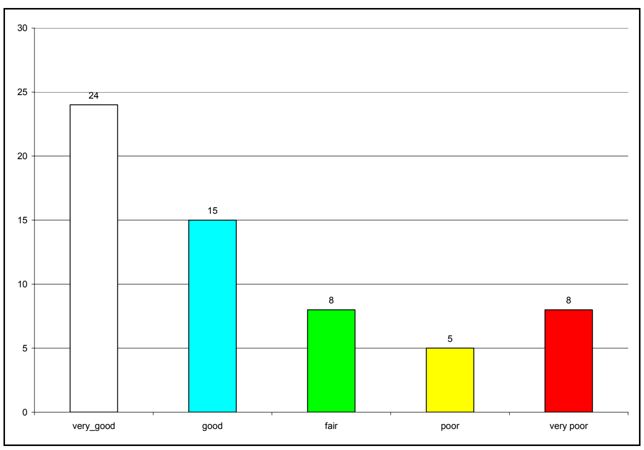


Figure – Bar Chart Population Results

3.2.6 Observations

The following picture shows a KABAR unit in Orangeville west end. Note the back right corner is damaged. Closer inspection shows that the seam is broken and that a coat hanger or similar foreign object could be inserted into the unit. This unit is at end of life as it is not serving is primary function.

Picture - KABAR Unit

The Health Index results show that about 13.5% of the pad mounted switchgear is near or at end of life. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 21.5% of the pad mounted switchgear will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 65.0% of the pad mounted switchgear is in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

3.3 Pad Mounted Transformers

3.3.1 Description

Pad mounted transformers are metal enclosed, sitting on a concrete pad, on the ground. Underneath the transformer (below ground line) is a space with formwork to provide space for the cables to bend from a general horizontal configuration to a vertical connection point.

Pad mounted transformers are larger than pole mounted transformers, and are often in industrial or residential neighbourhoods.

Units are available in 3 phase or single phase configurations.

Picture – Pad Mounted Transformer

Pad mount transformers are installed in areas requiring lower voltages than what the distribution system provides, and where overhead pole mounted transformers (on poles) can not be installed. These units are often green, to give them a low profile appearance. Units are supplied power with underground cable, and the secondary service wires leave the transformer also underground. These units are often installed in residential areas and selected other areas. Their presence at ground level makes them potential candidates for more rigorous periodic inspection and testing.

Included in this group, are "trans-pad" units, which consist of a ground level metal enclosure, which contains pole mounted transformers. This is an older practice, which Orangeville Hydro has discontinued to install many years ago; existing units are maintained.

Trans-pad units are part of this category, because of the metal enclosure, foundation, and underground cable entry/exit.

Picture – Transpad Transformer

3.3.2 *Demographics*

The demographics for pad mounted transformers can be viewed in two ways:

- Age and Geographic Area
- PCB Levels

3.3.2.1 *Age and Geographic Area*

Pad mounted transformers are installed in Grand Valley (GV) and Orangeville; in Orangeville, they are installed on two voltage levels: 4kV and 28kV (OV-4, OV-28).

Age	AREA			TOTAL	PRCT
	GV	OV-28	OV-4		
0-9 YR		346	50	396	48.1
10-19 YR	1	186	20	207	25.2
20-29 YR	1		8	9	1.1
30+ YR	1		17	18	2.2
UNKWN	25		168	193	23.5
TOTAL	28	532	263	823	100.0
PRCT	3.4	64.6	32.0	100.0	

Table - Demographics Pad Mounted Transformers

Transformers with unknown age, in Orangeville, on the 28kV system are assigned an age band (0-9 or 10-19) in proportion to the existing known data (see section 2.4.2.1 of this report). For this same group of transformers, the PCB level has been set to <2 ppm, if there was no information provided in the database.

In reviewing the available data, it is evident that approximately 23.5% of the transformers have an unknown age. The majority of the units are on the 4kV system, where, in the past, Orangeville Hydro has purchased used transformers. It is recommended that Orangeville Hydro

- review their records to update the age information, and
- review their data entry methods, to harmonize the various data entries.

3.3.2.2 *PCB Levels*

In addition to the above information, the following information on PCB content is available:

Age	PCB LEVEL				TOTAL	PRCT
	<2	LOW	HIGH	UNKWN		
0-9 YR	350	2	2	42	396	48.1
10-19 YR	188			19	207	25.2
20-29 YR	1			8	9	1.1
30+ YR				18	18	2.2
UNKWN	95	17		81	193	23.5
TOTAL	634	19	2	168	823	100.0
PRCT	77.0	2.3	0.2	20.4	100.0	

Table - Demographics Pad Mounted Transformers

There are approximately 20% of transformers with no information on PCB level. Approximately half of these transformers have an unknown age. The vast majority are installed on the Orangeville 4kV system. It is recommended that more information be collected on this sub-group of transformers to determine the PCB level.

Age	PCB LEVEL				TOTAL	PRCT
	<2	LOW	HIGH	UNKWN		
GV	26			2	28	3.4
OV-28	532				532	64.6
OV-4	76	19	2	166	263	32.0
TOTAL	634	19	2	168	823	100.0
PRCT	77.0	2.3	0.2	20.4	100.0	

Table - Demographics Pole Mounted Transformers

There are 193 transformers (23.5%) with an unknown age. Orangeville Hydro has purchased used transformers in the past. It is recommended that additional efforts be made to identify the age of the transformers, either by searching old paper records (transformer purchases), or reviewing information in the field. Sometimes where a serial number and manufacturer exists, it is possible to engage the manufacturer in identifying more about the transformers.

It is evident that 77% of the transformers have non detectable levels of PCB's (less than 2 ppm).

3.3.3 *Asset Management Practices*

Many utilities do very little in the way of condition assessment, beyond the basic visual inspection. If the transformer fails, a limited number of customers will be affected directly. If the distribution system is in a looped configuration (open, operating radially), it would be possible to re-configure the distribution system to restore power to other transformers and customers that are not faulted, and thereby also provide isolation for the faulted equipment.

The major elements of the installation are as follows:

- concrete pad

- metal enclosed transformer
- empty space under transformer for cable entry and exist
- space around transformer to service, maintain, and replace transformer in the future
- anti collision bollards on the outside in high risk areas, to minimize the potential damage to pad transformers as a result of motor vehicle accidents.

Anti-collision bollards are not required in all locations. Orangeville Hydro requires bollards in the following locations:

- high traffic areas
- shopping malls
- shopping plazas

Although not required, some industrial customers have installed them in the past.

Functional obsolescence is another consideration for pad transformers. If one or more of the following criteria have been met, Orangeville Hydro considers the pad mount transformer functionally obsolete, and therefore at end of life:

- transformer manufacturer is ABB
- transformer manufacturer is Camtran, and the paint is peeling or significant signs of rust have started
- transformer is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole
- transformer has PCB levels at 50 ppm or greater

(continued next page)

Health Index Formulation – Pad mounted Transformers

The following table summarizes the Health Index formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Tank & Enclosure Condition	VI	3	A,B,C or D	3,2,1,0	9
2	Tank Leaks	VI	2	A,B,C or D	3,2,1,0	6
3	Bushing Condition	VI	1	A,B,C or D	3,2,1,0	3
4	Foundation & Grounding Condition	VI	1	A,B,C or D	3,2,1,0	3
5	Anti-collision bollards	VI	1	A,C,D or N	3,1,0	3
6	Overall Condition	VI	2	A,B,C or D	3,2,1,0	6
7	Thermograph Condition	DR	3	A,C,D or N	3,2,1,0	9
8	Functional Obsolescence	DR	---	---	---	---

Max Score = 39

HI = 100*Score/Max

Table – Pad Transformer Health Index Formulation

To calculate the total Health Index, divide the accumulated points by 39, and then multiply by 100. If functional obsolescence has a C, then divide score by 2 and for a D, divide score by 4. Note the maximum score may need to be adjusted depending on the number of "N" entries.

3.3.4 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	GV	4kV	27kV	TOTAL	PRCT
VERY GOOD		10	14	24	42.9
GOOD		14	9	23	41.1
FAIR		2	3	5	8.9
POOR		2	1	3	5.4
VERY POOR			1	1	1.8
TOTAL	0	28	28	56	100.0
PERCENT	0.0	50.0	50.0	100.0	

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	GV	4kV	27kV	TOTAL	PRCT
VERY GOOD	6	94	245	345	41.9
GOOD	6	132	193	331	40.2
FAIR	6	19	52	77	9.4
POOR	5	18	26	49	6.0
VERY POOR	5	0	16	21	2.6
TOTAL	28	263	532	823	100.0
PERCENT	3.4	32.0	64.6	100.0	

Table – Population Results

At this point, the contribution of PCB's has not been included. Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

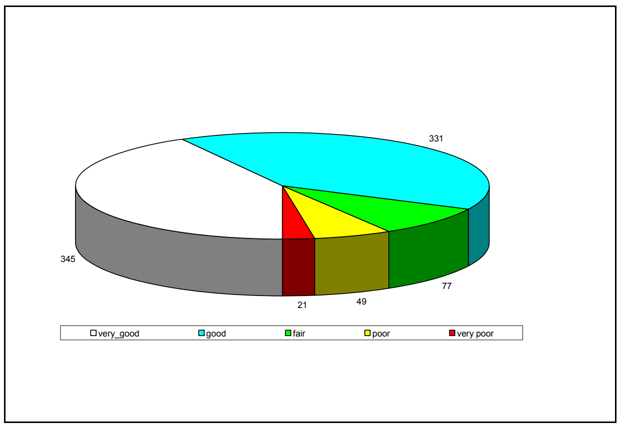


Figure – Pie Chart Population Results

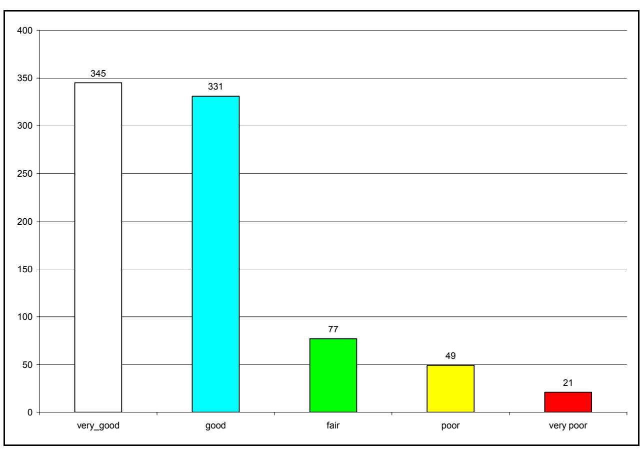


Figure – Bar Chart Population Results

3.3.5 *Observations*

All the pad transformers sampled are in the Orangeville area, and none were selected in Grand Valley. As a result the Grand Valley transformers were spread out evenly among the five categories, most likely over-estimating the POOR and VERY POOR items.

The Health Index results show that about 2.5% of the pad mounted transformers are near or at end of life. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 15.5% of the pad mounted transformers will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 82.0% of the pad mounted transformers in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

3.4 Duct Banks and Manholes

3.4.1 *Description*

A duct bank consists of plastic pipe (or other materials) typically arranged in a box or rectangular pattern, encased in concrete. This type of environment physically protects cable, and is self supporting for some types of excavation, outside of the duct bank. The duct bank ends at a manhole or service pit.

Orangeville Hydro has two types of duct banks in use:

- road crossings – joint use, short sections to cross a road right of way under pavement
- planned underground cable system in downtown core - installed when a roadway is rebuild and/or paved – these are in anticipation of a need in the future.

The majority of the duct banks do not end in a manhole, rather than a service pit. In a service pit, duct bank ends are backfilled with clean fill after the cable was commissioned, and thus inspection, service, and repairs are more involved.

3.4.2 *Demographics*

At the time of writing this report, Orangeville Hydro was not able to produce records on the number, location, configuration, ownership (i.e. joint use) or length of duct banks.

There are few duct banks in the Orangeville Hydro system.

There are some joint use duct banks in residential areas. Most are used at road crossings, or in areas in anticipation of future cable runs. There is also a new road crossing being built June 2009. Orangeville Hydro is assessing its ownership of these items.

3.4.3 *Observations*

At the present time, a condition assessment of duct banks is not planned. In the future, the following parameters should be considered:

- duct bank size relative to cable size
- ducts available or blocked due to previous cable failure
- availability of spare ducts
- existence of manholes, and their access
- ownership, joint use, who the other stakeholders may be
- what is the answer to the question: "If the duct bank is damaged, who pays for the repairs?"

4. Substation Equipment

Orangeville Hydro has 5 (municipal) substations, labelled MS1, MS2, MS3, MS4 and MS5. Each substation, installed in an outside yard, consists of an overhead supply from the 46kV system, to a transformer (3 phase unit or 3x1 phase unit), and then to switchgear. From the switchgear, cables leave the station, and go up poles in the area (station cable risers).

For the purposes of the ACA, station cable risers, connected to equipment inside the station fence, are considered part of the station infrastructure.

MS #1 is scheduled for demolition in July 2009. The remaining active substations are MS#2, MS#3, MS#4, and MS#5; their details are summarized in the following table:

ID #	MS #2	MS #3	MS #4	MS #5	COUNT
STREET ADDRESS	CENTENIAL RD.	DAWSON RD.	HIGH SCHOOL	FIFTH AVE.& THIRD ST.	
MAKE	FERRANTI PACKARD	WESTINGHOUSE	FERRANTI PACKARD	WESTINGHOUSE	
YEAR	1975	1967	1977	1965	
UNIT KVA	5000	5000	5000	5000	
UNITS	1	1	1	1	4
PRI VOLTAGE	44000	44000	44000	44000	
SEC VOLTAGE	4160/2400	4160/2400	4160/2400	4160/2400	
SER#	1-3902	293587	306263	293033	
IMP%	6.14	5.39%	5.8	5.6	
POLARITY		SUBT.			
OIL CAPACITY		1213	756	1220	
TRANS WEIGHT		31,130 LBS	28,600 LBS	31,300 LBS	
TAP SETTINGS	ON TAP #4	ON TAP #3	ON TAP #3	ON TAP #3	
FEEDER COUNT	3	3	3	2	11

Table – Substation Transformer Information

ID #	MS #1	SPARE	COUNT
STREET ADDRESS	MILL ST.	400 C LINE	
MAKE	SUPREME POWER SUPPLY	FERRANTI PACKARD	
YEAR	1954	1964	
UNIT KVA	1000	3000	
UNITS	3	1	4
PRI VOLTAGE	44000	44000	
SEC VOLTAGE	2400/4800	4160/2400	
SER#	46054, 46055, 46056	1/1/2360	
IMP%	5.5 at 75* C	5.68%	
POLARITY	SUBT.	SUBTR	
OIL CAPACITY	596	915	
TRANS WEIGHT	14,200 LBS	23,200 LBS	
TAP SETTINGS	ON TAP #3		

Table – Spare Substation Transformer Information

In summary, there are

- 4 transformers in service
- 4 spare transformers (existing plus 3 from MS#1)
- 11 feeders in service, each a 3 phase feed, with one cable per phase.

This section has the following sub-sections:

4.1 Substation Transformers (46-4kV)

4.2 Substation Switchgear

4.3 Substation Riser Cables (4kV)

4.4 Substation HV Structures

4.5 Substation Civil Infrastructure

4.1 Substation Transformers (46-4kV)

4.1.1 Description

Substation transformers consist of 1 phase or 3 phase units, that convert 46kV 3 phase electricity to 4kV 3 phase electricity. All transformers are installed outside. Each transformer is mounted on a concrete pad, in a fenced off station yard.

Primary connections are made by open 46kV bus, to bushings mounted on the top of the transformer. Secondary connections are via a throat to the switchgear. Each transformer has an off load tap changer.

Picture - Substation Transformer

These transformers do not have an on load tap changer, but rather, they have an off load tap changer. In order to change the taps of the transformer, it is necessary to de-energize the transformer.

4.1.2 Demographics

Each substation has one transformer (3 phase) or three (1 phase) transformers. There is also one present in the operations spares group. The total count is found in the table in section 4.0.

4.1.3 Asset Management Practices

Substation transformers are a significant asset for all utilities, not so much for the direct cost of replacement but more so for the risk it represents if it fails. Replacement of a transformer can take 12 months or longer, because of long manufacturing time frames. Consequently many utilities take numerous planned steps to investigate the transformers including internal and external components, in order to anticipate potential problems before they result in an outage.

Transformers are governed by their ability to dissipate heat generated in the steel core. Most design standards limit the core temperature to 200 deg C (peak value), and for this reason the ability of the transformer to transfer heat to the environment (ambient temperature) is critical. The transformer components can be grouped into the following categories:

- Core and Coils – main power transformation machine. A failure here generally requires a rebuild of the core & coils, or a replacement of the entire unit.
- Oil Parameters – cooling mechanism. Impurities collect here and give indication of what failure mechanisms are present, and the degree to which they are active
- Enclosure and Radiators – enclosure to discipate heat and keep ambient air/moisture separate from the oil, and core & coils.
- Overall Parameters – other contributing factors including bushings (to keep water and other contaminants out of the transformer while permitting the conductor a transition from air to inside)
- Functional Obsolescence – premature end of life due to site conditions, changes in the market place, changes in technology, corporate changes and/or external changes (i.e. regulatory).

Core and Coils consist of the following measurables:

- Furan – this chemical is the result of paper degradation. With time, temperature and general chemical action, the paper on the coils that is in contact with the oil degrades. If furan levels are high, then there is a risk of internal flash over, indicating the transformer is at end of life.
- Core temperature – if sensors are installed, this permits a more accurate gauge of the past performance of transformer. Some utilities correlate temperature with amps (kVA) and ambient temperature, if direct core measurement is not possible.

Oil Parameters consist of the following measurables:

- DGA – dissolved gas analysis – measures the content of dissolved gasses in the oil. This is an indicator of local hot spots and the related oil degradation.
- Standard Oil Tests – this measures the physical and electrical parameters of the oil, including water content. If the dielectric value decreases below a minimum value, then the turn to turn insulation in the coils will fail, resulting in internal flashover.
- Present oil temperature and peak temperature – an indication of poor heat dissipation in the past
- Oil level (relative to temperature) – is there enough oil?

Enclosure and Radiators consist of the following measurables:

- Tank integrity and Conservator – If the tank rusts extensively, or develop leaks, then the oil, the primary heat transfer means between core and outside, will leak out and the transformer will not be able to dissipate heat.

- Cooling System – this includes the radiators and fans on the transformer. Fans assist with air flow over the radiators to dissipate heat inside the transformer. See transformer ratings of ONAN and ONAF; under some conditions transformers can increase their capacity by 33% with fans at full.
- Control Cabinet – for the fans and related equipment on the transformer.

Overall Parameters consist of the following measurables:

- Thermograph condition – inspection of electrical connections; are local hot spots?
- Bushing Condition and leaks – this is how the electrical power gets from the outside to the inside of the transformer. If these fail, the transformer will not perform as expected.
- Foundation Condition – the transformer, because of its weight, requires a foundation. If the foundation fails, then the transformer may tilt or fall over and be mechanically damaged.

Functional obsolescence – A transformer is defined as functionally obsolete if the PCB level is above 50 ppm, or the combination of DGA and furan show that the transformer is at end of life.

4.1.4 *Health Index Formulation – Substation Transformer*

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	DGA	DR	4	A,B,C,D,E	4,3,2,1,0	16
2	Standard Oil Tests	DR	3	A,B,C,D,E	4,3,2,1,0	12
3	Furan	DR	4	A,B,C,D,E	4,3,2,1,0	16
4	Thermograph condition	DR	2	A,B,C,D	3,2,1,0	6
5	Bushing Condition	VI	1	A,B,C,D	3,2,1,0	3
6	Bushing Leaks	VI	1	A,B,C,D	3,2,1,0	3
7	Control Cabinet	VI	1	A,B,C,D	3,2,1,0	3
8	Cooling System	VI	1	A,B,C,D	3,2,1,0	3
9	Tank integrity/Conservator	VI	2	A,B,C,D	3,2,1,0	6
10	Foundation Condition	VI	2	A,B,C,D	3,2,1,0	6
11	Overall Condition	VI	2	A,B,C,D	3,2,1,0	6
12	Functional obsolescence	DR	—	—	—	—

Max Score = 80
HI = 100*Score/Max

Table – Transformer Health Index Formulation

The maximum score for condition criteria (all A) is 80. One need not have complete information about an asset class to compute its Health Index. When only partial data exist it is possible to calculate a valid Health Index if the maximum condition score for the partial data set is greater than or equal to 70% of the maximum possible condition score for a full data set. (for a detailed explanation see section 1.5.4.3)

In another example, using the weightings and maximum possible scores in the above table, assume a transformer with partial data has a maximum condition score of 40 out of the Health Index maximum possible score of 80. That transformer, therefore, has only 50% of the maximum score, and would not have a valid Health Index. On the other hand, if that transformer with partial data had a maximum condition score of 57, it would have 71% of its maximum and a valid Health Index.

To calculate the total Health Index, divide the accumulated points by [max score], and then multiply by 100. If functional obsolescence results in a "C", then final score must be divided by 2. If Functional obsolescence is "D" then final score must be divided by 4.

4.1.5 Health Index Results

The Health Index Results are provided in two stages. First, there are the oil results, from the dissolved gas and standard oil tests. Next there is the summary results for the entire transformer.

4.1.5.1 DGA and Standard Oil

The following tables summarize the data and results:

Data	MS#2	MS#3	MS#4	MS#5
Basic Data				
Manufacturer	Ferranti	Westinghouse	Northern	Westinhouse
Matter Analyzed	Mineral oil	Mineral oil	Mineral oil	Mineral oil
HV and LV (kV):	44 & 4.16	44 & 4.16/2.4	44 & 4.16	44 & 4.16/2.4
Temp (°C)	30	n/a	37	26
KVA	5000	5000	5000	5000
MFG Year	1975	1967	1999	1965
Oil Volume	694 G	1213 Gals	1337 L	1120 Gals
Syringe	AG871	AJ882	AF519	N/A

Table – Transformer Basic Data from DGA Report

Data	MS#2	MS#3	MS#4	MS#5
Dissolved Gas Astm D3612				
Date analyzed (MM/DD/YY)	10/6/2008	10/6/2008	10/6/2008	10/6/2008
Analysis number	125056	125055	125057	125058
Hydrogen (H2) ppm	2	3.9	10	13
Oxygen (O2) ppm	21060	25589	8814	24322
Nitrogen (N2) ppm	65290	60628	84031	62022
Carbon monoxide (CO) ppm	131	109	926	138
Methane (CH4) ppm	2	1.2	15	1.4
Carbon Dioxide (CO2) ppm	2864	905	2526	1427
Ethylene (C2H4) ppm	3.4	1	43	3.3
Ethane (C2H6) ppm	1.1	1.1	2.7	1.1
Acetylene (C2H2) ppm	0.5	0.5	0.5	0.5
Gas % (ASTM)	9.23	8.96	9.72	9.08
Total Combustible Gas (ppm)	138	114	997	156

Table – Transformer DGA results

Data	MS#2	MS#3	MS#4	MS#5
Standard Test ASTM				
Date analyzed (MM/DD/YY)	10/10/2008	10/10/2008	10/10/2008	10/14/2008
Analysis number	128114	128113	122115	128116
Dielectric Breakdown (kV) D877	32	29	49	34
Dielectric Breakdown (kV) D1816-1mm	n/r	n/r	n/r	n/r
Dielectric Breakdown (kV) D1816-2mm	n/r	n/r	n/r	n/r
Dielectric Breakdown (kV) CE1-156	n/r	n/r	n/r	n/r
Number of readings	5	5	5	5
Sample Temperature (°C)	25	24	24	21
Acid number (mg KOH/g) D974	0.009	0.003	0.009	0.003
Color (ASTM Units) D1500	1	1.5	1.5	1.5
Interfacial Tension (mN/M) D971	44.2	45.3	42.4	45
Visual Examination D1524	Particles	Particles	Carbon particles	Carbon particles
Specific Gravity (60/60 °F) D1298	0.8804	0.8672	0.8602	0.8652
Water Content (ppm) D1533	9.6	21	4.2	11
Power Factor at 25 °C (%) D924	n/r	n/r	n/r	n/r
Power Factor at 100 °C (%) D924	n/r	n/r	n/r	n/r
HI Calculation - Summary				
DGA condition rating	A	A	A	A
standard oil tests	B	E	A	B

Table – Transformer Standard Oil Results and HI results

It is evident that the transformer at MS#3 is experiencing some technical challenges. In particular, the Dielectric breakdown voltage is low, and the water content is increasing. Together, these two parameters contributed to the Standard Oil Test being VERY POOR condition.

4.1.5.2 General Health Index Results – without DGA and Standard Oil Tests

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	1	33.3
GOOD	2	66.7
FAIR	0	0.0
POOR	0	0.0
VERY POOR	0	0.0
TOTAL	3	100.0

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	2	25.0
GOOD	4	50.0
FAIR	1	12.5
POOR	1	12.5
VERY POOR	0	0.0
TOTAL	8	100.0
PERCENT	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

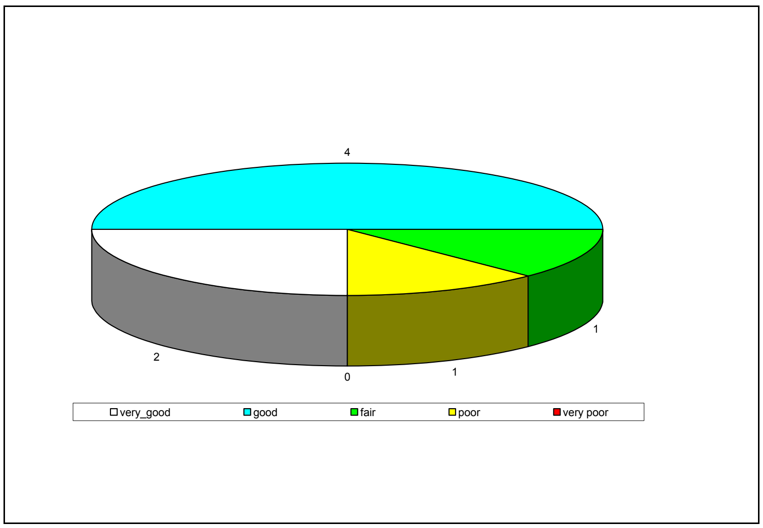


Figure – Pie Chart Population Results

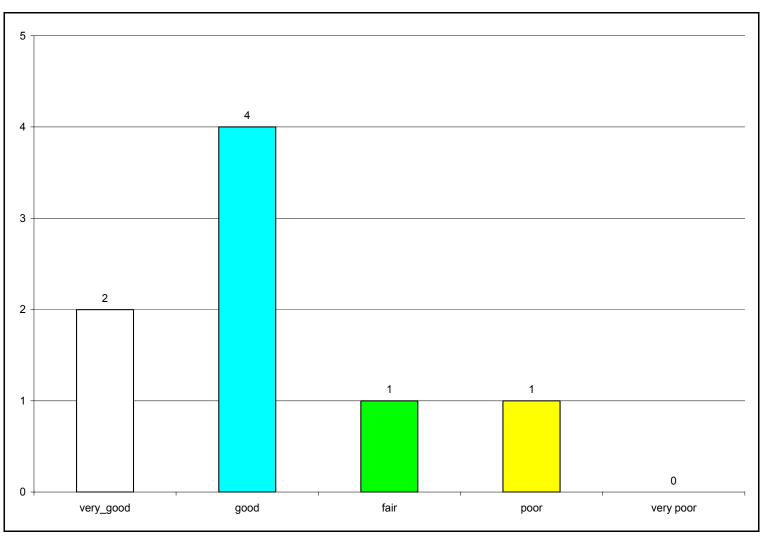


Figure – Bar Chart Population Results

4.1.5.3 General Health Index Results – with DGA and Standard Oil Tests

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	1	33.3
GOOD	1	33.3
FAIR	1	33.3
POOR	0	0.0
VERY POOR	0	0.0
TOTAL	3	100.0

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	2	25.0
GOOD	4	50.0
FAIR	1	12.5
POOR	1	12.5
VERY POOR	0	0.0
TOTAL	8	100.0
PERCENT	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

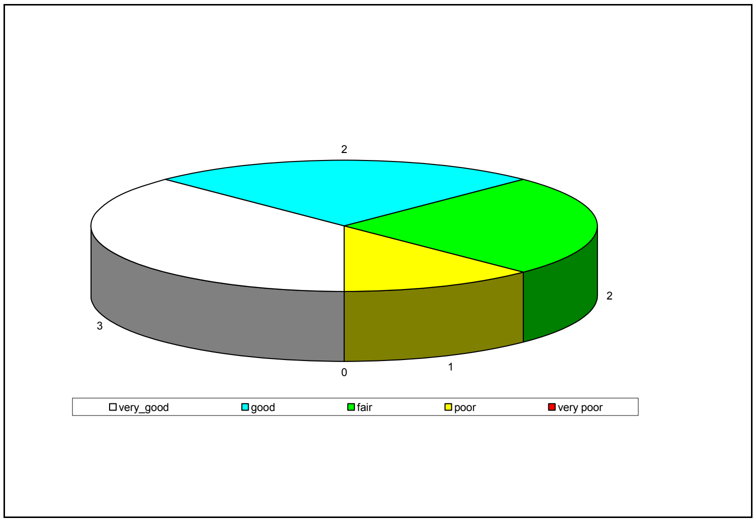


Figure – Pie Chart Population Results

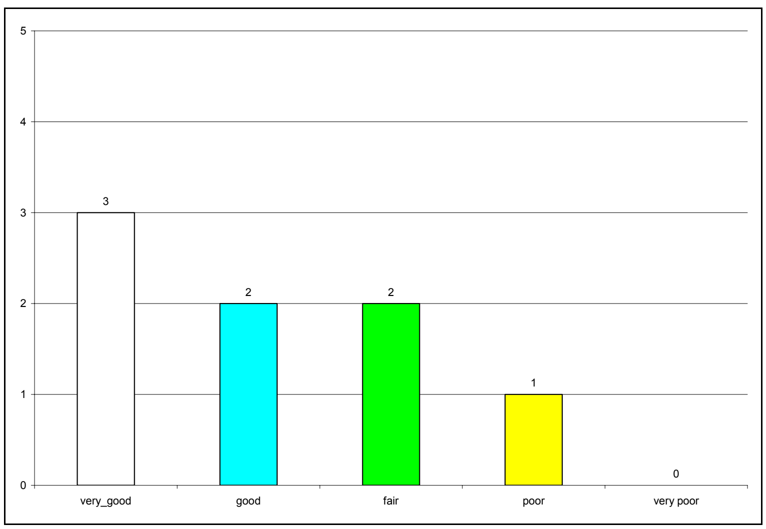


Figure – Bar Chart Population Results

4.1.6 Observations

This asset class, the sample size of 3 is not sufficient to assess the population within the confidence level parameters previously defined. If this is required for the short term, the other transformer(s) should be surveyed in a targeted survey to collect the remaining information.

4.1.6.1 *Without DGA and Standard Oil Results*

The Health Index results show that ZERO units (0.0%) of the substation transformers are at high risk of failure. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

A total of 2 units (25%) of the substation transformers, which includes the spares, will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 75.0% of the substation transformers are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

4.1.6.2 *With DGA and Standard Oil Results*

The Health Index results show that ZERO units (0.0%) of the substation transformers are at high risk of failure. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

A total of 3 units (37.5%) of the substation transformers, which includes the spares, will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 62.5% of the substation transformers are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

4.2 Substation Switchgear

4.2.1 Description

Each station has switchgear (4kV) to provide protection (fuses) and switching of the feeders. Switchgear is used both to de-energize equipment to allow work to be done and to clear faults downstream.

Picture - Substation Switchgear

There is no revenue class metering installed in this switchgear, but there are PT's and CTs to aid crews in local measurements and diagnostics. There are generic meters for voltage, current and power.

4.2.2 *Demographics*

The demographics is based on the number of compartments; the picture above has 4 feeder compartments and 1 main compartment. For the demographics below, only feeder compartments are considered. There is no switch or fuse in the main compartment. There is one switchgear compartment per feeder. Each of these compartments can be considered as one unit.

SUB	TOTAL	PERCENT
MS1	0	0.0
MS2	3	27.3
MS3	3	27.3
MS4	3	27.3
MS5	2	18.2
TOTAL	11	100.0

Table - Demographics Substation Switchgear

4.2.3 *Asset Management Practices*

Substation switchgear is equipment used to distribute electrical power from the transformer to various feeders that leave the substation. This 4kV equipment is metal enclosed, manually operated equipment. It contains fuses and bus bar.

Measureable parameters that give an indication of end of life, can be grouped in the following way:

<u>Power Conductors</u>

- Switch – primary switching and isolation means – permits Orangeville Hydro to operate the distribution system and provide isolation for the sub station transformer as required.
- Insulation – the space within the switchgear, between bus bars (sections air insulated). The failure of the insulation would not permit electrical power to be transmitted.
- Bus bar – the conductor connecting all electrical power components. Significant degradation would prevent the switchgear from operating properly.

<u>Enclosure and Environment</u>

- Enclosure – since this equipment is installed outside, it provides a controlled environment for the switch and bus bars to operate properly. Degradation or failure of the enclosure would lead to service interruptions.
- Foundations – supports the switchgear and provides a means of egress for underground cables leaving the station. Degradation of the foundation leads to equipment tilting and possibly falling down, thereby not being functional.
- Overall condition

4.2.4 *Health Index Formulation – Substation Switchgear*

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Enclosure condition	VI	1	A,B,C or D	3,2,1,0	3
2	Foundation	VI	1	A,B,C or D	3,2,1,0	3
3	Insulation condition	DR	3	A,B,C or D	3,2,1,0	9
4	Switch Condition	DR/VI	3	A,B,C or D	3,2,1,0	9
5	Busbar Condition	VI	1	A,B,C or D	3,2,1,0	3
6	Overall condition	VI	1	A,B,C or D	3,2,1,0	3
7	Functional Obsolescence	DR	—	—	—	—

Max Score = 30
HI = 100*Score/Max

Table – Substation Switchgear Health Index Formulation

To calculate the total Health Index, divide the accumulated points by 30, and then multiply by 100. If functional obsolescence results in a "C", then divide score by 2, and if a "D" is present, divide score by 4.

4.2.5 Health Index Results

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	6	66.7
GOOD	3	33.3
FAIR	0	0.0
POOR	0	0.0
VERY POOR	0	0.0
TOTAL	9	100.0

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	7	63.6
GOOD	3	27.3
FAIR	1	9.1
POOR		0.0
VERY POOR		0.0
TOTAL	11	100.0
PERCENT	100.0	

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

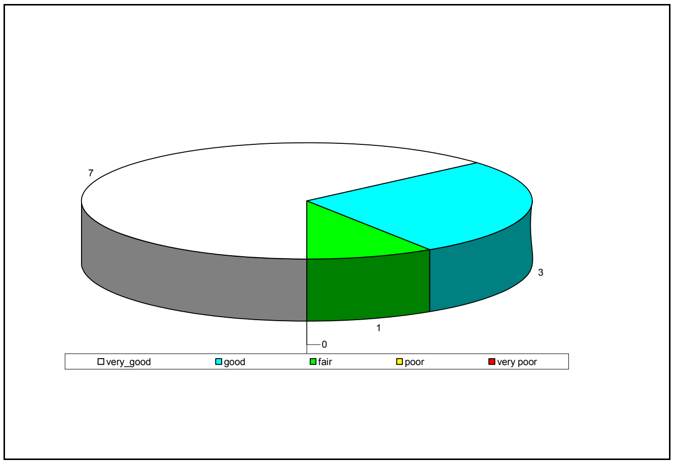


Figure – Pie Chart Population Results

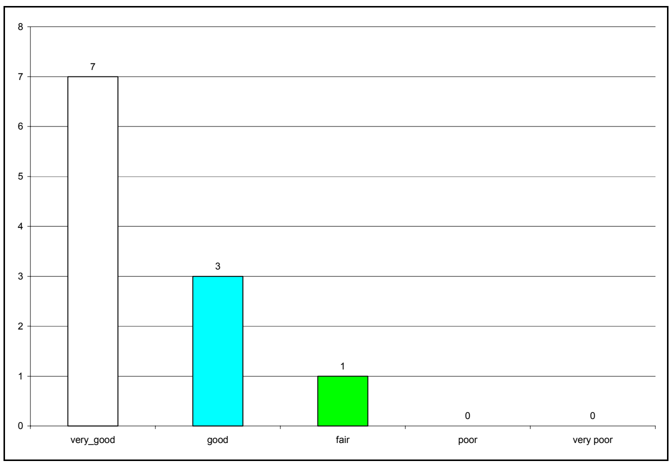


Figure – Bar Chart Population Results

4.2.6 Observations

The Health Index results show that there are no compartments of substation HV switchgear near or at end of life.

About 9.0% of the substation HV switchgear compartments will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 91.0% of the substation HV switchgear compartments are in "GOOD" or "VERY GOOD" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

4.3 Substation Riser Cable (4kV)

4.3.1 Description

Station cables are underground buried cables (4kV) to connect the switchgear (inside the station) to the overhead distribution system (outside the station).

Each feeder has one station cable riser, consisting of three cables, each with one core (conductor). Cables are bonded to ground at each end. There are no fuses at the interface between station cable and overhead bare wire, but there is a surge arrestor per phase.

Picture - Cable Riser

The particular cable riser shown here has surge arrestors 1 pole span away.

4.3.2 Demographics

Each station feeder has two or three cable installations, one cable for each phase. Exact feeder counts can be found in section 4.0.

4.3.3 Asset Management Practices

As with underground cables, the station riser cables are relatively short runs, and are replaced, if the cable is damaged. Both ends of the cable are bonded to ground.

Both ends of the cable are visible for visual inspection; the station end is in the switchgear, and the riser end is visible either from the ground, or with bucket truck (see picture).

Orangeville Hydro commissions thermographic scans of the cables and connections to determine if overheating is present.

Other aspects to consider when managing power cables:

- Hi-pot tests (DC) only at rated voltage, low power – some utilities do this prior to a full power energization.
- Cable on potential helps keep water out
- Cable de-watering process – can help if done properly, but few examples; caution with splices

4.3.4 *Health Index Formulation – Substation Riser Cables*

The following table summarizes the Health Index formulation. This Health Index formulation is very similar to other underground cables.

#	CONDITION CRITERIA	VI/DR	WEIGHT	CONDITION RATING	FACTORS	MAXIMUM SCORE
1	Pothead/Connectors/Terminations	VI	4	A,B,C,D	3,2,1,0	12
2	Foundation/Support Steel/Grounding	VI	2	A,B,C,D	3,2,1,0	6
3	Overall Cable Condition	VI	3	A,B,C,D	3,2,1,0	9
4	Thermograph Scan	DR	3	A,B,C,D	3,2,1,0	9

Max Score = 36

HI = 100*Score/Max

Table - Substation Cables and Terminations Health Index Formulation

4.3.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	3	25.0
GOOD	6	50.0
FAIR	3	25.0
POOR		0.0
VERY POOR		0.0
TOTAL	12	100.0

Table - Sample Results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	8	24.2
GOOD	15	45.5
FAIR	8	24.2
POOR	1	3.0
VERY POOR	1	3.0
TOTAL	33	100.0

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

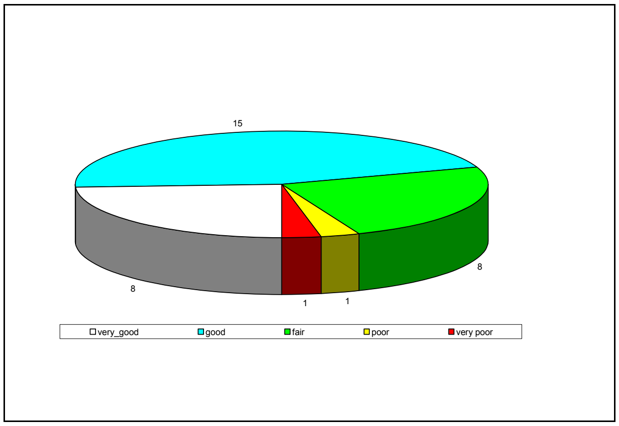


Figure – Pie Chart Population Results

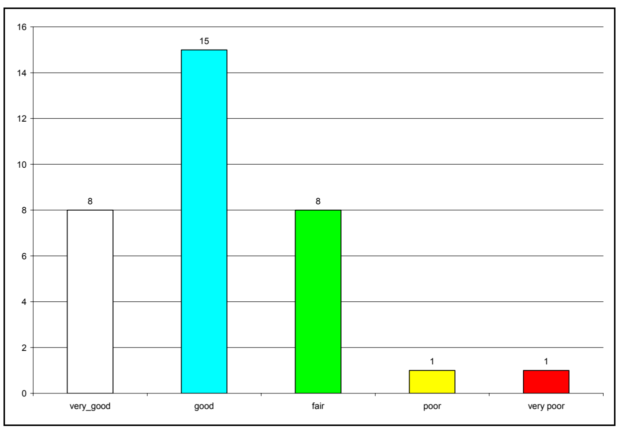


Figure – Bar Chart Population Results

4.3.6 *Observations*

The Health Index results show that about 3.0% of the substation riser cables are near or at end of life. Refurbishment or replacement likely is required within the next five years to prevent imminent failure.

About 27.0% of the substation riser cables will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 70.0% of the substation riser cables are in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

4.4 Substation HV Structures

4.4.1 Description

At distribution stations, structures provide mounting space for electrical equipment necessary to transfer power from a high voltage connection to station equipment. Substation structures may also provide a termination point for overhead and/or underground conductors entering and/or leaving the station. The structures can be made of galvanized steel, concrete poles and/or wood supports.

Pictured below is an overhead substation HV structure, with Overhead supply conductors terminating on the pole based tower.

Picture - Substation Structure

Each station has a structure that contains the following equipment:

- insulators to receive the 46kV power from a nearby overhead pole line
- two poles (concrete or wood), or a metal lattice support structure
- manual operated load break switch
- fuses to protect the transformer
- insulators and bus bar

- surge arrestors.

This equipment together provides the necessary mechanical support for the electrical conductor, and provides the necessary protection against lightning strikes and down stream fault currents.

4.4.2 Demographics

There is one structure in each substation.

4.4.3 Asset Management Practices

HV structures are part of every station, with open air electrical bus. Orangeville Hydro has substation structures to manage the 46kV connections (high voltage) to each of the Municipal stations (MS).

The overhead connection goes to a switch, fuses, and surge arrestors. The structure is made of concrete, wood or metal lattice, and has a foundation. Bus work leaves the structure to the primary connection of the transformers.

Many utilities will manage each component of the structure separately. Over-riding all component condition assessments is the structure itself including foundations. If the structure is near end of life, and failing, often the entire structure including components is re-engineered. Sometimes existing components can be re-used. If components fail, then each component is replaced, not the general structure. If all components are approaching end of life at the same time, the utility may choose to replace the entire structure as one construction project, if the structure is showing advance age or accelerated approach to end of life.

Switches are managed like load break switches except that there are some minor variances to be considered:

- Grounding mats are permanently installed in the substation, whereas field crews need to take portable mats to field locations.
- Station switches sometimes have kirk key interlocks to assist in the proper sequence of events during switching within the station.

Other parameters that are sometimes considered, but do not contribute to end of life, because these items can be easily repaired, and do not reduce the switches ability to operate properly:

- switch name plates
- locking devices
- existence and/or requirement of mechanical interlocks.

4.4.4 *Health Index Formulation – Substation HV Structure*

The following table summarizes the Health Index Formulation.

Item #	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Switch	VI	1	A,B,C or D	3,2,1,0	3
2	Insulator	VI	1	A,B,C or D	3,2,1,0	3
3	Pole	VI	2	A,B,C or D	3,2,1,0	6
4	Foundation & Grounding	VI	2	A,B,C or D	3,2,1,0	6
5	Overall condition	VI	3	A,B,C or D	3,2,1,0	9
6	Thermograph Scan	DR	1	A,B,C or D	3,2,1,0	3

Max Score = 30

HI = 100*Score/Max

Table – Station HV Structure Health Index Formulation

4.4.5 *Health Index Results*

The field survey data is reviewed and the Health Index is calculated. Since the Sample is the same as the population, only the population is presented here:

RESULT	TOTAL	PRCT
VERY GOOD	2	50.0
GOOD	1	25.0
FAIR	1	25.0
POOR		0.0
VERY POOR		0.0
TOTAL	4	100.0

Table – Population Results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

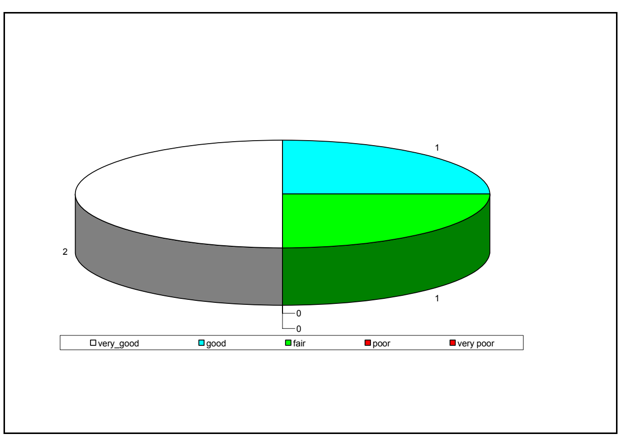


Figure – Pie Chart Population Results

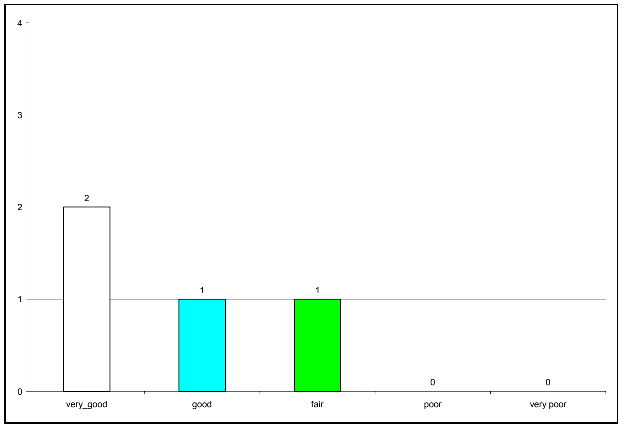


Figure – Bar Chart Population Results

4.4.6 *Observations*

The Health Index results show that none of the substation HV structures are near or at end of life.

About 25.0% (or count of 1) of the substation HV structures will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 75.0% of the substation HV structures are in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

4.5 Substation Civil Infrastructure

4.5.1 *Description*

Substation civil includes all aspects of ground, fence, foundations, and other civil works not specifically included in other equipment asset condition assessment definitions (i.e. transformers, switchgear, etc). Substation civil infrastructure is required to establish a controlled environment for the electrical equipment to operate properly. Specifically, it includes

- station fences
- roads
- station yard
- area lighting
- grounding system
- foundations
- drainage and geo-technical

- spill containment
- structures - to assist in the supporting of conductors connecting electrical equipment – this is covered in the next section
- buildings
- conductors and insulators

Picture - Station Fence

Station buildings may be located in and about distribution stations. Most of these are relay and control buildings used primarily to house protection and metering equipment, batteries, and control and communication systems. Some buildings may be used for the storage of equipment and tools.

4.5.2 Demographics

Every station has one "unit" of station civil infrastructure.

4.5.3 Asset Management Practices

Substation civil infrastructure is required to establish a controlled environment for the electrical equipment to operate properly. This includes, but not limited to:

- grounding
- physical space (separation) between equipment and the public (i.e. fence, station yard, etc)
- structures to assist in the supporting of conductors connecting electrical equipment

- conductors for electrical power
- lighting and roads to assist in station maintenance and operations

Orangeville Hydro asset management process, involves several steps, including contracting out to a 3rd party who regularly do substation inspections, and provide comments and reports back, referencing sections of the Ontario Electrical Safety Code (OESC). Orangeville Hydro also completes monthly inspections of stations using internal staff (both crews and front office staff).

Other utilities in Ontario use a very similar approach – monthly inspections complete with maintenance and repair programs. Some utilities also rely on local decision making in determining the need for repairs or replacement.

Each of the items can be broken down into specific items with measurable parameters – see below.

Elements of the substation civil infrastructure include:

1) **station fences** – also known as "security fence"; These are built around distribution facilities to protect the public from hazardous electrical contact, and to protect facilities from intrusion and vandalism. Its height, integrity and grounding are key indicators to its health. The Ontario Electrical Safety Code provides some guidelines.
2) **Access roads and internal roadways** – to provide vehicles a safe and managed way to enter and leave the station. Roads are also used for the delivery of large equipment like transformers and switchgear. As a result, several aspects contribute to the condition of the road: grade, level, pot holes, etc.

Picture - Station Fence Gate and Access Road

3) **Station Yard** – a measure for the surface treatment and any vegetation that may exist. Most stations have gravel (crushed stone) covering. Water pooling, patches of ice, or vegetation

coverage are indications that the nature of the crushed stone grounding grid is changing, and may not meet the original intentions.

4) **Area Lighting** – the lighting system provides light at night for people to see. Lighting levels can range from basic security lighting to determine if something or someone is moving in/near the station to full working level lighting, so that people can do reading at site 24/7, and do not need to bring work lights with them. As these stations are seldom visited, and are in some cases in sensitive areas, a minimal level of lighting is present (security level).

Picture - Station Ground Rod

5) **Grounding System** - Grounding systems establish the necessary voltage gradient control to permit people to walk safely within the station, and to divert fault current and stray current in a safe manner. This includes ground rods, ground wire, fence bonding, ground cover (crushed rock), and other components.

6) **Foundations** - provide support for equipment and help transfer forces of weight and transverse loadings into the ground in such a way that the equipment does not move, or sink deeper into the ground. The frost line plays a key role in deciding how much foundation is required, in order to avoid up-heaving of the foundation, shifting of the ground, or sink holes around the foundations.

   The foundation itself often consists of concrete, which can begin to crack or spall. Sometimes this is a material problem, other times it is water and ice penetration into the concrete, resulting in a wedge type force on the inside of the concrete and causes it to start breaking into pieces. If this starts happening, it is necessary to replace the concrete pad or foundation or pile.

7) **Drainage and Geotechnical** – This category summarizes how the station manages water and other substances that drain away from the site. Water needs to be drained from the site during different times of the year, in a controlled manner in order to not wash away materials put in place (i.e. ground grid, crushed stone, fence post foundations, etc).

8) **Spill Containment** – provides a means for trapping oil and other substances on the substation property that should not escape to the surrounding area. It was noted that the substations generally did not have this, and that the transformers are oil filled. If the station were built today, it would be required to have this. It is recommended that Orangeville Hydro review the date of construction, and the present legislation in Ontario and determine if the present condition is in agreement with any requirements that may exist.

9) **Structures** – this is covered in the next section

10) **Buildings** – these typically contain protection & control equipment, DC power supply, metering, communications equipment, and batteries and systems related to the substation operation. There are no buildings at the Orangeville Hydro substations.

11) **Conductors and Insulators** – A general category for all items that carry primary electrical current, and the elements needed to support the conductor. Not included are switches, which are typically load break and managed as a separate asset.

4.5.4 Health Index Formulation – Station Civil

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Fence Condition	(1)	3	(1)	(1)	9
2	Roads	VI	2	A,B,C or D	3,2,1,0	6
3	Station yard	VI	1	A,B,C or D	3,2,1,0	3
4	Area lighting	VI	1	A,B,C or D	3,2,1,0	3
5	Ground grid	(2)	1	(2)	(2)	3
6	Foundations	VI	1	A,B,C or D	3,2,1,0	3
7	Drainage and Sewer	VI	1	A,B,C or D	3,2,1,0	3
8	Spill Containment	VI	1	A,B,C or D	3,2,1,0	3
9	Overall condition	VI	1	A,B,C or D	3,2,1,0	3

Max Score = 36

HI = 100*Score/Max

Table – Station Civil Health Index Formulation

Notes:

1. Information available in sub-table – all data appears available in TILTRAN reports. When Health Index is calculated below, and result is converted to 100% basis, re-normalize to basis of "9" and add in the points here.
2. Information available in sub-table – all data appears available from site inspection reports. When Health Index is calculated below, and result is converted to 100% basis, re-normalize to basis of "3" and add in the points here.
3. To calculate the total Health Index, divide the accumulated points by 36, and then multiply by 100.

4.5.4.1 Fence Condition

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Fence grounding	VI	1	A,B,C or D	3,2,1,0	3
2	Fence space (bottom)	VI	1	A,B,C or D	3,2,1,0	3
3	Fence barbed wire	VI	1	A,B,C or D	3,2,1,0	3
4	Fence gate	VI	1	A,B,C or D	3,2,1,0	3
5	Fence sign's	VI	1	A,B,C or D	3,2,1,0	3
6	Fence Height	VI	1	A,B,C or D	3,2,1,0	3
7	Overall condition	VI	1	A,B,C or D	3,2,1,0	3

Max Score = 21

HI = 100*Score/Max

Table – Fence Health Index Formulation

Info source:

1. Fence grounding → TILTRAN
2. Fence space (bottom) → TILTRAN
3. Fence barbed wire → TILTRAN
4. Fence gate → TILTRAN
5. Fence signs → TILTRAN
6. Fence Height → Orangeville Hydro
7. Overall condition → Orangeville Hydro

4.5.4.2 *Ground Grid*

The following table summarizes the Health Index Formulation.

Item	Condition Criteria	DR/VI	Weight	Condition Ratings	Factors	Max Score
1	Grounding connections	VI	1	A,B,C or D	3,2,1,0	3
2	Structure bonding	VI	1	A,B,C or D	3,2,1,0	3
3	Resistance measurement	DR	3	A,B,C or D	3,2,1,0	9
3	Grounding outside of fence	VI	1	A,B,C or D	3,2,1,0	3
4	Overall condition	VI	1	A,B,C or D	3,2,1,0	3

Max Score = 21

HI = 100*Score/Max

Table – Ground Grid Health Index Formulation

Note: If the resistance measurement is D, then also divide the Health Index result by 4. If the result is C, then divide the Health Index result by 2.

Info source:

1. Grounding connections → Site visual inspection
2. Structure bonding → TILTRAN
3. Resistance measurement → Orangeville Hydro
4. overall condition → Site visual inspection

It should be noted, that the ground grid Health Index can still be calculated if the resistance measurement check is not available. If the resistance measurement is completed, and the results indicate a "D", then the calculated Health Index should be divided by 4.

4.5.5 Health Index Results – Station Civil

The field survey data is reviewed and the Health Index is calculated. The results of the sample are presented in the table below:

RESULT	TOTAL	PRCT
VERY GOOD	2	66.7
GOOD	1	33.3
FAIR		0.0
POOR		0.0
VERY POOR		0.0
TOTAL	3	100.0

Table - Sample results

When the sample is extracted to the population, the results can be found in the following table:

RESULT	TOTAL	PRCT
VERY GOOD	2	50.0
GOOD	1	25.0
FAIR	1	25.0
POOR		0.0
VERY POOR		0.0
TOTAL	4	100.0

Table – Population results

Results from the aforementioned table are presented as a pie graph and in a bar chart (below):

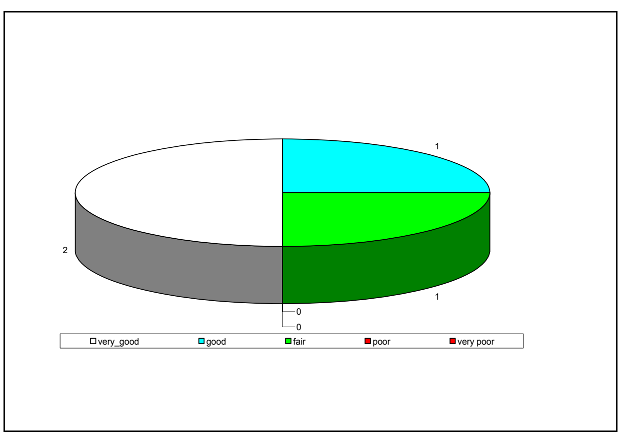


Figure – Pie Chart Population Results

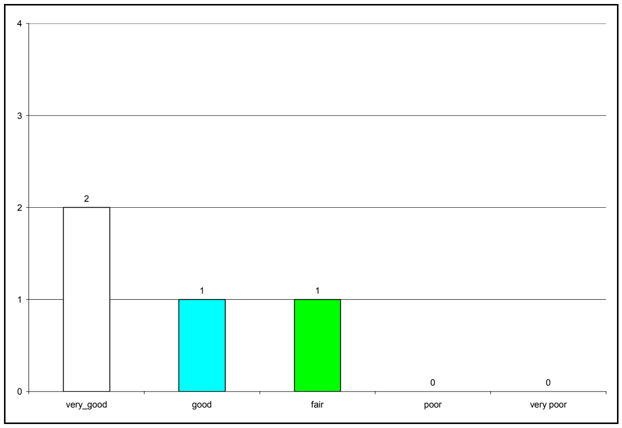


Figure – Bar Chart Population Results

4.5.6 Observations

The Health Index results show that none of the substation HV structures are near or at end of life.

About 25.0% (or count of 1) of the substation HV structures will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further.

The remaining 75.0% of the substation HV structures are in “GOOD” or “VERY GOOD” condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5 year period.

5. Other Infrastructure

This section summarizes other infrastructure managed by Orangeville Hydro that does not fit the standard definitions of Overhead, underground or substation definition. This includes:

5.1 Metering Installations

5.2 Right of Way

5.3 Operating Spares

5.4 Other Assets not Included

5.1 Metering Installations

5.1.1 Description

Metering installations consist of two groups:

- Meters on feeders from Hydro One for general energy consumption – these are located in Hydro One substation, and generally not accessible by Orangeville Hydro. It is assumed that Hydro One manage these.
- Meters on customer services – these are located on every service in the service territory.

Picture - Revenue Meter

This asset class includes the following:

- actual meter
- any recording device
- instrument transformers (PTs, CTs)
- wiring
- communications devices to permit data transfer to a remote location
- enclosures and conduit.

Future meters (TOU) will have wide area radio transceivers to facilitate communications with Orangeville Hydro central operations. The radio transceiver infrastructure is a separate asset not part of this report.

5.1.2 Demographics

Demographics are not provided in this report on this asset.

5.1.3 Asset Management Practices

Metering systems are governed by the laws and regulations of the OEB, IESO, Government of Ontario and Measurements Canada. The end of life criteria is based on weather the meter seal date has expired or not.

Over the next several months, all metering installations will be changed out from regular units to TOU in the following sequence. To facilitate this, the metering configurations will be upgraded from 2.5 element (most common) to 3 element, as required:

- Residential units
- Small Commercial
- Large Industrial/Commercial that are not already TOU setup.

With the new TOU meters, In the event of a meter failure, or the failure of communications or the communications of poor data, a metering technician would be dispatched to assess the condition. Therefore, it may be assumed that a metering installation is in GOOD condition, based on exception reporting.

Metering seal dates for meters, PTs and CTs assumed to govern the useful life of the installation. This is governed by Measurement Canada. The expected meter life is 7 years.

5.1.4 Health Index Formulation - metering

Installations assumed to be in GOOD condition.

Metering seal dates for meters, PTs and CTs assumed to govern the useful life of the installation.

At this time, a Health Index is not proposed.

5.2 Right of Way

5.2.1 Description

A Distribution Right-of-Way (ROW) consists of connected urban and rural land corridors with rights to construct, operate and maintain electric utility distribution lines (i.e., distribution feeders). A ROW provides the land base for constructing and installing lines at voltage levels of 50 kV and below. These corridors provide a secure means for the safe and reliable distribution of electricity.

This includes any back yard pole line sections.

ROW needs to be maintained periodically to avoid power outages due to trees or other outside influences. Some utilities use a 3 – 6 year cycle, which includes assessment, partial/full remediation, weeding, grass cutting, or other vegetation management practices.

5.2.2 Demographics

At the time of writing, Orangeville Hydro was not able to produce information to “count” the amount of right of way present.

5.2.3 Health Index Formulation – Right of Way

No Health Index formulation is proposed at this time.

5.3 Operating Spares

5.3.1 Description

Operating spares are major electrical equipment that is kept in a central location, so that replacements can happen quickly. This affects:

Overhead Systems – Poles and Line Sections

- poles
- cross arms

- guying and anchoring materials
- wire
- insulators

Overhead Systems

- pole transformers
- fuse cutouts
- load break switches
- in-line switches
- fault indicators

Underground systems

- pad transformers
- pad mounted switchgear
- underground cable and accessories

Other

- substation transformers (1 unit, 3 phase in storage; MS#1 soon to be added)

For each of these, the appropriate Health Index, developed for other, similar asset groups should be used.

5.3.2 Demographics

At the time of writing, Orangeville Hydro was not able to provide information on the count of these items; consequently a condition assessment using previously discussed methods was not completed.

5.3.3 *Asset Management Practices*

System spares are held for the maintenance/replacement of distribution fixed assets and planned projects. It primarily includes transformers, poles, switches, protective devices, metering systems, and component replacement parts for the distribution system.

A key driver in establishing the spares inventory levels is to ensure that the OEB mandated time frames regarding connections, can be met. Other factors in the establishment of spares and inventory levels are the vendor lead-time, demand levels and the forecasted work program.

The degradation processes for spare transformers and switchgear stored outdoors are similar to those that are still operational. These are discussed in full in the reviews of those assets. The rate and severity of degradation is dependent on a number of inter-related factors, particularly the environment in which the equipment is stored. For items not in use, and therefore not subject to electrical, operational or load related degradation, moisture ingress and other moisture and environmental effects such as corrosion are the most significant.

In particular, this applies to:

- substation transformer
- pole mounted transformer
- pad mounted transformer
- pole top switches
- inline switches
- fuses and fuse cutouts.

Other items stored outside are Poles and pad mounted switchgear. Again, pad transformers and switchgear are most susceptible to rusting, leaks and housing failure due. Poles are generally not affected by weather, especially when stored off the ground.

The remaining components, also known as wire system components, are stored inside, at the Orangeville Hydro Service Center:

- wire
- underground cable
- insulators
- guying and anchoring materials
- fault indicators
- cross arms

This method of storage reduces the impact weather can have on the infrastructure. Items are still subject to mechanical damage due to scrapes, falls, or other un-wanted contact.

5.3.4 Health Index Formulation – Operating Spares

The Health Index formulation for assets kept as operating spares, is the same as those for assets in service. If a parameter from the unit that is installed does not apply, then that parameter of the Health Index Formulation can be excluded by identifying it as "N" (not applicable).

5.3.5 Health Index Results

These items were not evaluated.

5.4 Other Assets Not Included

The following assets are described here for reference, to indicate what they are, but during the execution of this project, it became evident that they are not part of the scope of work.

5.4.1 Secondary Services

Secondary services include all wire and hardware that connect to the secondary side of the bushings of the pad or pole transformer. Typical voltage levels as described in the Conditions of Service[7] for Orangeville Hydro include:

- 120/240, 3 wire, 1 phase (Edison voltage)
- 120/208, 4 wire, 3 phase
- 347/600, 4 wire, 3 phase

Wire type and hardware are selected based on the following parameters:

- the service size of the user (Amps),
- the distance the service is from the point of connection at the transformer,
- the service voltage level, and
- the installation method (overhead vs. underground).

For the scope of this work, this asset is not included in the condition assessment.

5.4.2 *Customer Owned Services*

Client owned services are predominantly connected on the 46kV and any other large user; some are connected to the 28kV system.

For customer owned services, the customer owns the following equipment, as defined in the Orangeville Hydro Conditions of Service (COS):

- station complete with fence, grounding system and related per the Ontario Electrical Safety Code (OESC)
- primary Load Break Switch (46kV or 28kV)
- transformer
- primary fuse (may be supplied by Orangeville Hydro).

Orangeville Hydro will provide the physical electrical connection, either overhead or underground, depending on the policy of the utility for the service area. Orangeville Hydro reserves the right to operate the load break switch in order to manage and operate the distribution system.

This asset group does not require Orangeville Hydro to maintain or replace electrical infrastructure as it is customer owned. Therefore, it is excluded from this scope of work.

6. Observations, Conclusions and Recommendations

This section has the following sub-sections:

6.1 Observations

6.2 Recommendations

6.3 Possible Next Steps

6.4 Conclusions

6.1 Observations

The following summarizes some of the observations in working with the data and information provided by Orangeville Hydro. In some cases, specific recommendations are made. Most recommendations are found in the next section.

6.1.1 Assets

Regarding in-line switches, some of the data records were incomplete; for example where are they, what type are they, and when was operated within the last 2 years; it is recognized that Orangeville Hydro is collecting additional data presently to refine results. The record of operations proves the switch condition, and its suitableness for operations. This information will support both the demographics and condition assessment process.

Both fault indicators and pad mounted switchgear have particular manufacturers and/or other physical characteristics such that the devices are no longer suitable for operations environment at Orangeville Hydro. Consequently, electrical equipment with these characteristics is functionally obsolete. If there are other asset groups or types of equipment that need to be classified as functionally obsolete, these decisions should be documented, so that all work groups within Orangeville Hydro are aware of this.

Distribution overhead line sections and underground cable both have circuit sections that have been identified for conversion from 4kV to 28kV. A multi year plan should be developed for the completion of this project, including identifying the general sequence of changes. A report should exist, as to the sequence of regions, based on technical criteria, so that the person assembling the annual capital plans has some reference material to work from. The report should be updated approximately every 5 years, indicating what was completed when, and any new priorities that have been set. Also, a technical review of the power grid configurations and supply options may point out some efficiencies and/or other benefits not presently known.

For Distribution line sections, there are several examples of older construction, which do not meet the present engineering standard. In the last 10 years, the engineering standard has changed to armless construction, with increased pole height and pole mounted equipment between phase wire and neutral. Upgrading these line sections, or replacing transformers presents Orangeville Hydro with some technical challenges. Consequently, the line sections have been identified as functionally obsolete.

Overall, both distribution line sections and underground cable are well managed.

6.1.2 Asset Management Process

During the course of the project, there were several questions were asked by Orangeville Hydro about software packages to manage data for asset management purposes.

Most software packages have the ability to import data tables or text files (i.e. CSV format), to populate some form of database. Sometimes this is used to test the software or to seed live data, thereby avoiding typing in all the data by hand.

Software packages are VERY GOOD at managing data, if they manage the data according to a process that Orangeville Hydro wishes to follow. On the other hand, any software package will not work, if there is insufficient data, or if Orangeville Hydro has not defined for itself how it manages its asset information, in particular the requirements and flow to make the necessary decisions.

Some have said that Asset Management requires data management much like the manner in which dollars and cents are managed in the financial system; with checks, balances, audits, and processes to assist in timely decision making.

More recently the British PAS-55 standard has been published, which attempts to define ISO-9001 type processes within the asset management framework. Many Utilities are still evaluating these standards, and have not embraced them. Most notably, Hydro One and BCTC are on the committee to establish PAS-55 and recently Hydro One issued an RFP looking for technical experts to help them implement PAS-55. By adopting some of the elements of ISO-9001 or PAS-55, Orangeville Hydro would include some of the concepts that leading utilities are starting to embrace, and thereby become one of the leading utilities in this regard.

6.1.3 General Data

Concerns exist for distribution line sections, load break switches and underground cable. For load break switches, there is marginal volume of information available. It is recommended that a short term maintenance program be implemented to acquire all required condition data.

In working with the data (in MS Excel), it is evident that date formats, phase information, and other technical information was not always entered using a consistent format. Some re-formatting was required. It is recommended that Orangeville Hydro standardise the data format. Furthermore, blank entries should not occur, unless there is a clear understanding as to what blank means: (a) that no data has been collected (i.e. unknown), or (b) some previously agreed to default value applies.

6.2 Conclusions

This section summarizes the conclusions of this report.

In general, Orangeville Hydro has GOOD processes, including data collection methods. This report contributes to the Orangeville Hydro processes in the following ways. Details are provided in the sections below:

- A review of the existing process, with recommendations (next section) on improvements for the overall betterment of the process, data and results
- Some additional new data parameters for some assets
- Standardized manner of reporting results for all assets
- An interpretation of the ACA results into remaining life

It contains the following sections:

6.2.1 Process Overview

6.2.2 Data Availability

6.2.3 Health Index Results

6.2.1 Process Overview

In general, it has been found that Orangeville Hydro has undertaken a careful and thoughtful evaluation of condition assessment needs.

At the beginning of the process, assets were defined in order to clarify what is included and what is not included. This important step clarified each asset class. This step facilitates the asset count reporting (demographics) as well as reporting on the asset management practices of Orangeville Hydro. One result of this step, is the separation of cable risers from substation cables. Cable risers have surge arrestors and fuse cutouts, whereas substation cables are protected by switchgear fusing.

The data collection methods, tools and technologies are generally appropriate to the task of measuring asset condition, providing the right data at an appropriate cost. The methods and procedures for data collection are documented for data collection by Orangeville Hydro staff.

This project consolidated the existing information and applied new procedures in summarizing the information. Some new data parameters were identified, including how to measure the parameters. These increase the knowledge that Orangeville Hydro will have about their assets.

Composite Health Indices have been recommended for Orangeville Hydro use by Hatch in every case. Health Indices provide a basis for assessing the overall health of an asset. Health Indices are based on identification of the modes of failure for the asset and its sub-systems, as well as functional obsolescence drivers, and then developing measures of generalized degradation or degradation of key sub-systems that can lead to end-of-life for the entire asset.

The use of statistical sampling and the projection of the sample to the population were added to the Orangeville Hydro process, in order to complete a first pass on all assets, without the need to collect condition information on all assets in each asset class.

6.2.2 Data Availability

The data availability is generally GOOD to VERY GOOD. The only assets ranked "POOR" on this aspect were for fuse cutouts, duct banks and Right of Way.

The most common way of managing fuse cutouts is on a run-to-failure basis and can be easily replaced. These fuse cutouts are understood as those that are not associated with transformers and not associated with cable risers. These devices are used for switching, isolation and feeder tap protection.

For Duct Banks and Right of Way, It is recommended that Orangeville Hydro review their process and data collection methods, both for demographics and for condition.

6.2.3 Results

The condition of the Orangeville Hydro assets has been evaluated in all circumstances where viable condition criteria are in place and sufficient condition data exists. Health Indices have been calculated for every asset with a recommended Health Index formulation and sufficient condition data to satisfy the minimum requirements for application of that formulation.

For some assets, maintenance and condition data has been collected for virtually every asset owned by Orangeville Hydro. In other asset classes, a smaller proportion of the total asset base has been tested and/or inspected, and the size and nature of the samples taken is sufficient to extend the results to the balance of the assets in that class through statistically relevant sampling. Very few assets have insufficient data.

A consistent approach has been used in developing the Health Index formulations, so that the meaning of the categories (VERY GOOD, GOOD, FAIR, POOR, VERY POOR) is consistent across most assets.

In general terms, a "VERY POOR" asset can be interpreted to be very close to end-of-life, requiring urgent attention in the form of a risk assessment potentially leading to asset replacement or a major overhaul. Assets in the "POOR" category can be interpreted as being close to end-of-life, requiring risk assessment potentially leading to replacement or significant maintenance expenditures in a 1 to 5 year time frame.

As might be expected, the vast majority of the assets owned by Orangeville Hydro are ranked in "GOOD" or "VERY GOOD" condition, meaning that these assets are generally being managed effectively and are being maintained in a condition suitable for many more years of service. There is a relatively small proportion of assets found in "VERY POOR" or "POOR" condition, as expected.

In the Orangeville Hydro fleet of assets, the following assets have shown noticeably higher than average results in the VERY POOR condition:

- in-line switches,
- fault indicators
- pad mount switchgear

In addition, higher than expected counts were found in

- distribution line sections,
- load break switches
- underground cable

Functional obsolescence, as a parameter of asset management, was introduced to categorize other properties or indicators that an asset can no longer meet its expected purpose. This term has an over-riding contribution to the Health Index calculation process. Over time (into the future), Orangeville Hydro will need to add information to this category, based on its experience with different assets, and how they perform in the Orangeville Hydro system.

6.3 Recommendations

The following recommendations are made. No attempt was made to prioritize the recommendations.

6.3.1 General

Several oil filled assets have been identified with PCB's, but at present, not all equipment in the affected asset classes have been clearly identified as containing or not containing PCB's. Once all equipment in these asset classes is clearly identified, a strategy should be developed to reduce the amount of PCB's being managed by Orangeville. Depending on the location, it may be necessary to do soil testing before and/or after the equipment removal to confirm that no PCB's have leaked.

Some assets have a high percentage of POOR or VERY POOR condition results. As sampling was done on these assets, it may have over-stated the actual percentage (or number) of assets in the POOR and VERY POOR category. If the demographics have a small count, Orangeville Hydro should consider a full survey of all assets in that asset class. If a sample is chosen, then assets not previously surveyed should be sampled.

Over several years, each asset class should be sampled on an annual basis or as required, with each sample not having any repeats from previous years, until all assets have been sampled at least once. This will provide Orangeville Hydro with a progressively improving picture of asset condition, and a progressively reduced margin of error and a progressively increasing confidence level of the asset condition.

Feeder lengths – the present method involved measuring distances on scaled, paper maps is somewhat inaccurate, given that in some cases 1mm = 5 meters, and the road width on the drawings is a few mm in size. In the future, once GPS data is available (one type of more accurate data), it should be possible to gather more accurate information on line sections from real world coordinates (in AutoCAD or Microstation). This is especially true for cable risers and similar installations, where the vertical portion of conductor could not be accurately accounted for. It is recommended that GPS data be collected on all poles and ground level mounted equipment.

Backyard construction (also known as “rear lot”) always poses a challenge for utilities; this includes general access, maintenance, repair and in some cases condition assessment. Again, a technical report summarizing where these locations are, how much exists, and where the priorities for conversion exist, would help the person responsible for the annual capital budgets, in defining what needs to be done. The report should be updated approximately every 5 years with what was completed, and any new priorities that exist or may have been set.

Land Right of Way (ROW) and easements – many utilities in Ontario request easements and other titles of land in order to maintain the electrical infrastructure. Historically, utilities have not regularly inspected the easements and actively enforced their right to access their infrastructure. It is recommended that Orangeville Hydro confirm the easements it has, as well as those it may need to service its infrastructure, and decide on what action to take in order to be able to maintain its infrastructure 365/7/24 – without such a review, there will be situations where power restoration may take longer or not be possible, as trucks or similar may not be able to gain access to poles and other infrastructure. This applies to overhead and underground systems.

An extension to land ROW is the tree trimming requirements. Some utilities have decided that tree trimming, and the more general vegetation management is an “asset” in that money is spent in one year to manage the vegetation, and for the next 3 – 6 years, almost no other monies will be needed for the line section that was cut down. It is recommended that a vegetation management plan be developed after the ROW’s have been identified. Again, a technical report that identifies priorities should be produced. The report should be updated every 3 years, including dates of sections that were maintained.

6.3.2 Overhead Systems

The overhead system relies on load break switches in order to be sectionalized. It is recommended that all load break switches be taken out of service in the next 6 months and have a complete maintenance/inspection cycle performed. This will provide Orangeville Hydro with condition data on the switch, as well as confidence that the switch will most likely operate when required. A planned outage on the switch will allow crews to complete a full inspection of all components, and collect condition assessment and some technical data.

The failure of a load break switch to operate would require de-energizing a much larger part of the distribution system, and would affect a large number of customers. The failure of a load break would have a much larger system and customer impact.

Orangeville Hydro has started on a pole cataloguing system. This system should be continued, but also expanded to include various parameters:

- GPS coordinate and picture
- Wood pole material, class, length
- Ground line pole diameter, and pole diameter at 3 ft
- Framing on the pole
- Pole ID number
- Installation year
- Pole date stamp (year of manufacture)

There are a small number of fault indicators in the system (approximately 30 pc). It is recommended that a full survey (100%) sample be completed. The present results show 67% of the units in VERY POOR condition, and this should be confirmed. Furthermore, it is recommended that a directive be produced that clearly indicates where fault indicators should be located.

Line section data – when opportunity presents itself, confirm the wire type for circuit sections that are not known.

It is recommended that Orangeville Hydro review in-line switches, both nomenclature and location, to determine what type are in the field and where they are, and document in a suitable way.

Regarding fuse cutouts - Clarify the location of all fuse cutouts in the system (cable risers, transformers, line taps, etc), including those with solid blade, and classify them according to the asset definitions (demographics). Once the asset listing is complete, execute the required condition assessment of the components based on asset definitions.

Orangeville Hydro should consider repeating the ACA on pole transformers, and sample more units in Grand Valley.

6.3.3 Underground Systems

Duct Banks and Manholes

- Orangeville Hydro should also identify where it has cables in duct banks. Data on the duct banks should include configuration of the duct bank, what else is co-located, year of construction, routing, depth (if available), duct size, spare ducts and the owner of all components.

- Duct bank ownership was not clearly communicated by Orangeville Hydro to Hatch. One question touched on during meetings – if a duct bank breaks, who will pay for the repairs? It is recommended that Orangeville Hydro resolve the duct bank ownership question.
- For Duct Banks and Right of Way, It is recommended that Orangeville Hydro review their process and data collection methods, both for demographics and for condition.
- If duct banks are the preferred method of installation (i.e. in the downtown), Orangeville Hydro should consider a master plan for the area to be serviced, and identify where duct banks will be required in the future. In this way, when road reconstruction occurs (typically every 15 years), Orangeville Hydro will be ready to specify what needs to be included at time of construction so that a usable system of ducts will exist in the future, with minimal road or sidewalk re-construction work.

Pad Mounted Transformers

- Transpad units (for definition, see section 3.3.1) – consideration should be given to improving the physical location of the transpad units, with fencing or similar, so that the area cannot be used for storage, or garbage collection. Alternatively, a new pad mounted transformer would eliminate the transpad units from service completely.
- Pad mounted transformers – as with pole mounted, it is recommended that Orangeville Hydro continue with the PCB investigation, including the labelling of transformers, and where PCB's are found, continue with the planning for removal.
- It is recommended that all pad mounted equipment be tagged with GPS coordinates, as well as at least one digital photograph. Over the years, it is possible to review digital pictures to assist in the asset condition assessment process.

Underground Cable

- It is recommended that Orangeville Hydro look at the cost of splicing underground cable when faults occur, rather than always replacing with new. Some utilities have policies such that two splices in a cable is the maximum number, after which the cable gets replaced.

6.3.4 Other

Large users often own their own electrical equipment, including load break switches. It is recommended that these large users be required to show evidence of proper maintenance of their electrical equipment, especially components that Orangeville Hydro may be required to operate, or that could adversely affect Orangeville Hydro. Orangeville Hydro may need to specify the minimum standard with references to the Ontario Electrical Safety Code, the Orangeville Hydro Conditions of Service, and possibly the Distribution System Code. Orangeville Hydro can facilitate this process by assisting large users with outage management. Some utilities provide one free outage (including Saturdays), in order to assist the large users with their due diligence.

A database should be created linking customer number to transformer equipment number, in order to be able to assess the electrical loading of the distribution system, from the bottom up. In the future, it would be possible to link TOU meter data to a supply point (transformer), and calculate its loading. From there, transformers on a feeder can be aggregated for feeder loading and compared to TOU meters installed on feeders or other strategic locations. This may help identify any theft of power, should this be a concern. More practically, it may show locations where transformers are substantially under-loaded, or perhaps over-loaded, permitting adjustments to the population of transformers in the field, where practical.

During the course of the project, a list of operating spares was not provided. If such a list does not exist, it is recommended that Orangeville Hydro establish one and review it periodically against the assets in the field, to determine if sufficient spares exist. This type of review would look critically at components in the present system, and attempt to answer the question "if I needed to replace component XYZ tomorrow, do I know what I need?".

It may be time to re-work the optimization report of 1997, in regard to load flows, contingency analysis and reliability of distribution system. This would include a review of the 4kV system to determine if the present and future projected reduced loading can be served with fewer MS stations, and a re-configuration of the grid – Is it possible to reduce the number of MS stations again by one (1), and if so which one? What sequence of events are proposed for the conversion of 4kV to 28kV?

6.4 Possible Next Steps

The following summarizes various preliminary scope of work descriptions that Hatch can perform for Orangeville Hydro:

1) Regulatory Support – service area expansion in Grand Valley
2) Engineering Documentation Update
3) Software model of Distribution System
4) Optimization Report – system configuration, open points, capacitors, etc.
5) Asset Registry
6) Updated ACA report

6.4.1 Regulatory Support

Orangeville Hydro communicated that the next largest growth will occur in and around Grand Valley. One option available to Orangeville Hydro, is that the Hatch Management Group, together with the Hatch Transmission & Distribution group assist Orangeville Hydro with the interpretation of present regulations, in order to take advantage of the load growth potentials in the area. This more competitive stance is time sensitive and dependent on several events occurring over the next several months. These decisions need to be balanced against the corporate direction given to Orangeville Hydro and its desire (and ability) to grow.

The scope of work would include:

- Documenting areas of potential growth, including year and system impact
- Identify Strengths, Weaknesses, Opportunities, Threats – and balance against corporate priorities and regulatory requirements
- Establish strategy and tactics to move forward
- After all necessary approvals – implement action

The outcome should be an expanded distribution system, where required, and more customers.

6.4.2 Engineering Documentation Update

Many of the drawings and reports used as reference material in this report do not have a catalogue number. More importantly, engineering drawings are generally missing the following:

- Standardized title block
- Date and revision number of last change
- Revision block for history of revisions – what got changed
- Indication of drafter and reviewer, as part of engineering document quality program
- Drawing number – a way of cataloguing documents.

Over the last 10 years, there have been significant advances in CAD, both with Microstation and AutoCAD. For example, it is possible to have a model of the town, including street names and lot numbers, and reference that external file from inside a drawing file. The result is that there is one master copy of the background, that when updated, all the other documents dependant on it are automatically updated.

Drawings, like databases, should have all data within them, but the collection should have the data occur only once, so that multiple copies do not need to be updated.

The proposed scope of work could include:

- CAD services to update various documents
- Management Consulting – to assist Orangeville Hydro in establishing procedures to manage data, and produce engineering documents in a timely manner, with quality review

6.4.3 Software model of the Distribution System

With the pending Green Energy Act[8], Utilities will be asked to make ready to answer some of the following questions:

- How much distributed generation can be added to their system
- Where can what type of DG be added

In addition, the benefits of a software model include:

- Voltage regulation and short circuit studies of the system
- Configuration reviews for supply, or emergency restoration
- Evaluation of significant changes in the system

The scope of work would involve collecting specific information about the distribution system, including wire size, type, length, equipment (transformers, switches, etc), load information, and any metering information especially TOU, that can be time-correlated. The work scope would result in a software model from which electrical calculations can be done.

6.4.4 Optimization Report

The Optimization Report[9], written in 1997, describes the configuration of the power system and reviews various configurations to reduce losses, improve operability, and review contingency configurations in case of local outage.

The report uses an electronic model of the distribution system that is geo-referenced, and performs load and short circuit calculations.

The 1997 report is now 12 years old, and the system configuration and load distribution have changed. A revision to the report should include future load scenarios (i.e. no 4kV system), and potential other or alternate work can be identified that helps Orangeville Hydro meet the general objectives, but may also reduce the capital or O+M expenditures over the long term, by looking at technical solutions.

6.4.5 *Asset Registry*

In support of any asset condition assessment is the need for accurate demographics. How much of each asset exists?

A more detailed review of the work management system, including how work is communicated to the field, and what information is requested back from the field, could lead to the collection of key data, with minimal extra overhead, to facilitate this process. Data can be collected in several ways, including:

- Targeted asset demographics activities (counting and documenting)
- Construction and repair activities – asking key questions at the time of repair, when it is possible to approach the assets much closer because of their de-energized state.

One of the steps would be to create the necessary registry, using some of the Microsoft tools available. The specific tool depends on what products are available.

The work scope would involve the following

- documenting the existing process,
- documenting the desired objectives of Orangeville Hydro
- developing a new process including various forms, gates, and policies
- implementing the process
- merging the collected information into a central asset registry and running several reports to prove its effectiveness
- assembling a summary report on the results.

6.4.6 *Updated ACA report*

Within the next two years, after Orangeville Hydro has had time to implement some of the recommended changes in this report, and other changes that Orangeville Hydro feels may be necessary, Hatch would welcome the opportunity to work with Orangeville Hydro again, to update this report and document the improvements in data, process and results.

The work scope would look at the data (demographic and condition), update the Health Index formulations based on new processes, and calculate the results. A summary report or a full report could be created with the new results, and a commentary on the changes made.

Hans Ziemann
HZ :dj
Attachment(s)/Enclosure

REFERENCES

[1] http://en.wikipedia.org/wiki/Orangeville,_Ontario; see also appendix F

[2] http://en.wikipedia.org/wiki/East_Luther-Grand_Valley,_Ontario; see also appendix F

[3] Horstmann; http://www.powerdeliveryproducts.com

[4] http://www.kabar-almat.com/almatspecialties2.htm

[5] S and C; http://www.sandc.com/products/padmountedgear/pmh_main.asp

[6] S and C; http://www.sandc.com/products/padmountedgear/pme_main.asp

[7] Conditions of Service (COS), Orangeville Hydro Website, version 6.0, section 2.3.4.1; for copy, see appendix F2.

[8] An Act to enact the Green Energy Act, 2009 and to build a green economy, to repeal the Energy Conservation Leadership Act, 2006 and the Energy Efficiency Act and to amend other statutes (a.k.a The Green Energy Act), bill 150, royal assent given May 14, 2009. Of note are:

- A new section 25.36 requires transmitters and distributors toconnect generation facilities to their transmission systems ordistributions systems if specified criteria are satisfied.
- A new section 25.37 requires distributors, transmitters, the OPAand the IESO to provide prescribed information about the distri-bution system's or transmission system's ability to accommo-date generation from a renewable energy generation facility.Section 26 is amended to require transmitters and distributors toprovide priority access to their systems for renewable energygeneration facilities that meet prescribed requirements.

[9] Orangeville Hydro Optimization Report, 1997 (see appendix F1)

APPENDIX A

Demographic Data

The following Items are contained in the Appendix

- 2.4_pole tx
- 3.2_pad mounted switches
- 3.3_pad tx
- OH and UG sections
- _27.6kV & 4kV cutouts Sept 2008.xls
- _44kV customers Sept 2008.xls
- _44kV MS info sep2008.xls
- _Grand Valley cutouts Sept 2008.xls
- 2.2_air break Switch Sept 2008.xls
- 2.3_inline switches Sept 2008.xls
- fault indicators.xls
- substn feeders.xls

APPENDIX B

Health Index Parameter Guide

Project Report

Aug 2009

Orangeville Hydro Limited
Asset Condition Assessment

Appendix B - Health Index Parameter Guide

Table of Contents

1. Overview 2

2. Overhead System 3

2.1 Distribution Line Section 3
2.2 Load Break Switches 7
2.3 In Line Switches 10
2.4 Pole Mounted Transformers 11
2.5 Fault Indicators 14
2.6 Fuse Cutouts 15
2.7 Voltage Conversion Transformers 16

3. Underground System 19

3.1 Buried Cable 19
3.2 Pad Mounted Switches 21
3.3 Pad Mounted Transformers 24
3.4 Duct Banks and Manholes 28

4. Substation Equipment 29

4.1 Substation Transformers (44-4kV) 29
4.2 Substation Switchgear 34
4.3 Substation Cable Risers 37
4.4 Substation HV Structures 39
4.5 Substation Civil Infrastructure 43

WorkingTogether SAFELY

1. Overview

This document summarizes the Health Index Parameters, in particular, how to interpret the different parameters, and assign ABCD codings for evaluation in the Health Index.

The section numbering agrees with the main report. The parameter numbering agrees with table entries in the main report and the survey forms.

Where tables exist for functional obsolescence, the letter codes are listed in reverse order, as a reminder to the user that the most severe condition needs to be recorded.

Each asset (section X.Y) starts on a new page so that it is possible to extract the pages of one asset for condition assessment.

2. Overhead System

2.1 Distribution Line Section

Item	Condition Criteria
1	Pole condition
2	Wire Conductor
3	Insulators
4	Guying and Anchoring
5	Trees
6	Foundation and grounding
7	Functional obsolescence

2.1.1 Pole Condition

Wood Poles:

Condition Rating	Description
A	Pole is like new condition. No damaged wood fibre present. No indications of splitting. Pole treatment is visible and to the right level. Pole is not leaning.
B	Pole has aged normally, with some signs of splitting or some ground line rot. Circumference has decreased no more than 10%. Some notching evident, but less than ½ inch surface penetration. Pole is leaning at most 3% (deflection divided by above ground height).
C	One of the following conditions met: • Several longitudinal splits have occurred • Wood pole Ground line circumference has decreased 10% (without heart rot being present) • Heart rot is present • Reflectometer test shows residual strength is greater than 70%
D	Significant degradation has occurred. Pole is not expected to last 3 years, or may fail imminently. Two or more of the parameters in "C" have been met. Requires immediate corrective action.

Concrete poles exist, but are very few, and as such are ignored at the present time.

2.1.2 *Wire Conductor*

Condition Rating	Description
A	Phase conductor is ACSR or AAC, and appears to be in near new condition
B	Phase conductor is ACSR or AAC, and is showing some aging, or separation of strands. A splice may be present in the conductor. No strands are broken
C	One of the following conditions is met: • Phase conductor (not jumper) is copper, and there are no splices present • Phase conductor is ACSR or AAC and line section has two or more splices in it • Neutral or service conductor is sagging below required clearance amount
D	One of the following condition is met: • Phase conductor is copper and one or more splices exist in the line section • Neutral or service conductor is sagging below required clearance and contains one or more splices in it.

2.1.3 *Insulator Type*

Condition Rating	Description
A	Insulator is Polymer, and in near new condition.
B	Polymer Insulator shows normal signs of aging, including minor burn marks
C	Insulator is porcelain in near new condition
D	Insulator is porcelain with burn marks or chips missing

2.1.4 *Guying and Anchoring*

Condition Rating	Description
A	Guy wire, guy guard, anchor, and guy insulator in near new condition, and per present engineering standards. All equipment is externally clean, corrosion free. No external evidence of over loading, deformation, or malfunction. Number of guy wires appears to be within engineering parameters. Guy wires are properly arranged and balanced so that all dead-ended phase wires can be removed and re-attached without extra guys.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable

2.1.5 *Trees*

Condition Rating	Description
A	Trees are non existent, or more than 10ft from wire
B	Trees are close to wires, but not touching
C	Trees are touching wire, but not engulfing line section
D	Trees are engulfing wires and possibly poles.

2.1.6 *Foundation and Grounding*

Condition Rating	Description
A	Pole foundation is in near new condition. Grounding is in good condition.
B	Normal wear on foundation and ground. Ground rod may be visible. Ground conductor is attached to pole and suitably guarded in its lower section from accidental contact.
C	One of the following conditions met • Foundation or soil around foundation showing erosion, or other signs of change that could affect the foundation • Grounding conductors are frayed or broken, but more than 60% of the strands are still in tact • Ground rod is exposed • Ground wire is not properly attached to the pole • Ground wire is smaller than AWG#4 • If foundation is concrete, it has started to spall, and have cracks, but cracks to not connect the pole to the outside of the foundation • Standing water exists at the base of the pole (drainage is poor)
D	Two or more of "C" are present, or the conditions described in "C" are more severe than described. The ground wire is broken (not continuous) from top to ground rod.

2.1.7 Functional Obsolescence

The parameters ABCD are listed in reverse order, because, of the various billet points in the aug long weekend classic. The items are listed in DCBA order, so that it is obvious that the first condition that meets the required parameters.

Condition Rating	Description
D	One of the following conditions is met: • Pole is of a non standard material (not found in the engineering stores) • Pole framing is such that present standard insulators, framing, transformers, or similar can not be placed on the pole per the engineering standard • Pole framing such that transformer can not be placed between phase wire and neutral. • Equipment on the pole is such that an equivalent replacement from stores would not fit in the physical space available. • Equipment on the pole can not be operated, maintained or serviced given present operating policies of the utility. Isolation point(s) on neighbouring poles may be required. • Old style box fuses present (4kV system) • 4kV line section is to be replaced in the next year. • Pole line section is located in back yard and generally not accessible
C	One of the following is met: • Pole is in a high risk location and there are no anti vehicle barriers or similar measures in place that would prevent damage to the pole. • 4kV line section is slated to be replaced by 28kV in the next 5 years
B	Pole does not meet present engineering standards as constructed, but could be converted to present day framing, without changing out the pole.
A	Pole meets present engineering standards.

2.2 Load Break Switches

Item#	Condition Criteria
1	Arc Interrupter Condition
2	Insulation Quality
3	Contact Resistance
4	Control/Mechanism Box
5	Insulators
6	Overall Switch Condition

2.2.1 Arc Interrupter Condition

Condition Rating	Description
A	Arc interrupters are clean and are free of chips, cracks, flashover burns. Fasteners are secure. Mechanical portions move freely, without excessive force.
B	Arc interrupters are clean; however there are some minor chips and cracks. No flashover burns. Fasteners are secure.
C	Arc interrupters are not broken, however there are some major chips and cracks. Some evidence of flashover burns or tracking. Fasteners are secure.
D	Arc interrupters are broken/damaged beyond repair or are not field repairable. Fasteners are not secure.

2.2.2 Insulator Quality

Condition Rating	Description
A	All measurements exceed requirements
D	One or more measurements fail requirements

2.2.3 Contact Resistance

Condition Rating	Description
A	Contact resistance is well within specifications with high margins
B	Contact resistance is close to specification (little or no margin)
C	Contact resistance does not meet specification (by a small amount)
D	Contact resistance does not meet specification (by a significant margin)

2.2.4 Control and Mechanism Box Components

This applies to the mechanism box at ground line, as well as the pipe running up the pole.

Condition Rating	Description
A	Wiring, terminal blocks, relays, contactors, trip and close coils and switches all in good condition. Battery and charger in good condition. Operating mechanism, coils, relays, auxiliary switches, all in good condition. No sign of overheating or deterioration. Linkages, drive rods, trip latches clean, free from cracks, distortion, abrasion or obstruction. No visible evidence of poor mechanism settings, looseness, loss of adjustment, excess bearing wear or other out of tolerance operation. Heaters and insulation are effective.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

This applies to an installation with manual operator only. Mark on form if manual or automatic.

Condition Rating	Description
A	Manual operator is in good condition, showing no signs of rust. Unit is locked (open or closed). No visible evidence of looseness, loss of adjustment, excess bearing wear or other out of tolerance operation.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

2.2.5 Insulator Condition

Condition Rating	Description
A	Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Insulators are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

2.2.6 *Overall Switch Condition*

Condition Rating	Description
A	Switch is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating. Switch has provision to be locked out (both open and closed). Lock is in place. Switch base plate (mounting arm; often 8x8 inch square steel channel) is in good condition, including mechanical mechanisms onto which insulators are mounted. Grounding system including ground mat is in good condition. If portable ground mat is used, then connection point is accessible, not freyed. Number of switch operations on counter is below target value. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	The switch is damaged/degraded beyond repair.

2.3 In Line Switches

Item#	Condition Criteria
1	Thermographic Scan
2	Overall Condition
3	Functional Obsolescence

2.3.1 Thermograph Scan

Condition Rating	Description
A	Values well within specifications with high margins
B	Values close to specification (little or no margin)
C	Values do not meet specification (by a small amount)
D	Values do not meet specification (by a significant margin)

2.3.2 Overall Condition

Condition Rating	Description
A	Switch externally is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating. Appears to be well maintained with service records readily available. The operating designation is clearly visible and readable from ground level.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	Disconnect switch as failed or is damaged/degraded beyond repair.

2.3.3 Functional Obsolescence

Condition Rating	Description
D	The standard switch is 44kV, polymer, for all voltage systems. The switch that is installed is not the standard switch.
C	Last function test is more than 2 years ago, or unknown
B	Last function test is more than 1 year ago
A	None of the previous end of life conditions exist

2.4 Pole Mounted Transformers

Item#	Condition Criteria
1	Tank Condition
2	Tank Leaks
3	Bushing condition
4	Overall condition
5	Functional obsolescence

2.4.1 Tank Condition

Condition Rating	Description
A	No corrosion or rust on tank. No moisture ingress into tank, all gaskets and seals in good condition. No paint peeling evident.
B	Some rust and corrosion on tank, requires corrective maintenance within the next year. Each rust spot less than "quarter" size and the total count is less than 8.
C	Some rust and corrosion on tank, requires corrective maintenance within the next several months.
D	Significant corrosion on tank. Requires immediate corrective action.

2.4.2 Tank Leaks

Condition Rating	Description
A	No leakage of insulating oil at any of the bushing-metal interfaces, or tank interfaces. May be determined by physical inspection or review of maintenance records.
B	Minor leakage of the total quantity of oil.
C	Major leakage of the total quantity of oil.
D	Significant leakage of the total quantity of oil.

2.4.3 Bushing Condition

Condition Rating	Description
A	Bushings are not broken. They are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Bushings are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Bushings are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

2.4.4 Overall Condition

Condition Rating	Description
A	Pole Transformer is externally clean, corrosion free. All primary and secondary connections and devices are in good condition. No external evidence of over heating, bulging, malfunction or overloading. Number of service connections appears to be within engineering parameters. Appears to be well maintained with service records readily available. No reports of trouble calls or fuse blown within the last two years. Grounding connections are all present. Surge arrestor connection is on line side of fuse.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable; for example, the surge arrestor is not properly connected, or missing.
D	More than two of the above characteristics are unacceptable.

2.4.5 Functional Obsolescence

The following table will provide insight as to what letter code to use. Please take note of the items after the table:

Condition Rating	Description
D	One or more of the following criteria have been met • Transformer is of CSP type • Transformer is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole. • Transformer has PCB levels at 50ppm or greater
C	Transformer PCB level is unknown
B	Transformer PCB level is less than 50ppm, but above non detectable levels.
A	None of the previous end of life conditions exist

Additional Instructions

- If the transformer manufacturer or transformer type has resulted in a "D" then please make note of the reason on the back of the survey form.
- If the PCB level is known, please provide number

2.5 Fault Indicators

Item #	Condition Criteria
1	Overall condition
2	Application of units
3	Functional obsolescence

2.5.1 Overall Condition

Condition Rating	Description
A	Units are externally clean, corrosion free. No recent report (last 12 months) of malfunction. The indicator is visible from ground level and properly oriented to facilitate operations (finding faults).
B	One or more indicators is not visible from the ground (applicable to installed units, not to missing units)
C	Recent report of unit malfunction – unit has not been replaced.
D	Any other set of conditions not covered by B or C, whereby one or more of the above characteristics are unacceptable.

2.5.2 Application of Units

Condition Rating	Description
A	Unit is installed on all phases of the feeder, at location point, based on engineering & operations requirements.
C	One unit missing that should be installed.
D	More than one unit missing.

2.5.3 Functional Obsolescence

Condition Rating	Description
D	One or more of the following criteria have been met • Fault indicator is of battery powered type
A	None of the previous end of life conditions exist

2.6 Fuse Cutouts

Item#	Condition Criteria
1	Overall Condition
2	Functional obsolescence

2.6.1 Overall Condition

Condition Rating	Description
A	Asset is not broken. They are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure. Fuse can be easily reached with appropriate tools and operated. Operation is smooth, without sticking or excessive manual intervention. Fuse can swing free as required.
B	Assets are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Assets are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure. Fuse is somewhat difficult to operate.
D	Several aspects of the installation are in poor condition.
E	assets are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure

2.6.2 Functional Obsolescence

Condition Rating	Description
A	None of the following "failure" criteria are met
C	Surge arrestor is not installed correctly (i.e. on the line side of the fuse)
D	One or more of the following criteria have been met • Installation is not per the present engineering standard • Cutout is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole.

2.7 Voltage Conversion Transformers

Item #	Condition Criteria
1	Tank Condition
2	Tank Leaks
3	Bushing condition
4	Overall condition
5	Functional obsolescence

2.7.1 Tank Condition

Condition Rating	Description
A	No corrosion or rust on tank. No moisture ingress into tank, all gaskets and seals in good condition. No paint peeling evident.
B	Some rust and corrosion on tank, requires corrective maintenance within the next year. Each rust spot less than "quarter" size and the total count is less than 8.
C	Some rust and corrosion on tank, requires corrective maintenance within the next several months.
D	Significant corrosion on tank. Requires immediate corrective action.

2.7.2 Tank Leaks

Condition Rating	Description
A	No leakage of insulating oil at any of the bushing-metal interfaces, or tank interfaces. May be determined by physical inspection or review of maintenance records.
B	Minor leakage of the total quantity of oil.
C	Major leakage of the total quantity of oil.
D	Significant leakage of the total quantity of oil.

2.7.3 Bushing Condition

Condition Rating	Description
A	Bushings are not broken. They are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Bushings are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Bushings are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

2.7.4 Overall Condition

Condition Rating	Description
A	Pole Transformer is externally clean, corrosion free. All primary and secondary connections and devices are in good condition. No external evidence of over heating, bulging, malfunction or overloading. Number of service connections appears to be within engineering parameters. Appears to be well maintained with service records readily available. No reports of trouble calls or fuse blown within the last two years. Grounding connections are all present. Surge arrestor connection is on line side of fuse.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

2.7.5 *Functional Obsolescence*

The following table will provide insight as to what letter code to use. Please take note of the items after the table:

Condition Rating	Description
D	One or more of the following criteria have been met • Transformer is of CSP type • Transformer is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole. • Transformer has PCB levels at 50ppm or greater
C	Transformer PCB level is unknown
B	Transformer PCB level is less than 50ppm, but above non detectable levels.
A	None of the previous end of life conditions exist

Additional Instructions

- If the transformer manufacturer or transformer type has resulted in a "D" then please make note of the reason on the back of the survey form.
- If the PCB level is known, please provide number

3. Underground System

3.1 Buried Cable

Item#	Condition Criteria
1	Pothead/Connectors/Terminations
2	Grounding
3	Overall Cable Condition
4	Thermograph Scan
5	Functional Obsolescence

3.1.1 Pothead/Connectors/Terminations

Condition Rating	Description
A	Potheads and electrical exposed conductors/connectors are clean, corrosion free and are in good condition. No external evidence of overheating or any other abnormality. Potheads are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable, OR, are damaged/degraded beyond repair.

3.1.2 Grounding

Condition Rating	Description
A	Ground connections are tight, and free of corrosion. Cable is bonded to ground per present engineering policies (bonded at both ends to ground).
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable, OR, are damaged/degraded beyond repair.

3.1.3 *Overall Cable Condition*

Condition Rating	Description
A	Overall installation is externally clean, and free of corrosion/rust. All cable sections and connections are in good condition. No external evidence of any deterioration, overheating or abnormality.
B	Normal signs of wear with respect to the above characteristics and/or evidence of past repair.
C	One or two of the above characteristics are unacceptable and/or evidence of multiple repairs or failures
D	More than two of the above characteristics are unacceptable, OR, the cable is damaged/degraded beyond repair.

3.1.4 *Thermograph Scan*

Condition Rating	Description
A	Values well within specifications with high margins
B	Values close to specification (little or no margin)
C	Values do not meet specification (by a small amount)
D	Values do not meet specification (by a significant margin)

3.1.5 *Functional Obsolescence*

Condition Rating	Description
D	One or more of the following criteria have been met • Porcelin cable terminations or pot head • PILC cable • Three phase cable instead of single phase cable • Area identified for voltage upgrade in next 5 years • The cable has two or more splices in it
C	One of the following conditions met: • The cable has a splice in it • The area is identified for voltage upgrade in 5 – 10 years
A	None of the previous end of life conditions exist

3.2 Pad Mounted Switches

Item#	Condition Criteria
1	Enclosure Condition
2	Bushing Condition
3	Foundation & Grounding Condition
4	Anti-collision bollards
5	Overall Condition
6	Thermograph Condition
7	Functional Obsolescence

3.2.1 Enclosure Condition

Condition Rating	Description
A	No corrosion or rust on enclosure. No moisture ingress into tank, all gaskets and seals in good condition. No paint peeling on tank. Sealing of tank in good condition. The covers and/doors are locked, and when opened, move easily and freely (as expected). The enclosure is complete, with no holes or dents, or broken seams.
B	No rust or corrosion on enclosure.
C	Some rust and corrosion on enclosure, requires corrective maintenance within the next several months.
D	Significant corrosion on enclosure. Defective sealing. Requires immediate corrective action.

3.2.2 Bushing Condition

Bushings in this case may be spade type, or elastimold 200A/600A units with mating component installed on cables.

Condition Rating	Description
A	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Bushings are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Bushings are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

3.2.3 Foundation & Grounding Condition

Condition Rating	Description
A	Concrete foundation is level and free from cracks and spalling. Anchor bolts are tight and free from corrosion. Ground connections are direct to tank, secure, and not loose. The ground surrounding the unit is firm, with no signs of washout. The unit is level, and not slanted, or sinking at one corner or side. Number of ground wires, and size are in agreement with latest engineering standards
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Foundation, supports or grounding are damaged/degraded beyond repair.

3.2.4 Anti-collision bollards

For clarifications see section 3.2.5 – pad transformers.

Condition Rating	Description
A	If required, In good condition
C	If required, in poor condition
D	If required, not present or effective
N	Not required

3.2.5 Overall Condition

Condition Rating	Description
A	Switching Device is generally clean, corrosion free. All primary and secondary connections and devices are in good condition. No evidence of overloading, overheating, flash over, or burn marks. The number of operations is below established policy (since last major service). Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

3.2.6 Thermograph Condition

Condition Rating	Description
A	Values well within specifications with high margins
C	Values close to specification (little or no margin)
D	Values do not meet specification (by a small amount)
N	Values do not meet specification (by a significant margin)

3.2.7 Functional Obsolescence

Condition Rating	Description
D	One or more of the following criteria have been met: • Equipment is located in an area where voltage conversion is planned in the next 5 years, OR, • Unit is type KABAR, directly feeds a customer, and exists without adequate switching point on either side, OR, • Unit is type PMH, OR, • Unit is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole.
C	One or more of the following criteria have been met, but the conditions in "D" have not been met: • Unit is located in an area where voltage conversion is planned in 5-10 years, OR, • Unit is type KABAR, directly feeds a customer, and exists WITH adequate switching point on either side, OR, • Unit is type KABAR, DOES NOT directly feeds a customer, and exists without adequate switching point on either side.
B	All of the following criteria are met: • Switching unit is KABAR, AND, • has two acceptable switching units on either side (for each cable connection), AND • unit is not in a voltage conversion area (next 10 years), AND, • does not feed a customer directly.
A	None of the previous end of life conditions exist

3.3 Pad Mounted Transformers

Item #	Condition Criteria
1	Tank & Enclosure Condition
2	Tank Leaks
3	Bushing Condition
4	Foundation & Grounding Condition
5	Anti-collision bollards
6	Overall Condition
7	Thermograph Condition
8	Functional Obsolescence

3.3.1 Tank & Enclosure Condition

Condition Rating	Description
A	No corrosion or rust on tank. No moisture ingress into tank, all gaskets and seals in good condition. No paint peeling on tank. Sealing of tank in good condition. The covers and/doors are locked, and when opened, move easily and freely (as expected). The enclosure is complete, with no holes or dents, or broken seams.
B	No rust or corrosion on tank (or enclosure).
C	Some rust and corrosion on tank (or enclosure), requires corrective maintenance within the next several months.
D	Significant corrosion on tank (or enclosure). Defective sealing. Requires immediate corrective action.

3.3.2 Tanks Leaks

Condition Rating	Description
A	No oil leakage or water ingress at any of the bushing-metal interfaces. No oil leakage or water ingress at any of the flanges, access points covers, or gauges. Oil levels are acceptable.
B	Minor oil leaks evident, no moisture ingress likely.
C	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	Major oil leakage and probable moisture ingress at the bushings, or at one other location indicate the immediate need for a major reconditioning or replacement.

3.3.3 *Bushing Condition*

Bushings in this case may be spade type, or elastimold 200A/600A units with mating component installed on cables.

Condition Rating	Description
A	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Bushings are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Bushings are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

3.3.4 *Foundation & Grounding Condition*

Condition Rating	Description
A	Concrete foundation is level and free from cracks and spalling. Anchor bolts are tight and free from corrosion. Ground connections are direct to tank, secure, and not loose. The ground surrounding the unit is firm, with no signs of washout. The unit is level, and not slanted, or sinking at one corner or side. Number of ground wires, and size are in agreement with latest engineering standards
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Foundation, supports or grounding are damaged/degraded beyond repair.

3.3.5 *Anti-collision bollards*

Condition Rating	Description
A	If required, In good condition
C	If required, in poor condition
D	If required, not present or effective
N	Not required

Anti-collision bollards are not required in all locations. Orangeville Hydro requires bollards in the following locations:

- High traffic areas
- Shopping malls
- Shopping plaza's

Although not required, some industrial customers have installed them in the past.

3.3.6 Overall Condition

Condition Rating	Description
A	Transformer externally is clean, corrosion free. All primary and secondary connections and devices are in good condition. No external evidence of overloading, overheating or bulging. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

3.3.7 Thermograph Condition

Condition Rating	Description
A	Values well within specifications with high margins
C	Values close to specification (little or no margin)
D	Values do not meet specification (by a small amount)
N	Values do not meet specification (by a significant margin)

3.3.8 Functional Obsolescence

The following table will provide insight as to what letter code to use.

Condition Rating	Description
D	One or more of the following criteria have been met • Transformer manufacturer is ABB • Transformer manufacturer is Camtran, and the paint is peeling or significant signs of rust have started. • Transformer is non-standard size per present engineering policy, and a standard sized unit can not be installed in the equipment space of this pole. • Transformer has PCB levels at 50ppm or greater
C	Transformer PCB level is unknown
B	Transformer PCB level is less than 50ppm, but above non detectable levels.
A	None of the previous end of life conditions exist

3.4 Duct Banks and Manholes

No HI is proposed

4. Substation Equipment

4.1 Substation Transformers (44-4kV)

Item#	Condition Criteria
1	DGA
2	Standard Oil Tests
3	Furan
4	Thermograph condition
5	Bushing Condition
6	Bushing Leaks
7	Control Cabinet
8	Cooling System
9	Tank integrity/Conservator
10	Foundation Condition
11	Overall Condition
12	Functional obsolescence

4.1.1 DGA

Condition Rating	Description
A	DGA overall factor is less than 1.2
B	DGA overall factor between 1.2 and 1.5
C	DGA overall factor is between 1.5 and 2.0
D	DGA overall factor is between 2.0 and 3.0
E	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

WorkingTogether SAFELY

4.1.2 Standard Oil Tests

Condition Rating	Description
A	F1 + F2 + F3 = 0 or 1
B	If: F1 + F2 + F3 = 2 or 3
C	If: F1 + F2 + F3 = 4
D	If: F1 + F2 + F3 = 5
E	If: F1 + F2 + F3 > 5

Where minimum requirement is the Moisture test along with either the IFT or dielectric test:

Moisture PPM (T oC Corrected) (From DGA test)	Factor F1	IFT dynes/cm	Factor F2	Dielectric Strength (kV)	Factor F3
Less than 20	0	>20	0	>50	0
20 – 30	2	16-20	1	>40 – 50	1
>30 – 40	4	13.5-16	2	30 - 40	2
greater than 40	6	<13.5	4	less than 30	4

4.1.3 Furan oil Analysis

Condition Rating	Description
A	Less than 1.0 PPM of 2-furaldehyde
B	Between 1 – 1.5 PPM of 2-furaldehyde
C	Between 1.5 – 3 PPM of 2-furaldehyde
D	Between 3 - 10 PPM of 2-furaldehyde
E	Greater than 10 PPM of 2-furaldehyde

Furan – Transformer age is only to be used if Furan Analysis is not available

Condition Rating	Description
A	Less than 20 years old
B	20-40 years old
C	40-60 years old
D	Greater than 60 years old
E	Not Applicable

4.1.4 Thermograph Condition

Condition Rating	Description
A	Not hotspots
C	Minor hotspots
D	Major hotspots
N	No record of scan done

4.1.5 Bushing Condition

Condition Rating	Description
A	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Bushings are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Bushings are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

4.1.6 Bushing Leaks

Condition Rating	Description
A	No leakage of insulating oil at any of the bushing-metal interfaces, tank or piping interfaces, as determined by inspection of level indicator or maintenance records.
B	Minor leakage of the total quantity of oil in the bushing, as determined by inspection of level indicator or maintenance records
C	Major leakage of the total quantity of oil in the bushing, as determined by inspection of level indicator or maintenance records
D	Significant leakage of the total quantity of oil in the bushing, as determined by inspection of level indicator or maintenance records.

4.1.7 Control Cabinet

Condition Rating	Description
A	Wiring, terminal blocks, relays, contactors, trip and close coils and switches all in good condition. Battery and charger in good condition. Operating mechanism, coils, relays, auxiliary switches, all in good condition. No sign of overheating or deterioration. Linkages, drive rods, trip latches clean, free from cracks, distortion, abrasion or obstruction. No visible evidence of poor mechanism settings, looseness, loss of adjustment, excess bearing wear or other out of tolerance operation. Heaters and insulation are effective.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

4.1.8 Cooling System

Condition Rating	Description
A	All fans are working. Wiring in good condition, Controls accessible, No internal water Leaks in control cabinet.
B	Normal signs of wear with respect to the above characteristics; all fans working; minor rust on control cabinet may be present.
C	25% of fan not working or one of the above characteristics is unacceptable
D	50% or more than fan not working or none installed (and Required)
N	No fans installed, and none required

4.1.9 Tank integrity/Conservator

Condition Rating	Description
A	No corrosion or rust on tank. No moisture ingress into tank, all gaskets and seals in good condition. No external or internal rust in mechanism box. No paint peeling on tank or box. Sealing of box very effective – no evidence of moisture or insect ingress or condensation.
B	No rust or corrosion on tank, some evidence of slight moisture ingress or condensation in mechanism box.
C	Some rust and corrosion on both tank and on mechanism box, requires corrective maintenance within the next several months.
D	Significant corrosion on tank and on mechanism box. Defective sealing leading to water ingress and damage to protection, control and mechanism equipment. Requires immediate corrective action.

4.1.10 Foundation & supporting structure Condition

This applies to the transformer foundation and any supporting structure. The supporting structure may be wood or steel or other material. If none is present, the structure can be ignored.

Condition Rating	Description
A	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Transformer is level, with no indication of leaning, sinking, etc. General layout of supporting structure meets present engineering requirements.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Foundation, supports or grounding are damaged/degraded beyond repair.

4.1.11 Overall Condition

Condition Rating	Description
A	Transformer externally is clean, corrosion free. All primary and secondary connections and devices are in good condition. No external evidence of overvoltages, overloading or bulging. Appears to be well maintained with service records readily available. Grounding is in good condition.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

4.1.12 Functional Obsolescence

Condition Rating	Description
D	One or more of the following criteria have been met • Transformer has PCB levels at 50ppm or greater • Both furan and DGA scored “D”
C	One or more of the following criteria have been met • Transformer PCB level is unknown • Furan level scored “D”, and DGA is better than “D” • DGA scored “D”, and furan is better than “D”
B	Transformer PCB level is less than 50ppm, but above non detectable levels.
A	None of the previous end of life conditions exist

4.2 Substation Switchgear

Item#	Condition Criteria
1	Enclosure
2	Foundations
3	Insulation
4	Switch
5	Busbar
6	Overall condition
7	Functional Obsolescence

4.2.1 Enclosure

Condition Rating	Description
A	No corrosion or rust on enclosure. No moisture ingress into tank, all gaskets and seals in good condition. No paint peeling on tank. Sealing of tank in good condition. The covers and/doors are locked, and when opened, move easily and freely (as expected). The enclosure is complete, with no holes or dents, or broken seams.
B	No rust or corrosion on enclosure.
C	Some rust and corrosion on enclosure, requires corrective maintenance within the next several months.
D	Significant corrosion on enclosure. Defective sealing. Requires immediate corrective action.

4.2.2 Foundations

Condition Rating	**Description**
A	Foundation is in near new condition. Grounding is in good condition.
B	Normal wear on foundation and ground.
C	One of the following conditions met • Foundation or soil around foundation showing erosion, or other signs of change that could affect the foundation • Equipment is bonded to ground at less than two locations. • foundation concrete has started to spall, and have cracks; these are small cracks that do not connect the outside of the foundation to the inside • Standing water exists outside or inside the switchgear (drainage is poor) OR Ground rod(s) is exposed
D	Two or more of “C” are present, or the conditions described in “C” are more severe than described.

4.2.3 Insulator Condition

Condition Rating	Description
A	All test values are within expected values.
B	As found information is within 10% of “new” condition, but still acceptable according to manufacturers info. There is some evidence of discoloration, and minor tracking.
C	One of the following conditions met • One measurement failed, but it was possible to repair and/or clean to re-establish the insulation level as required. • Major discoloration, tracking or burn marks found inside the enclosure
D	Two or more of “C” are present, or the conditions described in “C” are more severe than described.

4.2.4 Switch

This is also known as contact resistance. Switch handle is covered in “overall condition” as it is located outside of the switchgear compartment.

Condition Rating	Description
A	Contact resistance is well within specifications with high margins
B	Contact resistance is close to specification (little or no margin)
C	Contact resistance does not meet specification (by a small amount)
D	Contact resistance does not meet specification (by a significant margin)

4.2.5 Busbar

Condition Rating	Description
A	Busbar is in near new condition. No discoloration (other than normal aging). No tracking or corona present. No deformations. Infra red study shows that there are no hot spots. No evidence of looseness.
B	Busbar shows normal wear – no major indicators of problems.
C	One of the previous parameters is at end of life, or unacceptable.
D	Two or more of the previous parameters are at end of life, or unacceptable.

4.2.6 *Overall Condition*

The items covered here are (a) items not covered in other sections previously, or (b) provide the field survey an opportunity to give an overall impression. If "C" or "D" is selected, then please make notes, and take a picture.

Condition Rating	**Description**
A	Equipment is in near new condition, according to present engineering standards. All equipment is externally clean, corrosion free. All connections and devices are in good condition. No external evidence of over heating, bulging, malfunction, deformation, discoloration or overloading. Appears to be well maintained with service records readily available. Spare parts, as required, are located at site. No reports of trouble calls or fuse blown within the last two years. Grounding connections are all present. Switch handle and mechanism is free to move, without sticking. The operating designation is clearly visible and readable from ground level.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable

4.2.7 *Functional Obsolescence*

Condition Rating	Description
D	One or more of the following criteria have been met • Ratio of (available fault level 3 phase)/(equipment rating) is greater than recommended standards (i.e. 100% for some equipment) • Ratio of (available fault level ½ cycle)/(equipment rating) is greater than recommended standards (i.e. 100% for some equipment)
C	One or more of the following criteria have been met • Ratio of (available fault level 3 phase)/(equipment rating) is greater than recommended standards (i.e. greater than 80% and less than 100% for some equipment) • Ratio of (available fault level ½ cycle)/(equipment rating) is greater than recommended standards (i.e. greater than 80% and less than 100% for some equipment) • Available system fault level is unknown, or equipment fault level is unknown
A	None of the previous end of life conditions exist

4.3 Substation Cable Risers

Item#	Condition Criteria
1	Pothead/Connectors/Terminations
2	Foundation & Grounding
3	Overall Cable Condition
4	Thermograph Scan

4.3.1 Pothead/Connectors/Terminations

Condition Rating	Description
A	Potheads & electrical exposed conductors/connectors are clean, corrosion free and are in good condition. No external evidence of overheating or similar. Potheads are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable, OR, are damaged/degraded beyond repair.

4.3.2 Foundation & Grounding

Condition Rating	**Description**
A	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable, OR, are damaged/degraded beyond repair.

4.3.3 Overall Cable Condition

Condition Rating	Description
A	Overall installation is externally clean, and free of corrosion/rust. All cable sections and connections are in good condition. No external evidence of any deterioration, overheating or abnormality. Surge arrestor is present.
B	Normal signs of wear with respect to the above characteristics and/or evidence of past repair.
C	One or two of the above characteristics are unacceptable and/or evidence of multiple repairs or failures
D	More than two of the above characteristics are unacceptable, OR, the cable is damaged/degraded beyond repair.

4.3.4 Thermograph Scan

Condition Rating	Description
A	Values well within specifications with high margins
B	Values close to specification (little or no margin)
C	Values do not meet specification (by a small amount)
D	Values do not meet specification (by a significant margin)

4.4 Substation HV Structures

Item#	Condition Criteria
1	Switch
2	Insulator
3	Pole
4	Foundation & Grounding
5	Overall condition
6	Thermograph Scan

4.4.1 Switch

This is a summary of the load break switch health index. All parameters from it are to be used here.

Condition Rating	Description
A	HI Score is not B, C or D
B	HI Score less than 90, but not "C" or "D"
C	HI Score less than 50, but not "D"
D	HI Score less than 30

4.4.2 Insulator Condition

Use this table if meggar values are present:

Condition Rating	Description
A	All test values are within expected values.
B	As found information is within 10% of "new" condition, but still acceptable according to manufacturers info. There is some evidence of discoloration, and minor tracking.
C	One of the following conditions met • One measurement failed, but it was possible to repair and/or clean to re-establish the insulation level as required. • Major discoloration, tracking or burn marks found inside the enclosure
D	Two or more of "C" are present, or the conditions described in "C" are more severe than described.

WorkingTogether SAFELY

Use this table if completing a visual inspection

Condition Rating	Description
A	Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	Insulators are broken/damaged beyond repair or are not field repairable or cementing or fasteners are not secure.

4.4.3 Pole

Wood Poles; If physical measurements are made, and the pole class, material, height and setting depth is known:

Condition Rating	**Description**
A	Pole is like new condition. No damaged wood fiber present. No indications of splitting. Pole treatment is visible and to the right level. Pole is not leaning.
B	Pole has aged normally, with some signs of splitting or some ground line rot. Circumference has decreased no more than 10%. Some notching evident, but less than ½ inch surface penetration. Pole is leaning at most 3% (deflection divided by above ground height).
C	One of the following conditions met: • Several longitudinal splits have occurred • Wood pole Ground line circumference has decreased 10% (without heart rot being present; see section 2.1.1) • Heart rot is present • Reflectometer test shows residual strength is greater than 70%
D	Significant degradation has occurred. Pole is not expected to last 3 years, or may fail imminently. Two or more of the parameters in "C" have been met. Requires immediate corrective action.

Concrete poles exist, but are very few, and as such are ignored at the present time.

Pole Age is not to be used here.

Visual inspection:

Condition Rating	Description
A	No decay, minor surface weathering
B	Good Mild surface weathering, negligible wood rot
C	Acceptable Wood surface well weathered, noticeable surface rot with area <10% beam surface
D	Heavily weathered wood surface, noticeable rot on 10%–25% of wood surfaces
E	Substandard Heavy weathering and deterioration of wood surfaces, noticeable rot on 25%–40% of wood surfaces, the cross arm needs replacement

4.4.4 Foundation & Grounding

Condition Rating	**Description**
A	Pole foundation is in near new condition. Grounding is in good condition. Concrete foundation is level and free from cracks and spalling. Ground connections are tight, and free of corrosion. Cable is bonded to ground per present engineering policies (bonded at both ends to ground).
B	Normal wear on foundation and ground.
C	One of the following conditions met • Foundation or soil around foundation showing erosion, or other signs of change that could affect the foundation • Grounding conductors are frayed or broken, but more than 60% of the strands are still in tact • Ground rod is exposed • If foundation is concrete, it has started to spall, and have cracks, but cracks to not connect the pole to the outside of the foundation • Standing water exists at the base of the pole (drainage is poor)
D	Two or more of "C" are present, or the conditions described in "C" are more severe than described.

4.4.5 *Overall Condition*

The items covered here are (a) items not covered in other sections previously, or (b) provide the field survey an opportunity to give an overall impression. If "C" or "D" is selected, then please make notes, and take a picture.

Condition Rating	Description
A	Equipment condition is in near new condition, according to present engineering standards. All equipment is externally clean, corrosion free. All primary and secondary connections and devices are in good condition. No external evidence of over heating, bulging, malfunction, discoloration or overloading. Appears to be well maintained with service records readily available. No reports of trouble calls or fuse blown within the last two years. Grounding connections are all present. Surge arrestor connection is on line side of fuse (if present).
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable

4.4.6 *Thermograph Condition*

Condition Rating	Description
A	Values well within specifications with high margins
C	Values close to specification (little or no margin)
D	Values do not meet specification (by a small amount)
N	Values do not meet specification (by a significant margin)

4.5 Substation Civil Infrastructure

Item#	Condition Criteria
1	Fence Condition
2	Access road
3	Station yard
4	Area lighting
5	Ground grid
6	Foundations
7	Drainage and Sewer
8	Spill Containment
9	Overall condition

4.5.1 Fence Condition

Item #	Condition Criteria
1	Fence grounding
2	Fence space (bottom)
3	Fence barbed wire
4	Fence gate
5	Fence signs
6	Fence Height
7	Fence overall condition

4.5.1.1 Fence Grounding

This applies to the fence fabric, not the gate.

Condition Rating	Description
A	All grounding is according to OESC 26-300 to 26-324. Metal chain link fence and seals in good condition.
B	One post not bonded according to code
C	Two posts not bonded according to code
D	more than two indicators that fence is not adequately bonded to ground

4.5.1.2 Fence Space bottom

Condition Rating	Description
A	Fence space is according to OESC. Measurement indicates that fence is always closer to ground (gravel) than required (i.e. 50mm).
B	One space does not meet requirements, but does not exceed 100mm
C	One space does not meet requirements (does not exceed 200mm), or, no more than 3 locations do not exceed 100mm
D	Numerous locations do not meet the code requirements on ground clearance

4.5.1.3 Fence Barbed wire

Condition Rating	Description
A	Fence has a minimum of three strands of barbed wire on top, per the OESC. All barbed wire strands are adequately bonded go ground.
B	One strand is not bonded to ground in at least one location
C	One barbed strand is missing or broken
D	Several deficiencies found

4.5.1.4 Fence Gate

Condition Rating	Description
A	Fence gate is bonded to ground. Gate is locked. Gate is free to swing, and does not hit the ground when opened. Center stops exist and are functional. Space under fence gate is per the OESC (less than 50mm).
B	One deficiency found
C	Two deficiencies found
D	Several deficiencies found

Note, where one or more deficiencies found, please make note on back of condition assessment form.

4.5.1.5 Fence Signs

Condition Rating	Description
A	Fence signs are posted according to the OESC. Signs are legible, and post the necessary info including voltage and telephone contact info.
B	One deficiency found
C	Two deficiencies found
D	Several deficiencies found

4.5.1.6 Fence Height

Condition Rating	Description
A	Fence height is per the OESC (1.8m), not including barbs.
B	Fence height is not satisfactory in one location
C	Fence height is not satisfactory in two locations
D	Several deficiencies found

4.5.1.7 Overall Condition

Condition Rating	Description
A	Fence is externally clean, corrosion free, and has no plants within the fence fabric. There is no evidence of warping. The bottom support wire is in good condition, keeping the fence straight. No external evidence of bulging present. Fence is sufficiently far away from other objects outside the substation (other fences, buildings, etc).
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

4.5.2 Access Road

Condition Rating	Description
A	Access road is well maintained, level, showing no signs of pot holes or washout (gravel).
B	One pothole or washout occurrence found
C	Road is passable but may cause damage to the vehicle or injury to a person
D	Roadway is in poor condition

4.5.3 Station Yard

Condition Rating	Description
A	The yard (gravel) is well maintained, with no evidence of vegetation or moss. Gravel is level.
B	One or the other condition: • A few plants growing, but no taller than 10 cm, OR, • Gravel is not level in some areas, with variance of no more than 10 cm between high and low
C	One or other condition • No more than 10% of the station yard is covered by vegetation, and the vegetation is no more than 20cm tall, OR, • Gravel is not level in some areas with variance of no more than 20 cm between high and low; ground grid is not exposed.
D	The yard is in poor condition

4.5.4 Area lighting

This may need to be assessed at night. This assumes that the station yard in question is required to have area lighting.

Condition Rating	Description
A	The area lighting is functional, no burnt out bulbs and the lighting level is within engineering requirements.
B	No more than 10% of the bulbs are burnt out.
C	No more than 20% of the bulbs are burnt out
D	The yard lighting is not functional
N	Yard lighting is not required at this location.

4.5.5 Ground Grid

Item#	Condition Criteria
1	Grounding connections
2	Structure bonding
3	Resistance measurement
4	Grounding outside of fence
5	overall condition

It should be noted, that the ground grid health index can still be calculated if the resistance measurement check is not available. If the resistance measurement is completed, and the results indicate a "D", then the calculated health index should be divided by 3.

4.5.5.1 Grounding Connections

This applies to the meshed network, and assumes that inspection points exist throughout the station yard. If they do not exist, then "N" needs to be selected.

Condition Rating	Description
A	All grounding inspection points (ground rods) are in good connection, showing no evidence of degradation.
B	No more than 10% of the ground rods show some form of degradation. Conductive connection still exists
C	No more than 20% of the ground rods show some form of degradation, OR, some ground rod connections do not have a conductive connection.
D	There are several deficiencies noted.
N	Inspection points are not available

In the case of B, C, D, please make note of the location and take pictures.

4.5.5.2 Structure bonding

Condition Rating	Description
A	All steel or similar structures in the station are adequately bonded to the station ground grid, where required.
B	All structures are bonded, but less than 10% of the structures are bonded to ground at only one location.
C	No more than 20% of the station structures are bonded to ground at one point only.
D	There are several deficiencies noted.

In the case of B, C, D, please make note of the location and take pictures.

4.5.5.3 Resistance Measurement

Condition Rating	Description
A	The station ground grid resistance value is below the engineered required value.
B	Measured value is within 10% of the engineered value, but below the required engineered value
C	Measured value is within 10% of the engineered value, but above the required value.
D	The measurements show that the present grid is insufficient, given the available fault current.

In the case of B, C, D, please make note of the location and take pictures.

4.5.5.4 Grounding Outside of Station Fence

Condition Rating	Description
A	There is a continuous ground wire around the outside of the station fence, at the required distance (see OESC, 1.0 m). The gravel is level and covers the wire at all locations to the minimum required distance. There is no vegetation growing in the gravel. There is no 3rd party infrastructure that has not been previously approved by Engineering.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

4.5.5.5 Overall Condition

Condition Rating	Description
A	The grounding grid is in good condition, no evidence of corrosion, and all components present (no copper theft). All connectors are of crimp type. No evidence of overheating, bulging, or damage.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

4.5.6 Foundations

This applies to all foundations in the station yard that are not specifically included elsewhere in the asset condition assessment process.

Condition Rating	Description
A	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are direct to tank, cabinets, supports without any intervening paint or corrosion.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Foundation, supports or grounding are damaged/degraded beyond repair.

4.5.7 Civil – Drainage and Sewer

Condition Rating	Description
A	Drains and sewers appear in good condition. All systems are free from any obstructions. No indications of wear or corrosion.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable and cannot be brought into acceptable condition.

4.5.8 Civil – Spill Containment

Oil containment systems capture spills from various pieces of distribution equipment. Generally, these systems consist of concrete vaults large enough to contain any potential spills from a particular piece of equipment. Also, such systems must be decoupled from normal drainage systems.

Condition Rating	Description
A	Containment system, connecting pipes, etc. appears in good condition and free from cracks, leaks, surface staining and deterioration. All systems are free from any obstructions
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable and cannot be brought into acceptable condition.

4.5.9 Overall Condition

This covers all aspects not expressly covered elsewhere in the condition assessment process.

Condition Rating	Description
A	Station civil infrastructure is in good condition, showing no wear or aging. There is no standing water in the station yard.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
N	No other aspects to evaluate

Hans Ziemann
HZ:dj
Attachment(s)/Enclosure

APPENDIX C

Completed Survey Forms

The following Items are contained in the Appendix

- 2.1 line section inspection form.xls
- 2.2 load break_switches_inspection_form.xls
- 2.3 In Line Switches_inspection_form.xls
- 2.4 Pole transformer_inspection_form.xls
- 2.5 Fault_indicators_inspection_form.xls
- 2.6 Voltage Conversion transformer_inspection_form.xls
- 3.1 Buried cable_inspection_form.xls
- 3.2 Pad mounted swiching units_inspection_form.xls
- 3.3 Pad transformers_inspection_form.xls
- 4.1 substation transformers_inspection_form.xls
- 4.2 substation switchgear_inspection_form.xls
- 4.3 substation cable risers_inspection_form.xls
- 4.4 substation HV structure_inspection_form.xls
- 4.5 substation Civil Infrastructure_inspection_form.xls

APPENDIX D

Health Index Calculations

The following Items are contained in the Appendix

oville line section calc
new2.2 Load break switches_hi lcal_July 02.xls
new2.3 In line switches _hi calc_July 02.xls
new2.4 Pole tx_hi calc_June27.xls
new2.5 Fault indicators_hi calc_June29.xls
new2.7 Voltage conversion transformers_June29.xls
new3.1 Buried cable_hi calc_June29.xls
new3.2 Pad Mounted Switches_hi calc_June29.xls
new3.3 Pad Mounted transformers_hi calc_June29.xls
new4.1 Substation Transformers (44-4kV)_hi calc_June29.xls
new4.2 Substation Switchgear_hi calc_June29.xls
new4.3 Substation cable Risers (4kV)_hi calc_June27.xls
new4.4 Substation HV Structures_hi calc_June29.xls
new4.5 Substation Civil Infrastructure_hi calc_June29.xls

APPENDIX E

Blank Survey Forms

The following Items are contained in the Appendix

- 2.2 Pole transformer_inspection_form.xls
- 2.3 Dis_load break_switches_inspection_form.xls
- 2.4 Fault_indicators_inspection_form.xls
- 2.5 DX Line Switches_inspection_form.xls
- 2.6 Fused cutouts_inspection_form.xls
- 3.1 Underground cable_inspection_form.xls
- 3.2 Pad transformers_inspection_form.xls
- 3.3 Pad mounted swiching units_inspection_form.xls
- 4.1_MS transformers_inspection_form.xls
- 5.1 A-Municipal Station Civil Infrastructure_inspection_form.xls
- 5.1 B-Municipal Station Civil Infrastructure_inspection_form.xls
- 5.1_MS Civil Infrastructure_inspection_form.xls
- X.1_pole line section_inspection_form.xls
- X.2 substn switchgear_inspection_form.xls
- X.3 substation cable_inspection_form.xls
- X.4 substn hv struct_inspection_form.xls

APPENDIX F

Orangeville Hydro Reference Data

The following Items are contained in the Appendix

- F1_operating diagrams_scanned_apr17
- F2_rate application_2008
- F3_list of equipment Apr08
- F4_DATA FROM ORANGEVILLE - May 19, 2008
- F7_population info
- F5_OH Load Optimization 1997.pdf
- F6_Conditions of Service - Version 6_0 2008.pdf

APPENDIX G

Site Visit Notes

The following Items are contained in the Appendix

- MS Word Document summarizing notes and observations
- Pictures from site visit May 14, 2009 – set 1
- Pictures from site visit May 14, 2009 – set 2
- Pictures from site visit June 02, 2009
- Pictures from site visit June 25, 2009

Project Report

Aug 2009

Orangeville Hydro Limited
Asset Condition Assessment

Appendix G - Site Visit Report

Table of Contents

1. Introduction ... 3

1.1 Scope ... 3
1.2 Technical Sagging Criteria ... 3

2. Town of Orangeville ... 4

2.1 Overhead - Line Sections ... 4
2.1.1 Section 01 – Highway 9 near Dufferin Rd #3 ... 4
2.1.2 Section 02 – Road Allowance between Concession B and C ... 4
2.1.3 Section 03 – Riddell, Richardson Rd south ... 5
2.1.4 Section 04 – Riddell, Richardson Rd north ... 5
2.1.5 Section 05 – C-Line Road (west side), south of Centennial ... 6
2.1.6 Section 06 – C-Line Rd (east side), south of Centennial ... 6
2.1.7 Section 07 – C-Line (west side), north of Centennial to hwy 9 ... 7
2.1.8 Section 08 – C-Line (east side), north of Centennial ... 7
2.1.9 Section 09 – Highway 9 near Diane Drive (going east) ... 8
2.1.10 Section 10A – Highway 9 near Diane Drive (going north) ... 8
2.2 Underground - Transpad Installation #528 ... 9
2.3 Underground - Pad mount Switchgear ... 10
2.3.1 Kabar Pad mount Switchgear #1314 ... 10
2.3.2 Pad mount Switchgear PME #1303 ... 10
2.4 Underground - Pad mount Transformers ... 11

2.4.1 Pad Transformer #424 11
2.4.2 Pad Transformer #440 11
2.5 Substation MS#5 12
2.5.1 Station Transformer 12
2.5.2 Station Yard 12
2.5.3 Station Fence 13
2.5.4 Station HV Structure 14
2.5.5 Station Switchgear 15
2.6 Overhead – Load break switch 15
2.6.1 Switch A 15
2.6.2 Switch B 16

3. Town of Grand Valley 17

3.1 Overhead - Line Sections 17
3.1.1 Section 30A – Water St 17
3.1.2 Section 30B – Emma St 17
3.1.3 Section 31A – Mill St east 18
3.1.4 Section 31B – Mill St west 18
3.1.5 Section 32A – Emma St south 19
3.1.6 Section 32B – Emma St north 19
3.1.7 Section 33 – Main St north 20
3.1.8 Section 34 – CrozierSt, ScottSst to Gier St 21
3.1.9 Section 35 – Gier St 21
3.1.10 Section 36 –BbielbySst, Scott St to Gier St 22
3.1.11 Section 37 – Amaranth St east - Bielby St to Pansford St 22
3.1.12 Section 38 – Mill St east – Pansford St to Main St 23
3.1.13 Section 39 – Main St south to River St 24
3.1.14 Section 40 –Rriver St - Main St south to Cooper St 24
3.1.15 Section 41 – Cooper St 25
3.1.16 Section 34A – Crozier St – Amaranth St east to Gier St 25
3.2 Underground – Riser Cables 26
3.3 Underground - Transpad Installations 26
3.4 Underground - Pad mount Switchgear 26
3.5 Underground - Pad mount Transformers 27
3.5.1 Pad mount Transformers #521 27
3.5.2 Pad mount Transformers #526 27
3.6 Overhead – Load Break Switch 28

1. Introduction

1.1 Scope

A field assessment of line sections was completed Jun 25th, 2009, by visiting different areas of the Town of Orangeville and the Town of Grand Valley. The summary level observations are included in this document.

This document has the following sections:

1. Introduction (this section)
2. Town of Orangeville
3. Town of Grand Valley

1.2 Technical Sagging Criteria

Discussions with the field crew indicate that most line sections are installed based on the following criteria – this information is presented from memory by Orangeville Hydro field crews, and therefore may be incomplete:

- 50 to 55m spans
- 556 AAC conductor
- typical sag info on 50m, 2 ft, 20 deg C

2. Town of Orangeville

2.1 Overhead - Line Sections

2.1.1 Section 01 – Highway 9 near Dufferin Rd #3

This line section is joint use. Hydro One owns the poles and top two circuits (44kV), whereas Orangeville Hydro owns the lower circuit (27kV).

Apparently, Hydro One is planning on adding another circuit in the middle position.

2.1.2 Section 02 – Road Allowance between Concession B and C

Description: from highway 9 to townline road (road allowance between Orangeville & Caledon

This line section was built in sections at different times. On the left is the line section owned and operated by Orangeville, whereas on the right is a line section owned and operated by Hydro One. This single phase circuit is the same circuit shared at SWITCH A and SWITCH B.

2.1.3 Section 03 – Riddell, Richardson Rd south

Description: Riddell road from Richardson rd south to townline road

2.1.4 Section 04 – Riddell, Richardson Rd north

This line section is of similar construction as the section on Riddell south.

2.1.5 Section 05 – C-Line Road (west side), south of Centennial

Description: town line road (south end) past Operations Center, north past Robb, to Centennial

This pole, located just north of the operations center, and just south of Robb Rd, is viewed from the north looking south.

Good condition. Some communication guys slack.

This line section is split into 05A and 05B because of different circuit counts; 05A is 27kV only, and 05B has both 27kV and 46kV.

2.1.6 Section 06 – C-Line Rd (east side), south of Centennial

Description: from town line road to centennial

This is the intersection of C-Line Road and Centennial, as viewed from the south, looking north. This section is on the right. The previous section is on the left.

The poles are hydro one owned, as is the 44kV. 4kV is Orangeville Hydro Owned.

2.1.7 Section 07 – C-Line (west side), north of Centennial to hwy 9

Picture 2.1.7A

Picture 2.1.7B

This line built mid 1990's. The transformer pole at 125 C-line (west side of road) is on a pole with date stamp 1986. It has 44 kV and 27kV present.

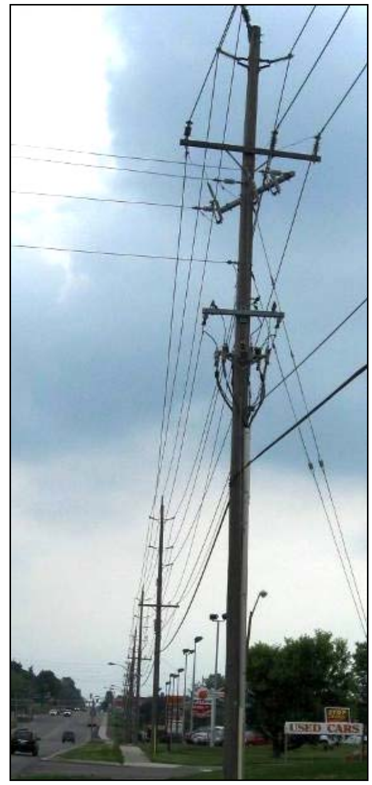
The line is in good condition.

2.1.8 Section 08 – C-Line (east side), north of Centennial

Cross arm based 4kV. This line section is on a Hydro One pole. Cable riser present at end for residential underground feed. Fuses are 2 spans south of the northern terminal pole.

This line section is split into two sections, 08A and 08B, as there are different number of circuits in each; three for the first, and two for the second (44kv and 4kV).

2.1.9 Section 09 – Highway 9 near Diane Drive (going east)



Description: From Tap pole, going east to Blind Line Road

This pole has three line sections connected to it. This view of the pole is from the west, looking east. Section 10 starts here and goes north (to the left).

The line section identified here, starts at this pole, and goes east (into the picture, into the distance). Diane Drive is evident just past the pole.

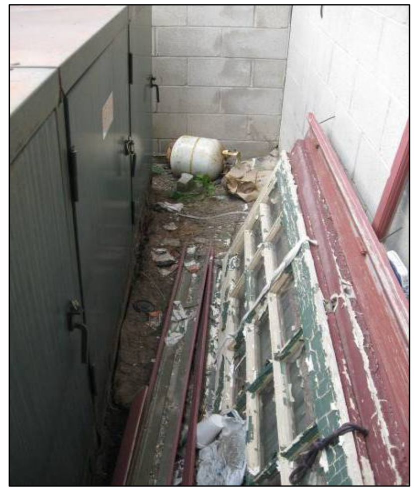
The line is in good condition. Pole top is armless construction, whereas some cross arm exists for 4kV.

2.1.10 Section 10A – Highway 9 near Diane Drive (going north)

Description: From Tap pole, going north across a field

Pole line crosses highway 9 and then an open field. Poles appear to be in good condition. Framing is armless construction, with no provision for additional equipment on the pole. The cable riser at end feeds a residential neighbourhood.

2.2 Underground - Transpad Installation #528



This is a typical trans-pad unit. There is evidence of significant rusting, which could be resolved with some painting. Address #23 Robb Blvd.

More importantly, the client is using the space for storage or garbage collection. The picture on the right clearly shows that access at the back is blocked. The apparent propane tank poses an additional hazard, that if there is an electrical fire, the propane tank may fragment explosively. It is un-clear what is stored in the large barrel. If necessary, Orangeville Hydro may want to consider a fence.

(continued next page)

2.3 Underground - Pad mount Switchgear

2.3.1 Kabar Pad mount Switchgear #1314

There are numerous rust spots at the hinges of the units. This should be investigated further. If the hinges have not already been affected then suitable treatment with paint and oil will prolong their life. If the hinges have already been affected, then replacement of the unit may be required.

The grass clipping on the concrete pad can be easily swept away. Located corner of C-Line and Diane Drive.

2.3.2 Pad mount Switchgear PME #1303

This pad mounted switchgear unit is in good to very good condition, except for the foundation. On the left hand side of the picture, it is evident that there has been some form of excavation, or a sink hole. There may be animals living in the space under the PME, or in the immediate area surrounding the PME unit. This poses a minor safety hazard for the public, in that if they are walking very close to the foundation, they could trip or fall. Located near #12 Brenda Drive. Generally good condition.

2.4 Underground - Pad mount Transformers

2.4.1 Pad Transformer #424

Pad transformer shows some rusting on top and occasional spots on the side. Unit foundation and ground surrounding foundation in good condition.

2.4.2 Pad Transformer #440

This pad transformer is showing significant rust, including blistering and holes into the enclosed space. Such an opening defeats the purpose of having an enclosure. (Located near 58 Cambridge st).

2.5 Substation MS#5

2.5.1 Station Transformer

The picture shows the transformer, and the Low Voltage Switchgear. The transformer is type conservator, with fans. There were no obvious large patches of rust, and the breather has blue crystal in it – an indication that it has been recently maintained and capable of extracting water from air entering the transformer. The foundation appears in good condition. There is some discolouration in the front left corner of the pad, possibly rust – indicating some galvanic action taking place. The nameplate shows the transformer was built in 1965, and is in good condition, very readable.

2.5.2 Station Yard

As evident in the pictures, the station yard has areas of overgrowth starting to be prominent and other areas with no overgrowth. With suitable ground treatment, vegetation can be easily and quickly removed.

Overall the yard is level, with no unevenness. Given that this is the summer, it is unlikely to observe water pooling due to snow melt or ground thaw.

The barrier outside the station fence was built by a developer for a development project in the past, in the area. It was decided that the presence of the substation was visually not acceptable.

2.5.3 Station Fence

General signage is present.

The station fence appears in good condition. There were no visible gaps under the fence. Bonding and grounding present both for the barbed wires and fence fabric (see picture). Gates and doors bonded with jumper grounds.

Fence does not appear to be damaged, or deformed.

2.5.4 Station HV Structure

As seen in the picture, the station structure is metal lattice based, different from station MS#2 (concrete pole). Evident is the load break switch on top, the surge arrestors, the fuses on the back side, and the busbar from the fuses to the transformer. There is no rust evident on the structure.

The foundation appears to be in good condition, with no significant cracking of the concrete, or rust marks. The ground around the foundation appears level, with no signs of heaving, or sink holes. Electrical grounding (bonding) is evident on the footing.

2.5.5 *Station Switchgear*

Generally the switchgear and foundation are in good to fair condition. The picture above shows the back side of the switchgear, with one compartment showing significant rust. Not inspected was the top or inside of the switchgear. Further investigation should be completed to determine why only one compartment of 4 appears to be affected by rust.

2.6 Overhead – Load break switch

2.6.1 *Switch A*

This switch is Hydro One owned. The single phase wire is owned by Hydro One to feed load on the east side of the road – at some point after this pole, it is believed that Orangeville Hydro owns the poles, but that Hydro One owns their single phase wire, They are using the existing neutral as a return path (they do not have their own neutral).

2.6.2 Switch B

Also present on the pole is a 1 phase circuit to feed some Hydro One load in the area – at this point after this pole, it is believed that Orangeville Hydro owns the poles, but that Hydro One owns their single phase wire, They are using the existing neutral as a return path (they do not have their own neutral).

The metering unit is evident on the pole.

3. Town of Grand Valley

3.1 Overhead - Line Sections

3.1.1 Section 30A – Water St

Description: main route along Water St from south entry point to Emma St.;

Line section to be re-built in near future because of road reconstruction. Related to this project is a sewage treatment plant in the area.

This area is close to the river, and generally sitting lower than the residential areas on either side of the river. It is subject to flooding every year, which affects the poles and foundations.

Visual inspection of several poles at ground line does not show noticeable degradation in the wood. More standardized testing is recommended, if this pole line is not to be replaced in the future.

3.1.2 Section 30B – Emma St

Description: from Water St to end
Line section is in good condition.
No pictures.

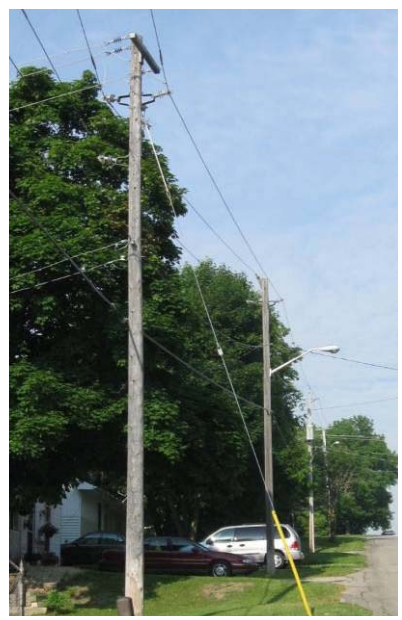
3.1.3 Section 31A – Mill St east

Line section runs from DS Grand Valley along Mill St West, from approximately Emma St to Water St.

Picture is view from DS Grand Valley, looking east.

Line section appears to be in good condition.

3.1.4 Section 31B – Mill St west



Line section runs from DS Grand Valley going west. Picture is of pole with circuit exit from DS Grand Valley, looking west.

Line section is in good condition. Some tree trimming may be required.

Span count: 3, not including pole in picture.

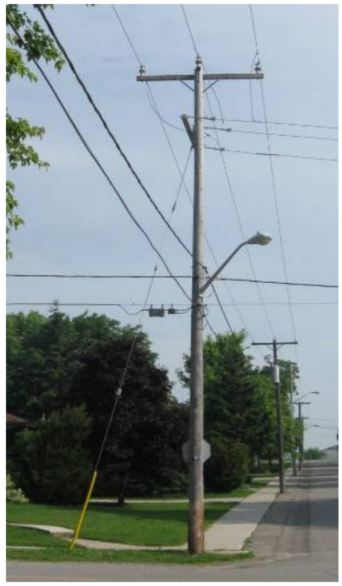
3.1.5 Section 32A – Emma St south

Description: from Mill st to Amaranth St W, including corner

Line section north and south of Amaranth Street is similar in construction – poles in the road way. This line section is south of Amaranth Street.

One particular tangent, picked at random, showed broken conduit for customer services, and a ground wire not attached to the pole. The ground wire extended out from the pole at least 2 ft.

Poles are generally in good condition. Cross arm based framing on tangents visible in picture.



Picture 3.1.5A - corner

Picture 3.1.5B - tangent

3.1.6 Section 32B – Emma St north

Picture 3.1.6A

Picture 3.1.6B

Picture 3.1.6C

Description: from Amaranth St W to north end

Span Count: 9, not including pole at Emma and Amaranth

This Line section is north of Amaranth Street. Poles are generally in good condition. Some ground wires on pole not well attached. Two different spans show a potential need for tree trimming.

Framing is mostly cross arm with some armless construction.

Picture 3.1.6A also shows the ground rod installation. One disadvantage with the pole line section being in the road way is that ground rods are more difficult to place and keep sufficiently deep buried in the ground. Most likely there is crushed gravel under the road surface, which is a poor conductor of electricity. A review of the grounding is recommended in general, this particular installation may require adjustment, as it may pose a trip hazard.

3.1.7 Section 33 – Main St north

Description: from line tap to northern end

This line section picture (3.1.7A) is looking north. It is evident that some tree trimming may be required.

The 3.1.7B picture shows the pole at ground line. The ground wire is not properly attached to the pole.

The poles on the line are showing their age, and are in fair condition. Markings could not be found on many poles, hence pole age and class is not known. One pole was class 3, 35 ft 1984.

Picture 3.1.7A

Picture 3.1.7B

3.1.8 Section 34 – CrozierSt, ScottSst to Gier St

Picture 3.1.8A **Picture 3.1.8B**

Span count: 3 spans; 4 poles

This pole at the intersection of Crozier Street and Gier Street has two guys opposite the tap position (Picture 3.1.8B). The lower guy is completely slack and not functional. Also the guy on the north side (closest to camera) appears to be slack and not functional. The anchor is not in line with the guy wire (Picture 3.1.8A). In Picture 3.1.8B, in the distance, Crozier Street from Gier Street to Amaranth Street, appears to require tree trimming.

3.1.9 Section 35 – Gier St

Description: Crozier St to Bielby St

Span Count: 9

This single phase feed, with secondary service supply is in good condition. It is set back from the road.

The upper left corner of the picture seems to indicate that tree branches are in the primary. In the event of icing, these ice weighted branches would rest on the phase conductor, adding weight to poles and wire. This may lead to a premature failure of the wire.

3.1.10 Section 36 –BbielbySst, Scott St to Gier St

Span Count: 3 spans; note, there is at least one stub pole in the line to support secondary and communications only (primary conductor goes over top of stub pole.

This is the terminal pole at the north end of the line section, as viewed from the north. The construction nail seems to indicate it was installed in 1956. Behind the camera is a stub pole, with span guys, across a road.

The pole, as pictured, looking south, is leaning to the right. The guy on the left, fro the communications, is somewhat slack and the anchor has been partially pulled out of the ground.

What standards, agreements or technical requirements are attached for 3rd parties that wish to attach their infrastructure to Orangeville Hydro (i.e. Joint use?)

3.1.11 Section 37 – Amaranth St east - Bielby St to Pansford St

Picture 3.1.11A

Picture 3.1.11B

This section of line along Amaranth is Hydro One owned poles, but Orangeville Hydro poles. The framing is cross arm based, and there appears to be adequate spacing on the pole for the addition of transformers or riser cables in the future in equipment space. Tree trimming looks adequate. It should be noted that the poles are in the road allowance on the road side of the sidewalk. Should road reconstruction be planned in the near future, consideration should be given as to the location of the pole line.

Picture 3.1.11B shows a 120/240V drop to building that appears to be the home of two organizations: (a) the Grand Valley Church of Christ, and (b) the happy valley learning center. The service down the pole is in black pipe, and did not have the typical markings of electrical conduit, but appears to be schedule 40 pipe. There is no mechanical guard on the lower portion just above the road surface.

This line section was rebuilt in 1985, after the tornado that went along Amaranth St.

3.1.12 Section 38 – Mill St east – Pansford St to Main St

This line section has a 44 kV 3 phase Hydro One circuit on top, and an Orangeville 12 kV 3 phase circuit below.

The poles appear to be leaning somewhat. The tree clearing appears adequate in that there are no branches in the immediate vicinity of the wires. The poles are framed with cross arms (older construction), and there appears to be sufficient space to add future equipment below the 12 kV and above the neutral.

3.1.13 Section 39 – Main St south to River St

This 12 kV 3 phase feeder, using vertical dead-end and angle construction, as well as tangent cross arm based appears in fair condition. Equipment space is only available on some poles, and other poles are leaning.

3.1.14 Section 40 –Rriver St - Main St south to Cooper St

Picture 3.1.14A

Picture 3.1.14B

Picture 3.1.14A is the terminal pole of this line section at Cooper Street. The down guy closest to the camera is slack and does not appear functional. The secondary wire leaving the pole, going to the left does not have a down or span guy to the right – this may explain why the pole is leaning strongly to the left. Picture 3.1.14B shows that some tree trimming may be required in this line section.

3.1.15 Section 41 – Cooper St

Description: 1 span just south of River St and Cooper St

This section appears to be pulling the dead-end pole at Cooper St and river st towards the south (cooper st). This line section appears to need tree trimming. Also the ground clearance of the first span should be checked.

3.1.16 Section 34A – Crozier St – Amaranth St east to Gier St

From the picture, it is evident that the poles are in the road way. Should road reconstruction be considered in the near future, it may be beneficial to change the location of the poles so that they are not damaged through motor vehicle accidents, or snow plows.

3.2 Underground – Riser Cables

Riser Pole from section 3.1.7

Riser Pole from section 3.1.10

3.3 Underground - Transpad Installations

NONE SURVEYED

3.4 Underground - Pad mount Switchgear

NONE SURVEYED

(continued next page)

3.5 Underground - Pad mount Transformers

3.5.1 Pad mount Transformers #521

This pad mounted transformer is showing a minor oil leak on the side, near the front (dark area on concrete pad).

3.5.2 Pad mount Transformers #526

In general, the transformer appears in good condition. There is evidence of standing water on the top of the unit, with large surface rust. Some of the edges are also showing rust. A suitable surface treatment to treat the rust and to re-paint the unit will extend life.

3.6 Overhead – Load Break Switch

NONE SURVEYED

Hans Ziemann
HZ:dj
Attachment(s)/Enclosure

1235 North Service Road West
Oakville, Ontario, Canada L6M 2W2
Tel 905 469 3400 ◆ Fax 905 469 3404

ORANGEVILLE HYDRO

Appendix B -

2014 Rate Application

Board Budget

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Orangeville Hydro Limited
2014 OPERATING BUDGET
FOR RATE APPLICATION

	2012 ACTUAL	2013 BUDGET	2014 BUDGET
DISTRIBUTION			
Transformer Station	$52,865	$63,934	$74,345
Misc Distribution Expenses (Engineering)	$199,406	$224,011	$218,470
Overhead Distribution	$113,035	$135,284	$160,934
Overhead Distribution - Tree Trimming	$79,007	$90,239	$99,132
Underground Distribution	$13,678	$18,693	$26,499
Customer Premises/Locates	$78,243	$85,796	$78,300
Transformer Distribution	$40,770	$45,910	$57,762
O/H & U/G Services	$93,810	$117,867	$131,276
Supervision/Maintenance & Engineering	$145,820	$176,962	$159,957
Meter Distribution	$107,292	$91,171	$117,572
TOTAL DISTRIBUTION	**$923,926**	**$1,049,866**	**$1,124,248**
BILLING & COLLECTING			
Supervision	$38,080	$30,496	$40,992
Meter Reading	$216,569	$151,437	$145,940
Billing	$303,485	$309,497	$342,350
Collecting	$181,514	$220,350	$212,437
TOTAL BILLING & COLLECTING	**$739,649**	**$711,780**	**$741,719**
ADMINISTRATION			
Community Relations/Conservation	$33,316	$26,254	$22,164
Directors Salaries & Expenses	$412,672	$430,826	$461,866
General Officers Salaries & Expenses	$145,448	$152,764	$155,672
General Administration Expenses & Salaries	$296,356	$307,816	$353,525
Miscellaneous General Expenses	$470,366	$456,993	$547,730
Maintenance of General Plant	$82,575	$88,688	$93,145
Capital Taxes	$0	$1,180	$1,180
TOTAL ADMINISTRATION	**$1,440,732**	**$1,464,521**	**$1,635,282**
TOTAL CONTROLLABLE EXPENSES	**$3,104,307**	**$3,226,167**	**$3,501,249**

Orangeville Hydro Limited
2014 CAPITAL BUDGET
FOR RATE APPLICATION

DESCRIPTION	2012 ACTUAL	2013 BUDGET	2014 BUDGET
DISTRIBUTION PLANT			
Land	125,868	22,400	0
Building - MS 1	0	0	0
Sub-Stations		71,135	119,607
Meter Points	0	0	0
Overhead Poles, Towers	90,427	153,667	49,922
Overhead Conductors,Devices	68,027	72,572	107,077
Underground Conduit	190,738	458,858	308,124
Underground Conductors, Devices	251,997	394,035	226,163
Distribution Transformers	396,530	347,260	385,854
Services	135,722	182,783	132,685
Meter Distribution	187,308	27,159	45,764
Total Gross Distribution Plant	**1,446,618**	**1,729,869**	**1,375,197**
Contributions & Grants-Credit	(297,008)	(557,560)	(298,474)
Total Net Distribution Plant	**1,149,609**	**1,172,309**	**1,076,722**
GENERAL PLANT			
Land	0.00	0	0
Building 400 C Line	23,668	7,000	29,500
Office Equipment	23,138	23,000	17,200
Computer Equipment	22,016	37,000	77,200
Computer Software	160,843	30,500	42,000
Rolling Stock	36,069	275,000	35,000
Work & Service Equipment	0	0	0
Stores Equipment	1,606	2,500	2,000
Tools	1,133	6,800	5,000
Measurement & Testing	499	6,000	5,000
Communication	0		0
Misc Equipment	112,979	2,000	5,600
Load Management Controls Customer Premises	0	0	0
System Supervisory Equipment	0	0	0
Total General Plant	**381,952**	**389,800**	**218,500**
TOTAL FIXED ASSETS	**1,531,561**	**1,562,109**	**1,295,222**

Orangeville Hydro Limited
Capital Budget Details 2014
General Plant Capital

Category	Project	Reason	G.L. accounts	Project Cost
Building		Bathroom Renovations	19051	7,000.00
		Parking lot expansion	19051	20,000.00
		Video Security for Front Lobby	19051	2,500.00
			Grand Total:	**29,500.00**
Office Equipment		Photo Copier	19150	10,000.00
		30 Comfortable Chairs for Meeting room	19150	6,800.00
		96" Overhead projection screen for meeting room	19150	400.00
			Grand Total:	**17,200.00**
Computer Equipment		PC Replacement Program (8)	19200	8,000.00
		Billing Printer/Plotter	19200	12,000.00
		Other Printer(s) Scanning Devices	19200	3,000.00
		Replacement Server	19200	10,000.00
		Tablets (Field/Operations)	19200	6,000.00
		Network Infrastructure	19200	5,000.00
		Future Proofing Capabilities (obtaining info i.e. ami data offsite)	19200	2,000.00
		Backup hardware upgrade	19200	3,000.00
		Computing Accessories	19200	5,000.00
		Trimble Nomad Handheld Computer	19200	6,000.00
		2 46" display monitors for engineering office and operation managers office (GIS)	19200	10,000.00
		Digital Auxbox-Call Audio Recorder	19200	7,200.00
			Grand Total:	**77,200.00**
Computer Software		MS Office Upgrade	19250	4,000.00
		Adobe Upgrades	19250	2,000.00
		O/S System software	19250	4,000.00
		Backup software upgrade	19250	2,000.00
		GP2013 (version 12)	19250	30,000.00
			Grand Total:	**42,000.00**
Vehicles		Replace Truck 29-President vehicle	19320	35,000.00
			Grand Total:	**35,000.00**
Stores Equipment		Misc.	19350	2,000.00
			Grand Total:	**2,000.00**
Tools, Shop & Garage Equipment		Misc.	19400	5,000.00
			Grand Total:	**5,000.00**
Measurement & Testing		Misc.	19450	5,000.00
			Grand Total:	**5,000.00**
Communication Equipment		Misc.	19550	
			Grand Total:	-
Miscellaneous Equipment		Fridges Qty 2	19600	1,600.00
		Artwork Boardroom	19600	2,000.00
		Misc.	19600	2,000.00
			Grand Total:	**5,600.00**
			Total Projects	**218,500.00**

2014 Operations Budget

21-Jun-13

Category	Status	Project	Need	Scope	G.L. Account	Estimated Line Hours	Eng Hours	Truck Hours	Project Cost
Renewal	**Not Started** Start Date: Expected 2014 Completion Date: Expected 2014	First St- Fifth Ave 27kV Conversion Phase 2	The poles are reaching end of life and are in need to be updated to meet current clearance standards and provide capability for future growth. The job can be completed now that the Orangeville Mall 44kV substation has been converted to 27.6kV removing the need for 44kV feeder in this area.	A subcontractor will install new duct along First Street. OHL will install a new switching cubicle and 2- 3 phase padmount transformers. New underground primary cable will be installed as needed.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	8.00	-	64,955.70
					18450	256.00	8.00	192.00	68,964.39
					18505	-	-	-	-
					18510	64.00	4.00	48.00	31,130.50
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**165,050.59**
					19950	-------	-------	-------	-
					Grand Total:	**320.0**	**20.0**	**240.0**	**165,050.59**
Renewal	**Not Started** Start Date: Expected 2014 Completion Date: Expected 2014	Parkview Heights-Transformer Replacement Phase 2	During asset inspections in 2011 OHL has identified that transformer assets are coming to end of life in this area. OHL has identified the transformers that have deteriorated the most to be replaced in 2013 & 2014.	A subcontractor will supply excavation for the new transformers. OHL will install 8 new pad mount transformers c/w new concrete vaults, grounding, elbows and labeling.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	192.00	8.00	192.00	63,925.50
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**63,925.50**
					19950	-------	-------	-------	-
					Grand Total:	**192.0**	**8.0**	**192.0**	**63,925.50**
Renewal	**Not Started** Start Date: Expected 2014 Completion Date: Expected 2014	Veteran's Way Poleline New 27.6kV Feeder	OHL requires a third 27.6kV feeder due to the existing and forcasted loading. HONI has confirmed the need for an additional feeder. HONI will construct a shared feeder to OHL's boundary. This will allow HONI to pick up HONI's LTLT customers on County Road 109 and connect future loads within HONI's service area. This third 27.6kV will benefit the current and future customers of both OHL and HONI.	Hydro One to rebuild 7 poles under a make ready project. OHL to install approx. 400m of 3 phase 556ASC conductor, a new load break switch and a pole mounted wholesale revenue metering unit. A sub-contractor MSP will complete the wholesale metering comissioning with the IESO.	18300	-	-	-	-
					18350	216.00	16.00	216.00	73,417.88
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	-	-	-	-
					18200	48.00	8.00	32.00	89,010.70
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**162,428.58**
					19950	-------	-------	-------	-
					Grand Total:	**264.0**	**24.0**	**248.0**	**162,428.58**
Renewal	**Not Started** Start Date: Expected 2014 Completion Date: Expected 2014	Cooper-George-Parkview-Main St South Pole Line Replacement Phase 2	OHL's annual inspections and staff reports have identified aged assets as well as inadequate clearances and undersized conductors.	A subcontractor will supply excavation for the new wood poles. OHL will supply and install 10 new wood poles c/w hardware, new secondary bus as needed. OHL will transfer all existing transformers and existing overhead and underground services to the new poles.	18300	96.00	8.00	96.00	24,159.19
					18350	192.00	8.00	144.00	19,659.56
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**43,818.76**
					19950	-------	-------	-------	-
					Grand Total:	**288.0**	**16.0**	**240.0**	**43,818.76**

Substation	***Not Started*** Start Date: Expected 2014	Municipal Substation - Major Service	OHL's annual inspections and gas analysis reports have determined that the substations require a scheduled major service. This is a continuation from 2013.	A subcontractor will clean, paint and inspect two substations as needed. They will also complete site works including signage, gate and fence renewal.	18200	32.00	2.00	16.00	30,595.89
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
	Completion Date: Expected 2014				**Gross Project Cost:**	-------	-------	-------	**30,595.89**
					19950	-------	-------	-------	-
					Grand Total:	**32.0**	**2.0**	**16.0**	**30,595.89**
Renewal	***Not Started*** Start Date: Expected 2014	10 Third Street 27.6kV Conversion	The apartment complex at 10 Third Street is fed from a three phase 4.16k/120/208V transclosure unit that was installed in the 1960's. The transclosure is a non-standard installation that is beyond its useful life. OHL will convert the service to 27.6kV and install a pad mounted transformer.		18300	64.00	4.00	64.00	11,762.79
					18350	-	-	-	-
					18400	-	4.00	-	14,632.85
					18450	32.00	4.00	32.00	10,955.33
					18505	-	-	-	-
					18510	32.00	-	-	15,032.24
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
	Completion Date: Expected 2014				**Gross Project Cost:**	-------	-------	-------	**52,383.21**
					19950	-------	-------	-------	-
					Grand Total:	**128.0**	**12.0**	**96.0**	**52,383.21**
Renewal	***Not Started*** Start Date: Expected 2014	Bythia-Victoria-Princess 27.6kV Conversion Phase 2	OHL has determined that the assets in this area are at end of life and the back yard primary pole line is difficult to access for restoration and maintenance activities as well as unsafe for climbing. OHL will convert this area to the 27.6kV system via an underground primary loop feed. Continuation from 2013.	Phase 1 in 2013 a subcontractor installed duct along the streets. The subcontractor as part of phase 2 will complete the remaining duct work. As part of phase 2 OHL will install new underground cable, 15 pad mount transformers c/w new grounding and concrete vaults. New underground services to 16 services on Victoria Street and a subcontractor will supply new underground meterbases on the 16 houses.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	8.00	-	152,465.70
					18450	180.00	8.00	180.00	66,393.90
					18505	-	-	-	-
					18510	360.00	-	360.00	123,027.45
					18550	72.00	8.00	72.00	36,134.85
					18615	-	-	-	-
					18620	-	-	-	-
	Completion Date: Expected 2014				**Gross Project Cost:**	-------	-------	-------	**378,021.90**
					19950	-------	-------	-------	-
					Grand Total:	**612.0**	**24.0**	**612.0**	**378,021.90**
Renewal	***Not Started*** Start Date: Expected 2014	Padmounted Transformer-Switchgear Painting	OHL asset inspections have found pad mounted transformers with excessive paint deterioration and	A subcontractor will paint approximately 45 padmounted transformers and 5 switching cubicles with an automotive grade paint solution.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	4.00	-	2,352.85
					18505	-	-	-	-
					18510	-	4.00	-	19,312.85
					18550	-	-	-	-
					18615	-	-	-	-
					18620	-	-	-	-
	Completion Date: Expected 2014				**Gross Project Cost:**	-------	-------	-------	**21,665.70**
					19950	-------	-------	-------	-
					Grand Total:	-	**8.0**	-	**21,665.70**
Customer Demand	***Not Started*** Start Date: Expected 2014	Various General Service Capital Contribution Projects	OHL is obligated under the DSC to connect new customer services that are funded through contributed capital.	OHL will connect approximately 5 new general service customer demand projects consisting of a mix of overhead and underground servicing.	18300	48.00	16.00	48.00	14,000.00
					18350	48.00	16.00	48.00	14,000.00
					18400	48.00	16.00	48.00	14,000.00
					18450	48.00	16.00	48.00	14,000.00
					18505	48.00	16.00	48.00	14,000.00
					18510	48.00	16.00	48.00	14,000.00
					18550	48.00	16.00	48.00	14,000.00
					18615	-	16.00	-	2,000.00
					18620	-	-	-	-
	Completion Date: Expected 2014				**Gross Project Cost:**	-------	-------	-------	**100,000.00**
					19950	-------	-------	-------	100,000.00
					Grand Total:	**336.0**	**128.0**	**336.0**	-

Customer Demand	***Not Started*** Start Date: Expected 2014 Completion Date: Expected 2014	Various Residential Capital Contribution Projects	OHL is obligated under the DSC to connect new customer services that are funded through contributed capital.	OHL will connect approximately 5-10 new or upgraded residential customers consisting of a mix of overhead and underground servicing.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	60.00	8.00	20.00	8,000.00
					18615	-	-	-	-
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**8,000.00**
					19950	-------	-------	-------	6,000.00
					Grand Total:	**60.0**	**8.0**	**20.0**	**2,000.00**
Customer Demand	***Not Started*** Start Date: Expected 2014 Completion Date: Expected 2014	Estimated Various Embedded Generation Projects (>10kW)	OHL is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes Embedded Generation projects >10kW.	OHL will connect approximately two embedded generation projects >10 kW. Each new embedded generation customer service requires servicing and commercial metering.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	-	-	-	-
					18615	16.00	40.00	20.00	10,816.54
					18620	-	-	-	2,175.00
					Gross Project Cost:	-------	-------	-------	**12,991.54**
					19950	-------	-------	-------	12,991.54
					Grand Total:	**16.0**	**40.0**	**20.0**	-
Customer Demand	***Not Started*** Start Date: Expected 2014 Completion Date: Expected 2014	Estimated Various Embedded Generation Projects (<10 kW)	OHL is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes Embedded Generation projects <10kW.	OHL will connect approximately five embedded generation projects <10 kW. Each new embedded generation customer service requires servicing and commercial metering.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	-	-	-	-
					18510	-	-	-	-
					18550	-	-	-	-
					18615	10.00	20.00	15.00	3,772.34
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**3,772.34**
					19950	-------	-------	-------	3,772.34
					Grand Total:	**10.0**	**20.0**	**15.0**	-
Customer Demand	***Not Started*** Start Date: Expected 2014 Completion Date: Expected 2014	Various Subdivisions	OHL is obligated under the DSC to connect new customer services that are funded through contributed capital. This includes new subdivision developments. OHL is required to offer the Peaksaver Plus program to customers. The program requires OHL to purchase and install a Zigbee compliant meter for each customer.	OHL will energize 2 new subdivisions and connect services as the houses are constructed; St. Paul's Place (33 connections) and Sarah Properties Phase 3 (50 connections). Also, OHL will connect services for previously energized subdivisions. This includes Mayberry Hills Phase 1 (30 connections), and Paula Court (13 connections). OHL will install a Zigbee chip in 300 meters.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	8.00	-	62,069.85
					18450	80.00	8.00	8.00	63,496.82
					18505	-	-	-	-
					18510	80.00	8.00	8.00	59,225.78
					18550	120.00	32.00	120.00	74,549.83
					18610	-	-	-	27,000.00
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**286,342.29**
					19950	-------	-------	-------	175,710.48
					Grand Total:	**280.0**	**56.0**	**136.0**	**110,631.81**
Renewal	***Not Started*** Start Date: Expected 2014 Completion Date: Expected 2014	Failed Transformer Replacement	OHL replaces failed transformers as required. Transformers fail due to overloading, degradation and foreign interference.	OHL will replace transformers as they fail. OHL expects 10-12 transfomers will fail.	18300	-	-	-	-
					18350	-	-	-	-
					18400	-	-	-	-
					18450	-	-	-	-
					18505	30.00	-	-	9,100.00
					18510	48.00	-	-	37,100.00
					18550	-	-	-	-
					18610	-	-	-	-
					18620	-	-	-	-
					Gross Project Cost:	-------	-------	-------	**46,200.00**
					19950	-------	-------	-------	-
					Grand Total:	**78.0**	-	-	**46,200.00**

Total Gross Distribution Project Costs:	1,375,196.29
Total Contributed Capital:	298,474.36
Total Gross Cost Less Contributed Capital:	1,076,721.93

ORANGEVILLE HYDRO

Appendix C -

Rate App Docs

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

2014 RATE APPLICATION OVERVIEW

Submitted by Jan Howard

Rate Base

Rate Base			
Description	**CGAAP**	**CGAAP**	
	2010 Board Approved	**2014 Test Year**	**Variance**
Fixed Assets Opening Balance	13,874,341	16,282,861	
Fixed Assets Closing Balance	14,599,051	16,711,602	
Average Fixed Asset Balance	**14,236,696**	**16,497,232**	**2,260,536**
Working Capital Allowance	3,389,898	3,757,782	367,883
Rate Base	**17,626,594**	**20,255,013**	2,628,419

Increase in rate base;

- Average fixed assets increase mostly due to smart meter capital added to the rate base – $1,918,432
- Change in accounting policy for depreciation expense
- Working capital allowance - increases in cost of power and OM&A expenses

Return on Capital

Cost of Capital		
Rate of Return	**2010 Board Approved**	**2014 Test Year**
40% - Return on Equity	9.85%	8.98%
56% - Return on Long Term Debt	5.63%	3.48%
4% -Return on Short Term Debt	2.07%	2.07%
Regulated Return	**7.18%**	**5.63%**

Return on Rate Base			
	2010 Board Approved	**2014 Test Year**	**Variance**
Rate Base	17,626,594	20,255,013	2,628,419
Regulated Rate of Return	7.18%	5.63%	
Regulated Return on Capital	1,265,021	1,139,565	(125,456)
Return on Equity	694,488	727,560	33,072
Return on Debt	570,534	412,005	(158,528)

Decrease in regulated return on capital from 7.18% to 5.63% *;

- Return on equity rate decrease from 9.85% to 8.98% *
- 3rd party debt interest rates decreased upon re-negotiation to lower rates in 2012

Increase in return on equity;

- Increase in rate base

Decrease in return on debt;

- 3rd party interest rates are lower

**In February of 2014 the OEB will update the cost of capital parameters. This will change the rate of return.*

OM&A Costs

OM & A Costs			
Description	CGAAP	CGAAP	
	2010 Board Approved	2014 Test Year	Variance
Operations	378,946	507,835	128,890
Maintenance	492,423	616,413	123,990
Billing and Collecting	549,953	741,719	191,765
Community Relations	20,862	17,278	(3,584)
Administrative and General	1,216,832	1,611,938	395,106
Rate Base	**2,659,015**	**3,495,183**	**836,167**

The following chart explains the increase in OM&A expenses over the 2010 rate application;

OM&A Cost Increase from 2010 Board Approved to 2014		
Payroll & Benefits	388,028	14.6%
Line Apprentice Addition	63,614	2.4%
Smart Meter costs	116,880	4.4%
Safety	50,568	1.9%
File Nexus	38,400	1.4%
Easements	4,950	0.2%
UCS Costs Increase	40,021	1.5%
Bad Debts	15,000	0.6%
IT Support Increase	30,000	1.1%
Rate Application Support (DSP)	29,000	1.1%
Audit Increase	7,000	0.3%
EDA Fee Increase	6,570	0.2%
GIS/USF/Training Increase	20,773	0.8%
Administration Staff Training Increase	10,665	0.4%
Inflation	14,699	0.6%
Total Increase	**836,167**	**31.4%**

The following should be noted;

- Payroll and benefits represents an increase of 3.65% year over year. One senior management staff wages achieved the top level and the regulatory assistant reached top level. In the 2014 budget, the Junior engineer and the accounting assistant were promoted to management level. The engineering tech reached top level of the position as well as the apprentice lineman. OMERS increases also occurred during this period.
- Smart meters costs are new costs minus the difference in manual meter reading. Safety costs were formally included in overhead costs and were removed due to change in accounting policy
- File Nexus has been implemented to go paperless i.e. environmentally friendly
- Easements are no longer capitalized
- UCS costs increased due to acquiring a software expert (billing TOU/MDMR), customer connect and teleworks
- Bad debts increased due to OEB collection procedures
- IT support increased to ensure compliance and attain secure systems
- Rate application support increase due to contracting the DSP to ensure we are compliant with the filing requirements
- Audit increase is consistent with more time spent on our complex audits due to changes in accounting policies and processes.
- EDA fee increase due to increase in customers
- Engineering GIS/USF costs have increased. Engineering training budget increase to maintain the talent and prepare to share the responsibilities of a higher level job in preparation for the position.
- Administration training increase also to maintain the current talent and prepare for the higher level position

Revenue Requirement

Description	CGAAP 2010 Board Approved	CGAAP 2014 Test Year	Variance
OM & A Expenses	2,659,015	3,495,183	836,167
Amortization Expense	1,103,911	818,343	(285,568)
Total Distribution Expenses	3,762,927	4,313,526	550,599
Regulated Return on Capital	1,265,021	1,139,565	(125,456)
Grossed up PILs	300,576	137,474	(163,102)
Service Revenue Requirement	**5,328,524**	**5,590,566**	262,041
Less Revenue Offsets	(454,952)	(466,088)	(11,136)
Base Revenue Requirement	**4,873,572**	**5,124,478**	**250,906**

- Amortization expense has decreased with the change in useful lives
- Regulated return on capital decreased;
- PILs decreased due to the change in useful lives, capital cost allowance is now greater than accounting depreciation
- Revenue offsets have increased slightly
- Main driver of the increase in revenue requirement is our OM&A expenses

Summary of Rate Impacts

Table 1.6 Bill Impacts on Delivery Portion of Customers Bill			
Rate Class	**Threshold Typical for Customer Class**	**Bill Impact $**	**Bill Impact %**
Residential	800 kWh	$ 0.18	0.47%
General Service < 50	2,000 kWh	$ (1.70)	-2.13%
General Service > 50	500 kW	$ 396.32	12.96%
Streetlight	3 kW	$ 2.19	19.76%
Sentinel Light	1 kW	$ 2.04	10.63%
Unmetered Scattered Load	193 kWh	$ 0.04	0.39%

Delivery portion includes distribution, low voltage, transmission and any rate riders to clear variance accounts. Due to the increases in low voltage, transmission and the completion of some rate riders the bill impacts are higher.

Bill Impacts on Distribution of Customers Bill			
Rate Class	**Threshold Typical for Customer Class**	**Bill Impact $**	**Bill Impact %**
Residential	800 kWh	$ (1.39)	-4.57%
General Service < 50	2,000 kWh	$ (5.27)	-8.71%
General Service > 50	500 kW	$ 3.16	0.25%
Streetlight	3 kW	$ (0.00)	-0.01%
Sentinel Light	1 kW	$ 0.04	0.26%
Unmetered Scattered Load	193 kWh	$ (0.61)	-7.54%

- Residential distribution rates decrease due to the removal of the smart meter incremental revenue rider
- GS <50 decrease due to the removal of the smart meter incremental revenue rider
- GS >50 increase only slightly
- Streetlight sentinel lights and unmetered scattered loads also have a minimal increase in distribution rates.

ORANGEVILLE HYDRO

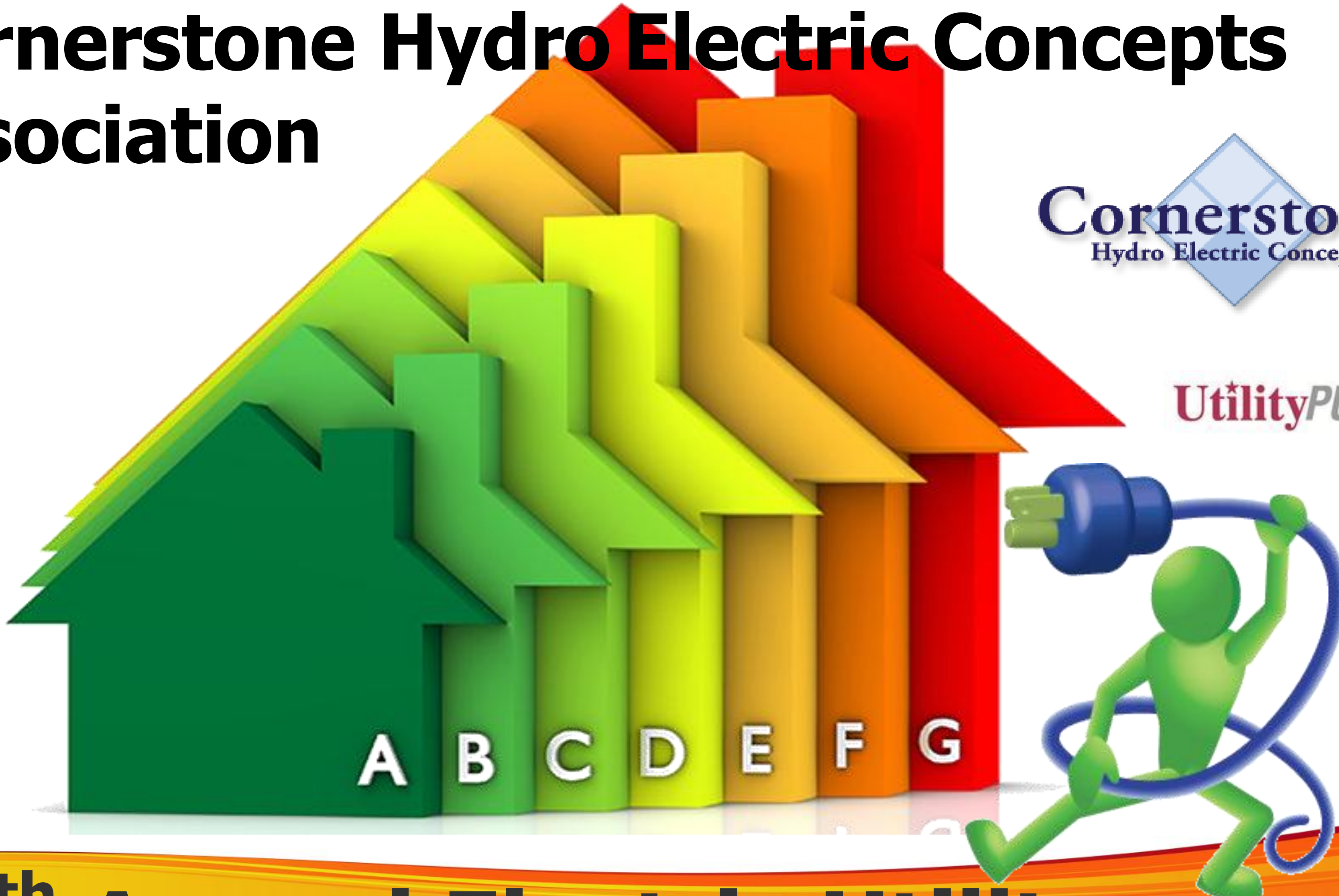
Appendix D -

CHEC UtilityPulse Report

June 2013

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Cornerstone Hydro Electric Concepts Association



CornerstonE
Hydro Electric Concepts

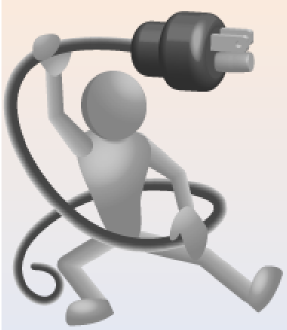
UtilityPULSE

15th Annual Electric Utility Customer Satisfaction Survey

The purpose of this report is to profile the connection between CHEC Group and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.



All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

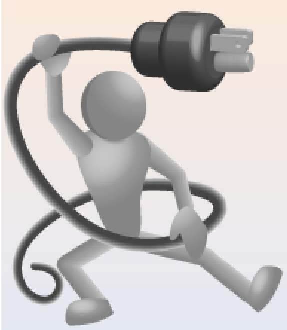
Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

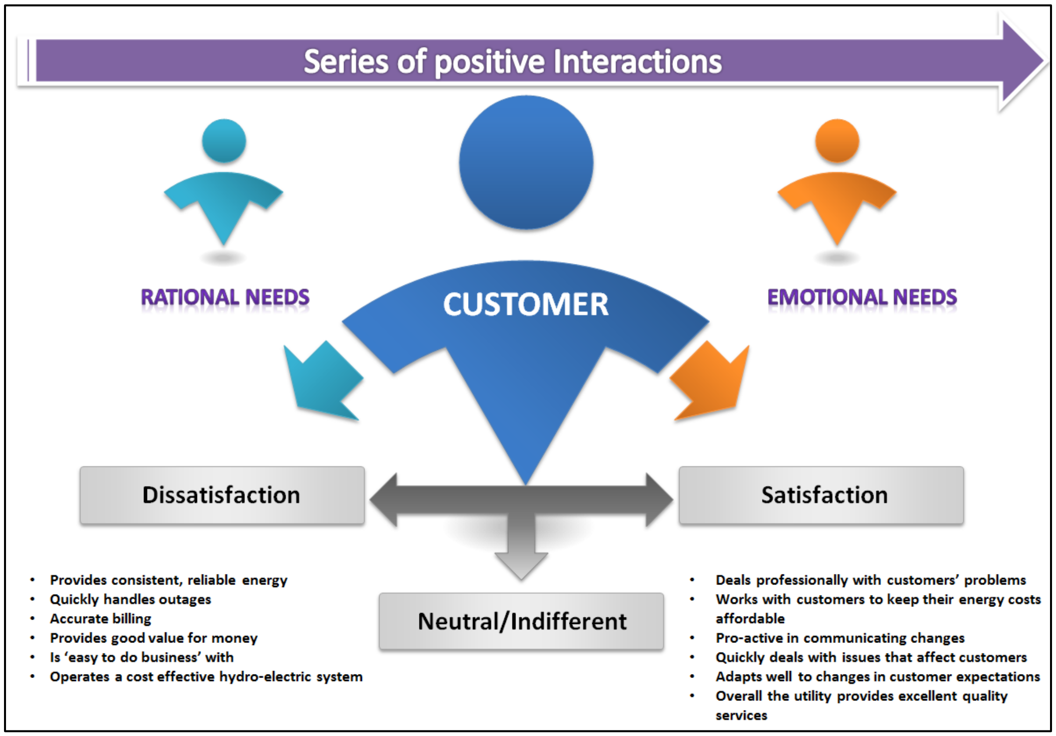
"Putting the Consumer First" was part of the title of the *Report of the Ontario Distribution Sector Review Panel.* Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

For the past 15 years, the only constant Ontario LDCs and their customers have faced is constant change. With topics such as SMART Meters, SMART Grid, green energy, infrastructure renewal, coupled with the recommendations from the Ontario Distribution Sector Review Panel, it is easy to predict that change will continue – for many years to come. One of the challenges for utilities today is to determine how to educate, empower and engage their residential and small business customers. The goal for utilities is to cut through the fog of fear, misinformation and confusion that exists amongst its customers, regarding a myriad of subjects, while retaining a very high level of trust, respect and credibility.

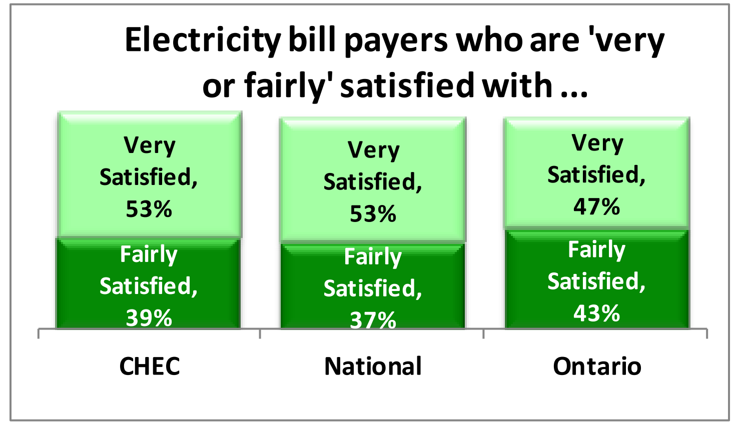


Trust and credibility are the foundational building blocks for ensuring that customers have both their rational and emotional requirements fulfilled. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, CHEC Group has done well. Overall, CHEC Group 87% [Ontario 82%; National 82%].

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction.

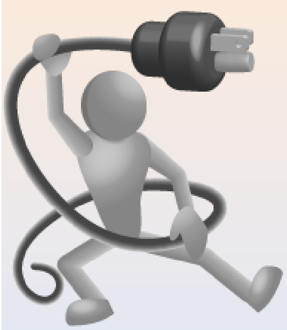


The old adage, "You cannot command respect, you have to earn respect" is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer. Customers have expectations of their electric utility that go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".



- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.
- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

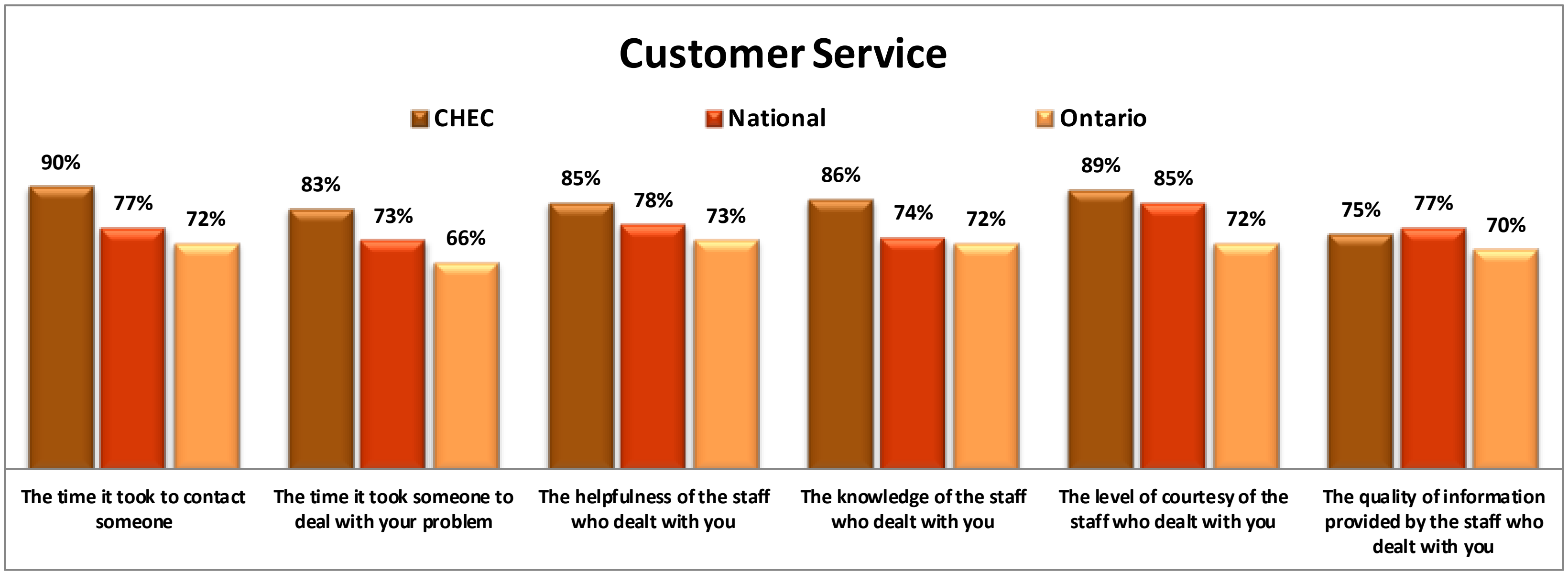


CHEC SATISFACTION SCORES – Electricity customers' satisfaction

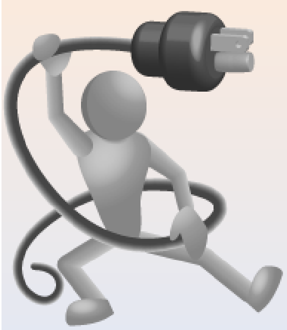
Top 2 Boxes: 'very + fairly satisfied'	2013	2012	2011	2010
PRE: Initial Satisfaction Scores	92%	-	-	-
POST: End of Interview	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Customers have needs and expectations AND they will have problems. How those problems are dealt with are “proof points” which will validate or invalidate their perceptions. Customer problems are far more diverse than they have ever been, thereby, causing customer service to change in response to those problems and needs. Given the increase in fragmentation of customer type and customer problems, the need for building a customer-centric culture in line with customers’ needs, preferences and expectations is important when customer satisfaction is important to the organization.



Base: total respondents who contacted the utility



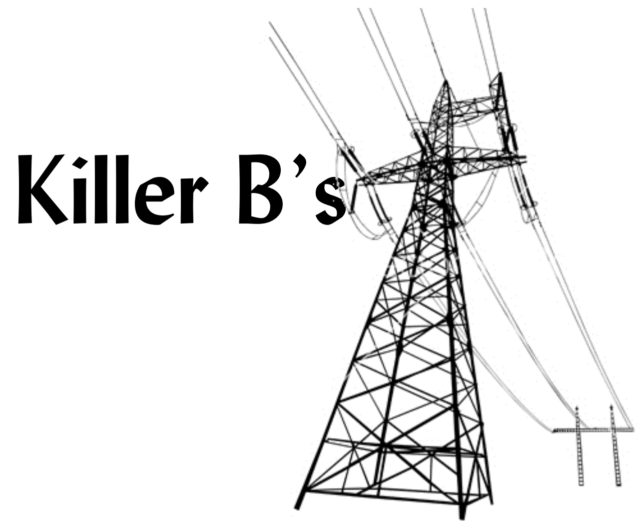
The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those that cause the most concern with customers.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	CHEC	National	Ontario
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

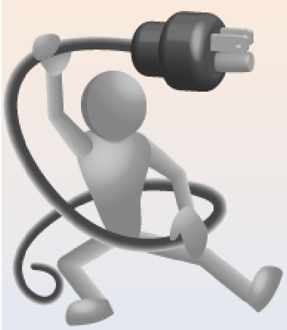
Base: total respondents / (-) not a participant of the survey year



Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	CHEC	National	Ontario
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year



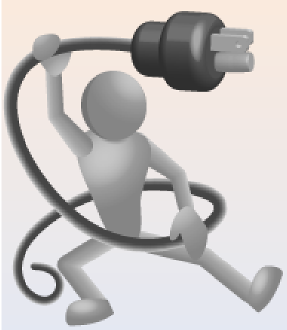
What do customers think about electricity costs?

There is a correlation between ability to pay and satisfaction with higher earners reporting the highest levels of initial satisfaction with their utility. It is also true that emotional connectivity, i.e. loyalty, also plays a role about what customers think about costs. Out of all the Ontario survey respondents this year, only 17% of Secure customers vs 43% of At Risk customers report that they sometimes or often worry about paying their electricity bill.

Is paying for electricity a worry or major problem …

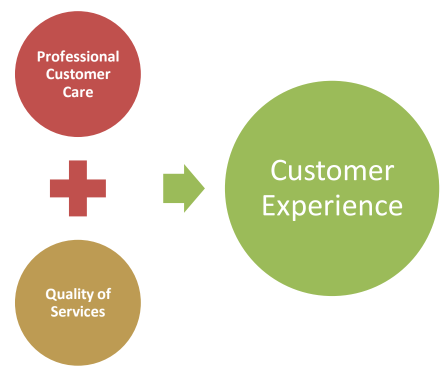
	CHEC	National	Ontario
Not really a worry	67%	70%	66%
Sometimes I worry	24%	18%	21%
Often it is a major problem	4%	8%	11%
Depends	3%	2%	1%

Base: total respondents



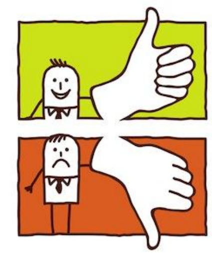
Customer Experience Performance rating (CEPr)

New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization.



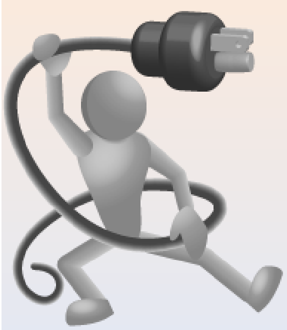
Customer Experience Performance rating (CEPr)			
	CHEC	**National**	**Ontario**
CEPr: all respondents	87%	83%	83%
CEPr: respondents *who have* contacted their utility	83%	79%	77%
CEPr: respondents *who have not* contacted their utility	88%	84%	85%

Base: total respondents



The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course, a negative transaction creates the perception that future transactions will be negative.



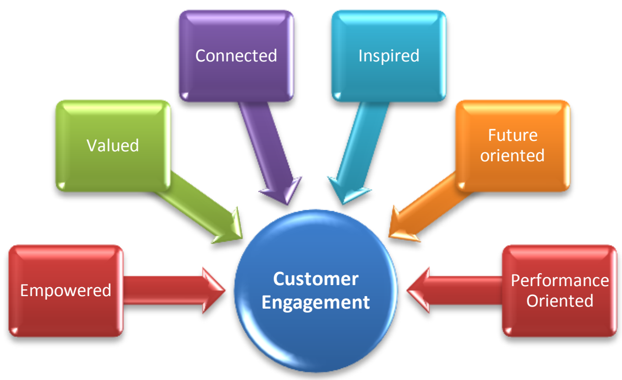
Customer Engagement Index (CEI)

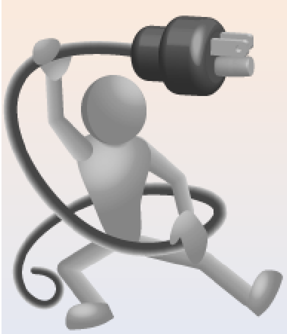
UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called "customer engagement". Here are the basic types:

1- Participation in programs or service offerings
2- Pro-active "reach-out" to customers
3- Customer loyalty
4- How customers think, feel and act towards the organization that serves them.

Drawing from our 25+ years of experience working with enterprises in both the private and public domains, we believe that basic types 1 & 2 are too simplistic and tend to be an efficiency measurement. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with – essentially an effectiveness and outcomes oriented measurement.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization. The six dimensions of an outcome based definition of customer engagement are: empowered, valued, connected, inspired, future oriented and performance oriented.



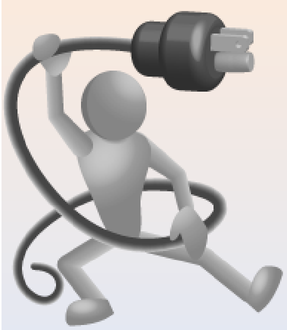


Utility Customer Engagement Index (CEI)			
	CHEC	National	Ontario
CEI	86%	81%	81%

Base: total respondents

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers for influencing satisfaction and affinity levels with their utility.



CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**A**

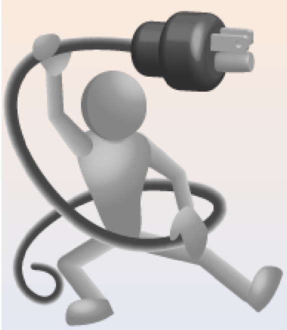
Base: total respondents

Corporate Image

Organizations today, are always under scrutiny and have to consider the reality AND perception of their image. Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial.

Attributes strongly linked to a hydro utility's image			
	CHEC	**National**	**Ontario**
Is a respected company in the community	89%	83%	84%
Maintains high standards of business ethics	88%	81%	81%
A leader in promoting energy conservation	85%	80%	80%
Keeps its promises to customers and the community	88%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	86%	79%	79%
Is a trusted and trustworthy company	89%	83%	83%
Adapts well to changes in customer expectations	80%	74%	73%
Is 'easy to do business with'	88%	82%	81%
Overall the utility provides excellent quality services	87%	85%	83%
Operates a cost effective hydro-electric system	79%	72%	68%

Base: total respondents with an opinion



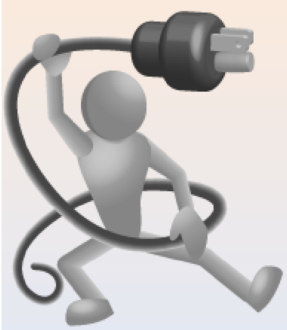
Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and SMART insights, on a number of subjects such as e-care, e-billing, conservation and more.

SMART Meters & SMART Grid

Do economic incentives have an impact on resource consumption patterns? *77% agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis. [Base: Ontario LDC respondents]*

SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities. It is clear that the need for education is immense. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.



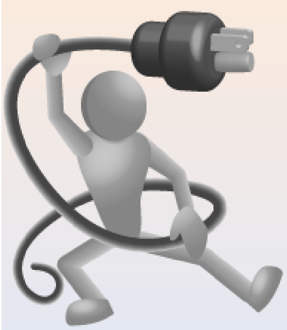
Level of knowledge about the SMART Grid

	Ontario LDCs
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%
I have a basic understanding of what it is and how it might work	17%
I've heard of the term, but don't know much about it	33%
I have not heard of the term	42%
Don't know	1%

Base: An aggregate of respondents from 2013 participating LDCs

Importance of pursuing implementation of the SMART Grid	
	Ontario LDCs
Very important	23%
Somewhat important	30%
Neither important or unimportant	9%
Somewhat unimportant	5%
Unimportant	10%
Don't know	23%

Base: An aggregate of respondents from 2013 participating LDCs

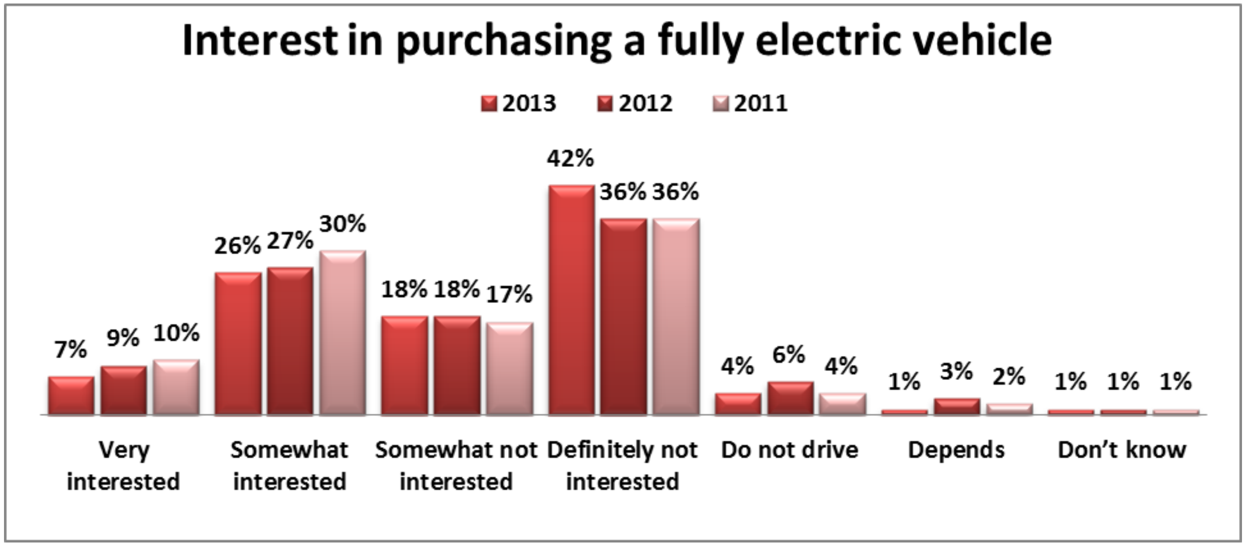


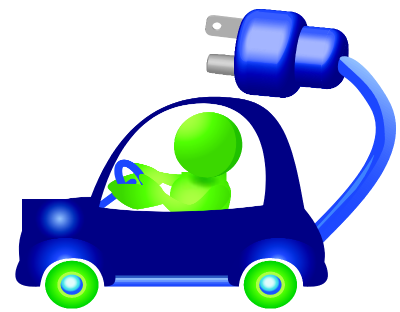
Support towards working with neighbouring utilities on SMART Grid initiatives	
	Ontario LDCs
Very supportive	38%
Somewhat supportive	37%
Neither supportive or unsupportive	4%
Somewhat unsupportive	2%
Unsupportive	6%
Don't know	12%

Base: An aggregate of respondents from 2013 participating LDCs

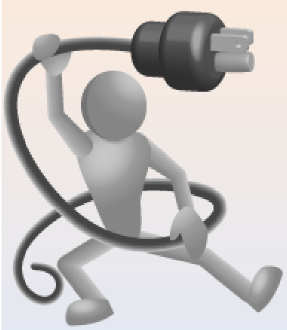
Purchasing an Electric Vehicle

Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 and 43% aged 18-34 are in favor of EVs replacing conventional cars.





Base: total respondents in the Ontario Benchmark survey



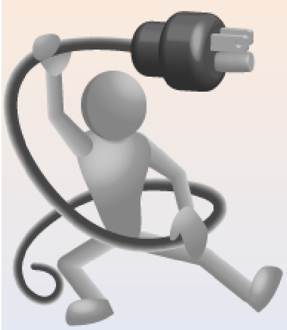
Energy Conservation & Efficiency

Improving energy efficiency does not mean that customers have to give up or forgo activities to save energy. Rather, new technologies and more effective behaviour will actually allow customers to do more, improving their living conditions rather than reducing their comfort. Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and energy saving through changes in customer awareness and behaviour.* During the survey interview process, we asked *"what are the 1 or 2 barriers for creating higher levels of energy efficiency?"* 21% identified "costs involved in making equipment/appliance changes", and 12% identified "lack of knowledge or lack of information". Respondents were asked: *"What will you be doing to conserve energy?"*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	20%	10%	69%	1%
Install timers on lights or equipment	15%	49%	35%	2%
Shift use of electricity to lower cost periods	21%	19%	57%	3%
Install window blinds or awnings	15%	26%	58%	1%
Install a programmable thermostat	15%	20%	63%	2%
Have an energy expert conduct an energy audit	9%	70%	18%	3%
Removing old refrigerator or freezer for free	14%	45%	37%	4%
Join the peaksaverPLUS™ program	18%	48%	21%	13%
Replacing furnace with a high efficiency model	13%	36%	48%	3%
Replacing air-conditioner with a high efficiency model	16%	39%	41%	4%
Use a coupon to purchase qualified energy saving products	33%	42%	21%	4%

Base: An aggregate of respondents from 2013 participating LDCs

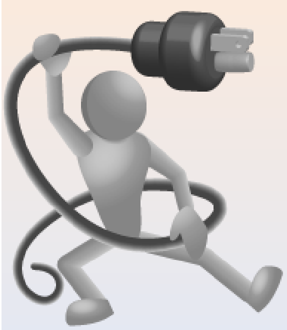


E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to: sign up for and change their services using the internet, find answers to their questions online about their accounts, learn about products, services and topics, i.e., green energy, electricity pricing, etc. It is about giving control to the customer.

83% of CHEC Group respondents have access to the internet and 14% have accessed their utility's website in the last six months.

Consumers will eventually adopt electronic billing and online customer care as many industries/companies begin providing consumer bills online, and critical mass is reached.



Using the internet for billing

	Ontario LDCs	CHEC
I am already receiving my hydro bill electronically	10%	4%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%	11%
I use on-line banking but prefer to have paper statements	30%	35%
I prefer to have the paper copy of my bills	23%	26%
I don't use on-line banking	17%	22%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

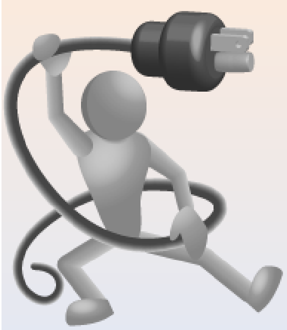
Social Media

Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. Respondents of this year's survey were asked *"how likely they would use social media such as twitter®, facebook® (and others) as a resource for energy efficiency tips or to help manage your electricity use"…*

Likelihood of using Social Media

	CHEC	Ontario LDCs	Ontario LDCs Age Group:18-34	Ontario LDCs Age Group: 55+
Very likely	4%	6%	10%	3%
Somewhat likely	7%	11%	17%	6%
Not likely	22%	20%	24%	17%
Not likely at all	64%	61%	48%	68%
Don't have social media account	2%	2%	0%	4%
Don't know	0%	1%	0%	1%

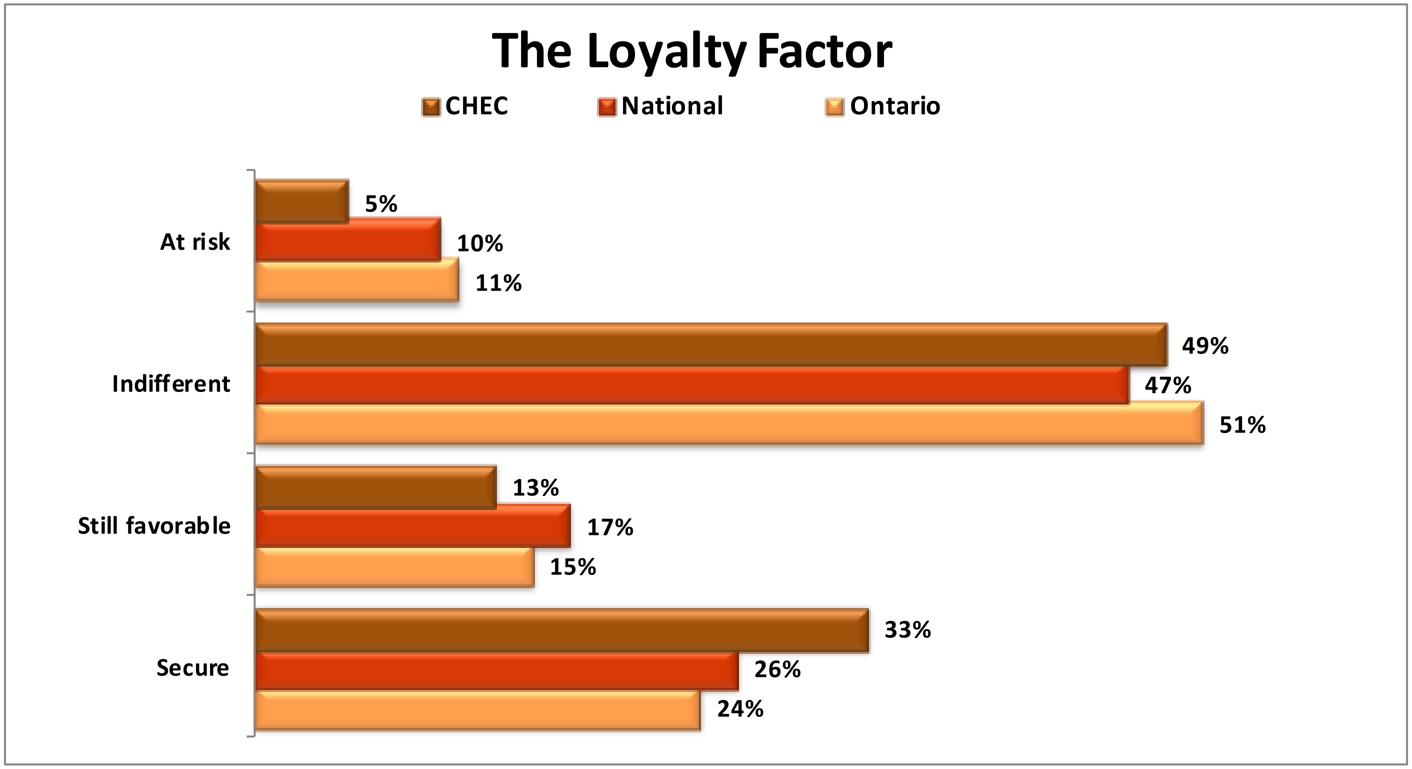
Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility



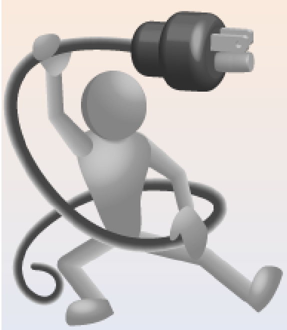
Customer Affinity

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about a customer's future behaviour but more about their "attitudinal" loyalty (are they advocates?).



Base: total respondents

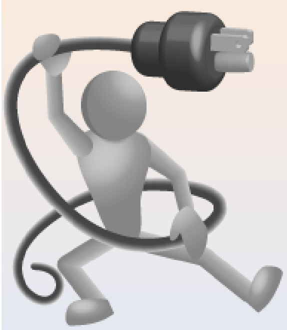


Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
CHEC				
2013	33%	13%	49%	5%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

Electricity customers' loyalty – Is a company that you would like to continue to do business with				
CHEC	2013	2012	2011	2010
Top 2 boxes: **'Definitely + Probably' would continue**	85%	-	-	-

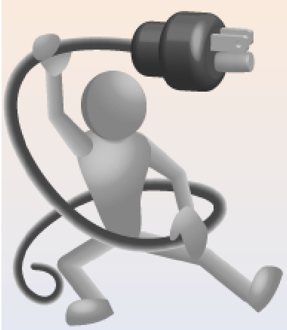
Base: total respondents / (-) not a participant of the survey year



Electricity customers' loyalty – is a company that you would recommend to a friend or colleague				
CHEC	2013	2012	2011	2010
Top 2 boxes: **'Definitely + Probably' would recommend**	78%	-	-	-

Base: total respondents / (-) not a participant of the survey year

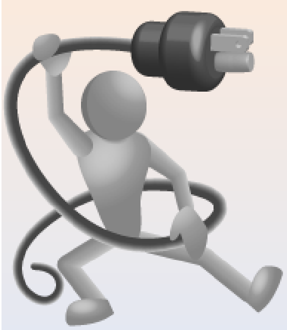
Every LDC has a brand and a brand image, while that image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Providing consistent reliable energy while being seen as 'easy to do business with', along with providing information and support for customers to use electricity more efficiently are core components of a successful relationship with customers.



Marketing – Communications

	CHEC	National	Ontario
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	69%	66%	61%
Works with customers to keep their energy costs affordable	73%	66%	65%
Adapts well to changes in customer expectations	80%	74%	73%
Operates a cost effective hydro-electric system	79%	72%	68%
Provides good value for money	76%	71%	68%
Topics that your utility scores very well on			
Is a trusted and trustworthy company	89%	83%	83%
Respected company in the community	89%	83%	84%
Accurate billing	88%	85%	86%
Overall the utility provides excellent quality services	87%	85%	83%
Provides consistent, reliable energy	91%	90%	90%

Base: total respondents with an opinion



UtilityPULSE is the only enterprise with multiple year customer trend data that appears on the List of Presenters and Submitters in the *Report of the Ontario Distribution Sector Review Panel.* With 14 years of data (15 now that the 2013 survey has been completed), we know that LDCs in Ontario have made excellent progress in the way(s) in which customers are cared for and served – despite the massive amounts of change that have taken place during that same timeframe.

We've often been asked: "What does it take to be seen as having great customer service?" Our answer continues to be "have genuine empathy for customers". If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires CHEC Group to ensure that it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture that supports both customer and employee engagement.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2013 customer satisfaction survey derived from speaking with 632 CHEC Group customers [April 10 - April 23, 2013]. After-all, people can't care about the things that they don't know about.

Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2013

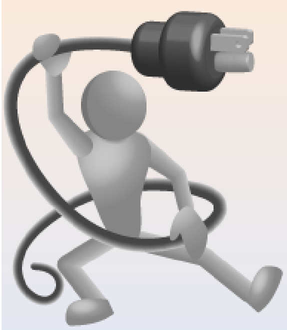


Table of contents

	Page
Executive summary	3
Satisfaction (pre & post)	24
- Customer Service	30
Bill payers’ recent problems and problem resolution	36
Customer Experience Performance rating (CEPr)	44
Customer Engagement Index (CEI)	47
UtilityPULSE Report Card®	50
The Loyalty Factor	58
- Customer commitment	65
- Word of mouth	68
Corporate Image	71
- Corporate Credibility & Trust	74
How can service to customers be improved?	77
SMART Meters & SMART Grid	79
Energy Conservation & Efficiency	84
Purchasing an Electric vehicle	88
E-care and E-billing	90
- Social Media	98
What do customers think about electricity costs?	99
What do Small commercial customers think?	103
Method	110
About Simul	113

Satisfaction (pre & post)

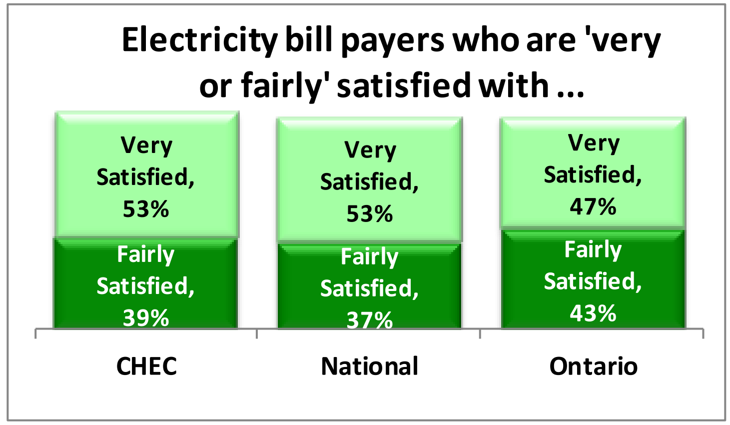
The old adage “You cannot command respect, you have to earn respect” is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer.

While private industry companies are compelled to understand their customers in order to drive sales and revenue, customer satisfaction measurement can form a similar focus for organizations in the absence of the commercial imperative, such as utilities which operate under monopolistic conditions. It can also help to build a connection with customers and front-line staff, and provide a uniting, motivating factor across the organization. Monopolies are not really different in what they should measure except that trying to determine which customers are “loyal” or “at risk” is not about their future behaviour but more about their “attitudinal” loyalty (are they advocates?). In the private sector customer satisfaction and loyalty are often seen as essential for survival and success. Public sector organizations, especially municipalities, have come to realize that looking after their customers and taking the opportunity to learn from them is key to delivering services which are both effective and efficient.

After 15 years of continued research with electric utility customers, expectations of their electric utility go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.

- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



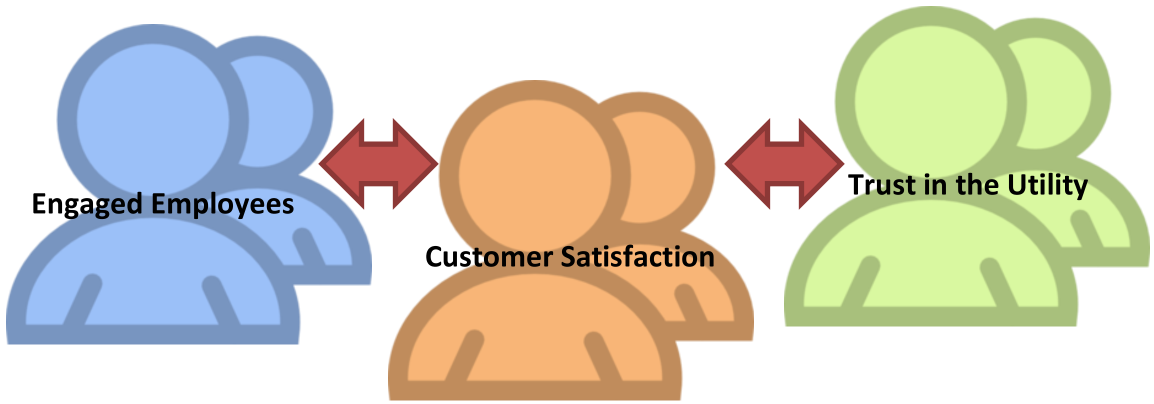
Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

Electricity bill payers who are 'very or fairly' satisfied with…

	2013	2012	2011	2010
CHEC	92%	-	-	-
National	90%	88%	89%	86%
Ontario	90%	86%	84%	80%

Base: total respondents / (-) not a participant of the survey year

Our research has found that in the utility industry environment, especially in Ontario, where most utilities are municipally owned, satisfaction is a strong driver of customer trust as well as, impacts employee engagement. The satisfaction of public customers/citizens both improves employee engagement and is improved by it.



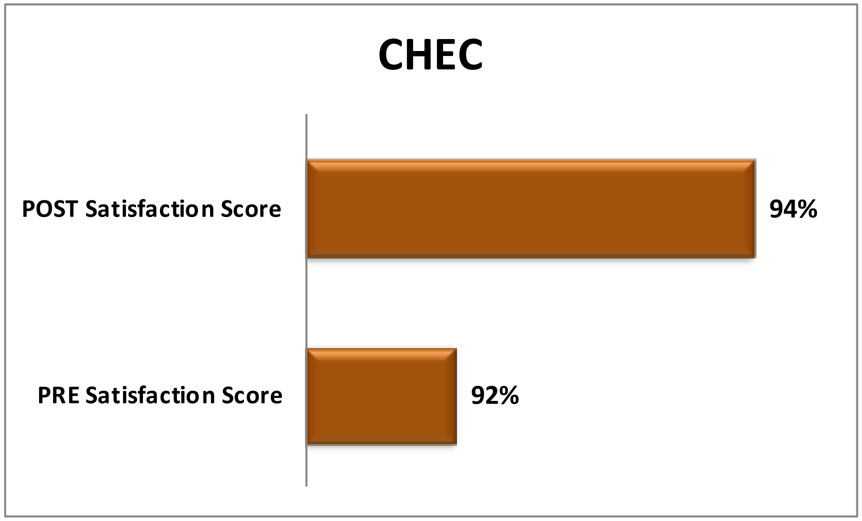
The synergy which exists between customer satisfaction and employee engagement has enormous implications for the performance of those who make up a utility's workforce. Many service personnel are motivated by their desire to help others; succeeding at this task (and having clear evidence that they have satisfied their "customers") can help keep them motivated and engaged.

Satisfied employees, who are working in an organizational culture which promotes service excellence is critical, too. Many companies make the mistake of measuring only customer satisfaction. Measuring organizational culture is the key because employees play an integral role in the customer relationship.

Employees do more than deliver customer service – they personalize the relationship between customer and the utility.

Creating loyal customers and loyal employees go hand in hand and it is the leaders of organizations that must create this alignment. Implementing service excellence works best when its principles are well understood and widespread collaboration is encouraged by management's visible actions. In our experience, this is best achieved by driving change from the 'top down' at the same time as inspiring and fully engaging employees from the 'bottom up'.

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility prior to prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.



Base: total respondents

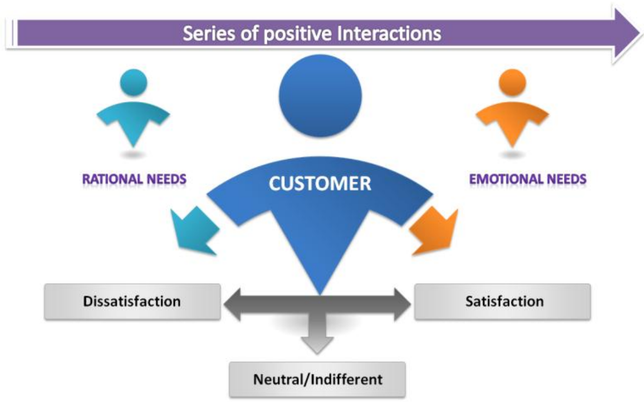
SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**CHEC**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	92%	90%	90%
POST: End of Interview	94%	91%	90%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction				
Top 2 Boxes: 'very + fairly satisfied'	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	92%	-	-	-
POST: End of Interview	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction.



Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
RATIONAL NEEDS			
Provides consistent, reliable energy	91%	90%	90%
Quickly handles outages	90%	88%	88%
Accurate billing	88%	85%	86%
Provides good value for money	76%	71%	68%
Is 'easy to do business' with	88%	82%	81%
Operates a cost effective hydro-electric system	79%	72%	68%
EMOTIONAL NEEDS			
Deals professionally with customers' problems	88%	83%	84%
Works with customers to keep their energy costs affordable	73%	66%	65%
Pro-active in communicating changes	85%	77%	80%
Quickly deals with issues that affect customers	85%	82%	82%
Adapts well to changes in customer expectations	80%	74%	73%
Overall the utility provides excellent quality services	87%	85%	83%

Base: total respondents with an opinion

Customer Service

Customer service is a series of activities grouped in processes designed to provide customers and other stakeholders with information or assistance which address customer's needs. Those needs are far more diverse than they have ever been thereby, compelling customer service to change in response to increasing customer demands. Given the increase in fragmentation of customer type and customer problems the need for building a customer-centric culture in line with customers' needs, preferences and expectations is important when customer satisfaction is important to the organization.

Customers don't want to be passed from CSR to CSR, unnecessary bureaucracy, to keep repeating why they are calling, to duplicate information already given, or to have to understand the inner workings of the utility organization.

Respondents were asked about six aspects of their most recent experience with a representative from CHEC Group.

- Information – quality of information provided
- Staff attitude – level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

Base: total respondents who contacted the utility

Satisfaction with Customer Service

Top 2 Boxes: 'very + fairly satisfied'	CHEC	National	Ontario
The time it took to contact someone	90%	77%	72%
The time it took someone to deal with your problem	83%	73%	66%
The helpfulness of the staff who dealt with you	85%	78%	73%
The knowledge of the staff who dealt with you	86%	74%	72%
The level of courtesy of the staff who dealt with you	89%	85%	82%
The quality of information provided by the staff who dealt with you	75%	77%	70%

Base: total respondents who contacted the utility

The customer service representative's role is essential to effectively handling customer issues/incidents/problems/requests. Having a skilled, trained representative is vital for a positive customer experience when a customer decides to make contact. Respondents who did have contact with a utility representative within the last 12 months were asked about their overall satisfaction with *that* experience.

Overall satisfaction with most recent experience			
	CHEC	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	76%	81%	76%

Base: total respondents who contacted the utility

This year we asked respondents to approximate the time since their most recent contact.

Approximation of how long ago most recent contact was made	
	CHEC
12+ months ago	5%
7-12 months ago	8%
4-6 months ago	16%
3 or less months ago	63%

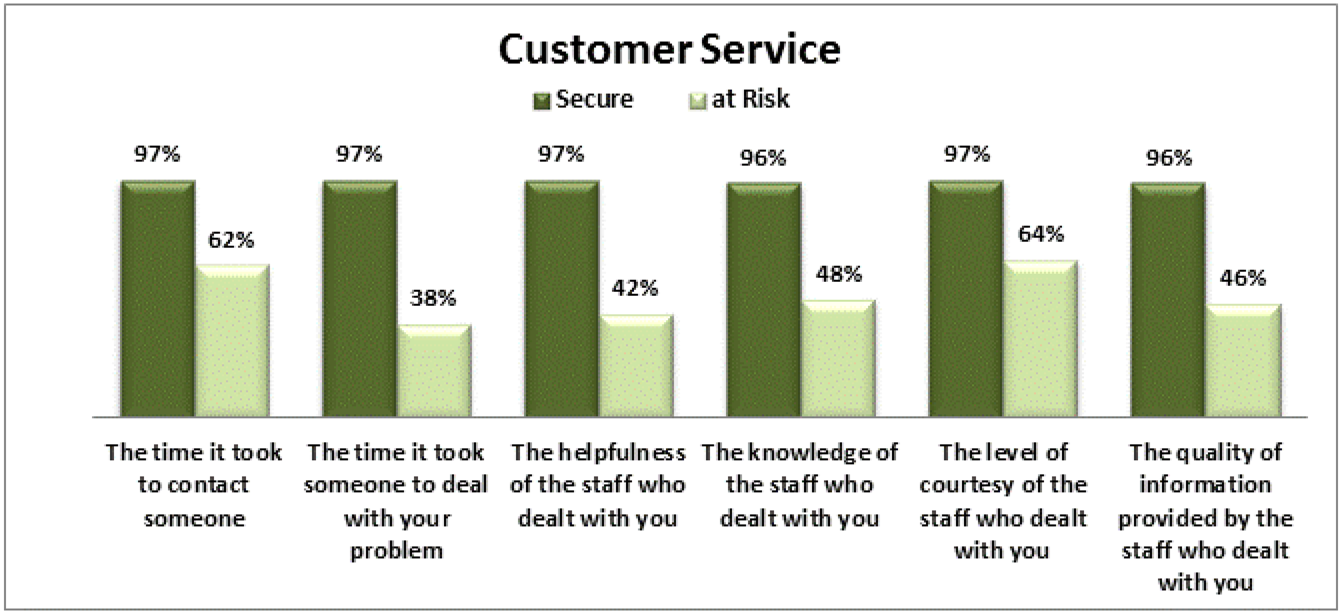
Base: total respondents who tried to contact the utility in the past 12 months

Customers value speed and responsiveness especially as it relates to solving problems. The more flexibility you're able to offer and the more empowerment given to employees, the better able employees will be to meet those "speed" and "responsiveness" requirements. Customers benefit, too, when employees are able to resolve problem issues "on the spot" instead of having to "talk to my manager."

SATISFACTION SCORES – Electricity customers' satisfaction			
National	**National**	**Problems Solved**	**Problems Not Solved**
Top 2 Boxes: 'very + fairly satisfied'	90%	93%	56%
Bottom 2 Boxes: 'fairly + very dissatisfied'	8%	5%	44%

Base: total respondents from 2013 National Benchmark survey

Empowerment is the backbone of the service recovery principle. In the face of error or problems, acting quickly and decisively, being empowered and turning a dissatisfied customer into a satisfied one tends to have a positive impact.



Base: data from the full 2013 database

Satisfaction with Customer Service

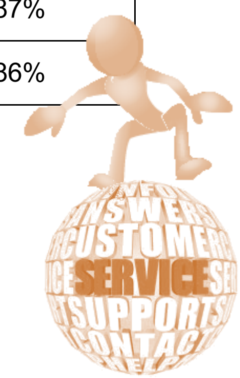
Top 2 Boxes: 'very + fairly satisfied'	Overall	Recent Experience Very Satisfied	Recent Experience Very Dissatisfied
The time it took to contact someone	80%	92%	45%
The time it took someone to deal with your problem	77%	95%	17%
The helpfulness of the staff who dealt with you	80%	98%	21%
The knowledge of the staff who dealt with you	80%	97%	21%
The level of courtesy of the staff who dealt with you	87%	97%	48%
The quality of information provided by the staff who dealt with you	77%	96%	21%

Base: data from the full 2013 database

Important attributes which shape perceptions about service quality			
	CHEC	**National**	**Ontario**
Is pro-active in communicating changes and issues which may affect customers	85%	77%	80%
Trusted and trustworthy company	89%	83%	83%
Respected company in the community	89%	83%	84%
Provides good value for money	76%	71%	68%
Customer-focused and treats customers as if they're valued	84%	76%	77%
Deals professionally with customers' problems	88%	83%	84%
Is a company that is 'easy to do business with'	88%	82%	81%
Quickly deals with issues that affect customers	85%	82%	82%
Provides information and tools to help manage electricity	84%	79%	80%
Adapts well to changes in customer expectations	80%	74%	73%
Delivers on its service commitments to customers	89%	85%	87%
Uses responsible business practices when completing work	89%	85%	86%

Base: total respondents with an opinion

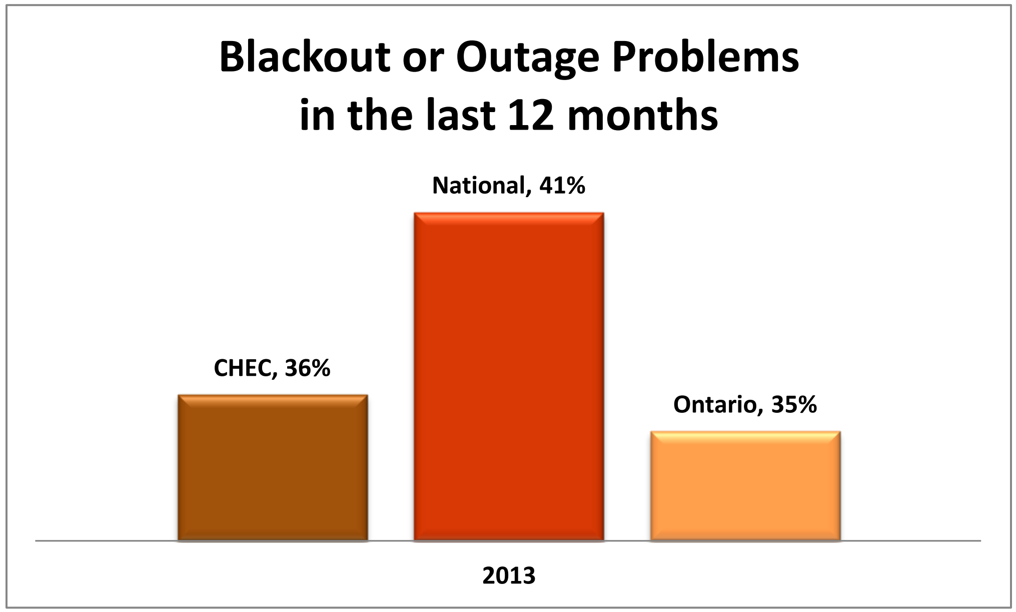
The service experience has a profound impact on customer service scores. The data shows a direct correlation between a very satisfied customer experience and the ratings given across all six measures of customer service. While there are a lot of things utilities cannot control, one thing they can control is the quality of service they provide.



Bill payers' recent problems and problem resolution

Outages and billing problems, we call them the "Killer B's", the two issues that are most likely to cause grief to utility customers.

At one time, if the power went off for a few minutes, it was considered annoying and inconvenient. However, with the onset of computers and smart appliances in homes and businesses, a power outage is now unbearable. Customers have little tolerance for an interruption in their flow of electricity.



Base: total respondents

While blackouts are rare, each one has the potential of affecting thousands of people. Think of the thousands of football fans at Super Bowl 2013 who sat in darkness for 38 minutes.

Besides the mere inconvenience an outage creates, economic loss is a principal concern. Typically during an outage, employees are unable to do their work because computers and other equipment are not able to operate. An outage therefore causes an employer to pay wages to idle employees, potentially causes employers to deal with overtime work to clear the backlog created by the down time. Outages also could potentially threaten life by interfering with the operation of life-support equipment i.e. those requiring life-support equipment i.e. ventilators for those afflicted with paralysis (although these instances would be rare and uncommon, the risk and potential liability do exist).

Despite a utility's best efforts, there will be times when the power goes off.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	CHEC	National	Ontario
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

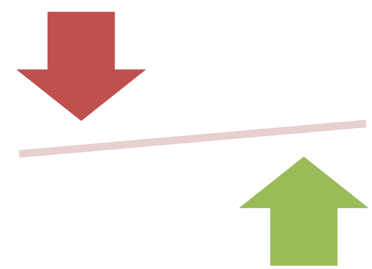
Base: total respondents

Reliability of service needs to be always given primary importance by electric utility systems. Reliability to a customer means that power made available to them is fault free and the outage or interruptions are tolerable and do not disturb their 'normal life'. Customer satisfaction can be improved through providing better quality power in terms of voltage and frequency fluctuations and reliability by reducing outages.

A "pain point" such as a power outage which will cause grief and could anger some customers will impact customer satisfaction scores.

Bill payers recalling a power failure or outage				
	Secure	**Favorable**	**Indifferent**	**At Risk**
Yes	19%	24%	34%	39%
No	80%	75%	65%	61%

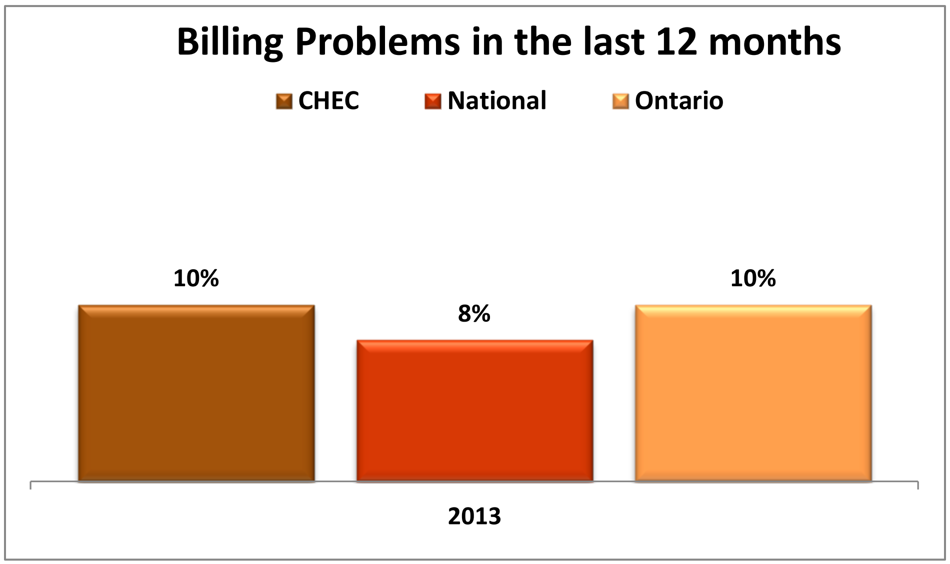
Base: data from the full 2013 database



Even though outages can have a negative impact on satisfaction, utility providers who manage these incidents properly-by providing sufficiently detailed information about the outage and restoring power when they say they will-may be able to mitigate declines, or even improve satisfaction.

For most customers, their bill is the only thing they see (or pay attention to) from their utility provider. It not only tells them how much to pay, it documents their service usage, breakdowns the various charges and provides contact information for customer service. As the principal form of communication between a utility and its customers, utilities cannot underestimate the importance of billing.

When it comes to billing, customers expect zero-defect delivery. Customers expect timely and accurate billings which they understand. Incorrect information, miscalculated balances, bills that are too difficult to understand result in time logged by your CSR's as well as dissatisfied customers. Improving billing activities has an immediate impact on the revenue streams of a utility, in terms of costs associated with managing call center applications.



Base: total respondents

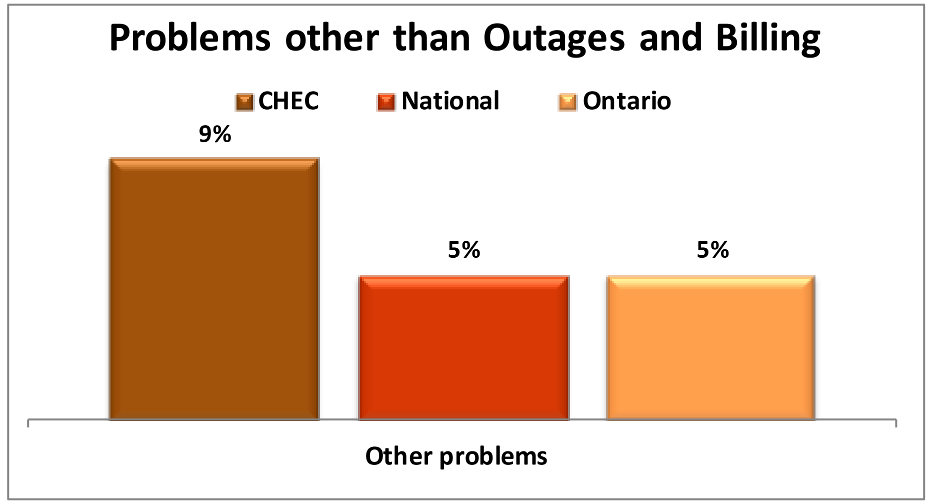
Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	CHEC	**National**	**Ontario**
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

Types of Billing Problems	
	CHEC
The amount owed was too high	40%
The bill was difficult to understand	13%
Complaint about rates or charges	11%
The bill arrived late	11%
Notice to terminate	6%
No bill/skipped bill	5%
The payment made was recorded incorrectly	3%

Base: total respondents with billing problems

As it relates to problems, the Killer B's – Bills and Blackouts still occupy top ranking – while moving/setting up a new account, maintenance repairs, high bills, information on pricing, SMART meters and energy conservation are issues which also contribute to inbound call-centre calls.



Base: total respondents

A customer who has experienced a problem or unfavourable service experience may spread negative word-of-mouth communication. While people have long complained about service providers in offline meeting places such as work lunch rooms, or social gatherings, today's social networks and online discussion forums mean such gripes often reach a considerably wider audience.

By understanding the complaint process and customer complaint behaviour, a utility can learn how to reduce the impact of an unfavourable service experience or complaint.

Our 15 years of research corroborates the notion that customer dissatisfaction and the handling of service recovery are key indicators of customer loyalty. A complaint allows the utility to obtain customer feedback that is useful in making improvements to increase customer satisfaction and loyalty. Effective resolution of customer problems can have a positive impact on customers' trust and commitment. The complaint handling process therefore, is a series of critical "moments of truth" in maintaining and developing customer relationships.

Percentage of Respondents with problems other than billing or power outages in the last 12 months

	CHEC	National	Ontario
Yes	9%	5%	5%
No	91%	95%	95%

Base: total respondents

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months

	CHEC	National	Ontario
Yes	69%	73%	74%
No	20%	19%	19%

Base: total respondents

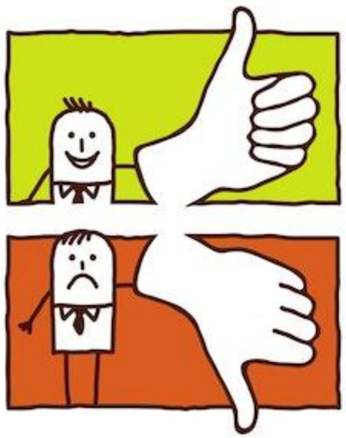
Utilities need to ensure that their customer complaint/service recovery processes are made to be more responsive and proactive. CSRs need to be capable enough to meet the growing demand of information conscious and tech savvy customers. Every minute counts when it comes to complaints being voiced with the aid of social media.

Attributes describing operational effectiveness			
	Overall Score	**Problem Solved**	**Problem Not Solved**
Provides consistent, reliable energy	91%	90%	81%
Delivers on its service commitments to customers	87%	86%	72%
Accurate billing	87%	85%	65%
Quickly handles outages and restores power	89%	88%	80%
Makes electricity safety a top priority	90%	91%	83%
Uses responsible business practices when completing work	88%	87%	76%
Is efficient at handling the hydro-electric systems	84%	83%	73%
Is a company that is 'easy to do business with'	85%	85%	63%
Operates a cost effective hydro-electric system	75%	73%	58%
Overall the utility provides excellent quality services	87%	86%	69%

Base: data from the full 2013 database from those respondents with an opinion

Technology is considered by many in the electricity utility industry to be both a blessing and a curse. On one hand, the LDC (and other service providers) can benefit from embracing technology to reduce costs and hopefully improve service thereby, putting control into the hands of the customer. On the other, when the problem has not been solved or is handled poorly, technology can enable the customer's dissatisfaction to go viral – the impact is on overall satisfaction with customers as well as employees.

Customer Experience Performance rating (CEPr)



New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

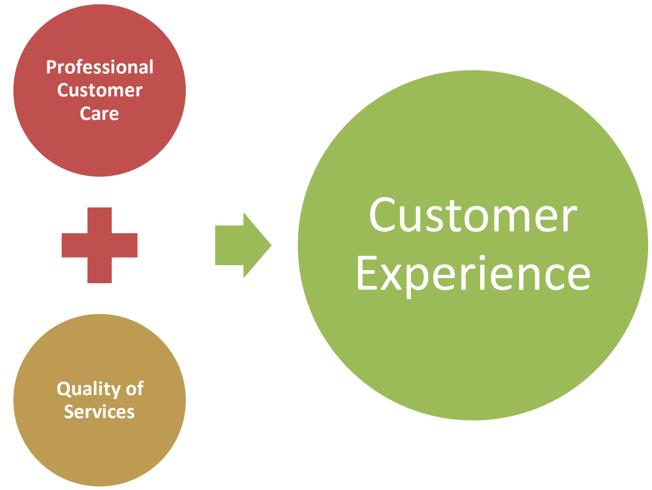
Great experiences occur when all functions of the organization align with one another to achieve the outcomes your customers seek. A good customer experience starts with understanding what your customers care about most and understanding which promises are most important to your customers.

At the heart of the CEPr are 4 central questions:

- Are interactions with the organization professional and productive?
- Is the organization 'easy to deal with'?
- Does the organization effectively meet your needs?
- Does the organization provide high quality services?

Some of the factors which contribute to the overall Customer experience:

- Delivering accessible and consistent customer service
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations



Customer Experience Performance rating (CEPr)			
	CHEC	**National**	**Ontario**
CEPr: all respondents	87%	83%	83%
CEPr: respondents *who have* contacted their utility	83%	79%	77%
CEPr: respondents *who have not* contacted their utility	88%	84%	85%

Base: total respondents

The CEPr (all respondents) for CHEC Group is 87%. On the surface this rating appears to be very high (and it is). But put the rating in context – it would mean that a very large majority of customers have a belief that they will have a good to excellent experience dealing with a CHEC Group professional. However, the balance of respondents are not anticipating a good to excellent experience, and as such could be more challenging to serve.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course a negative transaction creates the perception that future transactions will be negative. The key then is to emphasize problem resolution with a "one call" mindset.

The impact of Very Satisfied or Very Dissatisfied experiences on some operational attributes

CHEC	Overall Score	Recent Experience Very Satisfied	Recent Experience Very Dissatisfied
Provides consistent, reliable energy	91%	94%	85%
Delivers on its service commitments to customers	89%	93%	88%
Accurate billing	88%	90%	77%
Quickly handles outages and restores power	90%	93%	78%
Makes electricity safety a top priority	90%	95%	94%
Uses responsible business practices when completing work	89%	94%	91%
Is efficient at handling hydro-electric systems	86%	91%	81%
Overall the utility proves excellent quality services	87%	91%	78%

Base: respondents who have contacted the utility

Customer Engagement Index (CEI)

The UtilityPULSE Customer Engagement Index (CEI) is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand.

What is Customer Engagement?

Ask 10 pundits, experts or academics about the definition of customer engagement and you will not get a consistent answer. UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called “customer engagement”. Here are the basic types:

1- Participation in programs or service offerings
2- Pro-active “reach-out” to customers
3- Customer loyalty
4- How customers think, feel and act towards the organization that serves them.

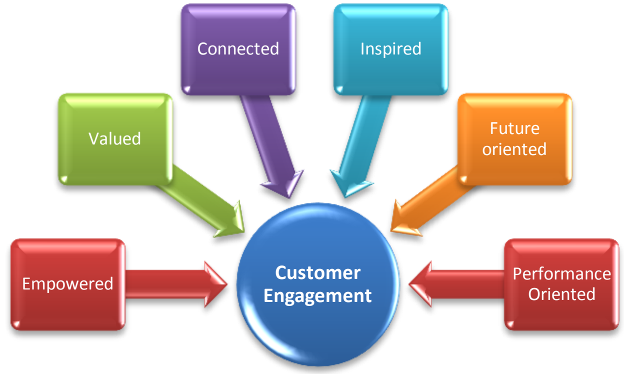
Ultimately, one has to decide if customer engagement is a program, or an outcome? Basic types 1 & 2 as shown above would suggest that engagement is a program. Types 3 & 4 are outcome based definitions. Drawing from our 25+ years of experience working with enterprises in both the private and public domains, we believe that basic types 1 & 2 are too simplistic and tend to be efficiency measurements. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with, essentially they are effectiveness and outcomes oriented measurements.

Your Annual UtilityPULSE survey tracks a customer's willingness to continue to do business, and willingness to recommend their local utility. Through a combination of calculations the end result is a Customer Loyalty index. That is, the number of customers that are: At risk, Indifferent, Favourable, Secure. The goal of every enterprise ought to be the creation of more Secure and Favourable customers. We believe that high levels of customer engagement correlate strongly to high levels of Secure and Favourable customer numbers.

We believe that a customer-centric definition of engagement is more valuable to individuals, teams and executives in an LDC for determining what needs to be done to ensure that the organization is successful today and successful again tomorrow – in a changed world.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

What does an engaged customer look like?



UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future oriented and performance oriented.

They include:

- Does the utility allow their customers to feel ***empowered*** about their interactions with the company and decisions affecting their electricity usage
- Does the utility give customers the sense of being ***valued***
- Does the utility act in ways which allows customers to stay ***connected***
- Do customers get ***inspired*** by the way the utility conducts business
- Is the utility forward thinking enabling customers to be ***future oriented***
- Does the utility conduct operations in such a way that customers believe that they are truly ***performance oriented*** in achieving goals and results

Utility Customer Engagement Index (CEI)			
	CHEC	National	Ontario
CEI	86%	81%	81%

Base: total respondents

UtilityPULSE Report Card®

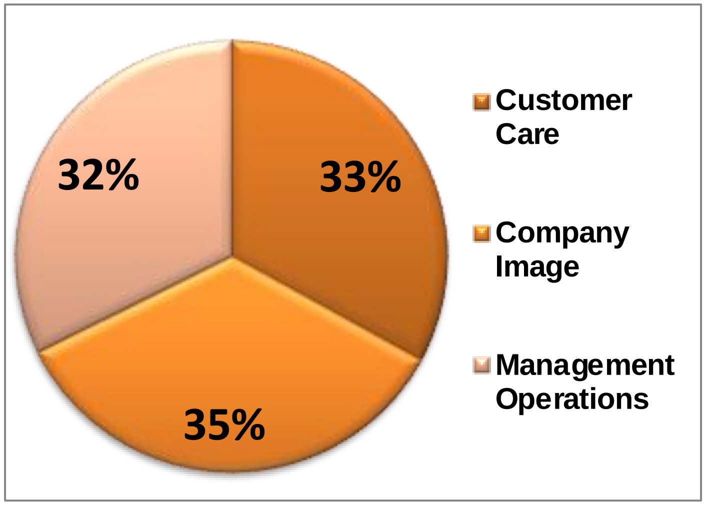
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over fifteen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things that customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), that customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card® the first is Customer psyche and the other is Customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect the Report Card provides feedback about your customers' perception on the importance of each category and driver – as it relates to the benchmark.

UtilityPULSE Report Card® for CHEC Group



Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry that they have about electricity. As our survey has shown since its inception the primary suggestion for improvement is “reduce prices”, which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means that, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn’t meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs and every now and again have to interface with their utility. How the utility handles various customers' requests and concerns is what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it.

A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players that residential customers (in particular) don't know who does what or who is responsible for what. So when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know that their utility is both a trusted and credible organization that is well managed, is accountable, is socially responsible and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product which utilities provide their customers and, they have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility has to get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring that their utility runs smoothly. Attributes such as: accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

Power Quality and Reliability

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable energy, handle outages and restore power quickly and make using electricity safely an important priority.

CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than “keeping the lights on”. Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect there are many moments of truth. Moments of truth are every customer touch point that a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

For communication, utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers, in a manner that speaks to them, the more satisfied they are with their overall service. “Sending out information” is not the same as having a “conversation” with a customer. We believe that it is increasingly important to channel your communications to the various customer segments which exist.

Obviously employees – in every area – play a critical role in customer service success. Consequently how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service which they actually provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.

Our survey work with employees shows that there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement. Our research has identified 6 main drivers that promote and support people giving their best: feeling empowered, valued, belonging, inspired, growing and performance oriented. There are 12 key processes from “attracting employees” to “saying goodbye to employees” that are part of your people model to get the best performance from every employee.

We believe that taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and from a people development perspective. Every organization has a culture – we believe that it is a leadership imperative to install and maintain a culture that ensures that you attain the achievements and successes of your utility’s many investments in people, technology and equipment.

The Loyalty Factor

If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

© UtilityPULSE

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer that affects the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

So what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Other favourable responses or behaviours can be classified into one of three categories that reflect the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy

Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs that help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies

Specific examples of potential compliance or influence behaviours that utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information that enables the utility to better serve the customer
- Paying bills online

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset that has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways, and foster happier and more loyal customers.

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

Secure customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

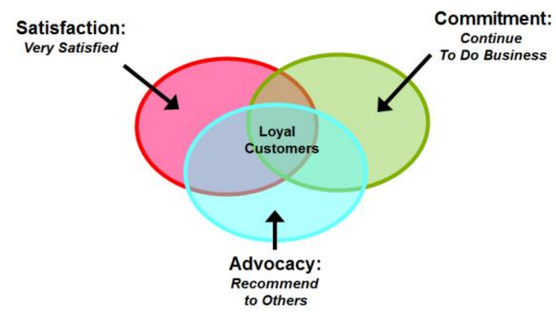
Still favorable customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are "very dissatisfied" with their electricity utility, "definitely" would switch and "definitely" would not recommend it.

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.

Customer Loyalty Model

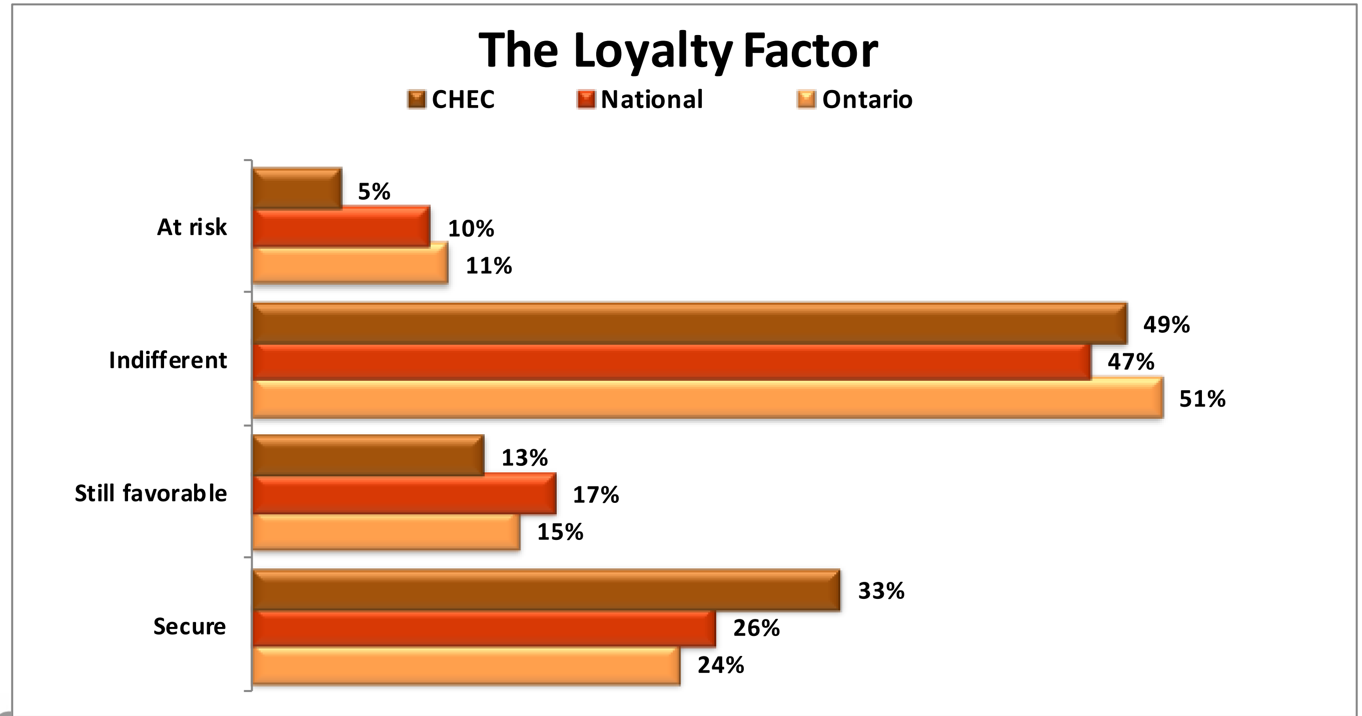


Loyalty is based on likelihood to:

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
		CHEC		
2013	33%	13%	49%	5%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year



Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
		Ontario		
2013	24%	15%	51%	11%
2012	20%	13%	53%	14%
2011	17%	13%	54%	16%
2010	21%	12%	52%	15%
		National		
2013	26%	17%	47%	10%
2012	30%	13%	46%	11%
2011	28%	14%	46%	12%
2010	17%	14%	60%	9%

Base: total respondents

Secure customers' experiences and perceptions are distinct from those of Indifferent customers. There is yet an even greater gap between those identified as Secure versus At Risk.

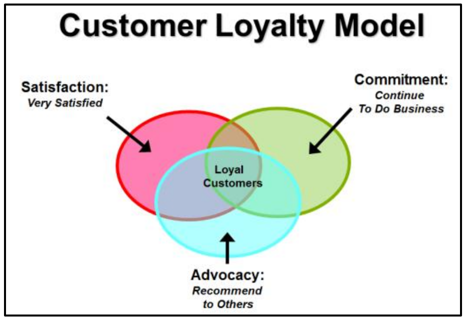
- Problems are experienced and remain unresolved far more often by the Indifferent or At Risk segments in comparison to others. This is not an unusual finding.
- Other areas of interaction also revealed considerable differences among the segments. Consistently, Secure customers' perceptions are most positive.

Important attributes which shape perceptions about customer affinity

	Overall Score	Secure	At Risk
Customer focused and treats customers as if they're valued	81%	95%	51%
Is pro-active in communicating changes and issues which may affect customers	82%	94%	59%
Deals professionally with customers' problems	86%	97%	62%
Works with customers to keep their energy costs affordable	70%	87%	40%
Quickly deals with issues that affect customers	84%	96%	60%
Delivers on its service commitments to customers	87%	97%	62%
Provides information and tools to help manage electricity consumption	83%	94%	61%
Is 'easy to do business with'	85%	98%	57%
Adapts well to changes in customer expectations	77%	91%	49%
The cost of electricity is reasonable when compared to other utilities	65%	81%	38%
Provides good value for your money	73%	89%	39%
Provides consistent reliable energy	91%	99%	80%
Operates a cost effective hydro-electric system	75%	91%	44%
Overall the utility provides excellent quality services	87%	98%	64%

Base:data from the full 2013 database from those respondents with an opinion

Customer commitment



Customer loyalty is a term that can be used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.**

Customer commitment to the local electricity supplier is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel that they "want to" vs "have to" do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is that customers will come to you when they need a product or service.

- Validate information received from 3rd parties with information and expertise that you have.
- Try new products/initiatives.
- Perhaps they will even trust you when recommendations are made.
- Be more price tolerant.
- More receptivity of utility viewpoints on various issues.
- More tolerance of errors or issues that inevitably take a swipe at the utility.
- Stronger levels of perception regarding how the utility is managed.

Though customers can not physically leave you, they can emotionally leave you and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

Electricity customers' loyalty – … Is a company that you would like to continue to do business with

	CHEC	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	85%	79%	80%
Definitely would continue	55%	47%	46%
Probably would continue	30%	31%	33%
Might or might not continue	7%	6%	6%
Probably would not continue	1%	4%	5%
Definitely would not continue	2%	6%	6%

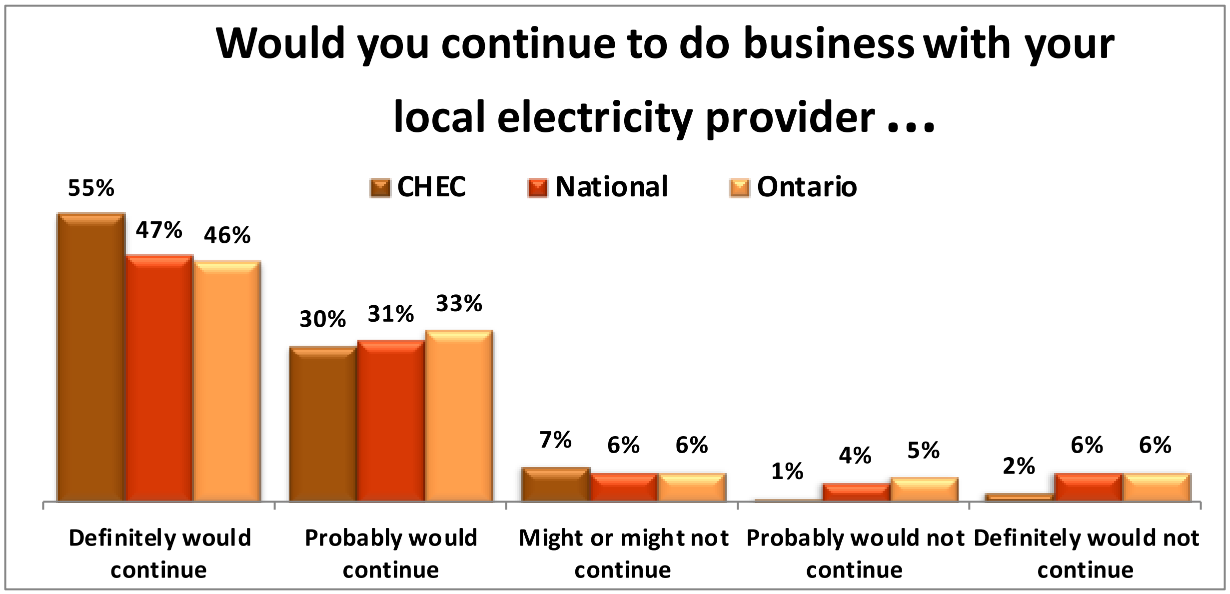
Base: total respondents

Electricity customers' loyalty – … Is a company that you would like to continue to do business with				
CHEC	<$40K	$70K+	18-34	55+
Top 2 Boxes: 'Definitely + Probably' would continue	90%	88%	92%	87%

Base: total respondents

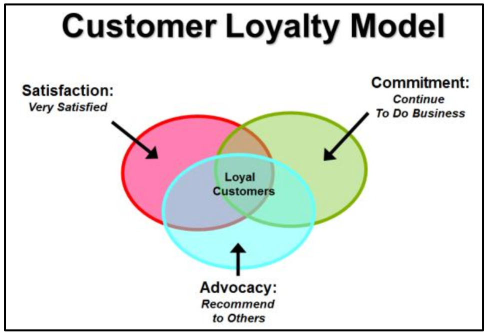
Electricity customers' loyalty – Is a company that you would like to continue to do business with				
CHEC	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would continue	85%	-	-	-

Base: total respondents / (-) not a participant of the survey year



Base: total respondents

Word of mouth



Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe that a loyal customer is one that is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.

When customers are loyal to a company, product or service, they not only are more likely to purchase from that company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. That equates to new customers and revenue. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.

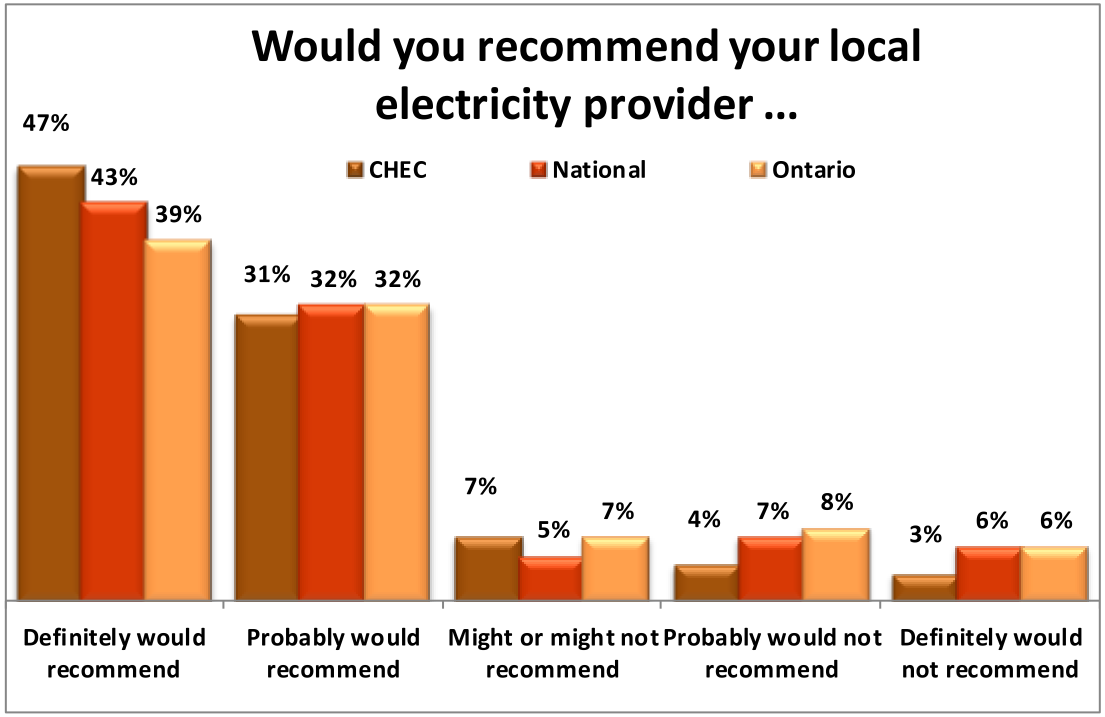
There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.

The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high that the offer will be "relayed" to others through word of mouth.

For an electric utility, specific examples of potential positive advocacy behaviour include:

- *Recommending that other customers specifically locate in the geographic area that is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Would you tell me if you agree or disagree with the following statement? CHEC is a company that you would recommend to a friend or colleague …



Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products provided better than marketing communication.

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	CHEC	**National**	**Ontario**
Top 2 boxes: 'Definitely + Probably' would recommend	78%	75%	71%
Definitely would recommend	47%	43%	39%
Probably would recommend	31%	32%	32%
Might or might not recommend	7%	5%	7%
Probably would not recommend	4%	7%	8%
Definitely would not recommend	3%	6%	6%

Base: total respondents

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague				
CHEC	**<$40K**	**$70K+**	**18-34**	**55+**
Top 2 boxes: 'Definitely + Probably' would recommend	84%	79%	90%	80%

Base: total respondents

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague				
CHEC	**2013**	**2012**	**2011**	**2010**
Top 2 boxes: 'Definitely + Probably' would recommend	78%	-	-	-

Base: total respondents / (-) not a participant of the survey year

Corporate image

Organizations today are always under scrutiny and have to consider the reality AND perception of their image. In the simplest of terms, how you are seen by your stakeholders is your corporate image and reputation. The corporate image is a dynamic and profound affirmation of the nature, culture and structure of an organization. This applies equally to corporations, businesses, government entities, and non-profit organizations.

The corporate image communicates the organization's mission, the professionalism of its leadership, the caliber of its employees and its roles within the marketing environment or political landscape. Every organization has a corporate image, whether it wants one or not.

All companies survive on the strength of the relationships they build with their customers. To build and maintain a corporate image, a company must express its brand consistently in a wide range of ways including websites, advertising and "information" materials, but also customer service, the look and layout of the workplace and the way the company functions as a whole. Failure to do that can mean a business could, at worst, appear fraudulent, and at best not exploit the brand's potential.

When properly designed and managed, corporate image will accurately reflect the level of the organization's commitment to quality, excellence and relationships with its various stakeholders, including customers, employees, suppliers, partners, governing bodies, and the general public at large. As a result, corporate image is a critical concern for every organization, one deserving the same attention and commitment by senior management as any other vital issue.

Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial. Below are some of the attributes measured in the annual UtilityPULSE survey which are strongly linked to a utility's image.

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Is a respected company in the community	89%	83%	84%
Maintains high standards of business ethics	88%	81%	81%
A leader in promoting energy conservation	85%	80%	80%
Keeps its promises to customers and the community	88%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	86%	79%	79%
Is a trusted and trustworthy company	89%	83%	83%
Adapts well to changes in customer expectations	80%	74%	73%
Is 'easy to do business with'	88%	82%	81%
Overall the utility provides excellent quality services	87%	85%	83%
Operates a cost effective hydro-electric system	79%	72%	68%

Base: total respondents with an opinion

These attributes measure different facets of reputation such as the extent to which the company is providing excellent quality services, whether the company is known as leader in the industry and respected in the community, how the company delivers value, reliable service and support, how the company efficiently manages its business, the company's approach to making the world a better place - environmental and social commitments, and the emotional connection the company has with the people.

People feel better about themselves when they believe they are dealing with an organization that cares about "doing the right thing". Today, being a good corporate citizen requires more than business as usual, it requires investments in society and the environment.

Our research has shown when customers attribute positive feelings to a utility's corporate visual identity systems, when they think that marketing communication activities reflect corporate values, and when they perceive the company as socially responsible, they tend to form a favourable image of that organization. Our research also shows that customers put more emphasis on an LDC's brand image as an influencer of satisfaction and loyalty today than they did 10-15 years ago.

Corporate Credibility & Trust

No organization or company can plunge trust and credibility among its customers and stakeholders – and survive. Building and maintaining credibility and confidence make up a deliberate process that occurs over numerous interactions usually over a long period of time.

Establishing trust and credibility, whether with business partners, customers or regulators, is not achieved overnight. Creating credibility is a process, which advances only through honest, continuous communication between the utility, its regulators, and the public at large. Credible communications are informed and nurtured by diligent efforts on the utility's part to understand the legal and regulatory framework in which it operates. Public trust in their local utility is the degree to which the public believes that the utility will act in a particular manner because the utility has incorporated the public's interest into its own. The public trusts the utility to produce consistent and reliable electricity.

Attributes strongly linked to a hydro utility's image

	CHEC	National	Ontario
Overall the utility provides excellent quality services	87%	85%	83%
Keeps its promises to customers and the community	88%	81%	82%
Customer-focused and treats customers as if they're valued	84%	76%	77%
Is a trusted and trustworthy company	89%	83%	83%

Base: total respondents with an opinion

Trust and credibility can be thought of as indicators of the degree of confidence stakeholders have in your organization's ability to deliver on its commitments. Trust and credibility are outcomes based on what your utility actually does, not what it might be doing.

Simul/UtilityPULSE research shows the underpinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.

Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.

Involvement — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and manpower to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Using the four components of demonstrating Credibility and Trust, the resultant index shows that LDCs enjoy a high level of credibility and trust. As Benjamin Franklin said, “It takes many good deeds to build a good reputation, and only one bad one to lose it.”

Credibility and Trust Index
Knowledge The utility is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value.
Integrity The utility is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.
Involvement The utility is actively involved in the industry, in the community and in things that affect the customer.
Trust The utility is an organization that can be trusted and is worthy of respect.
Overall CHEC Group 87% [Ontario 82%; National 82%]

How can service to customers be improved?

Perception is an opinion about something viewed and assessed and it varies from customer to customer, as every customer has different beliefs towards certain services and products that play an important role in determining customer satisfaction.

Customers are more informed, more aware, more conscious of what's going on around big issues in the world around them and in this age of internet and social media, they are better equipped to influence service quality and outcomes. They have learned to compare products and services, to document and monitor customer service and satisfaction, and to request or demand higher quality.

Customer satisfaction is determined by the customers' perceptions and expectations of the quality of the products and services. In many cases, customer perception is subjective, but it provides some useful insights for organizations to develop their marketing strategies. Just as in previous years, respondents were asked once again what their utility could do to improve service.

And we are interested in knowing what you think are the one or two most important things 'your local utility' could do to improve service to their customers?

One or two most important things 'your local utility' could do to improve service	
CHEC	**% of all suggestions**
Better prices/lower rates	45%
Improve/simplify/clarify billing	12%
Improve power reliability	10%
Concerns about SMART meters	8%
Better communication with customers	8%
Staff related concerns	8%
Information & incentives on energy conservation	5%
Remove hidden costs on bills	5%
Better on-line presence	5%
Be more efficient	4%
Increase service hours/availability of hydro representative	3%
Don't charge for previous debt	3%

Base: total respondents with suggestions

SMART Meters & SMART Grid

Consumers are used to paying different amounts during different times of day in a variety of settings. In larger cities, drivers pay more for parking when there is higher demand, such as during the day or during special events. Similarly, some highway toll charges increase during commuting hours, while drivers who drive across during off peak hours will save money. Customers even acknowledge that they will pay more for using their cell phone minutes during weekdays rather than nights and weekends.

Demand for energy is going up. Energy prices are climbing. What are customers to do?

Customers can respond to increases in energy prices in one of 3 ways:

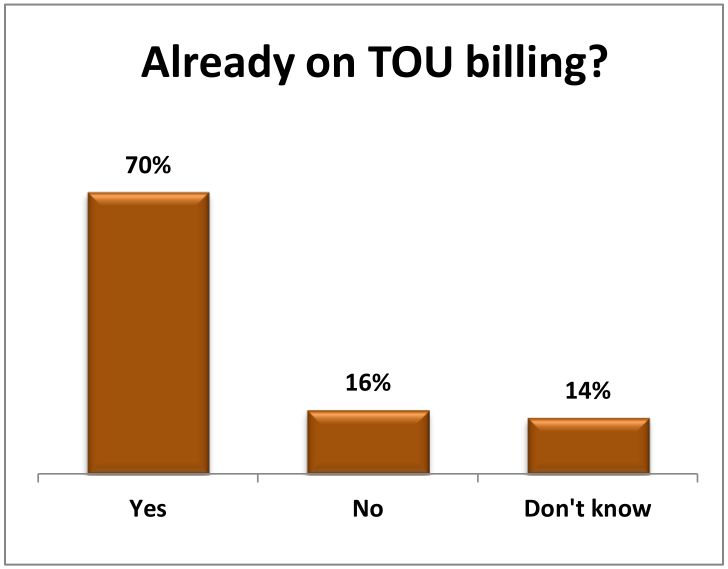
(1) changing energy usage behaviour,

(2) investing in energy-using technologies and practices, or

(3) making no change to their energy usage.

Time-of-use (TOU) pricing was designed to reward consumers who shift their load to off-peak times. Electricity rates on weekends and overnight are about half of the cost during peak hours. This is supposed to be an economic incentive for people to shift electricity use to off-peak hours.

There is a direct correlation between customer familiarity with SMART meters and their favourable views toward the technology. While the majority of respondents could identify they were on TOU billing, a significant proportion were not in the know. Lack of knowledge is a real barrier to ultimate acceptance and/or any type of behaviour modification.

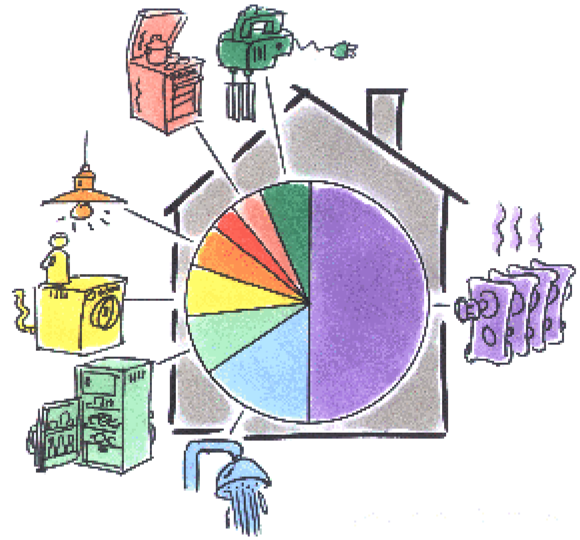


Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Do economic incentives, based on time-tiered pricing, have an impact on resource consumption patterns? Does awareness about electricity use change behaviours? Respondents of the 2013 survey seem to believe they have. *77% agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis. [Base: Ontario LDC respondents]*

Time-of-Use billing has changed the way in which you consume electricity on a day-to-day basis	
	Ontario LDCs
Agree strongly	42%
Agree somewhat	35%
Neither / Neutral	2%
Disagree somewhat	10%
Disagree strongly	11%

Base: An aggregate of respondents from 2013 participating LDCs



Most residential energy use, most of the time, is invisible to the user. Most people have only a vague idea of how much energy they are using for different purposes and what sort of difference they could make by changing day-to-day behaviour or investing in efficiency measures. Feedback is important so that energy usage becomes visible, thereby, creating more understanding and ultimately easier to exercise control.

When it comes to energy, people tend to overestimate the amount of energy used by devices that are "visible" to them and underestimate the amount of energy used by devices that are "not visible" to them. SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities.

The survey data indicates that customer awareness and understanding of the benefits that can be derived from SMART grid technologies are still in an early stage. For the most part respondents were mostly unfamiliar or uninformed.

Level of knowledge about the SMART Grid	
	Ontario LDCs
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%
I have a basic understanding of what it is and how it might work	17%
I've heard of the term, but don't know much about it	33%
I have not heard of the term	42%
Don't know	1%

Base: An aggregate of respondents from 2013 participating LDCs

Next respondents were asked what degree of importance they attached to their local hydro utility in pursuing the implementation of the SMART Grid and its associated technologies.

The SMART Insight from this poll is: even though more than half the respondents did not know much about the SMART Grid, 53% felt it was very or somewhat important to pursue its implementation and 75% responded that they were very or somewhat supportive of their local utility working with neighbouring utilities to get the most value out of the SMART Grid.

Importance of pursuing implementation of the SMART Grid	
	Ontario LDCs
Very important	23%
Somewhat important	30%
Neither important or unimportant	9%
Somewhat unimportant	5%
Unimportant	10%
Don't know	23%

Base: An aggregate of respondents from 2013 participating LDCs

Support towards working with neighbouring utilities on SMART Grid initiatives		
	Ontario LDCs	
Very supportive	38%	
Somewhat supportive	37%	
Neither supportive or unsupportive	4%	
Somewhat unsupportive	2%	
Unsupportive	6%	
Don't know	12%	0 %

Base: An aggregate of respondents from 2013 participating LDCs

Energy Conservation & Efficiency

Improving energy efficiency does not mean that citizens have to give up or forgo activities to save energy, that is, “turn off the lights and put on another sweater”. Rather, new technologies and more effective behaviour will actually allow citizens to do more, improving their living conditions rather than reducing their comfort.

Reducing the amount of energy we use by choosing energy-efficient appliances and services, and ensuring we do not waste energy can make a big difference. It is possible for residents to cut energy use without compromising on performance, through changes in customer behaviour and by investing in more efficient energy technologies – effectively doing more with less.
This makes sense both for society as a whole and for businesses, individuals and families. Less energy use means lower energy bills. People simply need to be aware of their energy use.

Energy efficiency can be broken down into two areas:

1) better use of energy through improved energy-efficient technologies; and

2) energy saving through changes in customer awareness and behaviour.

Energy efficiency has been seen as primarily about technologies: using the best technology to consume less energy. Examples include changing a household furnace or air condition unit for one that consumes one third less energy, using low-energy light bulbs and avoiding keeping appliances in 'standby' mode. Respondents were asked what they have done or will do to conserve energy.

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	20%	10%	69%	1%
Install timers on lights or equipment	15%	49%	35%	2%
Shift use of electricity to lower cost periods	21%	19%	57%	3%
Install window blinds or awnings	15%	26%	58%	1%
Install a programmable thermostat	15%	20%	63%	2%
Have an energy expert conduct an energy audit	9%	70%	18%	3%
Removing old refrigerator or freezer for free	14%	45%	37%	4%
Join the peaksaverPLUS™ program	18%	48%	21%	13%
Replacing furnace with a high efficiency model	13%	36%	48%	3%
Replacing air-conditioner with a high efficiency model	16%	39%	41%	4%
Use a coupon to purchase qualified energy saving products	33%	42%	21%	4%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

New technologies will have little effect if users cannot be convinced to use them. Changing customer behaviour has to be driven by increasing awareness of the benefits of energy saving, both for the individual and for society. Awareness of the energy that we use as individuals, families, households or organizations is very important – as is the impact that can be made by not wasting energy – both individually and collectively.

Behaviour is one of the parameters with a direct relation to individual energy consumption. Individual behaviour in energy use is determined by a number of factors, the most important of which are attitude, income and energy pricing. Less directly related are energy policy (including taxation) and technology availability as these relate to pricing and income respectively. However education can influence attitude in order to change behaviour; it can also inform individuals about energy policy and technology which feeds into behavioural change.

SMART Feedback from participants shows, predictably, the most frequently mentioned barrier to energy conservation was upfront financial costs. Not having the upfront funds limits the household's ability to invest in new appliances and to make other energy efficiency retrofits.

One participant noted that, even with programs that provide free appliance disposal, "if you get rid of your old fridge, you don't pay for disposal, but you need money for the cost of the new appliance". Likewise, another respondent commented that limited upfront funds "affect all households - but are particularly strong for low income households where there is no money to invest in retrofits."

Another barrier to conservation described by the survey respondents was awareness of programs and issues related to energy conservation. Generally speaking, the respondents felt that often lower-income and senior-occupied households did not have access to sufficient information that would allow them to reduce or to shift electricity usage. The respondents noted that although the person may have intentions of wanting to do the right thing, they are not sure or do not know exactly what the right thing to do is.

What are the 1 or 2 barriers to energy conservation experienced by Ontarians?

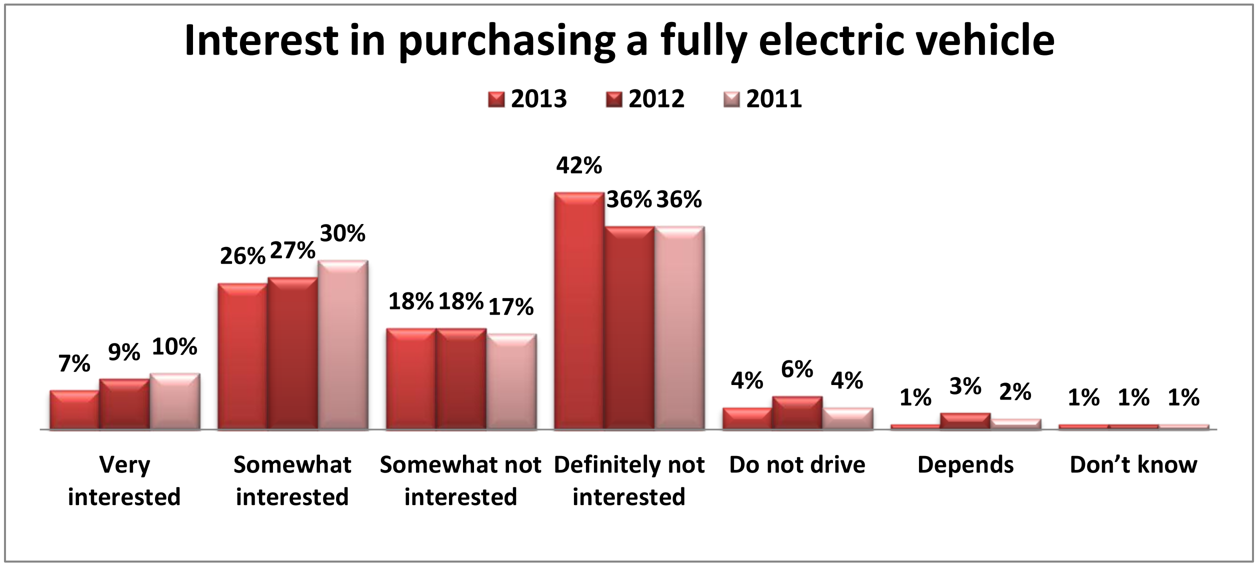
	Ontario
Cost involved in making equipment/appliance changes	21%
Lifestyle changes / inconvenient	11%
Lack of interest or personal responsibility	8%
Lack of knowledge	7%
Waiting for better technology / Greener options	6%
Lack of information / confusion as to the "right" thing to do	5%
Not enough incentives	4%
Have an issue with Government policies	3%
None	12%
Don't know	29%

Base: total respondents from 2013 Ontario Benchmark survey

Purchasing an Electric Vehicle

A clear majority (60%) of car drivers are strongly not in favour of electric vehicles replacing conventional vehicles at this time. There is, however a significant minority (34%) who do favour such a development. None-the-less the EV is having an impact on travel and its influence is set to increase.

An income breakdown of the "positive support" data shows the strength of opinion in the higher income ranges. 45% of respondents in the $40k-$70k income range and 43% of those making $70K or more are in favour of EVs replacing conventional vehicles over time, and less than one quarter (22%) of wage earners in the under $40k category. Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 are in favour of EVs replacing conventional cars. 43% of those aged 18-34 are receptive to the idea of purchasing an electric vehicle.



Base: total respondents from 2013 Ontario Benchmark survey

When asked how long it would be before they would consider an EV as an option for their next car purchase, only 1 in 10 (11%) would consider an EV within the next 24 months.

Interest in purchasing a fully electric vehicle

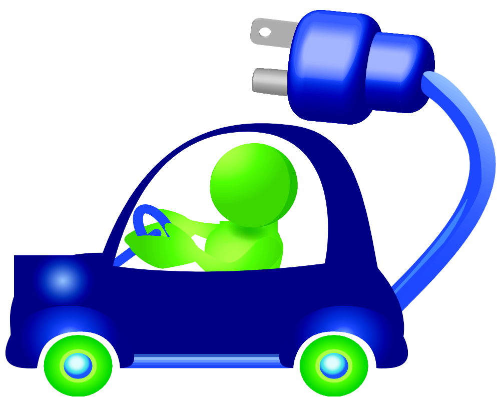
	Income <$40K	Income $40K<$70K	Income $70K +	Age 18-34	Age 35-54	Age 55+
Very interested	4%	10%	11%	14%	12%	3%
Somewhat interested	18%	35%	32%	29%	35%	19%
Somewhat not interested	17%	17%	21%	24%	21%	16%
Definitely not interested	46%	35%	34%	33%	28%	53%
Don't know	1%	0%	2%	0%	2%	1%

Base: total respondents from 2013 Ontario Benchmark survey

Length of time before purchasing a fully electric vehicle

	Ontario
Immediately to next 6 months	1%
7 to 12 months	2%
13 to 24 months	8%
Over 24 months	84%
Depends	1%
Don't know	3%

Base: total respondents from 2013 Ontario Benchmark survey



E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to:

- receive and pay bills on the internet,
- sign up for and change their services using the internet,
- find answers to their questions online about their accounts, i.e. statements, payments, balances
- learn about products, services and topics, i.e., green energy, electricity pricing, etc.

Do you have access to the internet?		
	Ontario LDCs	**CHEC**
Yes	86%	83%
No	14%	17%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

We asked respondents who were currently connected or had access to the internet if they in fact visited their local utility website. Out of all the respondents who had internet access, only 14% claim that they had actually been to their utility's website.

Over the past six months have you accessed your local utility website?		
	Ontario LDCs	**CHEC**
Yes	27%	14%
No	72%	86%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Does the average household customer feel comfortable enough with internet technology to believe it is the best place to get customer care or to receive and pay their bills?

Moving customer care and billing to the internet raises a number of questions and presents new opportunities to the utility industry.

- Is online billing and customer care a differentiator for utility providers?
- Can e-bills be used to improve customer loyalty by attracting customers to their website on a regular basis and thereby exposing customers to additional information, news, and education?
- Does the internet provide an environment where the most commonly asked general questions about a customer's hydro bill be highlighted or linked directly to the customer's bill?
- Can e-bills follow a cycle time that is customer driven? That is, could the customer determine the day in the billing cycle for the e-bill to be produced?

Likelihood of using the internet for future customer care needs for things such as:		
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**	**CHEC**
Setting up a new account	39%	29%
Arranging a move	47%	39%
Accessing information about your bill	59%	47%
Accessing information about your electricity usage	58%	49%
Accessing energy saving tips and advice	52%	43%
Learning more about SMART meters	49%	43%
Registering a complaint	43%	32%
Registering a compliment	48%	41%
Accessing information about Time Of Use rates	59%	49%
Maintaining information about your account or preferences	56%	46%
Paying your bill through the utility's website	35%	27%
Paying your bill using smart phone applications	23%	19%
Getting information about power outages	47%	41%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Ideally, utilities want customers to embrace e-billing and other electronic services; however, a hindrance on the most basic level will discourage customers from considering additional online services, i.e. accessing SMART meter data. The goal is to inform customers of their electricity usage, and make them aware of the potential to conserve electricity.

Accessed SMART meter information from the utility's website		
	Ontario LDCs	**CHEC**
Yes	8%	4%
No	91%	95%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

What utilities don't want to do is force their customers to contend with a time-consuming, labour-intense process. Instead, make it easy, quick and secure. A positive online experience will most likely lead to a better online relationship with customers that will grow over time. Inconsistent user experiences are harmful to customer confidence.

The respondents, who did access their SMART meter information, claimed they found it to be easy ('very + somewhat') to access their SMART meter information.

Ease of accessing SMART meter information on the utility's website		
	Ontario LDCs	**CHEC**
Top 2 Boxes: 'very + somewhat easy'	90%	88%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Respondents were asked about the likelihood of accessing SMART meter data on the website in future.

Likelihood of accessing SMART meter information on the utility's website in future		
	Ontario LDCs	**CHEC**
Top 2 Boxes: 'very + somewhat likely'	49%	42%
Bottom 2 Boxes: 'somewhat + very unlikely'	50%	58%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

The banking industry is one industry that has entered the online environment with consumers earlier than most industries; and therefore, many lessons can be learned from that industry for utility providers, including security, FAQs, prompt e-mail response, online bill history, and mistakes to avoid.

In order to convert traditional billing and payment customers to a paperless, automated solution, utilities need to understand the reasons behind customers' reservations, such as:

- process is not user-friendly leading to a poor customer experience
- online registration is or could be a hassle
- the extra work of keeping track, downloading etc. in a time pressed society
- password fatigue for customers who just don't want to manage another log-in credential
- apprehension that no longer receiving a paper bill could increase the likelihood that they'll inadvertently miss a bill and/or payment
- unease that payment information will not be secure and could be easily hacked.

Consumers will eventually adopt electronic billing and online customer care as many industries begin providing consumer bills online, and critical mass is reached. However, customers still want to have the choice of receiving customer care from a live person. Even after they start using online technology, customers still want to be able to receive hard copies of their bills as a backup.

Using the internet for billing

	Ontario LDCs	CHEC
I am already receiving my hydro bill electronically	10%	4%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%	11%
I use on-line banking but prefer to have paper statements	30%	35%
I prefer to have the paper copy of my bills	23%	26%
I don’t use on-line banking	17%	22%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Because utilities serve a diverse demographic that includes households, businesses, all income levels, and people from all walks of life, understanding customers’ concerns, needs and comfort levels will go a long way to ensuring that the solution is one that they will actually use. For example, interactive voice response (IVR) system with specific-language call flows, young working commuters might be more inclined to use mobile bill-pay, or those customers (e.g., senior citizens) who might not be as adept or comfortable with technology might prefer the ability to pay over the phone or in-person.

Understanding customer profiles will enable utilities to provide the right bill-pay options for them; thereby increasing usability rates--- and, the perception that they adapt well to changes in customer expectations.

Using the internet for billing

Ontario LDCs	18-34	55+
I am already receiving my hydro bill electronically	19%	8%
I use on-line banking and will definitely be requesting that my bill be sent electronically	20%	7%
I use on-line banking but prefer to have paper statements	36%	24%
I prefer to have the paper copy of my bills	9%	29%
I don't use on-line banking	5%	24%
Don't know	10%	8%

Base: An aggregate of respondents from 2013 participating LDCs

If utility companies ensure that the electronic billing solutions they offer customers are easy to use, convenient, feature-rich, comprehensive and secure, adoption rates will surely increase.

Likelihood of the following to encourage customers to go paperless for billing purposes		
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**	**CHEC**
Providing a one-time financial incentive to switch	53%	44%
Being entered into a special draw for customers who make the switch	42%	35%
Learning more about the benefits to going green with paperless billing	46%	37%
A better understanding of the convenience of paperless billing	45%	37%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Customers are afraid if they don't receive a paper bill in the mail each month, they are going to forget to make a payment as well as, incur penalties and late fees or even harm their credit score. By proactively delivering information to customers, by phone, text, and email, customers will remain informed and in control of their billing and account status and be more likely to use additional online services. Also, giving customers online access to the prior 18 to 24 months of billing statements will alleviate concerns over losing a bill or needing old statements. Ensuring that a switch to online processes does not change anything for a customer is key; the idea is to make sure customers are provided with everything they have always had, plus a lot more.

Social Media

Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. As customers increasingly turn to social channels to seek information and advice and to express opinions, there is no question that organizations must engage with those channels to deliver appropriate customer care and ensure positive experiences. Respondents of this year's survey were asked *"how likely they would use social media as a resource for energy efficiency tips or to help manage your electricity use"…*

Likelihood of using Social Media to gather information

	CHEC	Ontario LDCs	Ontario LDCs Age Group: 18-34	Ontario LDCs Age Group: 55+
Very likely	4%	6%	10%	3%
Somewhat likely	7%	11%	17%	6%
Not likely	22%	20%	24%	17%
Not likely at all	64%	61%	48%	68%
Don't have social media account	2%	2%	0%	4%
Don't know	0%	1%	0%	1%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

What do customers think about electricity costs?

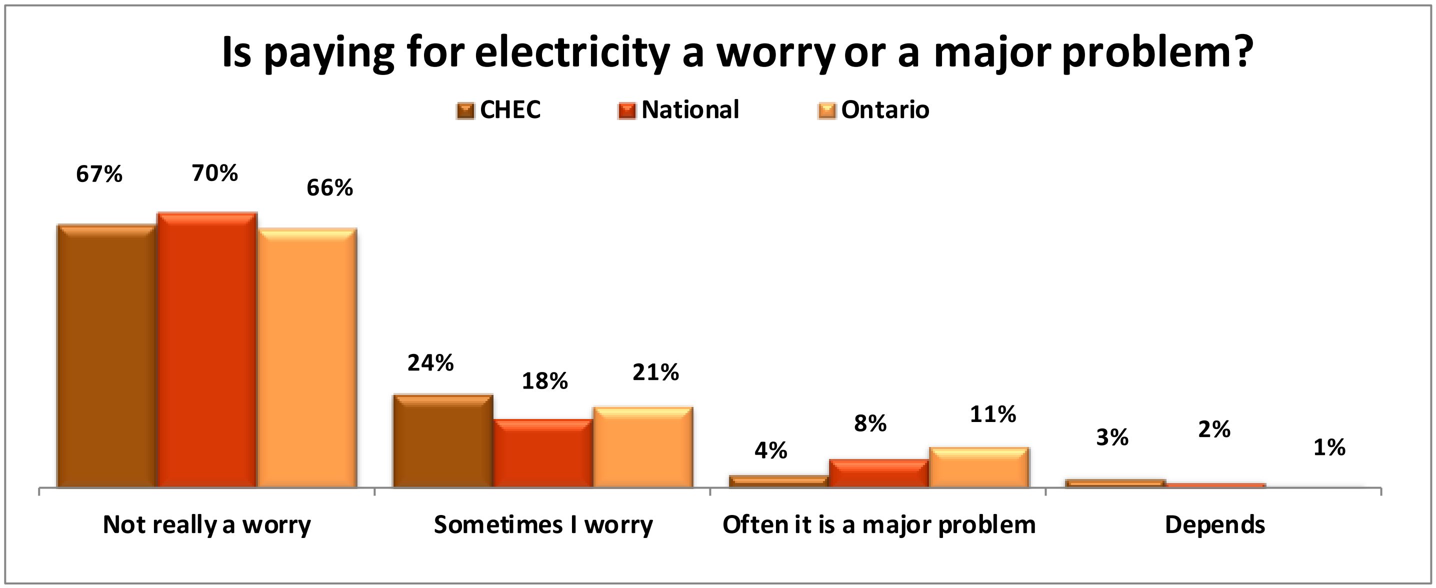
Today electric utilities are facing steadily, increasing costs to generate and deliver electricity. Utilities are building transmission lines, installing new equipment and fixing up power plants. While LDC's make continuous efficiency improvements and are working with regulators to contain costs and to keep electricity prices as low as possible, the fact is that rising electricity costs are becoming inevitable.

At a time when income growth seems to be stagnating, electricity is consuming a greater share of Canadians' after-tax income than at any time since the mid 1990's. Higher costs are being driven by both higher prices per kilowatt hour and greater electricity use at home, in roughly equal measure. While modern electronics and appliances require less electricity than older models, i.e. a new refrigerator runs on half the electricity of a model from the 1990's, houses have become bigger, which entail more air-conditioning and more electronics than before.

Next I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
		CHEC		
2013	67%	24%	4%	3%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year



Base: total respondents

There are certain kinds of costs that hit fixed-income (those on disability income) and low-income people the most, and one of those things is energy costs, which are not discretionary. Ontario is one of several provinces to install “SMART” electricity meters on households. They promote better resource use by billing customers extra for energy consumed during peak daytime hours, however in order to benefit from TOU a behaviour change in consumption must take place.

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
		CHEC		
<$40,000	54%	35%	7%	4%
$40<$70,000	61%	32%	3%	3%
$70,000+	80%	13%	3%	3%

Base: total respondents

Customers have a right to expect more than the mere delivery of electricity. They have the right to expect efficiency, competence and value for money. Utilities seeking to become more customer-centric must go beyond the transactional relationship of customer pays a price and receives electricity. Becoming customer-centric involves offering customers a value proposition; a complete package, filled with lots of human-friendly usability elements, peace of mind, and top-notch customer service.

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
		Ontario		
2013	66%	21%	11%	1%
2012	59%	27%	11%	2%
2011	52%	31%	13%	3%
2010	67%	23%	8%	2%
		National		
2013	70%	18%	8%	2%
2012	67%	22%	8%	2%
2011	63%	25%	8%	2%
2010	71%	20%	6%	1%

Base: 2013 Ontario and National benchmark surveys

What do small commercial customers think?

Residential and small business customers create the bulk of a utility's service transactions every day—and account for more than half of the energy consumed — understanding their needs and expectations is becoming more important than ever before.

In the 15 years that UtilityPULSE has undertaken electric utility satisfaction surveys, the data has mostly supported that the small business owner behaves much in the same way as the residential customer. While there are typically more similarities between small commercial and residential accounts, there are some fundamental differences in these customer classed segments. This year's data shows a difference in satisfaction levels for customer service; commercial customers responded more favourably than residential. On the subject of bills and outages, residential respondents reported more outage problems and fewer billing problems than commercial customers.

Small Commercial Customer (General Service < 50kW Demand)

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 kW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

Deposit requirements, monthly energy bills (and, therefore, energy usage), power quality, and reliability all directly impact a small business's financial situation. Unlike residential customers who tend to describe the cost of power interruptions in terms of a "inconvenience", commercial (and industrial) customers associate power interruptions with the cost of lost business, i.e., a loss in production is a loss in profits.

Likewise, based on the requirement of electricity to sustain business operations, there exists a difference in actual levels of demand response. For instance, small business and commercial users are unlikely to choose to decrease their electricity consumption if it is incompatible with efficient management of their business processes or threatens contracted deliveries to their primary product markets. In some cases, electricity consumption is a relatively small proportion of total input and operating costs, which substantially reduces the financial incentive for shutting down production during on peak pricing.

The tables associated with this report will contain Ontario LDC specific information as it relates to residential and commercial customers. Recognizing that smaller data samples are susceptible to greater data swings, for most LDCs there would be 60 or 90 responses from small commercial customers. We have compiled the following based on a group composite of all of our 2013 discussions with small commercial and residential customers.

Satisfaction: Pre & Post		
Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')	**Residential**	**Commercial**
Initially	92%	93%
End of Interview	93%	94%

Base: total respondents from the full 2013 database

As it relates to the six attributes associated with customer service:

Very or fairly satisfied with…	Residential	Commercial
The time it took to contact someone	79%	83%
The time it took someone to deal with your problem	76%	81%
The helpfulness of the staff who dealt with your problem	78%	85%
The knowledge of the staff who dealt with your problem	79%	85%
The level of courtesy of the staff who dealt with your problem	86%	92%
The quality of information provided by the staff member	76%	83%

Base: total respondents from the full 2013 database

Overall Commerical respondents were more satisfied with customer service than Residential respondents

Overall satisfaction with most recent experience		
	Residential	**Commercial**
Top 2 Boxes: 'very + somewhat satisfied'	78%	81%
Bottom 2 Boxes: 'somewhat + very dissatisfied'	20%	17%

Base: total respondents from the full 2013 database

Comparisons between Residential and Commercial		
Loyalty Groups	**Residential**	**Commercial**
Secure	30%	29%
Still Favourable	13%	14%
Indifferent	51%	50%
At risk	6%	7%

Base: total respondents from the full 2013 database

Loyalty Model Factors	*Residential*	*Commercial*
Very/somewhat satisfied	92%	93%
Definitely/probably would continue	84%	83%
Definitely/probably would recommend	78%	79%

Base: total respondents from the full 2013 database

Outages & Bill problems	Residential	Commercial
Respondents with outage problems	29%	23%
Respondents with billing problems	9%	13%

Base: total respondents from the full 2013 database

Residential respondents had reported more outage problems

Residential respondents reported fewer billing problems

Attempts to contact local utility…	Residential	Commercial
Respondents with outage problems	18%	37%
Respondents with billing problems	51%	69%

Base: total respondents from the full 2013 database

Important attributes which describe operational effectiveness		
	Residential	Commercial
Provides consistent, reliable energy	96%	95%
Delivers on its service commitments to customers	89%	89%
Accurate billing	86%	88%
Quickly handles outages and restores power	87%	85%
Makes electrical safety a top priority	55%	66%
Uses responsible business practices	67%	75%
Is efficient at managing the hydro-electric system	72%	71%
Is a company that is ‘easy to do business with’	85%	89%
Operates a cost effective hydro-electric system	61%	61%

Base: total respondents with an opinion from the full 2013 database

Important attributes which shape perceptions about corporate image		
	Residential	**Commercial**
Is a respected company in the community	85%	86%
Maintains high standards of business ethics	70%	76%
A leader in promoting energy conservation	74%	70%
Keeps its promises to customers and the community	72%	73%
Beyond creating jobs and paying taxes, is socially responsible	66%	65%
Is a trusted and trustworthy company	85%	87%
Adapts well to changes in customer expectations	62%	64%
Overall the utility provides excellent quality services	91%	92%

Base: total respondents with an opinion from the full 2013 database

Important attributes which shape perceptions about service quality and value		
	Residential	**Commercial**
Is pro-active in communicating changes and issues which may affect customers	79%	78%
Provides good value for money	69%	69%
Customer-focused and treats customers as if they're valued	75%	77%
Deals professionally with customers' problems	72%	82%
Quickly deals with issues that affect customers	71%	76%
Provides information and tools to help manage electricity consumption	82%	78%
Works with customers to keep their electricity costs affordable	61%	57%
The cost of electricity is reasonable when compared to other utilities	56%	53%

Base: total respondents with an opinion from the full 2013 database

Is paying for electricity a worry or a major problem?		
	Residential	**Commercial**
Not really a worry	70%	71%
Sometimes I worry	20%	19%
Often it is a major problem	6%	6%
Depends	3%	2%

Base: total respondents

Method

The findings in this report are based on telephone interviews conducted for Simul Corp. by Corsential between April 10 - April 23, 2013, with 632 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by CHEC.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 632 residential and commercial customers will differ by no more than ±3.90 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 3.90 percentage points in either direction from results that would have been obtained by interviewing all CHEC residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 1,652 households and businesses from the customer list supplied by CHEC. The 632 who completed the interview represent a 38% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted March 13 through March 26, 2013, with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve.

The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the

CHEC data on corporate image, Simul converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.63 for providing consistent, reliable energy. The average is 2.93 for working with customers to keep their energy costs affordable.

For reliable energy the standard deviation is 0.57. For affordable energy the S.D. is 0.92. These findings mean there is a wider range of opinion – meaning less consensus – about whether CHEC works with customers to keep their energy costs affordable than about whether CHEC energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Certain questions pertaining to conservation and conservation efforts used an aggregate data approach whereby similar data sets were accumulated to form a larger sample size establishing a higher confidence interval, forecasting value and modeling data.

In these instances, all of the sub-datasets from the entire UtilityPULSE database for 2013 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 6,000.

At a 95% confidence level the margin of error is ±1.23 and at a 99% confidence level the margin of error would be ±1.62. So the aggregate strategy has given a very good population sample size which better, or more accurately, reflects the true feelings and beliefs of the population as a whole.

Simul

UtilityPULSE

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For fifteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

ORANGEVILLE HYDRO

Appendix F -

Collective Agreement

2010 - 2014

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

ORANGEVILLE HYDRO LIMITED

Hereinafter referred to as

“the Board”

and

POWER WORKERS' UNION (CUPE Local 1000)

Hereinafter referred to as

“the Union”

OCTOBER 1, 2010 TO SEPTEMBER 30, 2014

I N D E X

	ARTICLE	PAGE
Allowances	14.	11
Arbitration	4.06	3
Attendance Bonus	9.04	8
Bereavement Leave	13.01	10
Break Periods	6.09	5
Clothing	14.01	11
Committees and Stewards	15.	13
Duration	18.	16
Gender and Number	16.03	14
General	16.	13
Grievance Procedure	4.	3
Health Insurance	10.	8
Holidays with Pay	7.	6
Hours of Work	6.	4
Inclement Weather	16.01	13
Job Sharing	16.08	15
Jury Duty	13.03	11
Layoff and Recall	12.04	10
Leave of Absence	13.	10
Letters of Intent	18.02	16
Lockouts	5.	4
Long Term Disability	9.05	8
Management's Rights	2.	2
On-Call	6.05	5
Overtime Rates	6.03	4
Paid Holidays	7.	6
Pension and Life Insurance	11.	9
Purpose and Coverage	1.	2
Seniority, Job Posting, Layoff & Recall	12.	9
Sick Leave	9.	7
Tools and Equipment	14.05	12
Training School	16.02	14
Travel Expenses	14.04	12
Union Recognition and Security	3.	2
Vacations	8.	6
Wage Rates and Job Classifications	17.	15
Worker's Compensation	14.06	12
Schedule "A"		17
Schedule "B"		18

Appendix "A" Job Sharing at Orangeville Hydro

ARTICLE 1 - PURPOSE AND COVERAGE

1.01 The purpose of this Agreement is to maintain a harmonious relationship between the Board and its employees, and to provide an orderly and amicable method of settling differences or grievances which might possibly arise.

ARTICLE 2 - MANAGEMENT'S RIGHTS

2.01 The Union agrees that the Board has the exclusive right to manage the Board's affairs, to direct staff, and to hire, promote, transfer, layoff, suspend, discharge or discipline employees for just cause.

2.02 The Board also has the right to make and alter from time to time, rules and regulations to be observed by the employees, provided that no change shall be made by the Board in such rules and regulations without prior notice to, and discussion with the Union at Labour Relations meetings.

2.03 The Board agrees that these functions will be exercised in a manner consistent with the provisions of this Agreement and a claim that the Board has exercised any of these rights in a manner inconsistent with any of the provisions of this Agreement, may be treated as a grievance and processed in accordance with Article 4.

ARTICLE 3 - UNION RECOGNITION AND SECURITY

3.01 The Board agrees to recognize the Union as the exclusive collective bargaining agent for all employees (including part-time) of Orangeville Hydro Limited, save and except supervisors, persons above the rank of supervisor and students employed during the school vacation period, in respect to hours of work, wages and working conditions.

3.02 It is agreed that all employees eligible to become members of this Union will pay an amount equal to the current monthly dues as a condition of employment.

3.03 Each week, the Board shall deduct an amount (or amounts) equivalent to regular weekly union dues from each employee in the bargaining unit. The monies deducted shall be remitted to the Union's Financial Officer prior to the end of each following calendar month. The President or the Financial Officer of the Union shall notify the Board, in writing, of the amount of such weekly dues to be deducted under this section and, from time to time, of any changes in the amount thereof. Payroll deductions will not include any fines. Union dues will be included on the employee's T4 slip. Deductions to commence from date of hire.

3.04 In consideration of the deduction and forwarding service by the Board, the Union agrees to indemnify and save the Board harmless against any claim or liability arising out of, or resulting from the collection and forwarding of these dues.

3.05 The Board and the Union agree that there shall be no discrimination, interference, restriction, coercion, harassment, intimidation or stronger disciplinary action, exercised or practiced with respect to an employee by reason of age, race, creed, colour, national origin, political or religious affiliation, sex, sexual orientation or handicap.

ARTICLE 4 - GRIEVANCE PROCEDURE

4.01 Complaints and grievances with respect to the interpretation, application, administration or alleged violation of the provisions of this agreement shall be dealt with in the following manner, and all grievances must be in writing and submitted to Management within fifteen (15) calendar days of the alleged grievance. Replies to grievances will also be in writing at all stages.

4.02 Step 1:

The employee, with the assistance of a steward, will take the grievance up with the immediate Management supervisor. Failing settlement at this level within one (1) calendar week, the employee, within two (2) calendar weeks from Management's reply, may then proceed to Step 2.

4.03 Step 2:

The employee, with the assistance of a steward, will take the grievance up with the Department Head. Failing settlement at this level within one (1) calendar week, the employee, within two (2) calendar weeks from Management's reply, may proceed to Step 3.

4.04 Step 3:

The employee, with the assistance of a steward and/or a Union representative, will take the grievance up with the President, at which time any or all of the people concerned may be present. Failing settlement at this level within thirty (30) calendar days, the matter may then be referred to arbitration.

4.05 Policy Grievance

It is agreed that a grievance arising directly between the Board and the Union shall be originated in writing either directly to the Union Steward, or the Business Representative of the Union or the President and Secretary of the Board within fifteen (15) working days of the incident giving rise to the grievance. The grievances shall be processed commencing at Article 4.04, Step 3. However, it is understood that the provisions of this section may not be used with respect to a grievance that could have been filed by an employee or a group of employees and that the regular grievance procedure shall not be thereby bypassed except by consent of both the Board and the Union.

4.06 Arbitration

It is agreed by the parties hereto that any grievance relating to the interpretation, application, administration or alleged violation of this Agreement which cannot be settled after exhausting the grievance procedure will be settled by arbitration as defined in the Ontario Labour Relations Act. No Board of Arbitration shall have the power to alter the provisions of this Agreement or to substitute any new provisions for any existing provisions. Each party to this Agreement will bear the expenses and fee of its arbitrator and the parties will share equally the expenses and fees of the Chairman.

4.07 As an alternative to Board of Arbitration a sole arbitrator may be used if there is a mutual Agreement between both parties.

ARTICLE 4 - GRIEVANCE PROCEDURE CONT'D

4.08 It is understood that the time limits as provided may be extended by mutual written Agreement of the parties. If the time limits provided above and mutually agreed upon time extensions are not observed by the Union, the grievance will be considered abandoned. If such time limits and any agreed upon time extensions are not observed by the Board, then the grievance will be considered to have advanced to the next stage of the Grievance Procedure.

4.09 If a grievance involves suspension or discharge of an employee, the grievance shall commence at Step 3.

4.10 As an alternative to Article 4.06 the parties may, by mutual Agreement, agree to refer a grievance to a Mediator/Arbitrator as a means of settlement. The Mediator/Arbitrator shall be mutually agreed to by the parties and each party shall pay for one half (1/2) of the expenses and remuneration of the Mediator/Arbitrator.

ARTICLE 5 - NO STRIKES OR LOCKOUTS

5.01 The Union and the Board agree that, for the duration of this Agreement there will be no strike or lockout as defined in the Labour Relations Act.

ARTICLE 6 - HOURS OF WORK AND OVERTIME RATES

6.01 The hours of work as follows shall be considered normal working hours and paid at the regular straight time rate of pay as shown on Schedule "A" and Schedule "B".

6.02 (a) Operations Department Employees
The regular work week of Operations Department employees covered by this Agreement shall be forty (40) hours of work per week consisting of five (5) consecutive days of eight (8) hours each, Monday to Friday, between the hours of 07:30 and 16:30 with a thirty (30) minute unpaid lunch (not to be in conflict with the Employment Standards Act of Ontario).

(b) Administration Department Employees
The regular work week of Administration Department Employees covered by this Agreement shall be thirty-seven and one-half (37.5) hours per week consisting of five consecutive days of seven and one-half (7.5) hours each, Monday to Friday, between the hours of 07:30 and 16:45 with a thirty (30) minute unpaid lunch (not to conflict with the Employment Standards Act of Ontario)

(c) Any changes of hours of work for Operations and Administration employees shall be discussed at Labour Relations Committee meetings.

6.03 (a) All work performed at other than the regular working hours shall be considered as overtime and payment shall be at the rate of two (2) times the employee's regular straight time rate of pay.

(b) All work performed on a paid holiday as defined in Article 7, shall be paid at the rate of two (2) times the employee's regular straight time.

6.04 (a) Overtime Cancellation Payments - All overtime cancelled within eighteen (18) hours of its scheduled commencement shall result in a cancellation payment of two (2) hours at straight time rate except in the following circumstances:

ARTICLE 6 - HOURS OF WORK AND OVERTIME RATES CONT'D

1. Overtime arranged during normal scheduled hours as an extension to those normal scheduled hours requires no cancellation payments.

2. Overtime arranged as an extension before the normal hours of work requires no cancellation payment if cancelled with more than sixteen (16) hours notice prior to its commencement.

(b) Overtime Minimum Payments
All scheduled overtime performed, or reported for due to lack of notice of cancellation, shall result in a minimum payment of the greater of two (2) hours at straight time pay or the actual time worked at the appropriate premium rate.

(c) When employees are called out for emergency work at other than the normal hours of work, a minimum call-out of two (2) hours at the prevailing overtime rate will be paid, except where two (2) or more calls fall within the two (2) hour period, in which case time will be continuous.

6.05 (a) On-Call
It is agreed that one hundred and ninety dollars ($190.00) effective October 1, 2010, one hundred and ninety five dollars ($195.00) effective October 1, 2011, two hundred dollars ($200.00) effective October 1, 2012, and two hundred and five dollars ($205.00) effective October 1, 2013 per week shall be paid to employees required to be on on-call duty on an alternating basis, which shall not be affected by call-outs, as set forth in this Article.

(b) Should a holiday (as defined in Article 7) fall during an employee's on-call period, the employee shall be paid an additional fifty dollars ($50.00) effective October 1, 2010 and fifty five dollars ($55.00) effective October 1, 2013 for that holiday.

(c) The Board shall supply a paging device to employees who are on call.

(d) The Board shall provide a vehicle for the person on call for use on Board business only and for travel to and from work.

6.06 Employees on on-call duty shall remain available by direct telephone contact within the community from which they shall be ready to proceed to their work location immediately upon notification of trouble from any source. It shall be the responsibility of the employee on-call to keep the answering service informed of the phone number at which they can be reached.

6.07 The Board and the Union agree that while employees are on on-call duty they will not perform work for any other authority than the Board.

6.08 An employee shall receive a meal allowance of fifteen dollars ($15.00) when working unscheduled overtime for one (1) hour or more prior to normal starting time, two (2) hours past normal quitting time or four (4) consecutive hours.

6.09 Break periods of fifteen (15) minutes each are permitted twice each day at a time mutually agreed. There will be no loss of pay during these periods.

ARTICLE 7 - PAID HOLIDAYS

7.01 (a) The following holidays shall be observed with pay:

New Year's Day	Labour Day
Good Friday	Thanksgiving Day
Victoria Day	Canada Day
Christmas Day	Civic Holiday
Boxing Day	Family Day

Dates observed as holidays shall be posted by January 30 for the calendar year.

(b) Three (3) floater days to be taken at a mutually agreeable time between the employee and the Board shall also be granted with pay.

(c) In addition the one- half (1/2) working day prior to Christmas Day and the one- half (1/2) working day prior to New Year's Day shall be observed with pay.

7.02 Whenever a holiday falls on a Saturday or Sunday, it shall be observed on the following Monday, or the day set aside by the Federal or Provincial Government or local council.

7.03 Regular and probationary employees who are not required to work on a day observed as a holiday, shall receive eight (8) hours regular straight time rate of pay for employees listed on Appendix "A" Operations and seven and one-half (7.5) hours regular straight time rate of pay for employees on Appendix "B" Administration.

ARTICLE 8 - ANNUAL VACATIONS

8.01 Vacation pay shall mean the normal basic earnings of the employee immediately prior to the date on which vacations monies become payable. In any event, and in the case of probationary employees, vacation payments will be made in accordance with the Employment Standards Act.

8.02 For the first two (2) years of employment an employee will be entitled to one (1) day vacation per month to a maximum of ten (10) days per year.

8.03 During the first six (6) months of employment no vacation can be taken.

8.04 The year in which the employee completes their third year of employment and annually thereafter, fifteen (15) days vacation with pay shall be granted.

8.05 The year in which the employee completes their eighth year of employment and annually thereafter, twenty (20) days vacation with pay shall be granted.

8.06 The year in which the employee completes their eighteenth year of employment and annually thereafter, twenty five days (25) vacation with pay shall be granted.

8.07 The year in which the employee completes their twenty-fifth year of employment and annually thereafter, thirty days (30) vacation with pay shall be granted.

ARTICLE 8 - ANNUAL VACATIONS CONT'D

8.08 When vacations are in excess of two (2) weeks, only two (2) weeks may be taken between June 15 and Labour Day. Requests to take in excess of two (2) weeks vacation during this period will be considered on an individual basis and may be granted solely at the discretion of Management.

8.09 Under special circumstances, requests to carry over up to one-week (5 days) vacation to the next year may be considered on an individual basis and may be granted solely at the discretion of the Management. Such carry-over days must be taken prior to March 31.

8.10 If during vacation an employee is confined to hospital, the employee shall have the right to cease vacation and utilize sick leave credits. Any such displaced vacation shall be taken at a mutually agreeable time between Management and the employee. The employee shall promptly on their return to work and at their own expense furnish Management with a statement from the attending physician certifying the employee's capability to return to work. The cost of this medical certificate/statement shall be at the expense of the Board.

8.11 Employees leaving the employ of the Board during the vacation year shall be paid for their earned vacation and unused vacation for which they have not been paid.

ARTICLE 9 - SICK LEAVE

9.01 Short Term Disability (0 to 15 weeks)
Employees will be granted twelve (12) days per year (one (1) day per month) as one hundred percent (100%) paid sick leave, to a maximum of seventy five (75) working days (fifteen (15) weeks). Illness will require a doctor's certificate if requested by Management. Monthly accumulation of one hundred percent (100%) paid sick days will accrue provided the employee has worked at least seventy five percent (75%) of the working days in the month, excluding vacations, paid holidays and paid leave of absence.

9.02 (a) Where an employee has not accumulated seventy-five (75) days of one hundred percent (100%) sick leave, the difference between the accumulated one hundred percent (100%) days and the maximum of seventy-five (75) days, shall be paid at sixty-seven percent (67%) of earnings.

9.02 (b) If an employee runs out of one hundred percent (100%) paid sick leave, there will still be up to seventy five (75) days (fifteen (15) weeks) of disability coverage at sixty-seven percent (67%) of earnings for any unrelated disability, due to accident or injury.

9.03 Exclusions:
The Short Term Disability plan in 9.01 and 9.02 does not cover disabilities or claims resulting from:

1. While on Pregnancy and/or Parental Leave
2. Intentionally self-inflicted injuries while sane or insane.
3. War service in the armed forces, or participation in a criminal act.
4. Accidental injuries arising out of or in the course of your employment, or disease covered by the Workplace Safety and Insurance Act or similar legislation.

ARTICLE 9 - SICK LEAVE CONT'D

9.04 Attendance Bonus

An employee who has been absent less than five (5) days due to accident, or illness or medical appointments within a calendar year shall receive a cash bonus equal to fifty percent (50%) of the value of the unused time less than five (5) days.

9.05 Long Term Disability

The Board agrees to pay the cost of premiums to provide a long term disability plan, to commence after one hundred and five (105) days (fifteen (15) weeks) from the date of disability which includes the period of payment under the terms of the Short Term Disability coverage, providing sixty-six and two-thirds percent (66 2/3%) of monthly earnings to a maximum of three thousand dollars ($3,000.00). While an employee is in receipt of this benefit the Board shall continue to pay its share of the cost of premiums for employee benefit plans for a period of up to twelve (12) months, which includes the one hundred and five (105) day (fifteen (15) week) waiting period.

9.06 Where an employee finds it necessary to visit a doctor's or dentist's office during working hours, the Board will allow paid time off. Such time off will be charged against the employee's sick leave credit.

9.07 If the Board requires a medical note from a qualified physician indicating that the employee is fit to return to work and any work restrictions, the cost of this medical note shall be at the expense of the Board.

ARTICLE 10 - HEALTH INSURANCE

10.01 The Board agrees to pay one hundred percent (100%) of the cost of premiums of the MEARIE Extended Health Care Plan "A" or its equivalent. The Board agrees to provide and contribute to the cost of premiums of the plan while the employee is in receipt of normal base wages, or on sick leave, Worker's Safety and Insurance Board payments, or paid leave of absence.

10.02 The Board agrees to pay one hundred percent (100%) of the cost of premiums of the MEARIE Dental Plan "F" or equivalent. Current Ontario Dental Association (ODA) fee schedule to be maintained during this Collective Agreement.

10.03 The Board agrees to pay one hundred percent (100%) of the cost of premiums of the MEARIE Vision Care, or equivalent, which allows up to three hundred and fifty dollars ($350.00) effective October 1, 2012 towards the purchase of prescription eye wear every twenty-four (24) months.

10.04 The Board to pay fifty percent (50%) of cost of premium for Extended Health Care Plan A, Dental Plan F, and Vision care as outlined in Articles 10.01, 10.02 and 10.03 for retirees who have a minimum of fifteen (15) years of service with the Board. To remain in effect until the retiree reaches the age of sixty-five (65) years old or accepts benefits from another provider.

ARTICLE 11 - PENSION AND LIFE INSURANCE

11.01 The Board and the employees shall participate in the Ontario Municipal Employees Retirement System, the Canada Pension Plan and the Group Life Insurance Plan as established.

ARTICLE 12 - SENIORITY, JOB POSTING, LAYOFF AND RECALL

12.01 Seniority

(a) Seniority is defined to mean the relative status of employees in the bargaining unit as measured by the length of service with the Board, excluding any period exceeding three (3) months, in which the employee is not at work due to illness, injury, leave of absence or layoff.

This article is not to be in conflict with the Employment Standards Act of Ontario or any other government legislation.

(b) An employee shall lose seniority and have their name removed from the records if they:

1) Quit voluntarily;
2) Are discharged and not reinstated through the grievance procedure;
3) Retire;
4) Are laid off for a period exceeding twelve (12) calendar months;
5) Fail to report to work after a layoff within ten (10) working days of recall, notice of which has been sent by registered mail by the Board to the last address which the employee left with the Board;
6) Are absent from work for three (3) working days or more without leave, unless it is not physically possible to notify Management.
7) Are absent from work for any reason for twenty four (24) consecutive months.

The provisions of this article not to be in conflict with the Employment Standards Act of Ontario for pregnancy and parental leave.

12.02 When a new employee is hired they shall serve a probationary period of six (6) months. During this period the employee shall receive all benefits of this collective Agreement, unless otherwise specified. Probationary employees shall not be permitted to lodge a grievance on discharge. Employees retained past the six (6) month probationary period shall be deemed satisfactory placed on the seniority list, and credited with seniority and sick leave accumulation from the date first hired.

12.03 (a) When vacancies occur or new jobs above the rank of beginner are created, these positions will be posted on a bulletin board accessible to all employees for a period of five (5) working days during which time present employees will have an opportunity to apply before outsiders are considered.

ARTICLE 12 - SENIORITY, JOB POSTING, LAYOFF AND RECALL CONT'D

(b) When promoting, demoting or transferring employees covered by this Agreement, qualifications and ability to perform the job satisfactorily shall be the primary consideration. In cases where qualifications and ability are equal among the applicants, seniority shall govern.

(c) Seniority in the Event of a Permanent Promotion
If an employee accepts a promotion outside of the bargaining unit and does not return to the bargaining unit within twelve (12) months of the date of the promotion, seniority within the bargaining unit will be lost for the purposes of layoff and recall only. If the employee returns on or before twelve (12) months, their seniority will continue to accrue from the date of promotion.

12.04 (a) Layoff and Recall
Both parties recognize that job security should increase in proportion to length of service. Therefore, in the event of layoff, employees shall be laid off in the reverse order of their seniority. Employees shall be recalled in the order of their seniority provided they are qualified to do the work. An employee will remain eligible for recall for a period of one (1) year from the date of layoff. An employee laid off in one classification will be given the opportunity of displacing an employee with less seniority in a similar or lower classification within the bargaining unit, provided the senior employee has the ability and qualifications to perform the job in a manner which will not affect the efficiency of the department beyond a twenty (20) working day familiarization period.

12.04 (b) No new employees will be hired until those laid off have been given an opportunity of re-employment.

ARTICLE 13 - LEAVE OF ABSENCE

13.01 (a) In the event of death in the immediate family of an employee, the employee will be granted leave of absence with pay for regularly scheduled work days for a period of up to five (5) consecutive working days to make arrangements for or to attend the funeral or to an estate settlement. Immediate family to mean: spouse, son or daughter

(b) In the event of death in the immediate family of an employee, the employee will be granted leave of absence with pay for regularly scheduled work days for a period of up to three (3) consecutive working days to make arrangements for or to attend the funeral or to an estate settlement. Immediate family to mean: father, mother, brother, sister, father-in-law, mother-in-law, daughter-in-law, son-in-law, grandparent, grandchild or any relative living with the employee.

(c) In the event of the death of a sister-in-law, brother-in-law, niece, nephew, aunt or uncle of an employee, the employee will be granted a leave of absence with pay on the day of the funeral in order to attend the funeral.

ARTICLE 13 - LEAVE OF ABSENCE CONT'D

13.02 A leave of absence with pay will be granted upon reasonable notice to the Board insofar as the regular operation of the department will permit.
These leaves will be granted to persons delegated to represent the membership at Union functions, provided such leave does not exceed five (5) working days, in any one instance. The union will compensate the Board in the following manner:

(i) Combined absences up to and including fifteen (15) person days - normal rate of pay plus forty-five percent (45%) payroll burden will be reimbursed. Any absences in excess of the fifteen (15) person days - normal rate of pay will be paid plus the Board's normal operating overheads.

(ii) The Board agrees to maintain the rate of pay for time spent by employees at grievance meetings if held during regular working hours. No payment shall be made for arbitration or mediation.

13.03 The Board shall grant leave of absence without loss of seniority or benefits to an employee who serves as a juror or witness in any court. The Board shall pay such an employee regular earnings at regular rate of pay, excluding payment for travelling, meals, or other expenses. The employee will present proof of service and endorse payment received for jury service or court witness to the Board.

13.04 Any employee desiring a leave of absence without pay may be granted such leave on reasonable notice to the Board insofar as the regular operation of the department in which they are employed will permit. Any such leave of absence shall not exceed an amount, which in the opinion of the Board, is reasonable.

13.05 Pregnancy/Adoption/Parental Leave(s)
Any employee of the Board that has completed thirteen (13) weeks of employment will be eligible for the above provisions as outlined in the Employment Standards Act.

13.06 Pregnancy/Adoption/Parental Leave
An employee who is pregnant and who started employment with the Board at least thirteen (13) weeks before the expected birth date is entitled to a leave of absence without pay in accordance with the Employment Standards Act of Ontario.

An employee who has completed at least thirteen (13) weeks of employment with the Board and who is the parent of a child is entitled to a leave of absence without pay following either the birth of the child, or the coming of the child into the custody, care and control of the parent for the first time, in accordance with the provisions of the Employment Standards Act of Ontario.

The provisions of the Employment Standards Act will apply with respect to seniority and benefit plans. Details regarding both pregnancy leave and parental leave will be made available.

ARTICLE 14 - ALLOWANCES

14.01 Clothing
The Board will supply to regular and probationary employees engaged in line work or other rough work, leather gloves which must be worn by the employees engaged in this type of work. These gloves will be replaced free of charge, when worn out gloves are turned in to (the Management).

ARTICLE 14 – ALLOWANCES CONT'D

14.02 (a) Regular employees required to work in a potential flash area must wear fire retardant clothing and each of these regular employees will **initially** be provided with the following:

- Five (5) long-sleeve rugby shirts
- Three (3) pairs of pants
- One (1) summer jacket
- One (1) winter jacket
- One (1) pair of coveralls
- Rain gear

Worn, damaged or unsafe fitting fire retardant clothing will be replaced **October 1st of each year with management approval.**

14.02 (b) An allowance of two hundred dollars ($200.00) per contract year shall be paid to regular employees classified as Line Technician, Engineering Technician, Utility Person, and Groundman towards the purchase of approved **work** clothing. Payment to be made upon an **itemized** receipt of purchase.

14.03 An allowance of two hundred and fifteen dollars ($215.00) effective October 1, 2010, two hundred and twenty dollars ($220.00) effective October 1, 2011, two hundred and twenty five dollars ($225.00) effective October 1, 2012 and two hundred and thirty dollars ($230.00) effective October 1, 2013 shall be paid per contract year towards the purchase of CSA approved safety boots for all employees required to wear them, upon surrender of a receipt of purchase or repair as follows:

14.04 Employees required to use their own automobiles on Board business shall be paid the composite rate set by the Canada Revenue Agency annually. (I.e. the latest rate set for 2006 and 2007 is fifty cents ($0.50) per kilometre.

14.05 Tools and Equipment
The Board agrees to provide such tools and equipment which are, in the Board's opinion, necessary to carry out the work involved in maintaining service. An employee must return worn out or broken articles in order to receive replacement. An employee will be responsible for replacement of lost tools and equipment for which they have signed for.

14.06 Worker's Compensation
Where a regular employee is unable to work due to a compensable injury suffered in the performance of their duties with the Board, pending a settlement of the insurable claim, the Board shall continue to pay the cost of premiums for employee benefits plans for a period of up to twenty-four (24) months.

ARTICLE 15 - COMMITTEES AND STEWARDS

15.01 The Board acknowledges the right of the Union to appoint or otherwise select committees and stewards in accordance with the sections of this article. The Union shall advise the Board of the names of personnel serving on these committees and as stewards, it being agreed to limit stewards to one and one alternate steward to act only in the absence from work of the regular steward.

15.02 It is acknowledged by the Union that stewards and committee members have regular duties to perform on behalf of the Board and that such persons will not unduly absent themselves from their duties without the expressed permission of the Board and that with this understanding, the Board will not make any pay deductions for attending such meetings during working hours.

15.03 Labour Relations Committee

Consisting of a maximum of two (2) stewards and Representative(s) of the Union and Board representatives with the responsibility of dealing with matters of Labour Relations. The Board will consult with the Union prior to implementing, altering, or deleting Board Policies, procedures and directives. Regular scheduled meetings will be held bi-monthly if required, at a time mutually agreeable to the Union and the Board representatives. An agenda outlining the matters for discussion will be submitted by each party to the other not less than two (2) working days prior to the scheduled meeting, except in cases of emergency.

15.04 Union Negotiating Committee

Consisting of two (2) regular employees of the Board and/or a PWU Representative(s), for the purpose of collective bargaining. Two (2) employees of the Board who are designated by the Union to attend negotiating meetings during regular working hours with the representatives of the Board shall not suffer any loss of regular pay by reason of such attendance with the Board representatives, up to a maximum of three (3) days, but not including Conciliation.

15.05 Joint Health and Safety Committee

Both parties are committed to the health and safety of all employees as demonstrated in the Orangeville Hydro Joint Health and Safety Policy. The Board will provide Core Certification Training for the bargaining unit member. Certified Health and Safety Representatives have the unilateral right to stop unsafe work.

ARTICLE 16 - GENERAL

16.01 Inclement Weather

Where in the opinion of Management, normal work of non-emergency nature cannot be continued during regular working hours by the reason of unduly adverse weather conditions, all reasonable steps will be taken to provide alternative work.

ARTICLE 16 - GENERAL CONT'D

16.02 Training School

When an employee has been selected by the Board to attend a training school, the Board agrees to maintain the employee's normal earnings, exclusive of overtime, for the period the employee is attending such training school. The Board further agrees to pay for the employee's meals and lodging if applicable. An employee shall not receive any compensation for travelling time or study periods outside normal working hours.

16.03 Gender and Number

Whenever the singular, masculine or feminine is used in this Agreement, it shall be considered as if plural, feminine or masculine has been used where the context of the party hereto so requires.

16.04 Part-Time and Temporary Employees

(a) Definitions:

Temporary

Temporary employees are persons hired for periods of limited duration of up to six (6) months to perform work in positions which are not likely to become part of the Board's continuing organization. Such positions may be extended for an additional six (6) months, by mutual Agreement with the Union. Any temporary employee who is hired into a permanent position, and who successfully completes the probationary period, shall have their continuous service recognized as seniority

(b) Temporary Part-Time and Temporary Employees

Temporary part-time and temporary employees shall not be entitled to the benefits of Articles 7, 8,9,10,11,12,13 and 14. This article not to be in conflict with the Employment Standards Act of Ontario, Ontario Municipal Retirement System (OMERS) or any other government legislation.

(c) Part -Time Employees

The establishment of a regular part-time position is a joint decision of local management and the utility steward made in the spirit of trust and co-operation. The parties will ensure that regular part-time positions are appropriately used to maintain corporate effectiveness, not split a regular full-time position.

Regular part-time employees are regularly employed on an average of twenty-four (24) hours or less per week calculated on a monthly basis. They are employed for a minimum of sixteen (16) hours per month. Regular part-time employees are treated as regular employees except where noted otherwise.

Pro-Ration Formula: Benefit for regular part-time employees are optional based on a pro-ration formula to a maximum of fifty percent (50%) paid by the Board.

ARTICLE 16 - GENERAL CONT'D

16.05 Copies of Agreement
The Union and the Board desire every employee to be familiar with the provisions of this Agreement and their rights and duties under it. For this reason, the Board shall arrange for the printing of sufficient copies of this Agreement with the cost of such printing to be borne equally by the Board and the Union.

16.06 Access to Personnel File
Employees shall have reasonable time to access their personnel file during regular working hours. Permission shall be granted by the employee's immediate supervisor, at a mutually agreed upon time.

16.07 Bulletin Board
The Board will make available a bulletin area for the posting of Union notices, meetings, social and recreational activities. This information will be posted and removed by the Steward.

16.08 Job Sharing
Job sharing arrangements shall be as per Appendix A entitled Job Sharing at Orangeville Hydro.

16.09 Purchased Services Agreement
During the term of this Collective Agreement, no regular employee will be declared surplus in their position as a result of the use of purchased services to perform the work performed by bargaining unit employees.

Any employee displaced to a classification at a lower hourly rate of pay due to the use of purchased services shall maintain their earnings at the pre displacement level for the duration of this Collective Agreement.

ARTICLE 17 - WAGE RATES AND JOB CLASSIFICATIONS

17.01 Rates of pay and job classifications, for pay purposes only, shall be shown on Schedule "A" (forty (40) hour week) and Schedule "B" (thirty-seven and one half (37.5) hour week) attached to and forming part of this Agreement.

17.02 When a full time employee is detailed to perform the principle duties of a higher paid position for a period of one day or more, the employee shall receive an additional five percent (5%), or the starting rate of the higher paid position, whichever is greater, for all time worked.

17.03 When a full time regular employee is temporarily assigned or detailed to relieve in a classification with a lower wage rate they shall be paid at their regular straight time hourly rate of their regular classification.

17.04 The Board agrees to the payment of wages by direct deposit on Friday morning of each week. The pay period shall consist of the period ending at the end of the employee's normal working hours Friday of the previous week. A statement of deposit will be made available to each employee by Thursday, no later than 4:00p.m.

ARTICLE 18 - DURATION

18.01 This Agreement shall become effective from the 1st day of October 2010 and remain in effect until the 30th day of September 2014. It is agreed however, that this Agreement shall continue in force from year to year from the 1st day of October to and including the 30th day of September in each year unless either of the parties hereto shall within the period of not more than ninety (90) days and not less than thirty (30) days prior to the expiration in any year give notice in writing to the other party that this Agreement shall cease to operate at the end of the then current year or that it desires to bargain with a view to the renewal with or without modification of the Agreement then in operation. In the event of notice given in accordance with the above, the parties shall exchange proposals within thirty (30) day at a time which shall be mutually agreeable.

18.02 Letters of Intent
Working conditions during the term of this Agreement shall be outlined in this Agreement and any Letters of Intent Document*.

*A letter of intent is a modification of the Collective Agreement executed by the parties in the following format during the term of the Collective Agreement.

Letter of Intent

Title ______________________________
Number ______________________________
Date ______________________________

It is jointly agreed that the following Letter of Intent shall form part of the Collective Agreement between the parties:

(TEXT PORTION OF LETTER OF INTENT)

ORANGEVILLE HYDRO LIMITED	THE POWER WORKERS' UNION (CUPE LOCAL 1000)
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________

SCHEDULE "A"

HOURLY WAGE RATES - OPERATIONS DEPARTMENT

			10.01.10	10.01.11	10.01.12	10.01.13
Working Foreman			39.23	40.37	41.54	42.79
Leadhand			36.21	37.26	38.34	39.49
Journeyman Lineman (rate A) (12 months after completion of level 4)			34.52	35.52	36.55	37.65
Learner Lineman	Level 4	(95% rate A)	32.79	33.74	34.72	35.77
	Level 3	(90% rate A)	31.07	31.97	32.90	33.89
	Level 2	(80% rate A)	27.62	28.42	29.24	30.12
	Level 1	(70% rate A)	24.16	24.86	25.59	26.36
	Start	(60% rate A)	20.71	21.31	21.93	22.59
Meter Mechanic	Level 4	(100%)	32.60	33.55	34.52	35.56
	Level 3	(95%)	30.97	31.87	32.79	33.78
	Level 2	(90%)	29.34	30.20	31.07	32.00
	Level 1	(80%)	26.08	26.84	27.62	28.45
	Start	(60%)	19.56	20.13	20.71	21.34
Senior Technician		(100%)	38.08	39.18	40.32	41.53
Engineering Technician	48 Months	(100%)	36.32	37.37	38.45	39.60
	36 Months	(95%)	34.50	35.50	36.53	37.62
	24 Months	(90%)	32.69	33.63	34.61	35.64
	12 Months	(80%)	29.06	29.90	30.76	31.68
	Start	(60%)	21.79	22.42	23.07	23.76
Line Technician	48 Months	(100%)	30.95	31.85	32.77	33.75
	36 Months	(95%)	29.40	30.26	31.13	32.06
	24 Months	(90%)	27.86	28.67	29.49	30.38
	12 Months	(80%)	24.76	25.48	26.22	27.00
	Start	(60%)	18.57	19.11	19.66	20.25
Utility Person	36 Months	(100%)	22.95	23.62	24.30	25.03
	24 Months	(95%)	21.80	22.44	23.09	23.78
	12 Months	(90%)	20.66	21.26	21.87	22.53
	6 Months	(80%)	18.36	18.90	19.44	20.02
	Start	(70%)	16.07	16.53	17.01	17.52
Ground man	18 Months		16.78	17.27	17.77	18.30
	6 Months		15.12	15.56	16.01	16.49
	Start		13.52	13.91	14.31	14.74
Meter Reader	18 Months		16.78	17.27	17.77	18.30
	6 Months		15.12	15.56	16.01	16.49
	Start		13.52	13.91	14.31	14.74

SCHEDULE "B"

HOURLY WAGE RATES - ADMINISTRATION DEPARTMENT

			10.01.10	10.01.11	10.01.12	10.01.13
Assistant to the Office Supervisor	36 Months	(100%)	25.68	26.42	27.19	28.01
	24 Months	(95%)	24.40	25.10	25.83	26.61
	12 Months	(90%)	23.11	23.78	24.47	25.21
	6 Months	(80%)	20.54	21.14	21.75	22.41
	Start	(70%)	17.98	18.49	19.03	19.61
Senior Clerk	24 Months	(100%)	31.08	31.98	32.91	33.90
	12 Months	(95%)	29.53	30.38	31.26	32.21
	Start	(90%)	27.97	28.78	29.62	30.51
Inventory/Purch. Finance Clerk	36 Months	(100%)	29.50	30.36	31.24	32.18
	24 Months	(95%)	28.03	28.84	29.68	30.57
	12 Months	(90%)	26.55	27.32	28.12	28.96
	6 Months	(80%)	23.60	24.29	24.99	25.74
	Start	(70%)	20.65	21.25	21.87	22.53
Customer Services Representative (includes 0.09 PE adj)	36 Months	(100%)	25.23	25.96	26.71	27.51
	24 Months	(95%)	23.97	24.66	25.37	26.13
	12 Months	(90%)	22.71	23.36	24.04	24.76
	6 Months	(80%)	20.18	20.77	21.37	22.01
	Start	(70%)	17.66	18.17	18.70	19.26
Cashier Clerk	36 Months	(100%)	21.04	21.65	22.28	22.95
	24 Months	(95%)	19.99	20.57	21.17	21.80
	12 Months	(90%)	18.94	19.49	20.05	20.66
	6 Months	(80%)	16.83	17.32	17.82	18.36
	Start	(70%)	14.73	15.16	15.60	16.07

Dated at ORANGEVILLE, Ontario this 1st day of October 2010.

Orangeville Hydro Limited	**Power Workers' Union (CUPE Local 1000)**
______________________	______________________
______________________	______________________
______________________	______________________

ORANGEVILLE HYDRO

Appendix F -

Collective Agreement

2010 - 2014 Summary

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

MEMORANDUM OF AGREEMENT

Between: Orangeville Hydro Limited

- And –

Power Workers' Union – CUPE Local 1000

September 27, 2010

The parties agree the following constitutes a full settlement of all matters in dispute.

The parties also agree that Orangeville Hydro Limited shall include the terms of the previous Collective Agreement (between the Power Workers' Union and Orangeville Hydro Limited) which expires September 30, 2010, provided, however, that all matters set out in the following statement of settlement are incorporated.

Original Signed by Union	**Original Signed by Management**

It is jointly agreed that the Collective Agreement covering the period of October 1, 2009 to September 30, 2010, will be amended as follows. All changes will be effective October 1, 2010, unless otherwise stated in this agreement. The parties herein agree that the term of the Collective Agreement shall be from October 1, 2010 to September 30, 2014. This Memorandum is subject to ratification by both parties.

Article 4 – Grievance Procedure

4.01 Complaints and **grievances with respect to the interpretation, application, administration or alleged violation of the provisions of this agreement** shall be dealt with in the following manner, and all grievances must be in writing and submitted to Management within fifteen (15) calendar days of the alleged grievance. Replies to grievances will also be in writing at all stages.

4.02 Step 1:

The employee, with the assistance of a steward, will take the ~~matter~~ **grievance** up with his or her immediate Management supervisor. Failing settlement at this level within one (1) calendar week, the employee, within two (2) calendar weeks from Management's reply, may then proceed to Step 2.

4.03 Step 2:

The employee, with the assistance of a steward, will take the **grievance** ~~matter~~ up with the Department Head. Failing settlement at this level within one (1) calendar week, the employee, within two (2) calendar weeks from Management's reply, may proceed to Step 3.

4.04 Step 3:

The employee, with the assistance of a steward and/or a Union representative, will take the **grievance** ~~matter~~ up with the President, at which time any or all of the people concerned may be present. Failing settlement at this level within thirty (30) calendar days, the matter may then be referred to arbitration.

4.05 Policy Grievance

It is agreed that a grievance arising directly between the Board and the Union shall be originated in writing either directly to the Union Steward, or the Business Representative of the Union or the President and Secretary of the Board within fifteen (15) working days of the incident giving rise to the grievance. The grievances shall be processed commencing at Article 4.04, Step 3. However, it is understood that the provisions of this section may not be used with respect to a grievance that could have been filed by an employee or a group of employees and that the regular grievance procedure shall not be thereby bypassed except by consent of both the Board and the Union.

4.06 Arbitration

It is agreed by the parties hereto that any **grievance** ~~difference of opinion~~ relating to the interpretation, application, administration or alleged violation of this Agreement which cannot be settled after exhausting the grievance procedure will be settled by arbitration as defined in the Ontario Labour Relations Act. No Board of Arbitration shall have the power to alter the provisions of this Agreement or to substitute any new provisions for any existing provisions. Each party to this Agreement will bear the expenses and fee of its arbitrator and the parties will share equally the expenses and fees of the Chairman.

Article 6 – Hours of Work and Overtime

6.05 (a) On-Call

It is agreed that ~~one hundred and eighty-five dollars ($185.00) effective October 1, 2008~~ **one hundred and ninety dollars ($190.00) effective October 1, 2010, one hundred and ninety five dollars ($195.00) effective October 1, 2011, two hundred dollars ($200.00) effective October 1, 2012 and two hundred and five dollars ($205.00) effective October 1, 2013** per week shall be paid to employees required to be on on-call duty on an alternating basis, which shall not be affected by call-outs, as set forth in this Article.

(b) Should a holiday (as defined in Article 7) fall during an employee's on-call period, the employee shall be paid an additional ~~forty~~ **fifty dollars ($50.00) effective October 1, 2010 and** ~~($40.00)~~, **fifty five dollars ($55.00) effective October 1, 2013** for that holiday.

Article 9 – Sick Leave

9.07 If the Board requires a medical note from a qualified physician **indicating that the employee is fit to return to work and any work restrictions** ~~to certify an employee's illness~~, the cost of this medical note shall be at the expense of the Board.

Article 10 – Health Benefits

10.03 The Board agrees to pay one hundred percent (100%) of the cost of premiums of the MEARIE Vision Care, or equivalent, which allows up to ~~$300.00~~ **three hundred and fifty dollars ($350.00) effective October 1, 2012** towards the purchase of prescription eye wear every twenty-four (24) months.

Article 14 – Allowances

14.03 An allowance **of two hundred and fifteen dollars ($215.00) effective October 1, 2010, two hundred and twenty dollars ($220.00) effective October 1, 2011, two hundred and twenty five dollars ($225.00) effective October 1, 2012 and two**

hundred and thirty dollars ($230.00) effective October 1, 2013 shall be paid per contract year towards the purchase of CSA approved safety boots for all employees required to wear them, upon surrender of a receipt of purchase or repair.

~~October 1, 2009 - $210.00 (this supersedes the interim letter of October 1, 2003)~~

Article 17 – Wage Rates and Job Classifications

General wage increase of 2.9% October 1, 2010 to all members
General wage increase of 2.9% October 1, 2011 to all members
General wage increase of 2.9% October 1, 2012 to all members
General wage increase of 3.0% October 1, 2013 to all members

Special Journeyperson Lineperson

- Year 1 - $1.00 per hour increase after the general wage increase

Article 18 – Duration

18.01 This Agreement shall become effective from the 1st day of October ~~2009~~ **2010** and remain in effect until the 30th day of September ~~2010~~ **2014.** It is agreed however, that this Agreement shall continue in force from year to year from the 1st day of October to and including the 30th day of September in each year unless either of the parties hereto shall within the period of not more than ninety (90) days and not less than thirty (30) days prior to the expiration in any year give notice in writing to the other party that this Agreement shall cease to operate at the end of the then current year or that it desires to bargain with a view to the renewal with or without modification of the Agreement then in operation. In the event of notice given in accordance with the above, the parties shall exchange proposals within thirty (30) days at a time which shall be mutually agreeable.

HOUSEKEEPING

Article 16 – General

Modify Clauses 8.10, 12.01(b), 12.02, 13.04, and 14.06 to conform with the intent of Clause 16.03 – to be reviewed during the revision to the Collective Agreement. Intent of the Collective Agreement not to be altered or changed.

NOT TO BE REPRODUCED IN THE COLLECTIVE AGREEMENT

The parties agree that the employees may submit vision care claims for all eligible employees/dependents in excess of three hundred dollars ($300.00) to a maximum of three hundred and twenty five dollars ($325.00) to the employer up until October 1, 2012 for reimbursement.

The parties agree that they will jointly review the concept of self-funding, employer paid vision care and reach a decision by July 1, 2012. If the parties are unable to reach a mutually agreeable decision the Vision Care Plan will continue as outlined in the Agreement.

The parties agree that there will be no decrease in the current vision coverage.

ORANGEVILLE HYDRO

Appendix G -

OHL006 Task 1 Signoff

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

AUTOMATED SOLUTIONS International Inc.	Orangeville Hydro Limited	Project	OHL006
		Task No.	1
	Distribution System Plan - Task 1 Sign-off	Date	2013-06-19
		Date Revised	2013-06-25
		Page	1 of 2

Project Task	1 – Distribution System Plan document	**Related Documents**
Change Order Number		

Does task have pre-requisites Yes ☒ No ☐

Tasks: Task 2 – 5yr Budget sheet preparation

Is task completion a pre-requisite Yes ☐ No ☒

Tasks:

Task Description

Prepare a Distribution System Plan document to meet the requirements of OEB Chapter 5

Deliverables

Data / Drawings:

- A DSP checklist will be provided, detailing the required data and documents for background information and/or to support the DSP

Documentation:

- Complete DSP, containing integrated asset management, smart grid and green energy plan components, in accordance with the requirements identified in the OEB Chapter 5 documentation
- Review of historical capital and maintenance plans
- Assessment and recommendations of existing information systems and processes related to the preparation of the DSP and asset management
- Review and recommendations of asset assessment strategy, methodology, processes and information systems

Assumptions

- OHL will provide all required data on a timely basis to allow preparation of a draft document for a target date of Aug 1
- OHL will take responsibility for the accuracy of the data provided

Client Resource Requirements

1. Review
   - 8 to 16 hours of staff time to answer questions and provide clarification of the data provided
2. Meetings
   - Kick-off meeting to cover project/task review and approval and initial review of data
   - Initial 5yr budget meeting
   - Final 5yr budget meeting
   - Draft review of DSP
   - Additional phone calls and web sessions may be scheduled to support the activities of the project/tasks
3. Questions

4. Data Clean-up
   - Work done on project OHL004 and OHL005 will assist with majority of questions that may typically arise.

Change Order Required:	Yes	☐	No	☒
Phased Delivery:	Yes	☒	No	☐
Review required to proceed:	Yes	☒	No	☐
Expected Delivery Date:	Initial:	2013-08-01	Final:	2013-09-30

____
Client Representative

____
Signature

____
Date

____
Reviewed with

____
Signature

____
Date

Appendix H -

OHL006 Task 2 Signoff

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

	Orangeville Hydro Limited	Project	OHL006
AUTOMATED SOLUTIONS International Inc.		Task No.	2
	Distribution System Plan - Task 2 Sign-off	Date	2013-06-19
		Date Revised	2013-06-25
		Page	1 of 2

Project Task	2 – 5yr Budget Worksheet preparation	**Related Documents**
Change Order Number		

Does task have pre-requisites Yes ☐ No ☒

Tasks:

Is task completion a pre-requisite Yes ☒ No ☐

Tasks: 1 – Distribution System Plan document

Task Description

Prepare a 5yr capital and O&M budget to support the DSP and COS application.

Deliverables

Data / Drawings:

- 5yr Budget Worksheet (annotated)
- Checklist of data required for the preparation and calculations in the 5yr budget
- Summary pages for capital and O&M will be provided in accordance with the OEB Chapter 5 requirements – USoA and IFRS breakdowns will be provided
- ASI will assist in the review of system information to identify required capital and maintenance activities

Documentation:

- Documentation of the above worksheet
- Summary pages/numbers to be included in the DSP document
- Review and recommendations for improvements of the information systems and processes related to the preparation of the 5yr budget

Assumptions

- OHL will provide all required data on a timely basis to allow preparation of a draft document for a target date of Aug 1
- OHL will take responsibility for the accuracy of the data provided

Client Resource Requirements

1. Review
    - Based on experience, engineering, operations and finance input is required to assist with the 5yr budget preparation
    - In addition to the two meetings identified below, a significant amount of time may be required to compile the necessary information. This is mainly dependent on existing information systems and processes within the utility. A review of these is included in the scope
    - In addition, phone calls or webinars may be required to answer questions and provide clarification of the data provided
2. Meetings
    - Initial 5yr budget meeting
    - Final 5yr budget meeting
    - Additional phone calls and web sessions may be scheduled to support the activities of the project/tasks
3. Questions
4. Data Clean-up

Change Order Required:	Yes	☐	No	☒
Phased Delivery:	Yes	☒	No	☐
Review required to proceed:	Yes	☒	No	☐
Expected Delivery Date:	Initial:	2013-07-19	Final:	2013-08-30

Client Representative	Reviewed with
Signature	Signature
Date	Date

ORANGEVILLE HYDRO

Appendix I -

OHL Dividend Policy

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

4 ADOPTION OF FINANCIAL STATEMENTS

The financial statements for the fiscal year ended December 31, 2005, together with the auditor's report, were presented.

Resolution 2006-03 **Moved by: Councillor Manwell**
Seconded by: Deputy Mayor MacGregor

THAT the financial statements for the fiscal year ended December 31, 2005, together with the auditor's report thereon, be adopted, as amended, to reflect a correction of the date of the Accumulated Amortization to be December 31, 2004.

CARRIED.

5 DIVIDEND POLICY

Resolution 2006-04 **Moved by: Councillor Strang**
Seconded by: Councillor Manwell

THAT a dividend policy for Orangeville Hydro be established as 50% of net income.

CARRIED.

6 APPOINTMENT OF AUDITORS

Resolution 2006-05 **Moved by: Deputy Mayor MacGregor**
Seconded by: Councillor Maycock

THAT BDO Dunwoody LLP be appointed as the auditors of the Corporation until the next annual meeting of the Shareholder, or until a successor is appointed at a remuneration to be fixed by the Board of Directors.

CARRIED.

7 CONFIRMATION OF ACTS OF DIRECTORS AND OFFICERS

Resolution 2006-06 **Moved by: Councillor Maycock**
Seconded by: Councillor Manwell

THAT all acts, contracts, by-laws, proceedings, appointments, elections and payments enacted, made, done and taken by the directors and officers of the Corporation since the date of the last Annual Shareholder's Meeting, June 6, 2005, be and the same are hereby approved, ratified and confirmed.

CARRIED.

ORANGEVILLE HYDRO

Appendix J -

OHL 2014 Budget

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Orangeville Hydro Limited

2014 Budget

Notes to 2014 Budget

Capital Budget

- The 2013 Gross Distribution Forecast is $169,314 under the budgeted amount of $1,729,869 which was mainly attributable to the System Renewal Projects that were deferred to 2014. The main reason that some projects were not completed in 2013 constraint was the limited number of lineman available to complete capital work for a portion of the year. During 2013 two subdivisions were energized, namely Sarah Properties Phase 3 and Robinson Farmstead.

- The 2014 Gross Distribution Plant Budget is $2,209,646, which includes larger projects that were deferred from 2013, such as the Parkview Heights Transformer replacement, and the West Broadway 27.6 kV UG Conversion. The Thomasfield Homes subdivision was included in the 2013 budget and will be recorded on the books in 2014.

- New projects in 2014 include the Bythia-Victoria-Princess St 27.6kV conversion, the First St-Fifth Ave 27.6kV conversion, the Veterans Way pole line with a new 27.6kV feeder, as well as the Gifford Street conversion.

- The 2014 General Plant Budget amounts to $523,500 with the inclusion of a new digger derrick truck that was originally budgeted in 2013, a replacement vehicle for the President, a CIS system upgrade, an upgrade to the Great Plains financial system, a billing printer and plotter, two display monitors for the GIS systems, a photocopier, and a parking lot expansion. The digger derrick was not purchased in 2013 due to the potential merger opportunities.

Beginning in 2013, the Ontario Energy Board required all LDC's to classify their capital expenditures into new categories. These categories are explained below:

System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system. These include subdivisions, embedded generation and capital contribution projects.

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. These include budgeted and unbudgeted jobs that improve the reliability of the system.

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. These include conversion jobs from the 27.6kV system.

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

Controllable Expenses

- Total 2014 Controllable Expenses are $3,581,031. The budget is approximately $185,000 greater than the 2013 forecast. Detail is provided below regarding the particular accounts.

  <u>Distribution Maintenance Expenses:</u>

- The 2013 Distribution Maintenance Forecast is $49,000 higher than 2013 budget due to the meter reverification of the three wholesale metering points that were completed in one year, as well as the substantial increase in locate costs due to the higher volume of locates due to the use of OneCall. In the Misc Distribution Expense (Engineering) account, the labour in 2013 was higher due to an overlap of staff while the new engineering technician was being trained in preparation for the departure of the current engineering technician.

- In the 2014 Distribution Maintenance budget, the overall budget is $58,000 higher than the 2013 Forecast, with two apprentice linemen included in the budget, therefore increasing the labour in many of the operations accounts in 2014, over the 2013 forecast. The Supervision account was lower in 2014 due to the removal of the Lines Supervisor from the budget.

Meter Reading, Billing and Collecting Expenses:

- The 2013 Forecast is $39,000 lower than the 2013 Budget due to the decrease in labour costs with the departure of a customer service representative, with the new customer service representative being hired three months later at a lower rate.

- The 2014 Billing account budget is $42,000 higher than the 2013 Forecast which is mostly attributable to Customer Connect expenses of $24,000. Customer Connect enables our customers to gain access to high value consumption data, to better understand their usage patterns, to educate themselves on rates and what affects them and to transact more effectively with the Utility.

  Additionally a new cost of $4,000 for the Utility Collaborative Services (UCS) Security Framework project also contributed to this increase in the 2014 Budget, where its primary objective is to increase the safety, reliability and resilience of UCS Business Operations against cyber-attacks by creating expectations and enforceable direction for staff members and vendors through well written policies and procedures.

  The remaining increase in the 2014 Budget is attributable to the higher labour costs in 2014.

- In the Collecting account, there was $5,000 budgeted in 2014 for legal costs that were not incurred in 2013 Forecast, which accounts for some of the budgeted overage. Labour was the other driver in the difference between 2013 forecast and budgeted amounts in 2014, due to the departure of the customer service representative.

Administration Costs:

- The 2013 Administration Forecast costs are $160,000 higher than the 2013 budget. There were a number of drivers that contributed to this increase:
  - $30,000 Distribution System Plan prepared for Cost of Service rate application
  - $56,000 Outside services pertaining to potential sale of utility
  - $12,000 Outside services pertaining to potential merger of utility
  - $15,000 Outside services pertaining to team building and succession planning, and personnel matters over usual costs
  - $11,000 New privacy, cyber and network security endorsement insurance and board matters
  - $18,000 File Nexus which provides the ability to scan and save all documents, allowing a reduction in paper, as well as a more efficient and time saving filing system

- The 2014 Administration budget is $77,000 higher than the 2013 Administration Forecast, however as noted above there were additional unbudgeted costs that occurred in 2013. There were a number of drivers that contributed to this increase:
  - $43,000 Cost awards for rate application – OEB, intervenors: Vulnerable Energy Customer Coalition, Energy Probe, and recently added School Energy Coalition
  - $22,000 Rate application assistance including legal costs
  - $7,000 Insurance rate increases
  - $6,000 Grand Valley Service Area Amendment
  - $7,000 Year End Audit cost increase
  - $14,000 Customer Survey
  - $20,000 File Nexus
  - $18,000 Additional labour costs for safety in miscellaneous general expenses due to new apprentices
  - $35,000 The CDM portion of labour costs split with administration was higher than budgeted, and labour costs increased due to achievement of new salary levels

Balance Sheet to 2014

- Will renew smart meter loan at $1.5 million for 5 years at an estimated rate of 4.00%.
- Cash forecast increases in 2014 with the inclusion of new $2.5 million borrowing at an estimated 4.00%. In 2014 this brings the debt to equity ratio to 54/46%.
- The regulatory assets have increased in 2013 due to the rate refund to customers for the change in accounting policies of the useful lives of capital assets. This repayment takes place over a 5 year time period, until the next cost of service application.
- PILS payable in 2012 was due to an underpayment of PILS that related to the increased net income due to smart meter revenue.
- All other forecasted assets and liabilities remain fairly constant.

Profit and Loss Statement to 2014

- OHL is projecting a net income of $706,619 and a projected dividend of $353,310.
- PILS decreased from 2013 onwards due to the change in asset useful lives where the accounting depreciation is lower than the capital cost allowance, which amounted to a larger deduction to income.
- Dividends paid in 2013 include the dividend payable of $423,000, as well as the $1,500,000 special dividend, which had been paid at the beginning of 2013.

5 Year Business Plan

- Moderate customer growth is projected, with a minor percentage increases to revenue and expenses.
- Other revenues in 2013 are showing a credit of $(256,130) due to recording of the accounting policy change of asset useful lives in the amount of $647,000.
- Rate base increases significantly from 2011 to 2012 due to the inclusion of smart meters into the rate base.
- Working capital allowance changed from 15% to 13% in 2014.
- Based on the 5 year Distribution System Plan, Actual Rate Base is expected to grow approximately $239,000 per year.
- The Rate Application Rate Base is based on the 2014 Cost of Service Rate Application before the Ontario Energy Board and is subject to change.

New Accounting Policy Impact on Financial Statements

It was determined by a report commissioned by the Ontario Energy Board and agreed upon by our Operations department that the useful lives of distribution assets were longer than the 25 year standard. Orangeville Hydro changed the useful lives of distribution assets in 2012.

Orangeville's cost of service rate application was approved May 1, 2010 and is recovering the depreciation expense based on a 25 year life until May 1, 2014. The depreciation expense has decreased for 2012 and 2013 therefore Orangeville is over-recovering the revenue requirement. The OEB provided accounting directions to refund the customers in rates based as directed below:

Accounting Policy Changes	**2012**	**2013**
Year End Net Fixed Assets under "OLD" CGAAP	15,218,427	15,461,363
Year End Net Fixed Assets under "NEW" CGAAP	15,595,344	16,282,861
Cumulative Amounts	(376,917)	(821,498)
2013 Amount Only		(444,581)
Deprecation Expense to be Returned to Customers		(821,498)
Return Component @ WACC 5.63%		(231,091)
Total to be Returned to Customers		(1,052,589)

The total amount of $1,052,589 will be refunded in the rates to our customers over a 5-year period.

Return Component

Distribution Revenue Reduction over next 5 years		231,091
Yearly Forecasted Amounts to 2018		46,218

The return component of $231,091 is deducted from our distribution revenue over 5 years until our next cost of service application, 46,218 yearly until 2018.

Depreciation Expense Component

Total Adjustment for Accounting Policy Change		821,498
Amount Booked in 2012		(173,590)
Total Adjustment for Accounting Policy Change for 2013		**647,908**

In 2012, we reduced our net income by $173,590, however after completing our 2014 rate application we found that the amount should be $376,917. Therefore, in 2013 our net income will be reduced by $647,908 ($821,498 – 173,590 = $647,908).

The impact of reducing net income by $647,908 is offset by:

Estimated 2013 Increases in Net Income			Impact on 2013 Net Income
Accounting Policy Changes	**Old Policy**	**New Policy**	
Other Revenue Amount on Income Statement			(647,908)
Change in Depreciation Expense	1,201,723	768,924	432,799
Adjustment from 2012 ($376,917-$173,590)			203,327
Total Accounting Policy Change Impacts			(11,782)
Change in Income Taxes	196,675	62,057	134,618
Increase to Net Income due to New Policy			111,055
Increase Smart Meter Rate Adders & PILs Decision			470,386
Total Increase to Net Income			**581,441**

The depreciation expense prior to the new policy would have decreased our net income by $1,201,723, however, with the new useful lives we only decrease our net income by $768,924. OEB accounting procedures instruct us to return this difference to the customers and offset this difference to income. The change took place in 2012 and 2013. We have re-based using the new useful lives and therefore included in our rate base therefore going forward into 2014 there will be no further adjustments.

We also achieve a higher income due to lower Income taxes as capital cost allowance is greater than accounting depreciation.

<u>Example of Impact to Return on Rate Base for 2014 Rates</u>

Revenue Requirement Component	2014 CGAAP or ASPE with the changes to the policies	2014 CGAAP without the changes to the policies	Difference
Closing NBV 2013	$ 16,282,861	$ 15,461,363	$ 821,499
Closing NBV 2014	$ 16,711,602	$ 15,458,405	$ 1,253,197
Average NBV	$ 16,497,232	$ 15,459,884	$ 1,037,348
Working Capital	$ 3,757,782	$ 3,751,208	$ 6,574
Rate Base	$ 20,255,013	$ 19,211,092	$ 1,043,922
Return on Rate Base	$ 1,139,565	$ 1,080,833	$ 58,732

Rate base is higher as depreciation is lower therefore the return on rate base is higher.

During the course of the rate application the above numbers are subject to change. The numbers will change based on the forecast capital expenditures for 2013 and the budget for 2014 as this will change the difference in net fixed assets. The Ontario Energy Board has also recently published the cost of capital parameters to be used in the rates for 2014 filers.

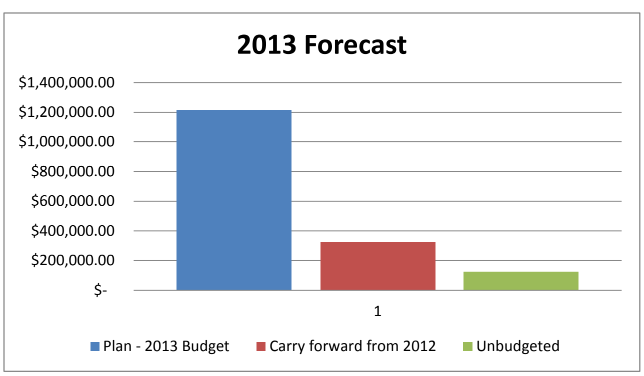
Orangeville Hydro Limited

CAPITAL

2013 FORECAST & 2014 BUDGET

DESCRIPTION	2013 FORECAST	2013 BUDGET	2014 BUDGET
DISTRIBUTION PLANT			
Land	12,500	22,400	0
Building - MS 1		0	0
Sub-Stations	22,039	71,135	119,607
Meter Points		0	0
Overhead Poles, Towers	84,119	153,667	122,472
Overhead Conductors,Devices	64,047	72,572	123,431
Underground Conduit	377,013	458,858	582,989
Underground Conductors, Devices	334,367	394,035	443,454
Distribution Transformers	514,169	347,260	562,967
Services	142,374	182,783	208,962
Meter Distribution	9,929	27,159	45,764
Total Gross Distribution Plant	**1,560,555**	**1,729,869**	**2,209,646**
Contributions & Grants-Credit	(487,576)	(557,560)	(640,216)
Total Net Distribution Plant	**1,072,980**	**1,172,309**	**1,569,430**
GENERAL PLANT			
Land	0	0	0
Building 400 C Line	5,167	7,000	29,500
Office Equipment	15,501	23,000	17,200
Computer Equipment	31,259	37,000	77,200
Computer Software	33,453	30,500	72,000
Rolling Stock	0	275,000	310,000
Work & Service Equipment	0	0	0
Stores Equipment	1,299	2,500	2,000
Tools	1,487	6,800	5,000
Measurement & Testing	10,070	6,000	5,000
Communication	0		0
Misc Equipment	2,555	2,000	5,600
Load Management Controls Customer Premises	0	0	0
System Supervisory Equipment	0	0	0
Total General Plant	**100,792**	**389,800**	**523,500**
TOTAL FIXED ASSETS	**1,173,771**	**1,562,109**	**2,092,930**

Category	Explanation	Reference Number	Project Description	Total 2013 Budget	Total 2013 Forecast	Total 2013 Contributed Capital Budget	Total 2013 Contributed Capital Forecast
System Access	Unbudgeted	B00-2013	Transformer Movement/Inventory		$ 52,316.48		
System Access	Carry forward from 2012	B57-2012	Mill & Leeson St Road Reconstruction		$ 6,706.84		
System Access	Unbudgeted	B65-2013	McCarthy St New Service		$ 2,619.13		
System Access	Unbudgeted	B89-2013	TRANSFORMER/SWITCHGEAR PAINT		$ 9,335.02		
System Access	Plan - 2013 Budget	C01-2013	Various General Service Capital Contribution Projects	$ 100,000.00	$ 221,084.27	$ (100,000.00)	$ (219,404.54)
System Access	Plan - 2013 Budget	C02-2013	Various Residential Capital Contribution Projects	$ 8,000.00	$ 5,739.34	$ (6,000.00)	$ (5,739.34)
System Access	Plan - 2013 Budget	FX1-2013	Estimated Various Embedded Generation Projects (>10kW)	$ 12,991.54	$ -	$ (12,991.54)	
System Access	Plan - 2013 Budget	FX2-2013	Estimated Various Embedded Generation Projects (<10 kW)	$ 3,772.34	$ 749.72	$ (3,772.34)	$ (749.72)
System Access	Unbudgeted	HOO-2013	Major Components Maintenance Jobs		$ 6,468.70		
System Access	Plan - 2013 Budget	S10-2013	Various Subdivisions	$ 645,591.00	$ 425,770.18	$ (434,796.00)	$ (261,681.91)
			System Access Total:	**$ 770,354.88**	**$ 730,789.68**	**$ (557,559.88)**	**$ (487,575.51)**
System Renewal	Unbudgeted	B42-2013	Water & William U/G Conversion		$ 9,550.66		
System Renewal	Plan - 2013 Budget	B52-2013	Fault Indicator Replacement	$ 15,914.05	$ 6,793.88		
System Renewal	Unbudgeted	B73-2013	28-30 Townline Pole & Service		$ 2,383.99		
System Renewal	Unbudgeted	B74-2013	37 Hillside Dr Pole & Service		$ 4,045.50		
System Renewal	Unbudgeted	B75-2013	81 Centennial TX & Vault Chg		$ 16,639.28		
System Renewal	Unbudgeted	B77-2013	Wholesale Metering		$ 2,500.38		
System Renewal	Plan - 2013 Budget	B79-2013	Parkview Heights- Transformer Replacement	$ 85,237.30	$ -		
System Renewal	Plan - 2013 Budget	B80-2013	Emma & Douglas St- Pole line Replacement	$ 57,777.48	$ 55,204.37		
System Renewal	Plan - 2013 Budget	B82-2013	Cooper-George-Parkview-Main St South Pole Line Replacement	$ 75,688.69	$ -		
System Renewal	Plan - 2013 Budget	B83-2013	Municipal Substation - Major Service	$ 71,134.92	$ 21,081.71		
System Renewal	Plan - 2013 Budget	B84-2013	Joyce-Fife-Mary-Spruyt-Baker Poletran Replacement	$ 26,262.71	$ -		
			System Renewal Total:	**$ 332,015.14**	**$ 118,199.77**		
System Service	Carry forward from 2012	B22-2013	Browns Farm Conversion		$ 192,877.06		
System Service	Carry forward from 2012	B48-2013	Centre & Church St Conversion		$ 74,969.67		
System Service	Carry forward from 2012	B50-2012	Faulkner/Elizabeth St Conversion		$ 35,008.69		
System Service	Plan - 2013 Budget	B61-2013	C-Line 27.6kV Conversion	$ 47,160.06	$ 49,583.22		
System Service	Carry forward from 2012	B63-2012	Lawrence Ave Conversion		$ 13,683.33		
System Service	Plan - 2013 Budget	B76-2013	Stoney Crescent 27.6kV Conversion	$ 56,007.53	$ 46,395.92		
System Service	Plan - 2013 Budget	B78-2013	First St- Fifth Ave 27kV OH-UG Conversion	$ 154,007.29	$ 27,909.14		
System Service	Plan - 2013 Budget	B81-2013	West Broadway 27.6kV UG Conversion	$ 157,917.93	$ -		
System Service	Plan - 2013 Budget	B85-2013	Bythia-Victoria-Princess 27.6kV Conversion Phase 1	$ 190,006.13	$ 252,872.34		
System Service	Plan - 2013 Budget	B86-2013	MS1 Site Restoration	$ 22,400.00	$ -		
System Service	Unbudgeted	B90-2013	Radial Fused Switch Installation		$ 18,266.58		
			System Service Total:	**$ 627,498.93**	**$ 711,565.95**		
General Plant	Plan - 2013 Budget	GP 2013 - 1	Vehicles	$ 275,000.00	$ -		
General Plant	Plan - 2013 Budget	GP 2013 - 2	Building	$ 7,000.00	$ 5,166.51		
General Plant	Plan - 2013 Budget	GP 2013 - 3	Office Equipment	$ 23,000.00	$ 15,501.31		
General Plant	Plan - 2013 Budget	GP 2013 - 4	Computer Equipment	$ 37,000.00	$ 31,259.35		
General Plant	Plan - 2013 Budget	GP 2013 - 5	Computer Software	$ 30,500.00	$ 33,453.25		
General Plant	Plan - 2013 Budget	GP 2013 - 6	Stores Equipment	$ 2,500.00	$ 1,299.00		
General Plant	Plan - 2013 Budget	GP 2013 - 7	Tools, Shop & Garage Equipment	$ 6,800.00	$ 1,487.10		
General Plant	Plan - 2013 Budget	GP 2013 - 8	Measurement & Testing	$ 6,000.00	$ 10,070.00		
General Plant	Plan - 2013 Budget	GP 2013 - 9	Miscellaneous Equipment	$ 2,000.00	$ 2,555.00		
			General Plant Total:	**$ 389,800.00**	**$ 100,791.52**		
			Total Actual Capital Expenditures	**$ 2,119,668.95**	**$ 1,661,346.92**	**$ (557,559.88)**	**$ (487,575.51)**



Category	2013 Budget	2013 Forecast	Variance
System Access	$ 770,354.88	$ 730,789.68	$ (39,565.20)
System Renewal	$ 332,015.14	$ 118,199.77	$ (213,815.37)
System Service	$ 627,498.93	$ 711,565.95	$ 84,067.02
General Plant	$ 389,800.00	$ 100,791.52	$ (289,008.48)
Total Gross Assets:	$ 2,119,668.95	$ 1,661,346.92	$ (458,322.03)
Contributed Capital	$ (557,559.88)	$ (487,575.51)	$ 69,984.37
Total Net Assets:	$ 1,562,109.07	$ 1,173,771.41	$ (388,337.66)

2014 Capital Projects by Category

Category	Explanation	Reference Number	Project Description	Total Project	Contributed Capital
System Access	Plan - 2014 Budget	C01-2014	Various General Service Capital Contribution Projects	$ 100,000.00	$ (100,000.00)
System Access	Plan - 2014 Budget	C02-2014	Various Residential Capital Contribution Projects	$ 8,000.00	$ (6,000.00)
System Access	Plan - 2014 Budget	F01-2014	Estimated Various Embedded Generation Projects (>10kW)	$ 12,991.54	$ (12,991.54)
System Access	Plan - 2014 Budget	F02-2014	Estimated Various Embedded Generation Projects (<10 kW)	$ 3,772.34	$ (3,772.34)
System Access	Plan - 2014 Budget	S11-2014	Various Subdivisions	$ 286,342.29	$ (175,710.48)
			System Access Total:	**$ 411,106.17**	**$ (298,474.36)**
System Renewal	Plan - 2014 Budget	B00-2014	Failed Transformer Replacement	$ 46,200.00	
System Renewal	Plan - 2014 Budget	B79-2014	Parkview Heights- Transformer Replacement Phase 2	$ 63,925.50	
System Renewal	Plan - 2014 Budget	B82-2014	Cooper-George-Parkview-Main St South Pole Line Replacement Phase 2	$ 43,818.76	
System Renewal	Plan - 2014 Budget	B83-2014	Municipal Substation - Major Service	$ 30,595.89	
System Renewal	Plan - 2014 Budget	B89-2014	Padmounted Transformer- Switchgear Painting	$ 21,665.70	
			System Renewal Total:	**$ 206,205.85**	
System Service	Plan - 2014 Budget	B78-2014	First St- Fifth Ave 27kV Conversion Phase 2	$ 165,050.59	
System Service	Plan - 2014 Budget	B85-2014	Bythia-Victoria-Princess 27.6kV Conversion Phase 2	$ 378,021.90	
System Service	Plan - 2014 Budget	B87-2014	Veteran's Way Poleline- New 27.6kV Feeder	$ 162,428.58	
System Service	Plan - 2014 Budget	B88-2014	10 Third Street 27.6kV Conversion	$ 52,383.21	
System Service	Plan - 2014 Budget	B91-2014	Gifford Street Conversion	$ 25,527.62	
			System Service Total:	**$ 783,411.89**	
General Plant	Plan - 2014 Budget	GP 2014 - 1	Computer Equipment	$ 77,200.00	
General Plant	Plan - 2014 Budget	GP 2014 - 2	Vehicles	$ 310,000.00	
General Plant	Plan - 2014 Budget	GP 2014 - 3	Building	$ 29,500.00	
General Plant	Plan - 2014 Budget	GP 2014 - 4	Office Equipment	$ 17,200.00	
General Plant	Plan - 2014 Budget	GP 2014 - 5	Computer Software	$ 72,000.00	
General Plant	Plan - 2014 Budget	GP 2014 - 6	Stores Equipment	$ 2,000.00	
General Plant	Plan - 2014 Budget	GP 2014 - 7	Tools, Shop & Garage Equipment	$ 5,000.00	
General Plant	Plan - 2014 Budget	GP 2014 - 8	Measurement & Testing	$ 5,000.00	
General Plant	Plan - 2014 Budget	GP 2014 - 9	Miscellaneous Equipment	$ 5,600.00	
			General Plant Total:	**$ 523,500.00**	
			Total 2014 Budget Capital Expenditures	**$ 1,924,223.91**	**$ (298,474.36)**
System Access	Carry forward from 2013	S06-2013	Mono Meadows (Sarah) Ph 1 - Connections	$ 969.20	
System Access	Carry forward from 2013	S07-2012	Thomasfield Homes - to be Energized	$ 451,072.50	$ (341,741.55)
System Access	Carry forward from 2013	S08-2013	Paula Court - Connections	$ 1,178.44	
System Access	Carry forward from 2013	S09-2013	Mono Meadows (Sarah) Ph 2 - Connections	$ 10,595.14	
			System Access Total:	**$ 463,815.28**	**$ (341,741.55)**
System Renewal	Carry forward from 2013	B79-2013	Parkview Heights- Transformer Replacement - Phase 1	$ 85,237.30	
System Renewal	Carry forward from 2013	B82-2013	Cooper-George-Parkview-Main St South Pole Line Replacement - Phase 1	$ 75,688.69	
System Renewal	Carry forward from 2013	B84-2013	Joyce-Fife-Mary-Spruyt-Baker Poletran Replacement	$ 26,262.71	
			System Renewal Total:	**$ 187,188.70**	
System Service	Carry forward from 2013	B81-2013	West Broadway 27.6kV UG Conversion	$ 157,917.93	
			System Service Total:	**$ 157,917.93**	
			Total Actual Capital Expenditures for Jobs Continued from 2013	**$ 808,921.90**	**$ (341,741.55)**
			Total Budget Capital Expenditures	**$ 2,733,145.81**	**$ (640,215.91)**

Category	2014 Budget	2013 Jobs continued	Total
System Access	$ 411,106.17	$ 463,815.28	$ 874,921.45
System Renewal	$ 206,205.85	$ 187,188.70	$ 393,394.55
System Service	$ 783,411.89	$ 157,917.93	$ 941,329.81
General Plant	$ 523,500.00		$ 523,500.00
Total Gross Assets:	$ 1,924,223.91	$ 808,921.90	$ 2,733,145.81
Contributed Capital	$ (298,474.36)	$ (341,741.55)	$ (640,215.91)
Total Net Assets:	$ 1,625,749.55	$ 467,180.35	$ 2,092,929.90

Orangeville Hydro Limited
OPERATING
2013 FORECAST & 2014 BUDGET

	2013 FORECAST	2013 BUDGET	2014 BUDGET
DISTRIBUTION			
Transformer Station	$76,405	$63,934	$73,326
Misc Distribution Expenses (Engineering)	$250,388	$224,011	$210,506
Overhead Distribution	$139,087	$135,284	$166,395
Overhead Distribution - Tree Trimming	$90,716	$90,239	$101,310
Underground Distribution	$4,142	$18,693	$26,696
Customer Premises/Locates	$115,000	$85,796	$116,489
Transformer Distribution	$48,513	$45,910	$57,762
O/H & U/G Services	$114,750	$117,867	$133,639
Supervision/Maintenance & Engineering	$182,963	$176,962	$159,957
Meter Distribution	$76,951	$91,171	$110,943
TOTAL DISTRIBUTION	**$1,098,915**	**$1,049,866**	**$1,157,023**
BILLING & COLLECTING			
Supervision	$40,082	$38,181	$40,992
Meter Reading	$142,635	$149,900	$138,201
Billing	$295,994	$306,423	$338,284
Collecting	$193,957	$217,276	$205,572
TOTAL BILLING & COLLECTING	**$672,668**	**$711,781**	**$723,049**
ADMINISTRATION			
Community Relations/Conservation	$28,001	$26,254	$21,554
Directors Salaries & Expenses	$448,859	$430,826	$461,866
General Officers Salaries & Expenses	$152,515	$152,764	$155,672
General Administration Expenses & Salaries	$306,128	$307,816	$353,803
Miscellaneous General Expenses	$600,346	$456,993	$613,454
Maintenance of General Plant	$88,370	$88,688	$94,609
Capital Taxes	$0	$1,180	$0
TOTAL ADMINISTRATION	**$1,624,219**	**$1,464,521**	**$1,700,958**
TOTAL CONTROLLABLE EXPENSES	**$3,395,802**	**$3,226,168**	**$3,581,031**

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
50160 Distribution Station Labour				
Labour - 100	-	$3,561.09	$10,538.03	
Labour - 600	789.95	537.63	553.74	
Total Distribution Station Labour	**789.95**	**4,098.72**	**11,091.77**	
50170 Distribution Station				
Trucks	110.00	240.00	240.00	
Administration	14,791.21	16,315.00	16,824.31	Admin-PILS/Municipal Taxes
Contract	28,946.49	32,411.28	28,059.72	Contract-MSP service, meter reading, consultant (monitoring problems), infrared testing, Oil & Gas analysis, Quarterly Inspections by Ascent
Total Distribution Station Equipment & Expenses	**43,847.70**	**48,966.28**	**45,124.03**	
50200 - 50250 O/H Distribution Operation				
Labour	7,421.90	11,059.88	14,359.21	
Trucks	1,905.00	1,360.00	1,360.00	
Direct Purchases	-			
Contract	2,544.80	1,400.00	1,407.60	Contract-Infrared Testing
Total O/H Distribution Operation	**11,871.70**	**13,819.88**	**17,126.81**	
50350 O/H Distribution Transformers				
Labour	4,158.82	2,055.62	2,089.98	
Trucks	1,015.00	360.00	360.00	
Materials	539.93			
Contract	120.00			
Total O/H Distribution Transformers	**5,833.75**	**2,415.62**	**2,449.98**	
50400 - 50450 U/G Distribution Operation & Expenses				
Labour	-	7,426.77	8,016.50	
Trucks	-	1,360.00	1,360.00	
Total U/G Distribution Operation & Expenses	**-**	**8,786.77**	**9,376.50**	
50550 U/G Distribution Transformers				
Labour	-	373.27	518.22	
Trucks	-	120.00	120.00	
Direct Purchases	-			
Contract	-			
Total U/G Distribution Transformers	**-**	**493.27**	**638.22**	
50650 Meter Expenses				
Labour - 100	40,258.95	53,399.14	58,867.66	Labour-Lines, Engineering and Utility Person
Labour - 700	9,776.70	10,424.86	10,701.59	Labour-Admin Support
Trucks	5,200.00	8,140.00	7,400.00	
Materials	-			
Direct Purchases	2,253.41	1,008.72	2,263.56	Contract-Metering services such as meter changeouts, high bill complaints, investigation, service troubleshooting, etc.
Contract	19,462.35	18,198.00	31,709.76	Contract-Reverifications, Rodan contract work, equipment maintenance, computer software support
Total Meter Expenses	**76,951.41**	**91,170.72**	**110,942.57**	

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
50710 - 50750 Locates				
Labour - 100	65,920.10	56,279.13	75,724.29	Labour-Lines, Engineering and Utility Person
Labour - 700	13,061.28	3,207.48	3,318.55	Labour-Admin Support and locate contract assistance
Trucks	29,560.00	22,480.00	30,000.00	Labour-Overtime 25 callouts/yr - one man double time
Direct Purchases	2,096.34	409.20	1,765.68	Contract-Increase in locates due to One Call
Contract	4,361.88	3,420.00	5,680.80	Customer Premises-Rodan Follow-up with customer, Voltage tests, etc.
Total Locates	**114,999.60**	**85,795.81**	**116,489.32**	
50850 Miscellaneous Distribution Expenses				
Labour	213,046.03	151,618.25	157,531.41	Labour-Actual 2013 increased due to overlap of two Eng Techs
Trucks	9,580.00	28,480.00	15,444.00	Admin-Training and Conferences for Junior Engineer and Engineering Tech
Direct Purchases	641.57			
Administration	19,036.41	15,515.04	24,399.00	Admin-ASI GoAsset Infrastructure Design Suite Subscription, ASI GoAsset Infrastructure Map Server, Support, USF Utilities Standards, Bentley Microstation Suppor
Contract	8,084.01	14,100.00	13,131.48	
Prepaids	-	14,297.52		
Total Miscellaneous Distribution Expenses	**250,388.02**	**224,010.81**	**210,505.89**	
50960 Other Rent Poles				
Other	7,610.00	7,583.15	7,734.81	
Total Other Rent Poles	**7,610.00**	**7,583.15**	**7,734.81**	
51050 Maintenance & Engineering Supervision				
Labour	174,978.01	169,577.14	152,530.68	Labour-Manager of Engineering and Operations 96% Labour Allocation
Trucks	5,343.00	1,440.00		Labour-Actual 2013 increased due to three months included Line Supervisor
Administration	2,189.78	5,444.92	6,916.40	
Prepaids	452.44	500.04	510.00	
Total Maintenance & Engineering Supervision	**182,963.23**	**176,962.10**	**159,957.08**	
51140 - 51145 Transformer Station Maintenance				
Labour - 100	1,971.57		848.48	
Trucks	450.00			
Materials	-	672.56	700.35	Contract-Maintenance of 1 sub-station / yr - includes switching to isolate & restore
Contract	29,345.76	10,195.96	15,561.36	Contract-grass cutting & weed spraying, snow removal
Total Transformer Station Maintenance	**31,767.33**	**10,868.52**	**17,110.19**	Contract-3 meter changes due to seal expiry in three locations
51200 O/H Maintenance of Poles & Towers				
Labour	16,604.91	20,013.33	30,657.32	Labour-O/T 24 hrs spread over the year
Trucks	4,975.00	4,320.00	5,760.00	Labour-On Call based on $205 per week plus $55/stat holiday
Materials	1,097.20	3,069.00	3,130.32	Material-used to repair or replace existing plant
Direct Purchases	212.01			Material-Joint use, Misc Rentals, Radio License, Equipment Rental
Contract	450.00	100.00	153.00	
Total O/H Maintenance of Poles & Towers	**23,339.12**	**27,502.33**	**39,700.64**	
51250 O/H Maintenance of Conductors & Devices				
Labour	65,460.28	57,728.70	74,818.89	
Trucks	13,025.00	9,360.00	9,360.00	
Materials	12,897.22	15,000.00	15,300.00	
Direct Purchases	861.59	1,620.00		
Administration	1,781.66		1,296.00	
Contract	2,240.56	2,670.00	1,057.74	
Total O/H Maintenance of Conductors & Devices	**96,266.31**	**86,378.70**	**101,832.63**	

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
51300 O/H Services				
Labour	21,644.56	23,996.54	23,706.39	
Trucks	5,335.00	4,320.00	4,320.00	
Materials	4,439.11	2,062.56	2,103.72	
Direct Purchases	-			
Contract	-	300.00	300.00	
Total O/H Services	**31,418.67**	**30,679.10**	**30,430.11**	
51350 O/H Distribution Lines Tree Trimming				
Labour	69,958.35	68,181.90	79,247.25	
Vehicles	16,715.00	21,600.00	21,600.00	
Direct Purchases	671.08	306.96	313.08	Direct Purchases-Misc. oil, gas, chains, files, pruners, handsaws
Contract	3,371.49	150.00	150.00	Contract-Chipper maintenance
Total O/H Distribution Lines Tree Trimming	**90,715.92**	**90,238.86**	**101,310.33**	
51500 U/G Maintenance of Conductors & Devices				
Labour	2,346.78	5,926.48	10,154.88	Labour-Upgrades, testing & dig-ins, primary cable repairs and terminations
Vehicles	440.00	1,440.00	1,440.00	
Inventory	897.11	639.48	3,825.00	
Direct Purchases	458.00	1,200.00	1,200.00	
Contract	-	700.00	700.00	Contract-U/G callouts, Site Damages and Equipment Rentals
Total U/G Maintenance of Conductors & Devices	**4,141.89**	**9,905.96**	**17,319.88**	
51550 U/G Services				
Labour	52,302.61	63,857.82	78,027.62	Labour-48 O/T hours for call-outs
Vehicles	10,810.00	10,860.00	10,860.00	Labour-includes Secondary Cable Burn-off Repairs, lawn restoration and service upgrades
Inventory	4,143.96	3,000.00	3,825.00	
Direct Purchases	2,338.21	1,190.52	2,539.80	
Contract	13,736.68	8,280.00	7,956.00	Contract-Electrician Call-outs, Equipment Rental
Total U/G Services	**83,331.46**	**87,188.34**	**103,208.42**	
51600 - 51601 O/H Line Transformers				
Labour	7,652.35	10,055.60	15,235.62	Labour-O/T - callouts for a total of 16 hrs
Vehicles	2,170.00	1,920.00	1,920.00	History shows approx 2 repairs/mth - blown tx's from overloads, lightning, birds, leaking or upgrading when re-building secondary
Inventory	11,533.18	1,650.00	2,550.00	
Contract	3,411.51	887.88	882.36	Contract-Ministry web site fee, Infrared test the rest of the padmounts
Total O/H Line Transformers	**24,767.04**	**14,513.48**	**20,587.98**	
51610 - 51611 U/G Line Transformers				
Labour	12,722.56	16,043.27	20,017.74	Vehicles- 1/2 of man hrs, usually 2 trucks
Vehicles	2,860.00	3,960.00	3,960.00	Vehicles- 1/2 of man hrs, usually 2 trucks
Inventory	1,610.24	750.00	6,757.56	Inventory-Replacement tx's, copper ground wire, bushing & hardware
Direct Purchases	375.60	2,343.84	1,820.76	
Contract	343.90	5,390.04	1,530.00	
Total U/G Line Transformers	**17,912.30**	**28,487.15**	**34,086.06**	
51700 - 51720 Sentinel Lights	-			
51750 Meter Maintenance	-			
TOTAL OPERATIONS	**1,098,915.40**	**1,049,865.57**	**1,157,023.22**	

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
Labour	40,081.89	38181.35	40,992.16	Labour-Supervision of Meter Reading, Billing and Collecting
53050 Supervision	**40,081.89**	**38181.35**	**40,992.16**	
Labour	3,731.54	1,752.95	1,107.57	Labour-includes portion of Engineering labour
Vehicles	960.00	480.00	480.00	
Administration	395.60			Contract- Utilismart-read Gen. Service <50 and >50 billing cycles, check readings & finals, Interval reads, demand reset seals
Contract	137,548.19	147,666.84	136,613.64	Contract-Savage Online Data Storage, Sensus TGB, Internet fees, UCS Harris
53100 Meter Reading	**142,635.33**	**149,899.79**	**138,201.21**	
Labour	123,823.17	130,468.00	134,666.38	
Administration	56,437.37	57,429.84	63,567.00	Admin-Training for CSR/Senior Clerk, CIS Conference, Postage, Bill Stationery, printer cartridges
Contract	95,560.27	96,746.16	121,349.88	Contract-UCS Harris, ITM Hosting, Util-assist Sync Operator, Customer Connect, UCS Senior Analyst, UCS Security Framework Project
Prepaids	-	2,212.08		
LDC Consolidated Billing	20,172.82	19,567.20	18,701.04	
53150 - 53155 Customer Billing	**295,993.63**	**306,423.28**	**338,284.30**	
Labour	96,359.72	107,139.94	105,651.31	
Vehicles	8,300.00	12,400.00	9,360.00	
Administration	19,250.14	20,079.00	20,428.20	Admin-Stationery, Postage, Training, Bank Charges for transmission of PAP's and Interac charges
Contract	22,710.22	32,233.32	35,132.28	Contract-URB Hand Delivery of Final Collection Notice, Legal Costs, Brinks Security, UCS Harris
Prepaids	(0.04)	424.20		
53200 Collecting	**146,620.04**	**172,276.46**	**170,571.79**	
Collecting Cash Over & Short	23.49			
53250 Cash Over & Short	**23.49**			
Bad Debt Expense	47,313.39	45,000.00	35,000.00	
53350 Bad Debt Expense	**47,313.39**	**45,000.00**	**35,000.00**	
TOTAL BILLING AND COLLECTING	**672,667.77**	**711,780.88**	**723,049.46**	
Labour	2,423.70	5,821.50	5,366.58	
Vehicles	620.00	720.00	720.00	
Administration	19,757.04	14,712.00	10,467.10	Administration-Informational letters, cable ads, promotional material, school program brochures
Contract	-			Administration-Customer education $8,000, Donations $5,000, LEAP Assistance - $5,912, On Hold messaging
Other	200.00			
54100 - 54150 Community Relations	**23,000.74**	**21,253.50**	**16,553.68**	
Labour	371,528.26	373,138.63	387,653.10	Labour-President and 65% of VP Administration Salary, Directors remuneration, and additional meetings
Vehicles	100.00	180.00	240.00	
Administration	65,993.31	50,510.16	62,779.20	Administration-EDA AGM: 2 Directors, President, VP, Admin
Contract	150.00			Administration-Georgian Bay District (GBD) AGM: 3 Directors, President & VP, Admin
Prepaids	11,087.52	6,997.08	11,193.86	Administration-2 Additional Conferences (President & VP, Admin), VP, Admin - additional training
56050 Executive Salaries & Expenses	**448,859.09**	**430,825.87**	**461,866.16**	

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
Labour	148,829.35	145,560.42	149,231.24	Labour-Manager of Finance & Rates
Administration	3,685.67	7,203.96	6,440.28	Administration-Manager of Finance & Rates Conferences & Training
56100 Management Salaries & Expenses	**152,515.02**	**152,764.38**	**155,671.52**	
Labour	293,310.60	285,026.35	332,311.31	Labour-60% of Inventory Purchasing Clerk, 100% Accounting Assistant/Regulatory Assistant
Administration	12,817.77	22,789.92	21,492.00	Administration-30% of Admin Assistant salary to OPA Expense for Recovery, Training and Seminars
56150 General Administration Salaries &	**306,128.37**	**307,816.27**	**353,803.31**	
Administration	63,741.63	46,346.10	88,730.24	Administration-Stationary, postage, telephone, equipment maintenance, staff year end
Contract	15,870.10	2,943.72	8,247.36	Administration-File Nexus, office supplies, bank charges
Prepaids	4.63	3,684.36		
56200 Office Supplies & Expenses	**79,616.36**	**52,974.18**	**96,977.60**	
Contract	239,070.53	123,895.72	163,076.40	Contract-Computer support, Legal, Great Plains system support, Human Resources
56300 Outside Services	**239,070.53**	**123,895.72**	**163,076.40**	Contract-Customer Survey, Specialized consultant assistance
Prepaids	30,909.65	8,632.32	8,179.20	
Other	-	21,999.96	20,348.40	
56350 Property Insurance	**30,909.65**	**30,632.28**	**28,527.60**	
Injuries & Damages/Prepd Ins	26,348.14	22,659.36	27,101.28	
Employee Pensions & Benefits	12,626.56	12,361.68	12,820.92	
Employee Pension/ Retiree Life Ins	24,615.01	24,509.52	26,275.08	
56400 - 56460 Total Insurance	**63,589.71**	**59,530.56**	**66,197.28**	
Administration	5,787.22	5,708.00	5,822.16	
Prepaids	-			Regulatory Expenses-OEB assessments, Cost Awards, Unknown compliance expenses
Other	31,826.14	38,754.96	79,512.24	Regulatory Expenses-Cost awards for Cost of Service application
56550 Regulatory Expenses	**37,613.36**	**44,462.96**	**85,334.40**	
Labour	29,843.93	30,219.48	48,492.85	Labour-Safety meetings for Lines staff
Direct Purchases	2,894.98	3,870.00	1,836.00	
Administration	102,539.64	66,029.45	107,852.82	Administration-Memberships-Chamber of Commerce, CHEC, EDA, Staff Appreciation
Contract	13,086.22	12,449.76	13,643.64	Contract-Safety Consultant
Prepaids	(0.02)	31,419.48		
56650 Regulatory & Misc. General Expenses	**148,364.75**	**143,988.17**	**171,825.31**	
Labour	6,646.08	5,326.00	5,486.02	Labour-% Inventory Purchasing Clerk,
Vehicles	-	280.00	280.00	
Direct Purchases	597.17			
Administration	46,589.81	46,362.72	47,143.20	Adminstration-% of Property taxes / water / hydro
Contract	34,536.97	28,906.20	41,700.00	Contract-lawn care, snow removal, office cleaning, equipment maintenance, GP support
Prepaids	-	7,813.44		
56750 Maintenance General Plant	**88,370.03**	**88,688.36**	**94,609.22**	
Electrical Safety Authority Fees	1,181.57	1,508.93	1,515.72	
56800 Electrical Safety Authority Fees	**1,181.57**	**1,508.93**	**1,515.72**	
Capital Taxes	-	1,179.96		
61050 Capital Taxes	**-**	**1,179.96**		
Donations	5,000.00	5,000.00	5,000.00	
62050 Donations	**5,000.00**	**5,000.00**	**5,000.00**	
TOTAL ADMINISTRATIVE	**1,624,219.18**	**1,464,521.14**	**1,700,958.20**	

Orangeville Hydro Limited
Combined Budget Forecast-Maintenance
For the Nine Months Ending Monday, September 30, 2013

	2013 ACTUAL + FORECAST	2013 BUDGET Jan - Dec	2014 BUDGET Jan - Dec	Description
Labour	14,375.32	32,701.40	30,444.78	
Vehicles	81.94	606.72	408.00	
Direct Purchases	78.40	200.04	204.00	
Administration	10,831.88	9,674.88	9,868.44	Administration-portion of the property taxes, property insurance, propane and misc purchases
Contract	-	250.00	350.00	
Prepaids	2,807.04	3,173.88	3,135.84	Prepaids-Insurance
84001 - 84900 Stores	**28,174.58**	**46,606.92**	**44,411.06**	
Labour	476.24	2,708.15	3,016.13	
Vehicles	440.03	1,500.00	1,224.00	
Direct Purchases	203.98			
Administration	18,979.12	21,308.40	21,073.56	Administration-Utilities, misc supplies, portion of property taxes
Contract	4,575.61	4,830.00	5,631.00	Contract-Cleaning, snow removal, Portion of building insurance costs
Prepaids	5,598.47	7,752.48	9,073.92	
87000 Garage	**30,273.45**	**38,099.03**	**40,018.61**	
Labour	4,167.10	5,096.31	5,256.90	
Trucks	232.99			
Truck Repairs - Mechanical	21,537.95			Repairs-Vehicle checks, pick up & delivery, arrange repairs etc.
Fuel	18,190.79			
Miscellaneous - Trucks	7,660.43	55,188.96	56,059.20	Misc-Monthly inspections, oil filter changes, repairs, hydraulic testing/repairs, fuel, plates for large and small vehicles
Prepaid Insurance	8,505.76	10,746.96	10,746.96	Prepaids-Insurance
Truck Expense/Depreciation	39,765.81	45,239.88	64,265.28	Depreciation-Digger Derrick increased depreciation
87001 - 87900 Vehicles	**100,060.83**	**116,272.11**	**136,328.34**	
Labour	3,000.00	3,392.44	4,191.70	
Direct Purchases	-			
Administration	-			
Contract	-			
89020 - 89025 Sick Leave Bonus	**3,000.00**	**3,392.44**	**4,191.70**	
Direct Purchases	9,558.13	15,500.04	8,160.00	Direct Purchases- Small line equipment used for both capital & maintenance, purchasing & testing gloves, reel return credits
Administration	170.55	420.00	204.00	Administration-Answering service, Cellular Telephone, Paging Devices
Contract	1,507.71	1,380.00	1,407.60	Contract-Answering Service
89030 Small Tools & Misc Equipment	**11,236.39**	**17,300.04**	**9,771.60**	
Administration	-			
Other	-			
89050 Engineering	**-**			
In Shop Time	9,450.58	8,040.51	15,607.24	
89088 - 89089 In Shop Time	**9,450.58**	**8,040.51**	**15,607.24**	
TOTAL OVERHEAD	**182,195.83**	**229,711.05**	**250,328.55**	

Orangeville Hydro Limited

2012-2018 Pro-Forma Financial Statements and 5 Year Forecast

Orangeville Hydro Limited
Balance Sheet

December 31	2012	2013	2014	2015	2016	2017	2018
Assets							
Current							
Cash	3,394,169	2,099,579	4,050,225	3,640,238	3,311,937	3,131,316	2,941,653
Accounts Receivable	3,054,001	3,101,735	3,121,164	3,150,886	3,180,906	3,211,226	3,241,849
Unbilled service revenue	2,514,278	2,514,278	2,514,278	2,514,278	2,514,278	2,514,278	2,514,278
Inventory	266,523	266,523	266,523	266,523	266,523	266,523	266,523
Other current assets	127,152	127,152	127,152	127,152	127,152	127,152	127,152
PILs recoverable							
	9,356,123	8,109,268	10,079,342	9,699,077	9,400,796	9,250,495	9,091,455
Capital assets	15,896,095	16,090,234	16,469,536	16,749,814	17,024,094	17,168,700	17,360,249
Regulatory assets	(122,014)	(818,309)	(645,590)	(551,658)	(503,461)	(485,684)	(507,453)
Other assets	510,000	500,000	490,000	480,000	470,000	460,000	450,000
Total Assets	25,640,205	23,881,192	26,393,288	26,377,233	26,391,429	26,393,511	26,394,252
Liabilities and Shareholder's Equity							
Current							
Accounts payable and accrued liabilities	3,904,415	3,876,025	3,876,025	3,876,025	3,876,025	3,876,025	3,876,025
Current PILs payable	82,695	0	0	0	0	0	0
Current portion of long-term debt	397,559	397,559	397,559	397,559	397,559	397,559	397,559
Current portion of Customer Deposit	28,000	28,000	28,000	28,000	28,000	28,000	28,000
	4,412,669	4,301,584	4,301,584	4,301,584	4,301,584	4,301,584	4,301,584
Long-term debt	9,191,132	8,827,010	10,990,609	10,593,050	10,195,491	9,797,932	9,400,373
Long-term customer deposits	825,053	717,000	691,000	691,000	691,000	691,000	691,000
Deferred Income Taxes	510,000	500,000	490,000	480,000	470,000	460,000	450,000
Employee future benefits	268,647	291,609	315,030	335,030	355,030	375,030	395,030
	15,207,500	14,637,203	16,788,223	16,400,664	16,013,105	15,625,546	15,237,987
Shareholder's equity							
Share capital	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714
Retained earnings	2,141,990	953,276	1,314,351	1,685,855	2,087,610	2,477,251	2,865,551
	10,432,704	9,243,990	9,605,065	9,976,569	10,378,324	10,767,965	11,156,265
Total Liabilities and Shareholders Equity	25,640,205	23,881,192	26,393,288	26,377,233	26,391,429	26,393,511	26,394,252

Orangeville Hydro Limited
Statement of Operations and Retained Earnings

For the year December 31	2012	2013	2014	2015	2016	2017	2018
Revenue	28,980,964	28,905,118	28,984,893	29,513,061	30,051,276	30,599,735	31,158,638
Direct Costs	22,906,425	23,364,553	23,831,844	24,308,481	24,794,651	25,290,544	25,796,355
	6,074,539	5,540,565	5,153,049	5,204,579	5,256,625	5,309,192	5,362,283
Other revenues							
Investment income	106,994	51,537	44,000	44,440	44,884	45,333	45,787
Gain (Loss) on disposal of capital assets	23,076	(7,005)	1,319	1,332	1,345	1,359	1,372
Other income	(171)	0	0	0	0	0	0
Other operating income	381,048	347,246	368,813	372,502	376,227	379,989	383,789
Regulatory Debits	(173,590)	(647,909)					
	6,411,896	5,284,435	5,567,181	5,622,853	5,679,082	5,735,872	5,793,231
Expenses							
Administration and general	1,412,562	1,601,218	1,684,405	1,709,400	1,734,769	1,760,516	1,786,647
Amortization	971,344	768,924	782,829	784,950	745,775	760,822	784,311
Billing and collecting	739,649	672,668	723,049	733,895	744,904	756,077	767,418
Community relations	28,170	23,001	16,554	16,802	17,054	17,310	17,569
Distribution	923,926	1,098,915	1,157,023	1,174,379	1,191,994	1,209,874	1,228,022
Interest	357,022	326,952	426,746	411,294	397,245	413,446	399,397
	4,432,672	4,492,858	4,790,605	4,830,720	4,831,740	4,918,045	4,983,365
Net income from operations for the year	1,979,224	791,577	776,576	792,133	847,341	817,827	809,866
Payments in lieu of income taxes (PILs)	433,219	62,057	69,957	70,656	71,363	72,076	72,797
Net income for the year	1,546,005	729,520	706,619	721,476	775,978	745,751	737,069
Retained earnings, beginning of year	2,146,756	3,027,748	1,834,268	2,187,578	2,548,316	2,936,305	3,309,181
Dividends paid	(665,012)	(1,923,000)	(353,310)	(360,738)	(387,989)	(372,875)	(368,534)
Retained earnings, end of year	3,027,748	1,834,268	2,187,578	2,548,316	2,936,305	3,309,181	3,677,715

5 YEAR BUSINESS PLAN

	2011 ACTUAL	2012 ACTUAL	2013 FORECAST	2014 BUDGET	2015 FORECAST	2016 FORECAST	2017 FORECAST	2018 FORECAST
Revenue								
Service Revenue	4,851,359	6,074,539	5,540,565	5,153,049	5,204,579	5,256,625	5,309,192	5,362,283
Other Revenue	503,104	337,357	(256,130)	414,132	418,274	422,456	426,681	430,948
Operating Expenses								
Controllable Expenses	2,961,041	3,104,307	3,395,802	3,581,031	3,634,476	3,688,721	3,743,777	3,799,657
Capital Taxes	1,158	-	-	0	0	0	0	0
Depreciation	1,095,592	971,344	768,924	782,829	784,950	745,775	760,822	784,311
Financial Expense (Bank)	403,672	340,066	311,152	410,946	395,494	381,445	397,646	383,597
Financial Expense (other)	24,540	16,956	15,800	15,800	15,800	15,800	15,800	15,800
Total Expenses	**4,486,003**	**4,432,673**	**4,491,678**	**4,790,605**	**4,830,720**	**4,831,740**	**4,918,045**	**4,983,365**
Net Income								
EBITDA	2,393,422	3,307,589	1,888,632	1,986,150	1,988,377	1,990,361	1,992,095	1,993,574
Net Income before Corporate Tax	868,460	1,979,223	792,757	776,576	792,133	847,341	817,827	809,866
Corporate Income Tax	213,493	433,219	62,057	69,957	70,656	71,363	72,076	72,797
Net Income after Corporate Tax	**654,967**	**1,546,004**	**730,700**	**706,619**	**721,476**	**775,978**	**745,751**	**737,069**
Generation Net Income after depreciation	**2,585**	**3,127**	**3,582**	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**
Source of Funds								
Net Income	654,967	1,546,004	730,700	706,619	721,476	775,978	745,751	737,069
Depreciation	1,095,592	971,344	768,924	782,829	784,950	745,775	760,822	784,311
Borrowing		2,500,000		2,500,000				
Contributed Capital	193,062	297,008	487,576	298,474	298,474	298,474	298,474	298,474
Total Source of Funds	**1,943,621**	**5,314,356**	**1,987,199**	**4,287,922**	**1,804,901**	**1,820,227**	**1,805,047**	**1,819,854**
Application of Funds								
Debt Retirement	5,618,524	397,559	397,559	397,559	397,559	397,559	397,559	397,559
Capital Expenditures	1,446,701	1,864,169	1,661,347	2,733,146	1,427,893	1,402,633	1,294,318	1,351,599
Smart Meter Expenditures & Recovery	320,197							
Dividends to Shareholders	383,754	665,012	1,923,000	353,310	360,738	387,989	372,875	368,534
Other								
Total Application of Funds	**7,769,176**	**2,926,740**	**3,981,906**	**3,484,015**	**2,186,190**	**2,188,181**	**2,064,752**	**2,117,692**
Equity								
Prior Year	9,280,494	9,551,711	10,432,703	9,240,403	9,593,713	9,954,451	10,342,440	10,715,315
Current Year	9,935,461	11,097,715	11,163,403	9,947,022	10,315,189	10,730,429	11,088,190	11,452,384
Dividends	(383,754)	(665,012)	(1,923,000)	(353,310)	(360,738)	(387,989)	(372,875)	(368,534)
Total	9,551,711	10,432,703	9,240,403	9,593,713	9,954,451	10,342,440	10,715,315	11,083,849
Debt								
Prior Year	7,764,715	7,445,276	9,588,691	9,191,132	11,293,573	10,896,014	10,498,455	10,100,896
Current Year	7,445,276	9,588,691	9,191,132	11,293,573	10,896,014	10,498,455	10,100,896	9,703,337
Total	7,445,276	9,588,691	9,191,132	11,293,573	10,896,014	10,498,455	10,100,896	9,703,337
Return on Equity	6.86%	14.82%	7.91%	7.37%	7.25%	7.50%	6.96%	6.65%
Actual Debt/Equity Ratio	0.44	0.48	0.50	0.54	0.52	0.50	0.49	0.47
Statistics								
Annual Wholesale Cost of Power	21,885,544	22,906,425	23,364,553	23,831,844	24,308,481	24,794,651	25,290,544	25,796,355
Net Expenses	2,961,041	3,104,307	3,395,802	3,581,031	3,634,476	3,688,721	3,743,777	3,799,657
Net Fixed Assets	14,330,776	15,762,111	15,924,837	16,341,559	16,627,824	16,908,091	17,058,684	17,250,233
Actual Rate Base	18,057,764	19,663,721	19,938,891	19,905,233	20,260,408	20,610,929	20,833,146	21,097,715
Rate Application Rate Base	17,626,594	17,626,594	17,626,594	20,255,013	20,255,013	20,255,013	20,255,013	20,255,013
Actual Return on Rate Base	6.15%	10.80%	6.00%	5.60%	5.59%	5.79%	5.72%	5.61%
Expected Return on Rate Base	7.18%	7.18%	7.18%	5.63%	5.63%	5.63%	5.63%	5.63%
Number of Customers	11,331	11,450	11,565	11,680	11,797	11,915	12,034	12,154
Controllable Expenses/Customer	261.32	271.12	293.64	306.59	308.09	309.59	311.10	312.62
Number of Staff	20	20	23	23	23	23	23	23
Customers Served/Staff	566.55	572.50	502.80	507.83	512.91	518.04	523.22	528.45
Labour as a % of Operating Expenses	41%	39%	41%	42%	42%	42%	42%	42%

ORANGEVILLE HYDRO

Appendix K -

2012 PILs

Notice of Assessment

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Ontario
Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

ORANGEVILLE HYDRO LIMITED
ATTENTION: C/O JAN HOWARD
400 C LINE
ORANGEVILLE ON L9W 3Z8

Issue Date	13-Aug-2013
Business No.	864639562TW0001
Reference No.	L1471096896

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2012	**Return As Filed**
Total Federal Tax	$231,364.00
Total Ontario Tax	$160,257.00
Total Credits	$0.00
Loss Carry-back	$0.00
Total Tax Payable	$391,621.00
Interest	$1,348.20
Current Penalty	$0.00
Credits/Payments	($392,969.20)
Total Assessment	**$0.00**

As of 13-Aug-2013, including the amount assessed above, you have an overall credit balance on your account of ($46,889.64).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

Appendix L -

Revised Bill Impacts

File Number:	EB-2013-0160
Exhibit:	8
Tab:	6
Schedule:	1
Page:	1
Date:	12-Feb-14

Appendix 2-W
Bill Impacts

Customer Class: **Residential** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption **100** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	100	$ 1.40	$ 0.0142	100	$ 1.42	$ 0.02	1.55%
Sub-Total A (excluding pass through)				$ 20.50			$ 18.93	**-$ 1.57**	**-7.65%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	100	-$ 0.13	-$ 0.0002	100	-$ 0.02	$ 0.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	100	-$ 0.03		100	$ -	$ 0.03	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		100	$ -	-$ 0.0009	100	-$ 0.09	-$ 0.09	
Low Voltage Service Charge	per kWh	$ 0.0011	100	$ 0.11	$ 0.0017	100	$ 0.17	$ 0.06	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	4.68	$ 0.39	$ 0.0839	4.81	$ 0.40	$ 0.01	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.63**			**$ 20.19**	**-$ 1.45**	**-6.68%**
RTSR - Network	per kWh	$ 0.0065	105	$ 0.68	$ 0.0069	105	$ 0.73	$ 0.05	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	105	$ 0.36	$ 0.0034	105	$ 0.36	$ 0.00	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.67**			**$ 21.27**	**-$ 1.40**	**-6.17%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	105	$ 0.46	$ 0.0044	105	$ 0.46	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	105	$ 0.13	$ 0.0012	105	$ 0.13	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	64	$ 4.29	$ 0.0670	64	$ 4.29	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	18	$ 1.87	$ 0.1040	18	$ 1.87	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	18	$ 2.23	$ 0.1240	18	$ 2.23	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	100	$ 7.50	$ 0.0750	100	$ 7.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.60**			**$ 31.20**	**-$ 1.40**	**-4.29%**
HST		13%		$ 4.24	13%		$ 4.06	-$ 0.18	-4.29%
Total Bill (including HST)				$ 36.83			$ 35.26	-$ 1.58	-4.29%
Ontario Clean Energy Benefit [1]				-$ 3.68			-$ 3.53	$ 0.15	-4.08%
Total Bill on TOU (including OCEB)				**$ 33.15**			**$ 31.73**	**-$ 1.43**	**-4.31%**
Total Bill on RPP (before Taxes)				**$ 31.71**			**$ 30.31**	**-$ 1.40**	**-4.41%**
HST		13%		$ 4.12	13%		$ 3.94	-$ 0.18	-4.41%
Total Bill (including HST)				$ 35.83			$ 34.25	-$ 1.58	-4.41%
Ontario Clean Energy Benefit [1]				-$ 3.58			-$ 3.42	$ 0.16	-4.47%
Total Bill on RPP (including OCEB)				**$ 32.25**			**$ 30.83**	**-$ 1.42**	**-4.40%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 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	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	per kWh		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	250	$ 3.50	$ 0.0142	250	$ 3.55	$ 0.05	1.55%
Sub-Total A (excluding pass through)				$ 22.60			$ 21.06	**-$ 1.54**	**-6.79%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	250	-$ 0.33	-$ 0.0002	250	-$ 0.05	$ 0.28	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	250	-$ 0.08		250	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		250	$ -	-$ 0.0009	250	-$ 0.22	-$ 0.22	
Low Voltage Service Charge	per kWh	$ 0.0011	250	$ 0.28	$ 0.0017	250	$ 0.43	$ 0.15	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	11.70	$ 0.98	$ 0.0839	12.03	$ 1.01	$ 0.03	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.25**			**$ 23.02**	**-$ 1.23**	**-5.07%**
RTSR - Network	per kWh	$ 0.0065	262	$ 1.70	$ 0.0069	262	$ 1.82	$ 0.12	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	262	$ 0.89	$ 0.0034	262	$ 0.89	$ 0.00	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 25.73**	**-$ 1.11**	**-4.14%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	262	$ 1.15	$ 0.0044	262	$ 1.15	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	262	$ 0.31	$ 0.0012	262	$ 0.31	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	160	$ 10.72	$ 0.0670	160	$ 10.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	45	$ 4.68	$ 0.1040	45	$ 4.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	45	$ 5.58	$ 0.1240	45	$ 5.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	250	$ 18.75	$ 0.0750	250	$ 18.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 51.28**			**$ 50.17**	**-$ 1.11**	**-2.16%**
HST		13%		$ 6.67	13%		$ 6.52	-$ 0.14	-2.16%
Total Bill (including HST)				$ 57.95			$ 56.70	-$ 1.25	-2.16%
Ontario Clean Energy Benefit [1]				-$ 5.80			-$ 5.67	$ 0.13	-2.24%
Total Bill on TOU (including OCEB)				**$ 52.15**			**$ 51.03**	**-$ 1.12**	**-2.15%**
Total Bill on RPP (before Taxes)				**$ 49.05**			**$ 47.94**	**-$ 1.11**	**-2.26%**
HST		13%		$ 6.38	13%		$ 6.23	-$ 0.14	-2.26%
Total Bill (including HST)				$ 55.43			$ 54.18	-$ 1.25	-2.26%
Ontario Clean Energy Benefit [1]				-$ 5.54			-$ 5.42	$ 0.12	-2.17%
Total Bill on RPP (including OCEB)				**$ 49.89**			**$ 48.76**	**-$ 1.13**	**-2.27%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 500 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	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	500	$ 7.00	$ 0.0142	500	$ 7.11	$ 0.11	1.55%
Sub-Total A (excluding pass through)				$ 26.10			$ 24.62	**-$ 1.48**	**-5.67%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	500	-$ 0.65	-$ 0.0002	500	-$ 0.09	$ 0.56	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	500	-$ 0.15		500	$ -	$ 0.15	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		500	$ -	-$ 0.0009	500	-$ 0.45	-$ 0.45	
Low Voltage Service Charge	per kWh	$ 0.0011	500	$ 0.55	$ 0.0017	500	$ 0.85	$ 0.30	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	23.40	$ 1.96	$ 0.0839	24.05	$ 2.02	$ 0.05	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.60**			**$ 27.74**	**-$ 0.87**	**-3.03%**
RTSR - Network	per kWh	$ 0.0065	523	$ 3.40	$ 0.0069	524	$ 3.63	$ 0.23	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	523	$ 1.78	$ 0.0034	524	$ 1.79	$ 0.01	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.79**			**$ 33.15**	**-$ 0.63**	**-1.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523	$ 2.30	$ 0.0044	524	$ 2.31	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523	$ 0.63	$ 0.0012	524	$ 0.63	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	320	$ 21.44	$ 0.0670	320	$ 21.44	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	90	$ 9.36	$ 0.1040	90	$ 9.36	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	90	$ 11.16	$ 0.1240	90	$ 11.16	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	500	$ 37.50	$ 0.0750	500	$ 37.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 82.43**			**$ 81.80**	**-$ 0.63**	**-0.76%**
HST		13%		$ 10.72	13%		$ 10.63	-$ 0.08	-0.76%
Total Bill (including HST)				$ 93.14			$ 92.43	-$ 0.71	-0.76%
Ontario Clean Energy Benefit [1]				-$ 9.31			-$ 9.24	$ 0.07	-0.75%
Total Bill on TOU (including OCEB)				**$ 83.83**			**$ 83.19**	**-$ 0.64**	**-0.76%**
Total Bill on RPP (before Taxes)				**$ 77.97**			**$ 77.34**	**-$ 0.63**	**-0.80%**
HST		13%		$ 10.14	13%		$ 10.05	-$ 0.08	-0.80%
Total Bill (including HST)				$ 88.10			$ 87.39	-$ 0.71	-0.80%
Ontario Clean Energy Benefit [1]				-$ 8.81			-$ 8.74	$ 0.07	-0.79%
Total Bill on RPP (including OCEB)				**$ 79.29**			**$ 78.65**	**-$ 0.64**	**-0.81%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	800	$ 11.20	$ 0.0142	800	$ 11.37	$ 0.17	1.55%
Sub-Total A (excluding pass through)				$ 30.30			$ 28.88	**-$ 1.42**	**-4.67%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	800	-$ 1.04	-$ 0.0002	800	-$ 0.15	$ 0.89	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		800	$ -	-$ 0.0009	800	-$ 0.71	-$ 0.71	
Low Voltage Service Charge	per kWh	$ 0.0011	800	$ 0.88	$ 0.0017	800	$ 1.36	$ 0.48	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	37.44	$ 3.14	$ 0.0839	38.48	$ 3.23	$ 0.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.83**			**$ 33.40**	**-$ 0.43**	**-1.29%**
RTSR - Network	per kWh	$ 0.0065	837	$ 5.44	$ 0.0069	838	$ 5.81	$ 0.37	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	837	$ 2.85	$ 0.0034	838	$ 2.86	$ 0.01	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.12**			**$ 42.07**	**-$ 0.06**	**-0.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	838	$ 3.69	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	838	$ 1.01	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	200	$ 17.60	$ 0.0880	200	$ 17.60	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 119.80**			**$ 119.75**	**-$ 0.05**	**-0.04%**
HST		13%		$ 15.57	13%		$ 15.57	-$ 0.01	-0.04%
Total Bill (including HST)				$ 135.37			$ 135.32	-$ 0.06	-0.04%
Ontario Clean Energy Benefit [1]				-$ 13.54			-$ 13.53	$ 0.01	-0.07%
Total Bill on TOU (including OCEB)				**$ 121.83**			**$ 121.79**	**-$ 0.05**	**-0.04%**
Total Bill on RPP (before Taxes)				**$ 115.26**			**$ 115.21**	**-$ 0.05**	**-0.04%**
HST		13%		$ 14.98	13%		$ 14.98	-$ 0.01	-0.04%
Total Bill (including HST)				$ 130.25			$ 130.19	-$ 0.06	-0.04%
Ontario Clean Energy Benefit [1]				-$ 13.02			-$ 13.02	$ -	0.00%
Total Bill on RPP (including OCEB)				**$ 117.23**			**$ 117.17**	**-$ 0.06**	**-0.05%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption 1,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,000	$ 14.00	$ 0.0142	1,000	$ 14.22	$ 0.22	1.55%
Sub-Total A (excluding pass through)				$ 33.10			$ 31.73	**-$ 1.37**	**-4.15%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0002	1,000	-$ 0.19	$ 1.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,000	-$ 0.30		1,000	$ -	$ 0.30	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0009	1,000	-$ 0.89	-$ 0.89	
Low Voltage Service Charge	per kWh	$ 0.0011	1,000	$ 1.10	$ 0.0017	1,000	$ 1.70	$ 0.60	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.32**			**$ 37.17**	**-$ 0.15**	**-0.39%**
RTSR - Network	per kWh	$ 0.0065	1047	$ 6.80	$ 0.0069	1048	$ 7.27	$ 0.46	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1047	$ 3.56	$ 0.0034	1048	$ 3.57	$ 0.01	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 47.68**			**$ 48.01**	**$ 0.33**	**0.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 144.71**			**$ 145.05**	**$ 0.34**	**0.23%**
HST		13%		$ 18.81	13%		$ 18.86	$ 0.04	0.23%
Total Bill (including HST)				$ 163.53			$ 163.90	$ 0.38	0.23%
Ontario Clean Energy Benefit [1]				-$ 16.35			-$ 16.39	-$ 0.04	0.24%
Total Bill on TOU (including OCEB)				**$ 147.18**			**$ 147.51**	**$ 0.34**	**0.23%**
Total Bill on RPP (before Taxes)				**$ 140.99**			**$ 141.33**	**$ 0.34**	**0.24%**
HST		13%		$ 18.33	13%		$ 18.37	$ 0.04	0.24%
Total Bill (including HST)				$ 159.32			$ 159.70	$ 0.38	0.24%
Ontario Clean Energy Benefit [1]				-$ 15.93			-$ 15.97	-$ 0.04	0.25%
Total Bill on RPP (including OCEB)				**$ 143.39**			**$ 143.73**	**$ 0.34**	**0.24%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,500 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,500	$ 21.00	$ 0.0142	1,500	$ 21.33	$ 0.33	1.55%
Sub-Total A (excluding pass through)				$ 40.10			$ 38.84	**-$ 1.26**	**-3.15%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,500	-$ 1.95	-$ 0.0002	1,500	-$ 0.28	$ 1.67	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,500	-$ 0.45		1,500	$ -	$ 0.45	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,500	$ -	-$ 0.0009	1,500	-$ 1.34	-$ 1.34	
Low Voltage Service Charge	per kWh	$ 0.0011	1,500	$ 1.65	$ 0.0017	1,500	$ 2.55	$ 0.90	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	70.20	$ 5.89	$ 0.0839	72.15	$ 6.05	$ 0.16	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.03**			**$ 46.61**	**$ 0.58**	**1.25%**
RTSR - Network	per kWh	$ 0.0065	1570	$ 10.21	$ 0.0069	1572	$ 10.90	$ 0.69	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1570	$ 5.34	$ 0.0034	1572	$ 5.36	$ 0.02	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 61.58**			**$ 62.86**	**$ 1.29**	**2.09%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1570	$ 6.91	$ 0.0044	1572	$ 6.92	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1570	$ 1.88	$ 0.0012	1572	$ 1.89	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	960	$ 64.32	$ 0.0670	960	$ 64.32	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	270	$ 28.08	$ 0.1040	270	$ 28.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	270	$ 33.48	$ 0.1240	270	$ 33.48	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	900	$ 79.20	$ 0.0880	900	$ 79.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 207.00**			**$ 208.30**	**$ 1.30**	**0.63%**
HST		13%		$ 26.91	13%		$ 27.08	$ 0.17	0.63%
Total Bill (including HST)				$ 233.91			$ 235.38	$ 1.47	0.63%
Ontario Clean Energy Benefit [1]				-$ 23.39			-$ 23.54	-$ 0.15	0.64%
Total Bill on TOU (including OCEB)				**$ 210.52**			**$ 211.84**	**$ 1.32**	**0.63%**
Total Bill on RPP (before Taxes)				**$ 205.32**			**$ 206.62**	**$ 1.30**	**0.63%**
HST		13%		$ 26.69	13%		$ 26.86	$ 0.17	0.63%
Total Bill (including HST)				$ 232.01			$ 233.48	$ 1.47	0.63%
Ontario Clean Energy Benefit [1]				-$ 23.20			-$ 23.35	-$ 0.15	0.65%
Total Bill on RPP (including OCEB)				**$ 208.81**			**$ 210.13**	**$ 1.32**	**0.63%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 2,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.47	1	$ 16.47	$ 0.21	1.29%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	2,000	$ 28.00	$ 0.0142	2,000	$ 28.44	$ 0.44	1.55%
Sub-Total A (excluding pass through)				$ 47.10			$ 45.95	**-$ 1.15**	**-2.45%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0002	2,000	-$ 0.38	$ 2.22	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	2,000	-$ 0.60		2,000	$ -	$ 0.60	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0009	2,000	-$ 1.79	-$ 1.79	
Low Voltage Service Charge	per kWh	$ 0.0011	2,000	$ 2.20	$ 0.0017	2,000	$ 3.40	$ 1.20	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.74**			**$ 56.04**	**$ 1.30**	**2.37%**
RTSR - Network	per kWh	$ 0.0065	2094	$ 13.61	$ 0.0069	2096	$ 14.53	$ 0.92	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	2094	$ 7.12	$ 0.0034	2096	$ 7.14	$ 0.02	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 75.47**			**$ 77.72**	**$ 2.25**	**2.98%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 269.29**			**$ 271.55**	**$ 2.26**	**0.84%**
HST		13%		$ 35.01	13%		$ 35.30	$ 0.29	0.84%
Total Bill (including HST)				$ 304.29			$ 306.85	$ 2.55	0.84%
Ontario Clean Energy Benefit [1]				-$ 30.43			-$ 30.68	-$ 0.25	0.82%
Total Bill on TOU (including OCEB)				**$ 273.86**			**$ 276.17**	**$ 2.30**	**0.84%**
Total Bill on RPP (before Taxes)				**$ 269.65**			**$ 271.91**	**$ 2.26**	**0.84%**
HST		13%		$ 35.05	13%		$ 35.35	$ 0.29	0.84%
Total Bill (including HST)				$ 304.70			$ 307.25	$ 2.55	0.84%
Ontario Clean Energy Benefit [1]				-$ 30.47			-$ 30.73	-$ 0.26	0.85%
Total Bill on RPP (including OCEB)				**$ 274.23**			**$ 276.52**	**$ 2.29**	**0.84%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 1,000 kWh

Charge	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	$ 33.2700	1	$ 33.27	$ 31.59	1	$ 31.59	-$ 1.68	-5.05%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	1,000	$ 10.10	$ 0.0096	1,000	$ 9.60	-$ 0.50	-4.95%
Sub-Total A (excluding pass through)				$ 50.39			$ 45.43	**-$ 4.96**	**-9.84%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0007	1,000	-$ 0.71	$ 0.59	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	1,000	-$ 0.20		1,000	$ -	$ 0.20	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0005	1,000	-$ 0.51	-$ 0.51	
Low Voltage Service Charge	per kWh	$ 0.0010	1,000	$ 1.00	$ 0.0015	1,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.61**			**$ 50.53**	**-$ 4.08**	**-7.46%**
RTSR - Network	per kWh	$ 0.0060	1047	$ 6.28	$ 0.0064	1048	$ 6.71	$ 0.43	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	1047	$ 3.25	$ 0.0031	1048	$ 3.26	$ 0.01	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.13**			**$ 60.49**	**-$ 3.64**	**-5.67%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 161.17**			**$ 157.53**	**-$ 3.63**	**-2.25%**
HST		13%		$ 20.95	13%		$ 20.48	-$ 0.47	-2.25%
Total Bill (including HST)				$ 182.12			$ 178.01	-$ 4.10	-2.25%
Ontario Clean Energy Benefit [1]				-$ 18.21			-$ 17.80	$ 0.41	-2.25%
Total Bill on TOU (including OCEB)				**$ 163.91**			**$ 160.21**	**-$ 3.69**	**-2.25%**
Total Bill on RPP (before Taxes)				**$ 157.45**			**$ 153.81**	**-$ 3.63**	**-2.31%**
HST		13%		$ 20.47	13%		$ 20.00	-$ 0.47	-2.31%
Total Bill (including HST)				$ 177.91			$ 173.81	-$ 4.10	-2.31%
Ontario Clean Energy Benefit [1]				-$ 17.79			-$ 17.38	$ 0.41	-2.30%
Total Bill on RPP (including OCEB)				**$ 160.12**			**$ 156.43**	**-$ 3.69**	**-2.31%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 2,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

Charge	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	$ 33.2700	1	$ 33.27	$ 31.59	1	$ 31.59	-$ 1.68	-5.05%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	2,000	$ 20.20	$ 0.0096	2,000	$ 19.20	-$ 1.00	-4.95%
Sub-Total A (excluding pass through)				$ 60.49			$ 55.03	**-$ 5.46**	**-9.03%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0007	2,000	-$ 1.43	$ 1.17	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0005	2,000	-$ 1.02	-$ 1.02	
Low Voltage Service Charge	per kWh	$ 0.0010	2,000	$ 2.00	$ 0.0015	2,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 68.13**			**$ 64.44**	**-$ 3.69**	**-5.42%**
RTSR - Network	per kWh	$ 0.0060	2094	$ 12.56	$ 0.0064	2096	$ 13.41	$ 0.85	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	2094	$ 6.49	$ 0.0031	2096	$ 6.51	$ 0.02	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 87.19**			**$ 84.37**	**-$ 2.82**	**-3.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 281.00**			**$ 278.20**	**-$ 2.80**	**-1.00%**
HST		13%		$ 36.53	13%		$ 36.17	-$ 0.36	-1.00%
Total Bill (including HST)				$ 317.53			$ 314.36	-$ 3.17	-1.00%
Ontario Clean Energy Benefit [1]				-$ 31.75			-$ 31.44	$ 0.31	-0.98%
Total Bill on TOU (including OCEB)				**$ 285.78**			**$ 282.92**	**-$ 2.86**	**-1.00%**
Total Bill on RPP (before Taxes)				**$ 281.36**			**$ 278.56**	**-$ 2.80**	**-1.00%**
HST		13%		$ 36.58	13%		$ 36.21	-$ 0.36	-1.00%
Total Bill (including HST)				$ 317.94			$ 314.77	-$ 3.17	-1.00%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 31.48	$ 0.31	-0.98%
Total Bill on RPP (including OCEB)				**$ 286.15**			**$ 283.29**	**-$ 2.86**	**-1.00%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **GS < 50kW**

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31)

TOU / non-TOU: TOU

Consumption 5,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 31.59	1	$ 31.59	-$ 1.68	-5.05%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	5,000	$ 50.50	$ 0.0096	5,000	$ 48.00	-$ 2.50	-4.95%
Sub-Total A (excluding pass through)				$ 90.79			$ 83.83	**-$ 6.96**	**-7.67%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	5,000	-$ 6.50	-$ 0.0007	5,000	-$ 3.57	$ 2.93	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	5,000	-$ 1.00		5,000	$ -	$ 1.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		5,000	$ -	-$ 0.0005	5,000	-$ 2.55	-$ 2.55	
Low Voltage Service Charge	per kWh	$ 0.0010	5,000	$ 5.00	$ 0.0015	5,000	$ 7.50	$ 2.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	234.00	$ 19.64	$ 0.0839	240.50	$ 20.18	$ 0.55	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 108.72**			**$ 106.18**	**-$ 2.54**	**-2.34%**
RTSR - Network	per kWh	$ 0.0060	5234	$ 31.40	$ 0.0064	5241	$ 33.54	$ 2.13	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	5234	$ 16.23	$ 0.0031	5241	$ 16.28	$ 0.05	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 156.35**			**$ 155.99**	**-$ 0.35**	**-0.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	5234	$ 23.03	$ 0.0044	5241	$ 23.06	$ 0.03	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	5234	$ 6.28	$ 0.0012	5241	$ 6.29	$ 0.01	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5000	$ 35.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	3200	$ 214.40	$ 0.0670	3200	$ 214.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	900	$ 93.60	$ 0.1040	900	$ 93.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	900	$ 111.60	$ 0.1240	900	$ 111.60	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	4400	$ 387.20	$ 0.0880	4400	$ 387.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 640.51**			**$ 640.19**	**-$ 0.32**	**-0.05%**
HST		13%		$ 83.27	13%		$ 83.22	-$ 0.04	-0.05%
Total Bill (including HST)				$ 723.77			$ 723.42	-$ 0.36	-0.05%
Ontario Clean Energy Benefit [1]				-$ 72.38			-$ 72.34	$ 0.04	-0.06%
Total Bill on TOU (including OCEB)				**$ 651.39**			**$ 651.08**	**-$ 0.32**	**-0.05%**
Total Bill on RPP (before Taxes)				**$ 653.11**			**$ 652.79**	**-$ 0.32**	**-0.05%**
HST		13%		$ 84.90	13%		$ 84.86	-$ 0.04	-0.05%
Total Bill (including HST)				$ 738.01			$ 737.65	-$ 0.36	-0.05%
Ontario Clean Energy Benefit [1]				-$ 73.80			-$ 73.77	$ 0.03	-0.04%
Total Bill on RPP (including OCEB)				**$ 664.21**			**$ 663.88**	**-$ 0.33**	**-0.05%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **GS < 50kW**

TOU / non-TOU: TOU

Consumption 10,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 31.59	1	$ 31.59	-$ 1.68	-5.05%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	10,000	$ 101.00	$ 0.0096	10,000	$ 96.00	-$ 5.00	-4.95%
Sub-Total A (excluding pass through)				$ 141.29			$ 131.83	**-$ 9.46**	**-6.70%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	10,000	-$ 13.00	-$ 0.0007	10,000	-$ 7.15	$ 5.85	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	10,000	-$ 2.00		10,000	$ -	$ 2.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		10,000	$ -	-$ 0.0005	10,000	-$ 5.10	-$ 5.10	
Low Voltage Service Charge	per kWh	$ 0.0010	10,000	$ 10.00	$ 0.0015	10,000	$ 15.00	$ 5.00	50.00%
Line Losses on Cost of Power	Monthly	$ 0.0839	468.00	$ 39.27	$ 0.0839	481.00	$ 40.37	$ 1.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 176.35**			**$ 175.74**	**-$ 0.62**	**-0.35%**
RTSR - Network	per kWh	$ 0.0060	10468	$ 62.81	$ 0.0064	10481	$ 67.07	$ 4.27	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	10468	$ 32.45	$ 0.0031	10481	$ 32.56	$ 0.11	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 271.61**			**$ 275.37**	**$ 3.75**	**1.38%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	10468	$ 46.06	$ 0.0044	10481	$ 46.12	$ 0.06	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	10468	$ 12.56	$ 0.0012	10481	$ 12.58	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10000	$ 70.00	$ 0.0070	10000	$ 70.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	6400	$ 428.80	$ 0.0670	6400	$ 428.80	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	1800	$ 187.20	$ 0.1040	1800	$ 187.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	1800	$ 223.20	$ 0.1240	1800	$ 223.20	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	9400	$ 827.20	$ 0.0880	9400	$ 827.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,239.68**			**$ 1,243.51**	**$ 3.83**	**0.31%**
HST		13%		$ 161.16	13%		$ 161.66	$ 0.50	0.31%
Total Bill (including HST)				$ 1,400.84			$ 1,405.17	$ 4.32	0.31%
Ontario Clean Energy Benefit [1]				-$ 140.08			-$ 140.52	-$ 0.44	0.31%
Total Bill on TOU (including OCEB)				**$ 1,260.76**			**$ 1,264.65**	**$ 3.88**	**0.31%**
Total Bill on RPP (before Taxes)				**$ 1,272.68**			**$ 1,276.51**	**$ 3.83**	**0.30%**
HST		13%		$ 165.45	13%		$ 165.95	$ 0.50	0.30%
Total Bill (including HST)				$ 1,438.13			$ 1,442.46	$ 4.32	0.30%
Ontario Clean Energy Benefit [1]				-$ 143.81			-$ 144.25	-$ 0.44	0.31%
Total Bill on RPP (including OCEB)				**$ 1,294.32**			**$ 1,298.21**	**$ 3.88**	**0.30%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

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	$ 33.2700	1	$ 33.27	$ 31.59	1	$ 31.59	-$ 1.68	-5.05%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	15,000	$ 151.50	$ 0.0096	15,000	$ 144.00	-$ 7.50	-4.95%
Sub-Total A (excluding pass through)				$ 191.79			$ 179.83	**-$ 11.96**	**-6.24%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	15,000	-$ 19.50	-$ 0.0007	15,000	-$ 10.72	$ 8.78	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	15,000	-$ 3.00		15,000	$ -	$ 3.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		15,000	$ -	$ 0.3259	15,000	$ 4,888.55	$ 4,888.55	
Low Voltage Service Charge	per kWh	$ 0.0010	15,000	$ 15.00	$ 0.0015	15,000	$ 22.50	$ 7.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	702.00	$ 58.91	$ 0.0839	721.50	$ 60.55	$ 1.64	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 243.99**			**$ 5,141.50**	**$ 4,897.50**	**2007.24%**
RTSR - Network	per kWh	$ 0.0060	15702	$ 94.21	$ 0.0064	15722	$ 100.61	$ 6.40	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	15702	$ 48.68	$ 0.0031	15722	$ 48.84	$ 0.16	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 386.88**			**$ 5,290.94**	**$ 4,904.06**	**1267.59%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	9600	$ 643.20	$ 0.0670	9600	$ 643.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	2700	$ 280.80	$ 0.1040	2700	$ 280.80	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	2700	$ 334.80	$ 0.1240	2700	$ 334.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	14400	$ 1,267.20	$ 0.0880	14400	$ 1,267.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,838.86**			**$ 6,743.03**	**$ 4,904.17**	**266.70%**
HST		13%		$ 239.05	13%		$ 876.59	$ 637.54	266.70%
Total Bill (including HST)				$ 2,077.91			$ 7,619.63	$ 5,541.72	266.70%
Ontario Clean Energy Benefit [1]				-$ 207.79			-$ 761.96	-$ 554.17	266.70%
Total Bill on TOU (including OCEB)				**$ 1,870.12**			**$ 6,857.67**	**$ 4,987.55**	**266.70%**
Total Bill on RPP (before Taxes)				**$ 1,892.26**			**$ 6,796.43**	**$ 4,904.17**	**259.17%**
HST		13%		$ 245.99	13%		$ 883.54	$ 637.54	259.17%
Total Bill (including HST)				$ 2,138.26			$ 7,679.97	$ 5,541.72	259.17%
Ontario Clean Energy Benefit [1]				-$ 213.83			-$ 768.00	-$ 554.17	259.16%
Total Bill on RPP (including OCEB)				**$ 1,924.43**			**$ 6,911.97**	**$ 4,987.55**	**259.17%**

	Current	Proposed
Loss Factor (%)	4.68%	4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 60 kW; 15,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 186.2300	1	$ 186.23	$ 199.81	1	$ 199.81	$ 13.58	7.29%
Distribution Volumetric Rate	per kW	$ 2.1927	60	$ 131.56	$ 2.3327	60	$ 139.96	$ 8.40	6.38%
Sub-Total A (excluding pass through)				$ 317.79			$ 339.77	**$ 21.98**	**6.92%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	60	-$ 30.32	-$ 0.3588	60	-$ 21.53	$ 8.79	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	60	-$ 1.73		60	$ -	$ 1.73	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		60	$ -	-$ 0.0691	60	-$ 4.15	-$ 4.15	
Low Voltage Service Charge	per kW	$ 0.3999	60	$ 23.99	$ 0.6103	60	$ 36.62	$ 12.62	52.61%
Line Losses on Cost of Power	per kWh	$ 0.0880	702.00	$ 61.78	$ 0.0839	721.50	$ 60.55	-$ 1.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 371.51**			**$ 411.26**	**$ 39.75**	**10.70%**
RTSR - Network	per kW	$ 2.4552	60	$ 147.31	$ 2.6187	60	$ 157.12	$ 9.81	6.66%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	60	$ 73.70	$ 1.2309	60	$ 73.85	$ 0.15	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 592.53**			**$ 642.24**	**$ 49.71**	**8.39%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 785.71**			**$ 835.53**	**$ 49.82**	**6.34%**
HST		13%		$ 102.14	13%		$ 108.62	$ 6.48	6.34%
Total Bill (including HST)				$ 887.85			$ 944.15	$ 56.30	6.34%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 94.41	-$ 5.63	6.34%
Total Bill on TOU (including OCEB)				**$ 799.07**			**$ 849.74**	**$ 50.67**	**6.34%**
Total Bill on RPP (before Taxes)				**$ 785.71**			**$ 835.53**	**$ 49.82**	**6.34%**
HST		13%		$ 102.14	13%		$ 108.62	$ 6.48	6.34%
Total Bill (including HST)				$ 887.85			$ 944.15	$ 56.30	6.34%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 94.41	-$ 5.63	6.34%
Total Bill on RPP (including OCEB)				**$ 799.07**			**$ 849.74**	**$ 50.67**	**6.34%**

Loss Factor (%) Current: 4.68%; Proposed: 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 100 kW; 45,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 186.2300	1	$ 186.23	$ 199.81	1	$ 199.81	$ 13.58	7.29%
Distribution Volumetric Rate	per kW	$ 2.1927	100	$ 219.27	$ 2.3327	100	$ 233.27	$ 14.00	6.38%
Sub-Total A (excluding pass through)				$ 405.50			$ 433.08	**$ 27.58**	**6.80%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	100	-$ 50.54	-$ 0.3588	100	-$ 35.88	$ 14.66	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	100	-$ 2.88		100	$ -	$ 2.88	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		100	$ -	-$ 0.0691	100	-$ 6.91	-$ 6.91	
Low Voltage Service Charge	per kW	$ 0.3999	100	$ 39.99	$ 0.6103	100	$ 61.03	$ 21.04	52.61%
Line Losses on Cost of Power	per kWh	$ 0.0880	2,106.00	$ 185.33	$ 0.0839	2,164.50	$ 181.64	-$ 3.68	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 577.40**			**$ 632.96**	**$ 55.56**	**9.62%**
RTSR - Network	per kW	$ 2.4552	100	$ 245.52	$ 2.6187	100	$ 261.87	$ 16.35	6.66%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	100	$ 122.84	$ 1.2309	100	$ 123.09	$ 0.25	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 945.76**			**$ 1,017.92**	**$ 72.16**	**7.63%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	47106	$ 207.27	$ 0.0044	47165	$ 207.52	$ 0.26	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	47106	$ 56.53	$ 0.0012	47165	$ 56.60	$ 0.07	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	45000	$ 315.00	$ 0.0070	45000	$ 315.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 1,524.80**			**$ 1,597.29**	**$ 72.49**	**4.75%**
HST		13%		$ 198.22	13%		$ 207.65	$ 9.42	4.75%
Total Bill (including HST)				$ 1,723.03			$ 1,804.94	$ 81.91	4.75%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 180.49	-$ 8.19	4.75%
Total Bill on TOU (including OCEB)				**$ 1,550.73**			**$ 1,624.45**	**$ 73.72**	**4.75%**
Total Bill on RPP (before Taxes)				**$ 1,524.80**			**$ 1,597.29**	**$ 72.49**	**4.75%**
HST		13%		$ 198.22	13%		$ 207.65	$ 9.42	4.75%
Total Bill (including HST)				$ 1,723.03			$ 1,804.94	$ 81.91	4.75%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 180.49	-$ 8.19	4.75%
Total Bill on RPP (including OCEB)				**$ 1,550.73**			**$ 1,624.45**	**$ 73.72**	**4.75%**

Loss Factor (%) Current: 4.68%; Proposed: 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 500 kW; 200,000 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	$ 186.2300	1	$ 186.23	$ 199.81	1	$ 199.81	$ 13.58	7.29%
Distribution Volumetric Rate	per kW	$ 2.1927	500	$ 1,096.35	$ 2.3327	500	$ 1,166.35	$ 70.00	6.38%
Sub-Total A (excluding pass through)				$ 1,282.58			$ 1,366.16	**$ 83.58**	**6.52%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	500	-$ 252.70	-$ 0.3588	500	-$ 179.42	$ 73.28	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	500	-$ 14.40		500	$ -	$ 14.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		500	$ -	-$ 0.0691	500	-$ 34.57	-$ 34.57	
Low Voltage Service Charge	per kW	$ 0.3999	500	$ 199.95	$ 0.6103	500	$ 305.15	$ 105.20	52.61%
Line Losses on Cost of Power	per kWh	$ 0.0880	9,360.00	$ 823.68	$ 0.0839	9,620.00	$ 807.31	-$ 16.37	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,039.11**			**$ 2,264.63**	**$ 225.52**	**11.06%**
RTSR - Network	per kW	$ 2.4552	500	$ 1,227.60	$ 2.6187	500	$ 1,309.36	$ 81.76	6.66%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	500	$ 614.20	$ 1.2309	500	$ 615.45	$ 1.25	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,880.91**			**$ 4,189.44**	**$ 308.53**	**7.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	209360	$ 921.18	$ 0.0044	209620	$ 922.33	$ 1.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	209360	$ 251.23	$ 0.0012	209620	$ 251.54	$ 0.31	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	200000	$ 1,400.00	$ 0.0070	200000	$ 1,400.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 6,453.58**			**$ 6,763.56**	**$ 309.98**	**4.80%**
HST		13%		$ 838.96	13%		$ 879.26	$ 40.30	4.80%
Total Bill (including HST)				$ 7,292.54			$ 7,642.82	$ 350.28	4.80%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 764.28	-$ 35.03	4.80%
Total Bill on TOU (including OCEB)				**$ 6,563.29**			**$ 6,878.54**	**$ 315.25**	**4.80%**
Total Bill on RPP (before Taxes)				**$ 6,453.58**			**$ 6,763.56**	**$ 309.98**	**4.80%**
HST		13%		$ 838.96	13%		$ 879.26	$ 40.30	4.80%
Total Bill (including HST)				$ 7,292.54			$ 7,642.82	$ 350.28	4.80%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 764.28	-$ 35.03	4.80%
Total Bill on RPP (including OCEB)				**$ 6,563.29**			**$ 6,878.54**	**$ 315.25**	**4.80%**

Loss Factor (%) Current: 4.68% Proposed: 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 1,000 kW; 500,000 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	$ 186.2300	1	$ 186.23	$ 199.81	1	$ 199.81	$ 13.58	7.29%
Distribution Volumetric Rate	per kW	$ 2.1927	1,000	$ 2,192.70	$ 2.3327	1,000	$ 2,332.70	$ 140.00	6.38%
Sub-Total A (excluding pass through)				$ 2,378.93			$ 2,532.51	**$ 153.58**	**6.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	1,000	-$ 505.40	-$ 0.3588	1,000	-$ 358.84	$ 146.56	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	1,000	-$ 28.80		1,000	$ -	$ 28.80	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1,000	$ -	-$ 0.0691	1,000	-$ 69.14	-$ 69.14	
Low Voltage Service Charge	per kW	$ 0.3999	1,000	$ 399.90	$ 0.6103	1,000	$ 610.30	$ 210.40	52.61%
Line Losses on Cost of Power	per kWh	$ 0.0880	23,400.00	$ 2,059.20	$ 0.0839	24,050.00	$ 2,018.28	-$ 40.92	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,303.83**			**$ 4,733.11**	**$ 429.28**	**9.97%**
RTSR - Network	per kW	$ 2.4552	1,000	$ 2,455.20	$ 2.6187	1000	$ 2,618.72	$ 163.52	6.66%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	1,000	$ 1,228.40	$ 1.2309	1000	$ 1,230.90	$ 2.50	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,987.43**			**$ 8,582.72**	**$ 595.29**	**7.45%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523400	$ 2,302.96	$ 0.0044	524050	$ 2,305.82	$ 2.86	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523400	$ 628.08	$ 0.0012	524050	$ 628.86	$ 0.78	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$14,418.72**			**$15,017.65**	**$ 598.93**	**4.15%**
HST		13%		$ 1,874.43	13%		$ 1,952.29	$ 77.86	4.15%
Total Bill (including HST)				$16,293.15			$16,969.95	$ 676.79	4.15%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,696.99	-$ 67.67	4.15%
Total Bill on TOU (including OCEB)				**$14,663.83**			**$15,272.96**	**$ 609.12**	**4.15%**
Total Bill on RPP (before Taxes)				**$14,418.72**			**$15,017.65**	**$ 598.93**	**4.15%**
HST		13%		$ 1,874.43	13%		$ 1,952.29	$ 77.86	4.15%
Total Bill (including HST)				$16,293.15			$16,969.95	$ 676.79	4.15%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,696.99	-$ 67.67	4.15%
Total Bill on RPP (including OCEB)				**$14,663.83**			**$15,272.96**	**$ 609.12**	**4.15%**

Loss Factor (%) Current: 4.68% Proposed: 4.81%

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**3**
Consumption	**215** kWh
	1 kW

	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	$ 1.5100	3	$ 4.53	$ 1.56	3	$ 4.69	$ 0.16	3.43%
Distribution Volumetric Rate	per kW	$ 8.3561	1	$ 4.76	$ 8.6430	1	$ 4.93	$ 0.16	3.43%
Sub-Total A (excluding pass through)				$ 9.29			$ 9.61	**$ 0.32**	**3.43%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	1	-$ 0.26	$ 3.0122	1	$ 1.72	$ 1.97	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	1	-$ 0.08		1	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.2293	1	-$ 0.13	-$ 0.13	
Low Voltage Service Charge	per kW	$ 0.3091	1	$ 0.18	$ 0.4717	1	$ 0.27	$ 0.09	52.60%
Line Losses on Cost of Power	per kWh	$ 0.0750	10.04	$ 0.75	$ 0.0839	10.32	$ 0.87	$ 0.11	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 9.89**			**$ 12.33**	**$ 2.44**	**24.72%**
RTSR - Network	per kW	$ 1.8516	1	$ 1.06	$ 1.9749	1	$ 1.13	$ 0.07	6.66%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	1	$ 0.54	$ 0.9514	1	$ 0.54	$ 0.00	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.49**			**$ 14.00**	**$ 2.52**	**21.91%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	225	$ 0.99	$ 0.0044	225	$ 0.99	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	225	$ 0.27	$ 0.0012	225	$ 0.27	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	215	$ 1.50	$ 0.0070	215	$ 1.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	137	$ 9.20	$ 0.0670	137	$ 9.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	39	$ 4.02	$ 0.1040	39	$ 4.02	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	39	$ 4.79	$ 0.1240	39	$ 4.79	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	215	$ 16.13	$ 0.0750	215	$ 16.13	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.50**			**$ 35.02**	**$ 2.52**	**7.75%**
HST		13%		$ 4.23	13%		$ 4.55	$ 0.33	7.75%
Total Bill (including HST)				$ 36.73			$ 39.58	$ 2.85	7.75%
Ontario Clean Energy Benefit [1]				-$ 3.67			-$ 3.96	-$ 0.29	7.90%
Total Bill on TOU (including OCEB)				**$ 33.06**			**$ 35.62**	**$ 2.56**	**7.73%**
Total Bill on RPP (before Taxes)				**$ 30.62**			**$ 33.14**	**$ 2.52**	**8.22%**
HST		13%		$ 3.98	13%		$ 4.31	$ 0.33	8.22%
Total Bill (including HST)				$ 34.60			$ 37.45	$ 2.85	8.22%
Ontario Clean Energy Benefit [1]				-$ 3.46			-$ 3.74	-$ 0.28	8.09%
Total Bill on RPP (including OCEB)				**$ 31.14**			**$ 33.71**	**$ 2.57**	**8.24%**

Loss Factor (%) Current: 4.68% Proposed: 4.81%

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**2,568**
Consumption	**132,737** kWh
	353 kW

	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	$ 1.5100	2,568	$ 3,877.68	$ 1.56	2,568	$ 4,010.70	$ 133.02	3.43%
Distribution Volumetric Rate	per kW	$ 8.3561	353	$ 2,946.19	$ 8.6430	353	$ 3,047.35	$ 101.16	3.43%
Sub-Total A (excluding pass through)				$ 6,823.87			$ 7,058.05	**$ 234.18**	**3.43%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	353	-$ 158.38	$ 3.0122	353	$ 1,062.04	$ 1,220.42	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	353	-$ 48.16		353	$ -	$ 48.16	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		353	$ -	-$ 0.2293	353	-$ 80.83	-$ 80.83	
Low Voltage Service Charge	per kW	$ 0.3091	353	$ 108.98	$ 0.4717	353	$ 166.31	$ 57.33	52.60%
Line Losses on Cost of Power	per kWh	$ -	6,212.11	$ -	$ 0.0839	6,384.67	$ 535.80	$ 535.80	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,726.73**			**$ 8,741.78**	**$ 2,015.05**	**29.96%**
RTSR - Network	per kW	$ 1.8516	353	$ 652.84	$ 1.9749	353	$ 696.32	$ 43.48	6.66%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	353	$ 334.77	$ 0.9514	353	$ 335.46	$ 0.68	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,714.34**			**$ 9,773.55**	**$ 2,059.21**	**26.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	138949	$ 611.38	$ 0.0044	139122	$ 612.14	$ 0.76	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	138949	$ 166.74	$ 0.0012	139122	$ 166.95	$ 0.21	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	132737	$ 929.16	$ 0.0070	132737	$ 929.16	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	84952	$ 5,691.78	$ 0.0670	84952	$ 5,691.78	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	23893	$ 2,484.84	$ 0.1040	23893	$ 2,484.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	23893	$ 2,962.70	$ 0.1240	23893	$ 2,962.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	132137	$11,628.08	$ 0.0880	132137	$11,628.08	$ -	0.00%
Total Bill on TOU (before Taxes)				**$20,561.18**			**$22,621.36**	**$ 2,060.18**	**10.02%**
HST		13%		$ 2,672.95	13%		$ 2,940.78	$ 267.82	10.02%
Total Bill (including HST)				$23,234.14			$25,562.14	$ 2,328.00	10.02%
Ontario Clean Energy Benefit [1]				-$ 2,323.41			-$ 2,556.21	-$ 232.80	10.02%
Total Bill on TOU (including OCEB)				**$20,910.73**			**$23,005.93**	**$ 2,095.20**	**10.02%**
Total Bill on RPP (before Taxes)				**$21,094.95**			**$23,155.13**	**$ 2,060.18**	**9.77%**
HST		13%		$ 2,742.34	13%		$ 3,010.17	$ 267.82	9.77%
Total Bill (including HST)				$23,837.29			$26,165.30	$ 2,328.00	9.77%
Ontario Clean Energy Benefit [1]				-$ 2,383.73			-$ 2,616.53	-$ 232.80	9.77%
Total Bill on RPP (including OCEB)				**$21,453.56**			**$23,548.77**	**$ 2,095.20**	**9.77%**

Loss Factor (%) Current: 4.68% Proposed: 4.81%

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**1**	
Consumption	**180**	**kWh**
	1	kW

	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	$ 3.3200	1	$ 3.32	$ 3.79	1	$ 3.79	$ 0.47	14.07%
Distribution Volumetric Rate	per kW	$ 12.9468	1	$ 12.95	$ 14.7685	1	$ 14.77	$ 1.82	14.07%
Sub-Total A (excluding pass through)				$ 16.27			$ 18.56	**$ 2.29**	**14.07%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	1	-$ 0.28	$ 2.5804	1	$ 1.47	$ 1.75	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	1	-$ 0.14		1	$ -	$ 0.14	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.4337	1	-$ 0.25	-$ 0.25	
Low Voltage Service Charge	per kW	$ 0.3156	1	$ 0.18	$ 0.4817	1	$ 0.27	$ 0.09	52.63%
Line Losses on Cost of Power	per kWh	$ 0.0750	8.42	$ 0.63	$ 0.0839	8.66	$ 0.73	$ 0.09	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 16.66**			**$ 20.78**	**$ 4.12**	**24.70%**
RTSR - Network	per kW	$ 1.8609	1	$ 1.86	$ 1.9848	1	$ 1.98	$ 0.12	6.66%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	1	$ 0.97	$ 0.9716	1	$ 0.97	$ 0.00	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19.49**			**$ 23.74**	**$ 4.24**	**21.76%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	188	$ 0.83	$ 0.0044	189	$ 0.83	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	188	$ 0.23	$ 0.0012	189	$ 0.23	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	180	$ 1.26	$ 0.0070	180	$ 1.26	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	115	$ 7.72	$ 0.0670	115	$ 7.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	32	$ 3.37	$ 0.1040	32	$ 3.37	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	32	$ 4.02	$ 0.1240	32	$ 4.02	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	180	$ 13.50	$ 0.0750	180	$ 13.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 37.16**			**$ 41.41**	**$ 4.24**	**11.42%**
HST		13%		$ 4.83	13%		$ 5.38	$ 0.55	11.42%
Total Bill (including HST)				$ 42.00			$ 46.79	$ 4.80	11.42%
Ontario Clean Energy Benefit [1]				-$ 4.20			-$ 4.68	-$ 0.48	11.43%
Total Bill on TOU (including OCEB)				**$ 37.80**			**$ 42.11**	**$ 4.32**	**11.42%**
Total Bill on RPP (before Taxes)				**$ 35.56**			**$ 39.80**	**$ 4.24**	**11.93%**
HST		13%		$ 4.62	13%		$ 5.17	$ 0.55	11.93%
Total Bill (including HST)				$ 40.18			$ 44.98	$ 4.80	11.93%
Ontario Clean Energy Benefit [1]				-$ 4.02			-$ 4.50	-$ 0.48	11.94%
Total Bill on RPP (including OCEB)				**$ 36.16**			**$ 40.48**	**$ 4.32**	**11.93%**

Loss Factor (%)	4.68%	4.81%

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**30**	
Consumption	**2,780**	**kWh**
	7	kW

	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	$ 3.3200	30	$ 99.60	$ 3.79	30	$ 113.61	$ 14.01	14.07%
Distribution Volumetric Rate	per kW	$ 12.9468	7	$ 94.19	$ 14.7685	7	$ 107.44	$ 13.25	14.07%
Sub-Total A (excluding pass through)				$ 193.79			$ 221.05	**$ 27.27**	**14.07%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	7	-$ 3.52	$ 2.5804	7	$ 18.77	$ 22.29	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	7	-$ 1.78		7	$ -	$ 1.78	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		7	$ -	-$ 0.4337	7	-$ 3.16	-$ 3.16	
Low Voltage Service Charge	per kW	$ 0.3156	7	$ 2.30	$ 0.4817	7	$ 3.50	$ 1.21	52.63%
Line Losses on Cost of Power	per kWh	$ 0.0880	130.10	$ 11.45	$ 0.0839	133.72	$ 11.22	-$ 0.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 202.24**			**$ 251.40**	**$ 49.16**	**24.31%**
RTSR - Network	per kW	$ 1.8609	7	$ 13.54	$ 1.9848	7	$ 14.44	$ 0.90	6.66%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	7	$ 7.05	$ 0.9716	7	$ 7.07	$ 0.01	0.20%
Sub-Total C - Delivery (including Sub-Total B)				**$ 222.83**			**$ 272.91**	**$ 50.07**	**22.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2910	$ 12.80	$ 0.0044	2914	$ 12.82	$ 0.02	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2910	$ 3.49	$ 0.0012	2914	$ 3.50	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2780	$ 19.46	$ 0.0070	2780	$ 19.46	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1779	$ 119.21	$ 0.0670	1779	$ 119.21	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	500	$ 52.04	$ 0.1040	500	$ 52.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	500	$ 62.05	$ 0.1240	500	$ 62.05	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	2180	$ 191.84	$ 0.0880	2180	$ 191.84	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 492.14**			**$ 542.23**	**$ 50.09**	**10.18%**
HST		13%		$ 63.98	13%		$ 70.49	$ 6.51	10.18%
Total Bill (including HST)				$ 556.11			$ 612.72	$ 56.61	10.18%
Ontario Clean Energy Benefit [1]				-$ 55.61			-$ 61.27	-$ 5.66	10.18%
Total Bill on TOU (including OCEB)				**$ 500.50**			**$ 551.45**	**$ 50.95**	**10.18%**
Total Bill on RPP (before Taxes)				**$ 495.68**			**$ 545.77**	**$ 50.09**	**10.11%**
HST		13%		$ 64.44	13%		$ 70.95	$ 6.51	10.11%
Total Bill (including HST)				$ 560.12			$ 616.72	$ 56.61	10.11%
Ontario Clean Energy Benefit [1]				-$ 56.01			-$ 61.67	-$ 5.66	10.11%
Total Bill on RPP (including OCEB)				**$ 504.11**			**$ 555.05**	**$ 50.95**	**10.11%**

Loss Factor (%)	4.68%	4.81%

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: non-TOU

Connections	**1**	
Consumption	**193**	**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	$ 6.3400	1	$ 6.34	$ 5.88	1	$ 5.88	-$ 0.46	-7.28%
Distribution Volumetric Rate	per kWh	$ 0.0089	193	$ 1.71	$ 0.0083	193	$ 1.60	-$ 0.12	-6.74%
Sub-Total A (excluding pass through)				$ 8.05			$ 7.48	**-$ 0.58**	**-7.17%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	193	-$ 0.19	$ 0.0015	193	$ 0.28	$ 0.48	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	193	-$ 0.08		193	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		193	$ -	-$ 0.0009	193	-$ 0.18	-$ 0.18	
Low Voltage Service Charge	per kWh	$ 0.0010	193	$ 0.19	$ 0.0015	193	$ 0.29	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0750	9.01	$ 0.68	$ 0.0839	9.26	$ 0.78	$ 0.10	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.65**			**$ 8.64**	**-$ 0.01**	**-0.10%**
RTSR - Network	per kWh	$ 0.0060	202	$ 1.21	$ 0.0064	202	$ 1.29	$ 0.08	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	202	$ 0.63	$ 0.0031	202	$ 0.63	$ 0.00	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.49**			**$ 10.56**	**$ 0.08**	**0.72%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	202	$ 0.89	$ 0.0044	202	$ 0.89	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	202	$ 0.24	$ 0.0012	202	$ 0.24	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	193	$ 1.35	$ 0.0070	193	$ 1.35	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	123	$ 8.26	$ 0.0670	123	$ 8.26	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	35	$ 3.61	$ 0.1040	35	$ 3.61	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	35	$ 4.30	$ 0.1240	35	$ 4.30	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	193	$ 14.45	$ 0.0750	193	$ 14.45	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 29.38**			**$ 29.46**	**$ 0.08**	**0.26%**
HST		13%		$ 3.82	13%		$ 3.83	$ 0.01	0.26%
Total Bill (including HST)				$ 33.20			$ 33.29	$ 0.09	0.26%
Ontario Clean Energy Benefit [1]				-$ 3.32			-$ 3.33	-$ 0.01	0.30%
Total Bill on TOU (including OCEB)				**$ 29.88**			**$ 29.96**	**$ 0.08**	**0.26%**
Total Bill on RPP (before Taxes)				**$ 27.66**			**$ 27.74**	**$ 0.08**	**0.28%**
HST		13%		$ 3.60	13%		$ 3.61	$ 0.01	0.28%
Total Bill (including HST)				$ 31.26			$ 31.34	$ 0.09	0.28%
Ontario Clean Energy Benefit [1]				-$ 3.13			-$ 3.13	$ -	0.00%
Total Bill on RPP (including OCEB)				**$ 28.13**			**$ 28.21**	**$ 0.09**	**0.31%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: non-TOU

Connections	**58**	
Consumption	**24,581**	**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	$ 6.3400	58	$ 367.72	$ 5.878	58	$ 340.94	-$ 26.78	-7.28%
Distribution Volumetric Rate	per kWh	$ 0.0089	24,581	$ 218.77	$ 0.0083	24,581	$ 204.02	-$ 14.75	-6.74%
Sub-Total A (excluding pass through)				$ 586.49			$ 544.96	**-$ 41.53**	**-7.08%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	24,581	-$ 24.58	$ 0.0015	24,581	$ 36.18	$ 60.76	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	24,581	-$ 9.83		24,581	$ -	$ 9.83	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		24,581	$ -	-$ 0.0009	24,581	-$ 23.30	-$ 23.30	
Low Voltage Service Charge	per kWh	$ 0.0010	24,581	$ 24.58	$ 0.0015	24,581	$ 36.87	$ 12.29	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0880	1,150.39	$ 101.23	$ 0.0839	1,182.34	$ 99.22	-$ 2.01	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 677.89**			**$ 693.93**	**$ 16.04**	**2.37%**
RTSR - Network	per kWh	$ 0.0060	25731	$ 154.39	$ 0.0064	25763	$ 164.87	$ 10.49	6.79%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	25731	$ 79.77	$ 0.0031	25763	$ 80.03	$ 0.26	0.33%
Sub-Total C - Delivery (including Sub-Total B)				**$ 912.05**			**$ 938.84**	**$ 26.79**	**2.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	25731	$ 113.22	$ 0.0044	25763	$ 113.36	$ 0.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	25731	$ 30.88	$ 0.0012	25763	$ 30.92	$ 0.04	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	24581	$ 172.07	$ 0.0070	24581	$ 172.07	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	15732	$ 1,054.03	$ 0.0670	15732	$ 1,054.03	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	4425	$ 460.16	$ 0.1040	4425	$ 460.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	4425	$ 548.65	$ 0.1240	4425	$ 548.65	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	23981	$ 2,110.32	$ 0.0880	23981	$ 2,110.32	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 3,291.29**			**$ 3,318.26**	**$ 26.97**	**0.82%**
HST		13%		$ 427.87	13%		$ 431.37	$ 3.51	0.82%
Total Bill (including HST)				$ 3,719.16			$ 3,749.64	$ 30.47	0.82%
Ontario Clean Energy Benefit [1]				-$ 371.92			-$ 374.96	-$ 3.04	0.82%
Total Bill on TOU (including OCEB)				**$ 3,347.24**			**$ 3,374.68**	**$ 27.43**	**0.82%**
Total Bill on RPP (before Taxes)				**$ 3,383.78**			**$ 3,410.75**	**$ 26.97**	**0.80%**
HST		13%		$ 439.89	13%		$ 443.40	$ 3.51	0.80%
Total Bill (including HST)				$ 3,823.68			$ 3,854.15	$ 30.47	0.80%
Ontario Clean Energy Benefit [1]				-$ 382.37			-$ 385.41	-$ 3.04	0.80%
Total Bill on RPP (including OCEB)				**$ 3,441.31**			**$ 3,468.74**	**$ 27.43**	**0.80%**
Loss Factor (%)		4.68%			4.81%				

ORANGEVILLE HYDRO

Appendix M -

Preliminary OPA

2013 CDM Report

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

saveONenergy

Ontario Power Authority
Conservation & Demand Management Status Report
Q3 2013 Preliminary Results Update

Orangeville Hydro Limited

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)	**1.1**	**0.5**	20%	**1.7**	60%	**7**
Net Energy Savings (GWh)	**0.1**	**8.0**	67%	**8.0**	68%	**45**

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.

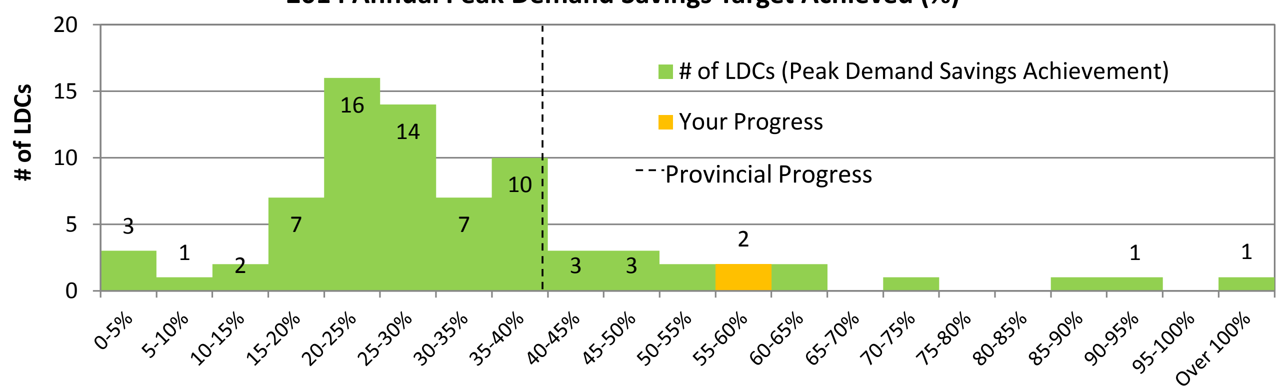
Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

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

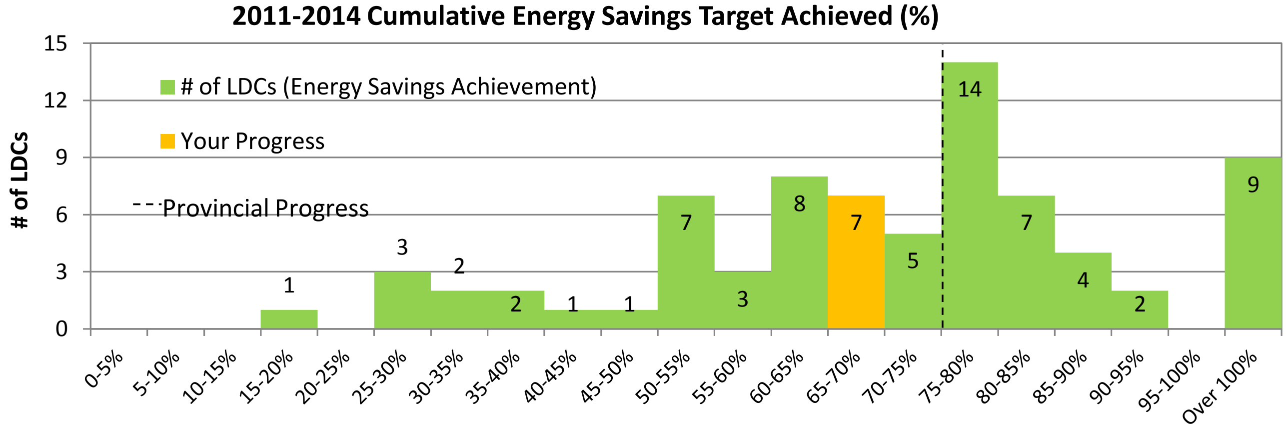
Comparison: Your Achievement vs. LDC Community Achievement

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)

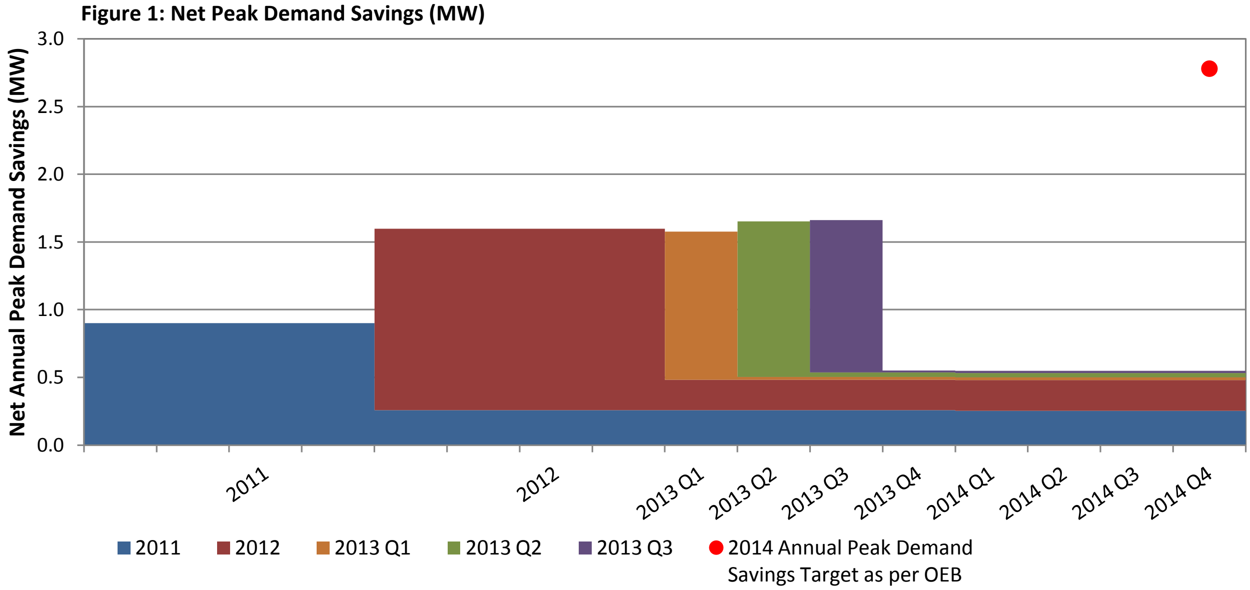
#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	0.90	0.26	0.26	0.25	0.25
2	2012 - Final*		1.34	0.23	0.23	0.23
3	2013 - Reported - Quarter 1			0.02	0.02	0.02
4	2013 - Reported - Quarter 2			0.03	0.03	0.03
5	2013 - Reported - Quarter 3			1.13	0.02	1.13
6	2014					
	Energy Efficiency	0.26	0.47	0.55	0.55	0.55
	Demand Response	0.64	1.11	1.11	0.00	1.11
	Net Annual Peak Demand Savings	0.90	1.60	1.66	0.55	1.66
	Unverified Net Annual Peak Demand Savings in 2014:				**0.5**	**1.7**
	2014 Annual Peak Demand Savings Target as per OEB:				**2.8**	**2.8**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**20%**	**60%**
	Incremental Reported (Unverified)	0.89	0.31	1.18		
	Incremental Final (Verified)	0.90	1.34	n/a		

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Reported DR3 (Ex Ante) (MW)**	1.11
Contracted DR3 (MW)**	1.28

** 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*	1.16	1.13	1.13	1.12	4.53
2	2012 - Final*	-0.02	0.96	0.93	0.93	2.79
3	2013 - Reported - Quarter 1			0.09	0.09	0.17
4	2013 - Reported - Quarter 2			0.16	0.16	0.31
5	2013 - Reported - Quarter 3			0.10	0.07	0.17
6	2014					
	Energy Efficiency	1.13	2.03	2.37	2.36	7.89
	Demand Response	0.03	0.03	0.02	0.00	0.08
	Net Energy Savings	1.13	2.08	2.39	2.36	7.97
	Unverified Net Cumulative Energy Savings 2011-2014:					**8.0**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**11.8**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**67%**
	Incremental Reported (Unverified)	0.41	1.05	0.34		
	Incremental Final (Verified)	1.16	0.96	n/a		

Figure 2: Net Cumulative Energy Savings (GWh)

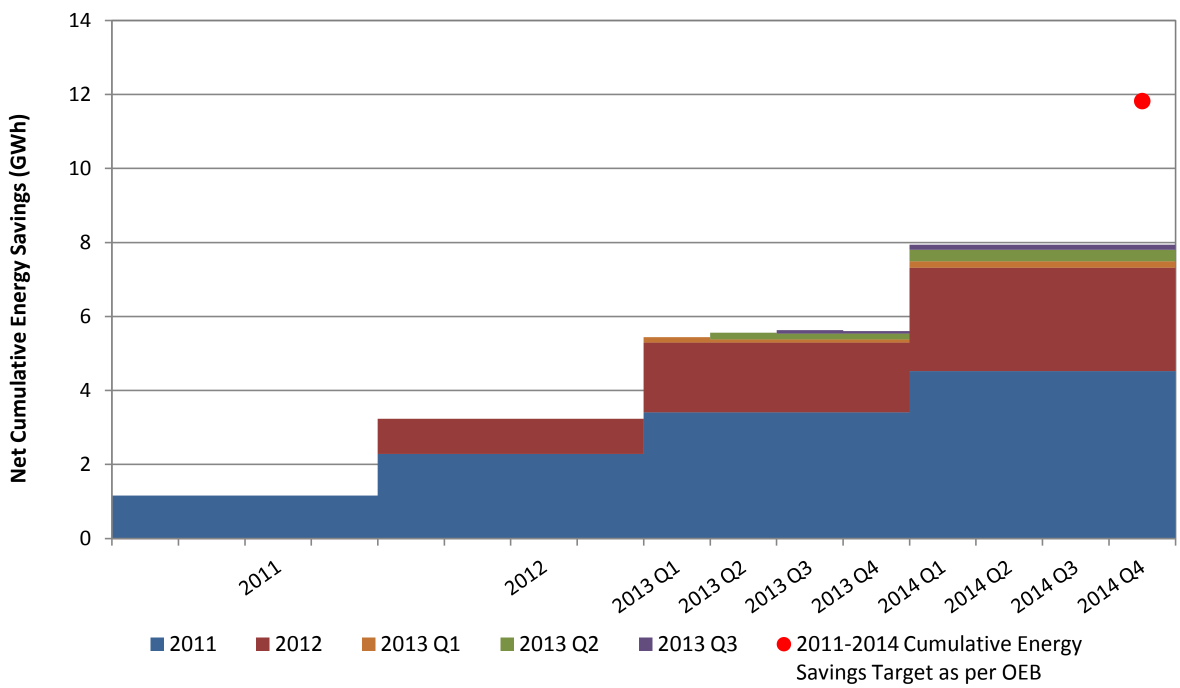


Table 3A: Orangeville Hydro Limited Initiative and Program Level Savings by Year (Scenario 1)

#	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	97	89	31		5	5	2		39,565	35,917	12,645		12	291,099
2	Appliance Exchange	Appliances	5	3	2		1	0	0		815	735	341		1	5,982
3	HVAC Incentives	Equipment	195	219	87		80	54	20		154,791	97,940	36,500		154	985,981
4	Conservation Instant Coupon Booklet	Coupons	1,109	65	67		3	0	0		41,018	2,964	2,737		3	178,440
5	Bi-Annual Retailer Event	Coupons	2,019	2,249	452		4	3	1		62,306	56,781	14,586		8	448,736
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-		-	-
7	Residential Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-		-	-
8	Residential Demand Response (IHD)	Devices	-	-	-		-		-		-		-		-	-
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-		-	-
Consumer Program Total							**92**	**63**	**24**		**298,493**	**194,338**	**66,809**		**178**	**1,910,238**
Business Program																
10	Retrofit	Projects	6	12	9		65	88	22		361,262	416,936	145,783		175	2,987,420
11	Direct Install Lighting	Projects	23	67	24		22	58	23		55,853	235,793	100,812		99	1,120,371
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-		-	-
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-		-	-
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-		-	-
16	Small Commercial Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	3	2	1		401	34	34		15,665	498	763		-	16,926
Business Program Total							**488**	**181**	**79**		**432,780**	**653,227**	**247,358**		**274**	**4,124,718**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-		-	-
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-		-	-
21	Retrofit	Projects	2		-		8		-		56,536		-		8	226,144
22	Demand Response 3*	Facilities	1	1	1		240	1,080	1,076		14,099	26,025	24,160		-	64,285
Industrial Program Total							**248**	**1,080**	**1,076**		**70,635**	**26,025**	**24,160**		**8**	**290,429**
Home Assistance Program																
23	Home Assistance Program	Homes	-	3	-		-	0	-		-	4,865	-		0	14,596
Home Assistance Program Total							**-**	**0**	**-**		**-**	**4,865**	**-**		**0**	**14,596**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-		-	-	-		-	-	-		-	-
Aboriginal Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	8	-	-		72	-	-		354,732	-	-		72	1,418,929
26	High Performance New Construction	Projects	0	1	-		0	31	-		688	100,276	-		31	303,582
27	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-		-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-		-	-
29	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-		-	-
Pre-2011 Programs completed in 2011 Total							**72**	**31**	**-**		**355,421**	**100,276**	**-**		**103**	**1,722,510**
Other																
30	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-		-	-
31	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-		-	-
Other Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Adjustment to Previous Year's Verified Results								**(15)**				**(23,654)**			**(15)**	**(94,614)**
Energy Efficiency Total							**258**	**241**	**69**		**1,127,564**	**952,208**	**313,404**		**563**	**7,981,280**
Demand Response Total (Scenario 1)							**641**	**1,114**	**1,110**		**29,764**	**26,523**	**24,924**		**-**	**81,211**
OPA-Contracted LDC Portfolio Total							**900**	**1,340**	**1,179**		**1,157,328**	**955,078**	**338,328**		**548**	**7,967,877**
														Full OEB Target:	**2,780**	**11,820,000**
														% of Full OEB Target Achieved to Date (Scenario 1):	**20%**	**67%**

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: Orangeville Hydro Limited Initiative and Program Level Savings by Quarter for current reporting year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 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	8	12	10		0	1	1		3,419	4,996	4,230	
2	Appliance Exchange	Appliances	-	2	-		-	0	-		-	341	-	
3	HVAC Incentives	Equipment	38	40	9		9	9	2		17,304	15,194	4,001	
4	Conservation Instant Coupon Booklet	Coupons	39	23	5		0	0	0		1,689	852	197	
5	Bi-Annual Retailer Event	Coupons	9	439	3		0	1	0		267	14,224	95	
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-	
7	Residential Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-	
8	Residential Demand Response (IHD)	Devices	-	-	-				-				-	
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-	
Consumer Program Total							**10**	**11**	**3**		**22,679**	**35,607**	**8,524**	
Business Program														
10	Retrofit	Projects	3	4	2		3	10	9		29,487	63,926	52,370	
11	Direct Install Lighting	Projects	7	14	3		8	12	3		33,058	55,917	11,837	
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-	
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-	
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-	
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-	
16	Small Commercial Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-	
17	Demand Response 3*	Facilities	1	1	1		34	39	34		1,339	874	763	
Business Program Total							**45**	**61**	**47**		**63,885**	**120,717**	**64,970**	
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	1		1,039	1,076	1,076		60,993	24,160	24,160	
Industrial Program Total							**1,039**	**1,076**	**1,076**		**60,993**	**24,160**	**24,160**	
Home Assistance Program														
23	Home Assistance Program	Homes	-	-	-		-	-	-		-	-	-	
Home Assistance Program Total							**-**	**-**	**-**		**-**	**-**	**-**	
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							**21**	**32**	**15**		**85,224**	**155,449**	**72,731**	
Demand Response Total (Scenario 1)							**1,073**	**1,115**	**1,110**		**62,332**	**25,034**	**24,924**	
OPA-Contracted LDC Portfolio Total							**1,094**	**1,148**	**1,126**		**147,556**	**180,484**	**97,655**	

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)	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.

	kW	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

ORANGEVILLE HYDRO

Appendix N -

Bill Impacts No Change

File Number:	EB-2013-0160
Exhibit:	8
Tab:	6
Schedule:	1
Page:	1
Date:	12-Feb-14

Appendix 2-W
Bill Impacts

Customer Class: Residential

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption 100 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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	100	$ 1.40	$ 0.0140	100	$ 1.40	$ -	0.00%
Sub-Total A (excluding pass through)				$ 20.50			$ 18.74	**-$ 1.76**	**-8.59%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	100	-$ 0.13	-$ 0.0002	100	-$ 0.02	$ 0.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	100	-$ 0.03		100	$ -	$ 0.03	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		100	$ -	-$ 0.0016	100	-$ 0.16	-$ 0.16	
Low Voltage Service Charge	per kWh	$ 0.0011	100	$ 0.11	$ 0.0017	100	$ 0.17	$ 0.06	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	4.68	$ 0.39	$ 0.0839	4.81	$ 0.40	$ 0.01	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.63**			**$ 19.93**	**-$ 1.71**	**-7.89%**
RTSR - Network	per kWh	$ 0.0065	105	$ 0.68	$ 0.0075	105	$ 0.78	$ 0.10	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	105	$ 0.36	$ 0.0039	105	$ 0.41	$ 0.05	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.67**			**$ 21.11**	**-$ 1.55**	**-6.86%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	105	$ 0.46	$ 0.0044	105	$ 0.46	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	105	$ 0.13	$ 0.0012	105	$ 0.13	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	64	$ 4.29	$ 0.0670	64	$ 4.29	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	18	$ 1.87	$ 0.1040	18	$ 1.87	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	18	$ 2.23	$ 0.1240	18	$ 2.23	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	100	$ 7.50	$ 0.0750	100	$ 7.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.60**			**$ 31.04**	**-$ 1.55**	**-4.77%**
HST		13%		$ 4.24	13%		$ 4.04	-$ 0.20	-4.77%
Total Bill (including HST)				$ 36.83			$ 35.08	-$ 1.76	-4.77%
Ontario Clean Energy Benefit [1]				-$ 3.68			-$ 3.51	$ 0.17	-4.62%
Total Bill on TOU (including OCEB)				**$ 33.15**			**$ 31.57**	**-$ 1.59**	**-4.78%**
Total Bill on RPP (before Taxes)				**$ 31.71**			**$ 30.15**	**-$ 1.55**	**-4.90%**
HST		13%		$ 4.12	13%		$ 3.92	-$ 0.20	-4.90%
Total Bill (including HST)				$ 35.83			$ 34.07	-$ 1.76	-4.90%
Ontario Clean Energy Benefit [1]				-$ 3.58			-$ 3.41	$ 0.17	-4.75%
Total Bill on RPP (including OCEB)				**$ 32.25**			**$ 30.66**	**-$ 1.59**	**-4.92%**

Loss Factor (%) — Current: 4.68% — Proposed: 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	per kWh		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	250	$ 3.50	$ 0.0140	250	$ 3.50	$ -	0.00%
Sub-Total A (excluding pass through)				$ 22.60			$ 20.84	**-$ 1.76**	**-7.79%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	250	-$ 0.33	-$ 0.0002	250	-$ 0.05	$ 0.28	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	250	-$ 0.08		250	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		250	$ -	-$ 0.0016	250	-$ 0.40	-$ 0.40	
Low Voltage Service Charge	per kWh	$ 0.0011	250	$ 0.28	$ 0.0017	250	$ 0.43	$ 0.15	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	11.70	$ 0.98	$ 0.0839	12.03	$ 1.01	$ 0.03	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.25**			**$ 22.62**	**-$ 1.63**	**-6.71%**
RTSR - Network	per kWh	$ 0.0065	262	$ 1.70	$ 0.0075	262	$ 1.95	$ 0.25	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	262	$ 0.89	$ 0.0039	262	$ 1.02	$ 0.13	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 25.59**	**-$ 1.25**	**-4.64%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	262	$ 1.15	$ 0.0044	262	$ 1.15	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	262	$ 0.31	$ 0.0012	262	$ 0.31	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	160	$ 10.72	$ 0.0670	160	$ 10.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	45	$ 4.68	$ 0.1040	45	$ 4.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	45	$ 5.58	$ 0.1240	45	$ 5.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	250	$ 18.75	$ 0.0750	250	$ 18.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 51.28**			**$ 50.04**	**-$ 1.24**	**-2.43%**
HST		13%		$ 6.67	13%		$ 6.51	-$ 0.16	-2.43%
Total Bill (including HST)				$ 57.95			$ 56.54	-$ 1.41	-2.43%
Ontario Clean Energy Benefit [1]				-$ 5.80			-$ 5.65	$ 0.15	-2.59%
Total Bill on TOU (including OCEB)				**$ 52.15**			**$ 50.89**	**-$ 1.26**	**-2.41%**
Total Bill on RPP (before Taxes)				**$ 49.05**			**$ 47.81**	**-$ 1.24**	**-2.54%**
HST		13%		$ 6.38	13%		$ 6.22	-$ 0.16	-2.54%
Total Bill (including HST)				$ 55.43			$ 54.02	-$ 1.41	-2.54%
Ontario Clean Energy Benefit [1]				-$ 5.54			-$ 5.40	$ 0.14	-2.53%
Total Bill on RPP (including OCEB)				**$ 49.89**			**$ 48.62**	**-$ 1.27**	**-2.54%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 500 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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	500	$ 7.00	$ 0.0140	500	$ 7.00	$ -	0.00%
Sub-Total A (excluding pass through)				$ 26.10			$ 24.34	**-$ 1.76**	**-6.74%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	500	-$ 0.65	-$ 0.0002	500	-$ 0.09	$ 0.56	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	500	-$ 0.15		500	$ -	$ 0.15	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		500	$ -	-$ 0.0016	500	-$ 0.79	-$ 0.79	
Low Voltage Service Charge	per kWh	$ 0.0011	500	$ 0.55	$ 0.0017	500	$ 0.85	$ 0.30	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	23.40	$ 1.96	$ 0.0839	24.05	$ 2.02	$ 0.05	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.60**			**$ 27.11**	**-$ 1.49**	**-5.23%**
RTSR - Network	per kWh	$ 0.0065	523	$ 3.40	$ 0.0075	524	$ 3.91	$ 0.50	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	523	$ 1.78	$ 0.0039	524	$ 2.04	$ 0.26	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.79**			**$ 33.05**	**-$ 0.73**	**-2.17%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523	$ 2.30	$ 0.0044	524	$ 2.31	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523	$ 0.63	$ 0.0012	524	$ 0.63	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	320	$ 21.44	$ 0.0670	320	$ 21.44	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	90	$ 9.36	$ 0.1040	90	$ 9.36	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	90	$ 11.16	$ 0.1240	90	$ 11.16	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	500	$ 37.50	$ 0.0750	500	$ 37.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 82.43**			**$ 81.70**	**-$ 0.73**	**-0.88%**
HST		13%		$ 10.72	13%		$ 10.62	-$ 0.09	-0.88%
Total Bill (including HST)				$ 93.14			$ 92.32	-$ 0.82	-0.88%
Ontario Clean Energy Benefit [1]				-$ 9.31			-$ 9.23	$ 0.08	-0.86%
Total Bill on TOU (including OCEB)				**$ 83.83**			**$ 83.09**	**-$ 0.74**	**-0.89%**
Total Bill on RPP (before Taxes)				**$ 77.97**			**$ 77.24**	**-$ 0.73**	**-0.93%**
HST		13%		$ 10.14	13%		$ 10.04	-$ 0.09	-0.93%
Total Bill (including HST)				$ 88.10			$ 87.28	-$ 0.82	-0.93%
Ontario Clean Energy Benefit [1]				-$ 8.81			-$ 8.73	$ 0.08	-0.91%
Total Bill on RPP (including OCEB)				**$ 79.29**			**$ 78.55**	**-$ 0.74**	**-0.94%**

Loss Factor (%) 4.68% 4.81%

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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	800	$ 11.20	$ 0.0140	800	$ 11.20	$ -	0.00%
Sub-Total A (excluding pass through)				$ 30.30			$ 28.54	**-$ 1.76**	**-5.81%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	800	-$ 1.04	-$ 0.0002	800	-$ 0.15	$ 0.89	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		800	$ -	-$ 0.0016	800	-$ 1.27	-$ 1.27	
Low Voltage Service Charge	per kWh	$ 0.0011	800	$ 0.88	$ 0.0017	800	$ 1.36	$ 0.48	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	37.44	$ 3.14	$ 0.0839	38.48	$ 3.23	$ 0.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.83**			**$ 32.50**	**-$ 1.34**	**-3.95%**
RTSR - Network	per kWh	$ 0.0065	837	$ 5.44	$ 0.0075	838	$ 6.25	$ 0.81	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	837	$ 2.85	$ 0.0039	838	$ 3.26	$ 0.41	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.12**			**$ 42.01**	**-$ 0.11**	**-0.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	838	$ 3.69	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	838	$ 1.01	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	200	$ 17.60	$ 0.0880	200	$ 17.60	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 119.80**			**$ 119.69**	**-$ 0.11**	**-0.09%**
HST		13%		$ 15.57	13%		$ 15.56	-$ 0.01	-0.09%
Total Bill (including HST)				$ 135.37			$ 135.25	-$ 0.12	-0.09%
Ontario Clean Energy Benefit [1]				-$ 13.54			-$ 13.52	$ 0.02	-0.15%
Total Bill on TOU (including OCEB)				**$ 121.83**			**$ 121.73**	**-$ 0.10**	**-0.08%**
Total Bill on RPP (before Taxes)				**$ 115.26**			**$ 115.15**	**-$ 0.11**	**-0.09%**
HST		13%		$ 14.98	13%		$ 14.97	-$ 0.01	-0.09%
Total Bill (including HST)				$ 130.25			$ 130.12	-$ 0.12	-0.09%
Ontario Clean Energy Benefit [1]				-$ 13.02			-$ 13.01	$ 0.01	-0.08%
Total Bill on RPP (including OCEB)				**$ 117.23**			**$ 117.11**	**-$ 0.11**	**-0.10%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption 1,000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,000	$ 14.00	$ 0.0100	1,000	$ 10.00	-$ 4.00	-28.57%
Sub-Total A (excluding pass through)				$ 33.10			$ 27.34	**-$ 5.76**	**-17.40%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0002	1,000	-$ 0.19	$ 1.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,000	-$ 0.30		1,000	$ -	$ 0.30	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0016	1,000	-$ 1.59	-$ 1.59	
Low Voltage Service Charge	per kWh	$ 0.0011	1,000	$ 1.10	$ 0.0017	1,000	$ 1.70	$ 0.60	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.32**			**$ 32.09**	**-$ 5.23**	**-14.01%**
RTSR - Network	per kWh	$ 0.0065	1047	$ 6.80	$ 0.0075	1048	$ 7.81	$ 1.01	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1047	$ 3.56	$ 0.0039	1048	$ 4.08	$ 0.52	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 47.68**			**$ 43.98**	**-$ 3.70**	**-7.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 144.71**			**$ 141.02**	**-$ 3.70**	**-2.55%**
HST		13%		$ 18.81	13%		$ 18.33	-$ 0.48	-2.55%
Total Bill (including HST)				$ 163.53			$ 159.35	-$ 4.18	-2.55%
Ontario Clean Energy Benefit [1]				-$ 16.35			-$ 15.93	$ 0.42	-2.57%
Total Bill on TOU (including OCEB)				**$ 147.18**			**$ 143.42**	**-$ 3.76**	**-2.55%**
Total Bill on RPP (before Taxes)				**$ 140.99**			**$ 137.30**	**-$ 3.70**	**-2.62%**
HST		13%		$ 18.33	13%		$ 17.85	-$ 0.48	-2.62%
Total Bill (including HST)				$ 159.32			$ 155.15	-$ 4.18	-2.62%
Ontario Clean Energy Benefit [1]				-$ 15.93			-$ 15.51	$ 0.42	-2.64%
Total Bill on RPP (including OCEB)				**$ 143.39**			**$ 139.64**	**-$ 3.76**	**-2.62%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,500 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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,500	$ 21.00	$ 0.0140	1,500	$ 21.00	$ -	0.00%
Sub-Total A (excluding pass through)				$ 40.10			$ 38.34	**-$ 1.76**	**-4.39%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,500	-$ 1.95	-$ 0.0002	1,500	-$ 0.28	$ 1.67	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,500	-$ 0.45		1,500	$ -	$ 0.45	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,500	$ -	-$ 0.0016	1,500	-$ 2.38	-$ 2.38	
Low Voltage Service Charge	per kWh	$ 0.0011	1,500	$ 1.65	$ 0.0017	1,500	$ 2.55	$ 0.90	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	70.20	$ 5.89	$ 0.0839	72.15	$ 6.05	$ 0.16	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.03**			**$ 45.07**	**-$ 0.96**	**-2.09%**
RTSR - Network	per kWh	$ 0.0065	1570	$ 10.21	$ 0.0075	1572	$ 11.72	$ 1.51	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1570	$ 5.34	$ 0.0039	1572	$ 6.12	$ 0.78	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 61.58**			**$ 62.90**	**$ 1.33**	**2.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1570	$ 6.91	$ 0.0044	1572	$ 6.92	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1570	$ 1.88	$ 0.0012	1572	$ 1.89	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	960	$ 64.32	$ 0.0670	960	$ 64.32	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	270	$ 28.08	$ 0.1040	270	$ 28.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	270	$ 33.48	$ 0.1240	270	$ 33.48	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	900	$ 79.20	$ 0.0880	900	$ 79.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 207.00**			**$ 208.34**	**$ 1.34**	**0.65%**
HST		13%		$ 26.91	13%		$ 27.08	$ 0.17	0.65%
Total Bill (including HST)				$ 233.91			$ 235.42	$ 1.51	0.65%
Ontario Clean Energy Benefit [1]				-$ 23.39			-$ 23.54	-$ 0.15	0.64%
Total Bill on TOU (including OCEB)				**$ 210.52**			**$ 211.88**	**$ 1.36**	**0.65%**
Total Bill on RPP (before Taxes)				**$ 205.32**			**$ 206.66**	**$ 1.34**	**0.65%**
HST		13%		$ 26.69	13%		$ 26.87	$ 0.17	0.65%
Total Bill (including HST)				$ 232.01			$ 233.52	$ 1.51	0.65%
Ontario Clean Energy Benefit [1]				-$ 23.20			-$ 23.35	-$ 0.15	0.65%
Total Bill on RPP (including OCEB)				**$ 208.81**			**$ 210.17**	**$ 1.36**	**0.65%**

Loss Factor (%) 4.68% (Current) 4.81% (Proposed)

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 2,000 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	$ 16.2600	1	$ 16.26	$ 16.30	1	$ 16.30	$ 0.04	0.25%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	2,000	$ 28.00	$ 0.0140	2,000	$ 28.00	$ -	0.00%
Sub-Total A (excluding pass through)				$ 47.10			$ 45.34	**-$ 1.76**	**-3.74%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0002	2,000	-$ 0.38	$ 2.22	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	2,000	-$ 0.60		2,000	$ -	$ 0.60	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0016	2,000	-$ 3.18	-$ 3.18	
Low Voltage Service Charge	per kWh	$ 0.0011	2,000	$ 2.20	$ 0.0017	2,000	$ 3.40	$ 1.20	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.74**			**$ 54.05**	**-$ 0.70**	**-1.28%**
RTSR - Network	per kWh	$ 0.0065	2094	$ 13.61	$ 0.0075	2096	$ 15.62	$ 2.02	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	2094	$ 7.12	$ 0.0039	2096	$ 8.16	$ 1.04	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 75.47**			**$ 77.83**	**$ 2.35**	**3.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 269.29**			**$ 271.65**	**$ 2.37**	**0.88%**
HST		13%		$ 35.01	13%		$ 35.32	$ 0.31	0.88%
Total Bill (including HST)				$ 304.29			$ 306.97	$ 2.68	0.88%
Ontario Clean Energy Benefit [1]				-$ 30.43			-$ 30.70	-$ 0.27	0.89%
Total Bill on TOU (including OCEB)				**$ 273.86**			**$ 276.27**	**$ 2.41**	**0.88%**
Total Bill on RPP (before Taxes)				**$ 269.65**			**$ 272.01**	**$ 2.37**	**0.88%**
HST		13%		$ 35.05	13%		$ 35.36	$ 0.31	0.88%
Total Bill (including HST)				$ 304.70			$ 307.38	$ 2.68	0.88%
Ontario Clean Energy Benefit [1]				-$ 30.47			-$ 30.74	-$ 0.27	0.89%
Total Bill on RPP (including OCEB)				**$ 274.23**			**$ 276.64**	**$ 2.41**	**0.88%**

Loss Factor (%) 4.68% (Current) 4.81% (Proposed)

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 1,000 kWh

Charge	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 33.35	1	$ 33.35	$ 0.08	0.24%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	1,000	$ 10.10	$ 0.0101	1,000	$ 10.10	$ -	0.00%
Sub-Total A (excluding pass through)				$ 50.39			$ 47.69	**-$ 2.70**	**-5.36%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0007	1,000	-$ 0.71	$ 0.59	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	1,000	-$ 0.20		1,000	$ -	$ 0.20	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0009	1,000	-$ 0.91	-$ 0.91	
Low Voltage Service Charge	per kWh	$ 0.0010	1,000	$ 1.00	$ 0.0015	1,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.61**			**$ 52.39**	**-$ 2.21**	**-4.05%**
RTSR - Network	per kWh	$ 0.0060	1047	$ 6.28	$ 0.0069	1048	$ 7.21	$ 0.93	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	1047	$ 3.25	$ 0.0035	1048	$ 3.72	$ 0.47	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.13**			**$ 63.32**	**-$ 0.81**	**-1.26%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 161.17**			**$ 160.36**	**-$ 0.80**	**-0.50%**
HST		13%		$ 20.95	13%		$ 20.85	-$ 0.10	-0.50%
Total Bill (including HST)				$ 182.12			$ 181.21	-$ 0.91	-0.50%
Ontario Clean Energy Benefit [1]				-$ 18.21			-$ 18.12	$ 0.09	-0.49%
Total Bill on TOU (including OCEB)				**$ 163.91**			**$ 163.09**	**-$ 0.82**	**-0.50%**
Total Bill on RPP (before Taxes)				**$ 157.45**			**$ 156.64**	**-$ 0.80**	**-0.51%**
HST		13%		$ 20.47	13%		$ 20.36	-$ 0.10	-0.51%
Total Bill (including HST)				$ 177.91			$ 177.01	-$ 0.91	-0.51%
Ontario Clean Energy Benefit [1]				-$ 17.79			-$ 17.70	$ 0.09	-0.51%
Total Bill on RPP (including OCEB)				**$ 160.12**			**$ 159.31**	**-$ 0.82**	**-0.51%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 2,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

Charge	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 33.35	1	$ 33.35	$ 0.08	0.24%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	2,000	$ 20.20	$ 0.0101	2,000	$ 20.20	$ -	0.00%
Sub-Total A (excluding pass through)				$ 60.49			$ 57.79	**-$ 2.70**	**-4.46%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0007	2,000	-$ 1.43	$ 1.17	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0009	2,000	-$ 1.82	-$ 1.82	
Low Voltage Service Charge	per kWh	$ 0.0010	2,000	$ 2.00	$ 0.0015	2,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 68.13**			**$ 66.41**	**-$ 1.73**	**-2.53%**
RTSR - Network	per kWh	$ 0.0060	2094	$ 12.56	$ 0.0069	2096	$ 14.42	$ 1.86	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	2094	$ 6.49	$ 0.0035	2096	$ 7.44	$ 0.95	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 87.19**			**$ 88.27**	**$ 1.08**	**1.24%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 281.00**			**$ 282.09**	**$ 1.09**	**0.39%**
HST		13%		$ 36.53	13%		$ 36.67	$ 0.14	0.39%
Total Bill (including HST)				$ 317.53			$ 318.77	$ 1.24	0.39%
Ontario Clean Energy Benefit [1]				-$ 31.75			-$ 31.88	-$ 0.13	0.41%
Total Bill on TOU (including OCEB)				**$ 285.78**			**$ 286.89**	**$ 1.11**	**0.39%**
Total Bill on RPP (before Taxes)				**$ 281.36**			**$ 282.45**	**$ 1.09**	**0.39%**
HST		13%		$ 36.58	13%		$ 36.72	$ 0.14	0.39%
Total Bill (including HST)				$ 317.94			$ 319.17	$ 1.24	0.39%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 31.92	-$ 0.13	0.41%
Total Bill on RPP (including OCEB)				**$ 286.15**			**$ 287.25**	**$ 1.11**	**0.39%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **GS < 50kW**

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption 5,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 33.35	1	$ 33.35	$ 0.08	0.24%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	5,000	$ 50.50	$ 0.0101	5,000	$ 50.50	$ -	0.00%
Sub-Total A (excluding pass through)				$ 90.79			$ 88.09	**-$ 2.70**	**-2.97%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	5,000	-$ 6.50	-$ 0.0007	5,000	-$ 3.57	$ 2.93	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	5,000	-$ 1.00		5,000	$ -	$ 1.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		5,000	$ -	-$ 0.0009	5,000	-$ 4.54	-$ 4.54	
Low Voltage Service Charge	per kWh	$ 0.0010	5,000	$ 5.00	$ 0.0015	5,000	$ 7.50	$ 2.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	234.00	$ 19.64	$ 0.0839	240.50	$ 20.18	$ 0.55	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 108.72**			**$ 108.45**	**-$ 0.27**	**-0.25%**
RTSR - Network	per kWh	$ 0.0060	5234	$ 31.40	$ 0.0069	5241	$ 36.05	$ 4.65	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	5234	$ 16.23	$ 0.0035	5241	$ 18.59	$ 2.36	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 156.35**			**$ 163.09**	**$ 6.75**	**4.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	5234	$ 23.03	$ 0.0044	5241	$ 23.06	$ 0.03	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	5234	$ 6.28	$ 0.0012	5241	$ 6.29	$ 0.01	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5000	$ 35.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	3200	$ 214.40	$ 0.0670	3200	$ 214.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	900	$ 93.60	$ 0.1040	900	$ 93.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	900	$ 111.60	$ 0.1240	900	$ 111.60	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	4400	$ 387.20	$ 0.0880	4400	$ 387.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 640.51**			**$ 647.29**	**$ 6.78**	**1.06%**
HST		13%		$ 83.27	13%		$ 84.15	$ 0.88	1.06%
Total Bill (including HST)				$ 723.77			$ 731.44	$ 7.67	1.06%
Ontario Clean Energy Benefit [1]				-$ 72.38			-$ 73.14	-$ 0.76	1.05%
Total Bill on TOU (including OCEB)				**$ 651.39**			**$ 658.30**	**$ 6.91**	**1.06%**
Total Bill on RPP (before Taxes)				**$ 653.11**			**$ 659.89**	**$ 6.78**	**1.04%**
HST		13%		$ 84.90	13%		$ 85.79	$ 0.88	1.04%
Total Bill (including HST)				$ 738.01			$ 745.68	$ 7.67	1.04%
Ontario Clean Energy Benefit [1]				-$ 73.80			-$ 74.57	-$ 0.77	1.04%
Total Bill on RPP (including OCEB)				**$ 664.21**			**$ 671.11**	**$ 6.90**	**1.04%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **GS < 50kW**

TOU / non-TOU: TOU

Consumption 10,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 33.35	1	$ 33.35	$ 0.08	0.24%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	10,000	$ 101.00	$ 0.0101	10,000	$ 101.00	$ -	0.00%
Sub-Total A (excluding pass through)				$ 141.29			$ 138.59	**-$ 2.70**	**-1.91%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	10,000	-$ 13.00	-$ 0.0007	10,000	-$ 7.15	$ 5.85	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	10,000	-$ 2.00		10,000	$ -	$ 2.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		10,000	$ -	-$ 0.0009	10,000	-$ 9.08	-$ 9.08	
Low Voltage Service Charge	per kWh	$ 0.0010	10,000	$ 10.00	$ 0.0015	10,000	$ 15.00	$ 5.00	50.00%
Line Losses on Cost of Power	Monthly	$ 0.0839	468.00	$ 39.27	$ 0.0839	481.00	$ 40.37	$ 1.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 176.35**			**$ 178.52**	**$ 2.16**	**1.23%**
RTSR - Network	per kWh	$ 0.0060	10468	$ 62.81	$ 0.0069	10481	$ 72.11	$ 9.30	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	10468	$ 32.45	$ 0.0035	10481	$ 37.18	$ 4.73	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 271.61**			**$ 287.81**	**$ 16.20**	**5.96%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	10468	$ 46.06	$ 0.0044	10481	$ 46.12	$ 0.06	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	10468	$ 12.56	$ 0.0012	10481	$ 12.58	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10000	$ 70.00	$ 0.0070	10000	$ 70.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	6400	$ 428.80	$ 0.0670	6400	$ 428.80	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	1800	$ 187.20	$ 0.1040	1800	$ 187.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	1800	$ 223.20	$ 0.1240	1800	$ 223.20	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	9400	$ 827.20	$ 0.0880	9400	$ 827.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,239.68**			**$ 1,255.95**	**$ 16.27**	**1.31%**
HST		13%		$ 161.16	13%		$ 163.27	$ 2.11	1.31%
Total Bill (including HST)				$ 1,400.84			$ 1,419.23	$ 18.38	1.31%
Ontario Clean Energy Benefit [1]				-$ 140.08			-$ 141.92	-$ 1.84	1.31%
Total Bill on TOU (including OCEB)				**$ 1,260.76**			**$ 1,277.31**	**$ 16.54**	**1.31%**
Total Bill on RPP (before Taxes)				**$ 1,272.68**			**$ 1,288.95**	**$ 16.27**	**1.28%**
HST		13%		$ 165.45	13%		$ 167.56	$ 2.11	1.28%
Total Bill (including HST)				$ 1,438.13			$ 1,456.52	$ 18.38	1.28%
Ontario Clean Energy Benefit [1]				-$ 143.81			-$ 145.65	-$ 1.84	1.28%
Total Bill on RPP (including OCEB)				**$ 1,294.32**			**$ 1,310.87**	**$ 16.54**	**1.28%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 15,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 33.35	1	$ 33.35	$ 0.08	0.24%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	15,000	$ 151.50	$ 0.0101	15,000	$ 151.50	$ -	0.00%
Sub-Total A (excluding pass through)				$ 191.79			$ 189.09	**-$ 2.70**	**-1.41%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	15,000	-$ 19.50	-$ 0.0007	15,000	-$ 10.72	$ 8.78	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	15,000	-$ 3.00		15,000	$ -	$ 3.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		15,000	$ -	$ 0.3259	15,000	$ 4,888.55	$ 4,888.55	
Low Voltage Service Charge	per kWh	$ 0.0010	15,000	$ 15.00	$ 0.0015	15,000	$ 22.50	$ 7.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	702.00	$ 58.91	$ 0.0839	721.50	$ 60.55	$ 1.64	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 243.99**			**$ 5,150.76**	**$ 4,906.76**	**2011.04%**
RTSR - Network	per kWh	$ 0.0060	15702	$ 94.21	$ 0.0069	15722	$ 108.16	$ 13.95	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	15702	$ 48.68	$ 0.0035	15722	$ 55.77	$ 7.09	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 386.88**			**$ 5,314.69**	**$ 4,927.81**	**1273.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	9600	$ 643.20	$ 0.0670	9600	$ 643.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	2700	$ 280.80	$ 0.1040	2700	$ 280.80	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	2700	$ 334.80	$ 0.1240	2700	$ 334.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	14400	$ 1,267.20	$ 0.0880	14400	$ 1,267.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,838.86**			**$ 6,766.78**	**$ 4,927.92**	**267.99%**
HST		13%		$ 239.05	13%		$ 879.68	$ 640.63	267.99%
Total Bill (including HST)				$ 2,077.91			$ 7,646.46	$ 5,568.55	267.99%
Ontario Clean Energy Benefit [1]				-$ 207.79			-$ 764.65	-$ 556.86	267.99%
Total Bill on TOU (including OCEB)				**$ 1,870.12**			**$ 6,881.81**	**$ 5,011.69**	**267.99%**
Total Bill on RPP (before Taxes)				**$ 1,892.26**			**$ 6,820.18**	**$ 4,927.92**	**260.42%**
HST		13%		$ 245.99	13%		$ 886.62	$ 640.63	260.42%
Total Bill (including HST)				$ 2,138.26			$ 7,706.81	$ 5,568.55	260.42%
Ontario Clean Energy Benefit [1]				-$ 213.83			-$ 770.68	-$ 556.85	260.42%
Total Bill on RPP (including OCEB)				**$ 1,924.43**			**$ 6,936.13**	**$ 5,011.70**	**260.43%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

		Current Board-Approved			Proposed			Impact	
Consumption	60 kW / 15,000 kWh	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
	Charge Unit								
Monthly Service Charge	Monthly	$ 186.2300	1	$ 186.23	$ 186.67	1	$ 186.67	$ 0.44	0.24%
Distribution Volumetric Rate	per kW	$ 2.1927	60	$ 131.56	$ 2.1972	60	$ 131.83	$ 0.27	0.21%
Sub-Total A (excluding pass through)				$ 317.79			$ 318.50	**$ 0.71**	**0.22%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	60	-$ 30.32	-$ 0.3588	60	-$ 21.53	$ 8.79	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	60	-$ 1.73		60	$ -	$ 1.73	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		60	$ -	-$ 0.1230	60	-$ 7.38	-$ 7.38	
Low Voltage Service Charge	per kW	$ 0.3999	60	$ 23.99	$ 0.5965	60	$ 35.79	$ 11.80	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	702.00	$ 61.78	$ 0.0839	721.50	$ 60.55	-$ 1.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 371.51**			**$ 385.93**	**$ 14.42**	**3.88%**
RTSR - Network	per kW	$ 2.4552	60	$ 147.31	$ 2.8153	60	$ 168.92	$ 21.61	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	60	$ 73.70	$ 1.4057	60	$ 84.34	$ 10.64	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 592.53**			**$ 639.19**	**$ 46.66**	**7.88%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 785.71**			**$ 832.48**	**$ 46.77**	**5.95%**
HST		13%		$ 102.14	13%		$ 108.22	$ 6.08	5.95%
Total Bill (including HST)				$ 887.85			$ 940.70	$ 52.85	5.95%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 94.07	-$ 5.29	5.96%
Total Bill on TOU (including OCEB)				**$ 799.07**			**$ 846.63**	**$ 47.56**	**5.95%**
Total Bill on RPP (before Taxes)				**$ 785.71**			**$ 832.48**	**$ 46.77**	**5.95%**
HST		13%		$ 102.14	13%		$ 108.22	$ 6.08	5.95%
Total Bill (including HST)				$ 887.85			$ 940.70	$ 52.85	5.95%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 94.07	-$ 5.29	5.96%
Total Bill on RPP (including OCEB)				**$ 799.07**			**$ 846.63**	**$ 47.56**	**5.95%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

		Current Board-Approved			Proposed			Impact	
Consumption	100 kW / 45,000 kWh	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
	Charge Unit								
Monthly Service Charge	Monthly	$ 186.2300	1	$ 186.23	$ 186.67	1	$ 186.67	$ 0.44	0.24%
Distribution Volumetric Rate	per kW	$ 2.1927	100	$ 219.27	$ 2.1972	100	$ 219.72	$ 0.45	0.21%
Sub-Total A (excluding pass through)				$ 405.50			$ 406.39	**$ 0.89**	**0.22%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	100	-$ 50.54	-$ 0.3588	100	-$ 35.88	$ 14.66	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	100	-$ 2.88		100	$ -	$ 2.88	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		100	$ -	-$ 0.1230	100	-$ 12.30	-$ 12.30	
Low Voltage Service Charge	per kW	$ 0.3999	100	$ 39.99	$ 0.5965	100	$ 59.65	$ 19.66	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	2,106.00	$ 185.33	$ 0.0839	2,164.50	$ 181.64	-$ 3.68	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 577.40**			**$ 599.50**	**$ 22.10**	**3.83%**
RTSR - Network	per kW	$ 2.4552	100	$ 245.52	$ 2.8153	100	$ 281.53	$ 36.01	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	100	$ 122.84	$ 1.4057	100	$ 140.57	$ 17.73	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 945.76**			**$ 1,021.60**	**$ 75.84**	**8.02%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	47106	$ 207.27	$ 0.0044	47165	$ 207.52	$ 0.26	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	47106	$ 56.53	$ 0.0012	47165	$ 56.60	$ 0.07	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	45000	$ 315.00	$ 0.0070	45000	$ 315.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 1,524.80**			**$ 1,600.97**	**$ 76.17**	**5.00%**
HST		13%		$ 198.22	13%		$ 208.13	$ 9.90	5.00%
Total Bill (including HST)				$ 1,723.03			$ 1,809.10	$ 86.07	5.00%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 180.91	-$ 8.61	5.00%
Total Bill on TOU (including OCEB)				**$ 1,550.73**			**$ 1,628.19**	**$ 77.46**	**5.00%**
Total Bill on RPP (before Taxes)				**$ 1,524.80**			**$ 1,600.97**	**$ 76.17**	**5.00%**
HST		13%		$ 198.22	13%		$ 208.13	$ 9.90	5.00%
Total Bill (including HST)				$ 1,723.03			$ 1,809.10	$ 86.07	5.00%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 180.91	-$ 8.61	5.00%
Total Bill on RPP (including OCEB)				**$ 1,550.73**			**$ 1,628.19**	**$ 77.46**	**5.00%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 500 kW; 200,000 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	$ 186.2300	1	$ 186.23	$ 186.67	1	$ 186.67	$ 0.44	0.24%
Distribution Volumetric Rate	per kW	$ 2.1927	500	$ 1,096.35	$ 2.1972	500	$ 1,098.60	$ 2.25	0.21%
Sub-Total A (excluding pass through)				$ 1,282.58			$ 1,285.27	**$ 2.69**	**0.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	500	-$ 252.70	-$ 0.3588	500	-$ 179.42	$ 73.28	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	500	-$ 14.40		500	$ -	$ 14.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		500	$ -	-$ 0.1230	500	-$ 61.50	-$ 61.50	
Low Voltage Service Charge	per kW	$ 0.3999	500	$ 199.95	$ 0.5965	500	$ 298.25	$ 98.30	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	9,360.00	$ 823.68	$ 0.0839	9,620.00	$ 807.31	-$ 16.37	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,039.11**			**$ 2,149.91**	**$ 110.80**	**5.43%**
RTSR - Network	per kW	$ 2.4552	500	$ 1,227.60	$ 2.8153	500	$ 1,407.66	$ 180.06	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	500	$ 614.20	$ 1.4057	500	$ 702.83	$ 88.63	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,880.91**			**$ 4,260.40**	**$ 379.49**	**9.78%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	209360	$ 921.18	$ 0.0044	209620	$ 922.33	$ 1.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	209360	$ 251.23	$ 0.0012	209620	$ 251.54	$ 0.31	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	200000	$ 1,400.00	$ 0.0070	200000	$ 1,400.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 6,453.58**			**$ 6,834.52**	**$ 380.95**	**5.90%**
HST		13%		$ 838.96	13%		$ 888.49	$ 49.52	5.90%
Total Bill (including HST)				$ 7,292.54			$ 7,723.01	$ 430.47	5.90%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 772.30	-$ 43.05	5.90%
Total Bill on TOU (including OCEB)				**$ 6,563.29**			**$ 6,950.71**	**$ 387.42**	**5.90%**
Total Bill on RPP (before Taxes)				**$ 6,453.58**			**$ 6,834.52**	**$ 380.95**	**5.90%**
HST		13%		$ 838.96	13%		$ 888.49	$ 49.52	5.90%
Total Bill (including HST)				$ 7,292.54			$ 7,723.01	$ 430.47	5.90%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 772.30	-$ 43.05	5.90%
Total Bill on RPP (including OCEB)				**$ 6,563.29**			**$ 6,950.71**	**$ 387.42**	**5.90%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 1,000 kW; 500,000 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	$ 186.2300	1	$ 186.23	$ 186.67	1	$ 186.67	$ 0.44	0.24%
Distribution Volumetric Rate	per kW	$ 2.1927	1,000	$ 2,192.70	$ 2.1972	1,000	$ 2,197.20	$ 4.50	0.21%
Sub-Total A (excluding pass through)				$ 2,378.93			$ 2,383.87	**$ 4.94**	**0.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	1,000	-$ 505.40	-$ 0.3588	1,000	-$ 358.84	$ 146.56	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	1,000	-$ 28.80		1,000	$ -	$ 28.80	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1,000	$ -	-$ 0.1230	1,000	-$ 123.00	-$ 123.00	
Low Voltage Service Charge	per kW	$ 0.3999	1,000	$ 399.90	$ 0.5965	1,000	$ 596.50	$ 196.60	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	23,400.00	$ 2,059.20	$ 0.0839	24,050.00	$ 2,018.28	-$ 40.92	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,303.83**			**$ 4,516.81**	**$ 212.98**	**4.95%**
RTSR - Network	per kW	$ 2.4552	1,000	$ 2,455.20	$ 2.8153	1000	$ 2,815.32	$ 360.12	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	1,000	$ 1,228.40	$ 1.4057	1000	$ 1,405.66	$ 177.26	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,987.43**			**$ 8,737.79**	**$ 750.36**	**9.39%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523400	$ 2,302.96	$ 0.0044	524050	$ 2,305.82	$ 2.86	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523400	$ 628.08	$ 0.0012	524050	$ 628.86	$ 0.78	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$14,418.72**			**$15,172.72**	**$ 754.00**	**5.23%**
HST		13%		$ 1,874.43	13%		$ 1,972.45	$ 98.02	5.23%
Total Bill (including HST)				$16,293.15			$17,145.17	$ 852.02	5.23%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,714.52	-$ 85.20	5.23%
Total Bill on TOU (including OCEB)				**$14,663.83**			**$15,430.65**	**$ 766.82**	**5.23%**
Total Bill on RPP (before Taxes)				**$14,418.72**			**$15,172.72**	**$ 754.00**	**5.23%**
HST		13%		$ 1,874.43	13%		$ 1,972.45	$ 98.02	5.23%
Total Bill (including HST)				$16,293.15			$17,145.17	$ 852.02	5.23%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,714.52	-$ 85.20	5.23%
Total Bill on RPP (including OCEB)				**$14,663.83**			**$15,430.65**	**$ 766.82**	**5.23%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**3**	
Consumption	**215**	**kWh**
	1	kW

	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	$ 1.5100	3	$ 4.53	$ 1.51	3	$ 4.53	$ -	0.00%
Distribution Volumetric Rate	per kW	$ 8.3561	1	$ 4.76	$ 8.3759	1	$ 4.77	$ 0.01	0.24%
Sub-Total A (excluding pass through)				$ 9.29			$ 9.30	**$ 0.01**	**0.12%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	1	-$ 0.26	$ 3.0122	1	$ 1.72	$ 1.97	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	1	-$ 0.08		1	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.4079	1	-$ 0.23	-$ 0.23	
Low Voltage Service Charge	per kW	$ 0.3091	1	$ 0.18	$ 0.4611	1	$ 0.26	$ 0.09	49.18%
Line Losses on Cost of Power	per kWh	$ 0.0750	10.04	$ 0.75	$ 0.0839	10.32	$ 0.87	$ 0.11	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 9.89**			**$ 11.92**	**$ 2.03**	**20.52%**
RTSR - Network	per kW	$ 1.8516	1	$ 1.06	$ 2.1232	1	$ 1.21	$ 0.15	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	1	$ 0.54	$ 1.0865	1	$ 0.62	$ 0.08	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.49**			**$ 13.75**	**$ 2.26**	**19.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	225	$ 0.99	$ 0.0044	225	$ 0.99	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	225	$ 0.27	$ 0.0012	225	$ 0.27	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	215	$ 1.50	$ 0.0070	215	$ 1.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	137	$ 9.20	$ 0.0670	137	$ 9.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	39	$ 4.02	$ 0.1040	39	$ 4.02	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	39	$ 4.79	$ 0.1240	39	$ 4.79	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	215	$ 16.13	$ 0.0750	215	$ 16.13	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.50**			**$ 34.77**	**$ 2.26**	**6.96%**
HST		13%		$ 4.23	13%		$ 4.52	$ 0.29	6.96%
Total Bill (including HST)				$ 36.73			$ 39.29	$ 2.56	6.96%
Ontario Clean Energy Benefit [1]				-$ 3.67			-$ 3.93	-$ 0.26	7.08%
Total Bill on TOU (including OCEB)				**$ 33.06**			**$ 35.36**	**$ 2.30**	**6.95%**
Total Bill on RPP (before Taxes)				**$ 30.62**			**$ 32.88**	**$ 2.26**	**7.39%**
HST		13%		$ 3.98	13%		$ 4.27	$ 0.29	7.39%
Total Bill (including HST)				$ 34.60			$ 37.16	$ 2.56	7.39%
Ontario Clean Energy Benefit [1]				-$ 3.46			-$ 3.72	-$ 0.26	7.51%
Total Bill on RPP (including OCEB)				**$ 31.14**			**$ 33.44**	**$ 2.30**	**7.38%**

	Current	Proposed
Loss Factor (%)	4.68%	4.81%

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**2,568**	
Consumption	**132,737**	**kWh**
	353	kW

	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	$ 1.5100	2,568	$ 3,877.68	$ 1.51	2,568	$ 3,877.68	$ -	0.00%
Distribution Volumetric Rate	per kW	$ 8.3561	353	$ 2,946.19	$ 8.3759	353	$ 2,953.17	$ 6.98	0.24%
Sub-Total A (excluding pass through)				$ 6,823.87			$ 6,830.85	**$ 6.98**	**0.10%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	353	-$ 158.38	$ 3.0122	353	$ 1,062.04	$ 1,220.42	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	353	-$ 48.16		353	$ -	$ 48.16	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		353	$ -	-$ 0.4079	353	-$ 143.80	-$ 143.80	
Low Voltage Service Charge	per kW	$ 0.3091	353	$ 108.98	$ 0.4611	353	$ 162.57	$ 53.59	49.18%
Line Losses on Cost of Power	per kWh	$ -	6,212.11	$ -	$ 0.0839	6,384.67	$ 535.80	$ 535.80	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,726.73**			**$ 8,447.88**	**$ 1,721.15**	**25.59%**
RTSR - Network	per kW	$ 1.8516	353	$ 652.84	$ 2.1232	353	$ 748.59	$ 95.76	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	353	$ 334.77	$ 1.0865	353	$ 383.08	$ 48.31	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,714.34**			**$ 9,579.55**	**$ 1,865.21**	**24.18%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	138949	$ 611.38	$ 0.0044	139122	$ 612.14	$ 0.76	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	138949	$ 166.74	$ 0.0012	139122	$ 166.95	$ 0.21	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	132737	$ 929.16	$ 0.0070	132737	$ 929.16	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	84952	$ 5,691.78	$ 0.0670	84952	$ 5,691.78	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	23893	$ 2,484.84	$ 0.1040	23893	$ 2,484.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	23893	$ 2,962.70	$ 0.1240	23893	$ 2,962.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	132137	$11,628.08	$ 0.0880	132137	$11,628.08	$ -	0.00%
Total Bill on TOU (before Taxes)				**$20,561.18**			**$22,427.36**	**$ 1,866.18**	**9.08%**
HST		13%		$ 2,672.95	13%		$ 2,915.56	$ 242.60	9.08%
Total Bill (including HST)				$23,234.14			$25,342.92	$ 2,108.78	9.08%
Ontario Clean Energy Benefit [1]				-$ 2,323.41			-$ 2,534.29	-$ 210.88	9.08%
Total Bill on TOU (including OCEB)				**$20,910.73**			**$22,808.63**	**$ 1,897.90**	**9.08%**
Total Bill on RPP (before Taxes)				**$21,094.95**			**$22,961.13**	**$ 1,866.18**	**8.85%**
HST		13%		$ 2,742.34	13%		$ 2,984.95	$ 242.60	8.85%
Total Bill (including HST)				$23,837.29			$25,946.08	$ 2,108.78	8.85%
Ontario Clean Energy Benefit [1]				-$ 2,383.73			-$ 2,594.61	-$ 210.88	8.85%
Total Bill on RPP (including OCEB)				**$21,453.56**			**$23,351.47**	**$ 1,897.90**	**8.85%**

	Current	Proposed
Loss Factor (%)	4.68%	4.81%

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**1**	
Consumption	**180**	**kWh**
	1	kW

	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	$ 3.3200	1	$ 3.32	$ 3.33	1	$ 3.33	$ 0.01	0.30%
Distribution Volumetric Rate	per kW	$ 12.9468	1	$ 12.95	$ 12.9774	1	$ 12.98	$ 0.03	0.24%
Sub-Total A (excluding pass through)				$ 16.27			$ 16.31	**$ 0.04**	**0.25%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	1	-$ 0.28	$ 2.5804	1	$ 1.47	$ 1.75	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	1	-$ 0.14		1	$ -	$ 0.14	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.7715	1	-$ 0.44	-$ 0.44	
Low Voltage Service Charge	per kW	$ 0.3156	1	$ 0.18	$ 0.4709	1	$ 0.27	$ 0.09	49.21%
Line Losses on Cost of Power	per kWh	$ 0.0750	8.42	$ 0.63	$ 0.0839	8.66	$ 0.73	$ 0.09	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 16.66**			**$ 18.33**	**$ 1.67**	**10.02%**
RTSR - Network	per kW	$ 1.8609	1	$ 1.86	$ 2.1339	1	$ 2.13	$ 0.27	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	1	$ 0.97	$ 1.1095	1	$ 1.11	$ 0.14	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19.49**			**$ 21.58**	**$ 2.08**	**10.68%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	188	$ 0.83	$ 0.0044	189	$ 0.83	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	188	$ 0.23	$ 0.0012	189	$ 0.23	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	180	$ 1.26	$ 0.0070	180	$ 1.26	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	115	$ 7.72	$ 0.0670	115	$ 7.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	32	$ 3.37	$ 0.1040	32	$ 3.37	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	32	$ 4.02	$ 0.1240	32	$ 4.02	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	180	$ 13.50	$ 0.0750	180	$ 13.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 37.16**			**$ 39.25**	**$ 2.08**	**5.61%**
HST		13%		$ 4.83	13%		$ 5.10	$ 0.27	5.61%
Total Bill (including HST)				$ 42.00			$ 44.35	$ 2.35	5.61%
Ontario Clean Energy Benefit [1]				-$ 4.20			-$ 4.44	-$ 0.24	5.71%
Total Bill on TOU (including OCEB)				**$ 37.80**			**$ 39.91**	**$ 2.11**	**5.60%**
Total Bill on RPP (before Taxes)				**$ 35.56**			**$ 37.64**	**$ 2.08**	**5.86%**
HST		13%		$ 4.62	13%		$ 4.89	$ 0.27	5.86%
Total Bill (including HST)				$ 40.18			$ 42.54	$ 2.35	5.86%
Ontario Clean Energy Benefit [1]				-$ 4.02			-$ 4.25	-$ 0.23	5.72%
Total Bill on RPP (including OCEB)				**$ 36.16**			**$ 38.29**	**$ 2.12**	**5.88%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**30**	
Consumption	**2,780**	**kWh**
	7	kW

	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	$ 3.3200	30	$ 99.60	$ 3.33	30	$ 99.90	$ 0.30	0.30%
Distribution Volumetric Rate	per kW	$ 12.9468	7	$ 94.19	$ 12.9774	7	$ 94.41	$ 0.22	0.24%
Sub-Total A (excluding pass through)				$ 193.79			$ 194.31	**$ 0.52**	**0.27%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	7	-$ 3.52	$ 2.5804	7	$ 18.77	$ 22.29	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	7	-$ 1.78		7	$ -	$ 1.78	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		7	$ -	-$ 0.7715	7	-$ 5.61	-$ 5.61	
Low Voltage Service Charge	per kW	$ 0.3156	7	$ 2.30	$ 0.4709	7	$ 3.43	$ 1.13	49.21%
Line Losses on Cost of Power	per kWh	$ 0.0880	130.10	$ 11.45	$ 0.0839	133.72	$ 11.22	-$ 0.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 202.24**			**$ 222.12**	**$ 19.88**	**9.83%**
RTSR - Network	per kW	$ 1.8609	7	$ 13.54	$ 2.1339	7	$ 15.52	$ 1.99	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	7	$ 7.05	$ 1.1095	7	$ 8.07	$ 1.02	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 222.83**			**$ 245.71**	**$ 22.88**	**10.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2910	$ 12.80	$ 0.0044	2914	$ 12.82	$ 0.02	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2910	$ 3.49	$ 0.0012	2914	$ 3.50	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2780	$ 19.46	$ 0.0070	2780	$ 19.46	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1779	$ 119.21	$ 0.0670	1779	$ 119.21	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	500	$ 52.04	$ 0.1040	500	$ 52.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	500	$ 62.05	$ 0.1240	500	$ 62.05	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	2180	$ 191.84	$ 0.0880	2180	$ 191.84	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 492.14**			**$ 515.04**	**$ 22.90**	**4.65%**
HST		13%		$ 63.98	13%		$ 66.95	$ 2.98	4.65%
Total Bill (including HST)				$ 556.11			$ 581.99	$ 25.88	4.65%
Ontario Clean Energy Benefit [1]				-$ 55.61			-$ 58.20	-$ 2.59	4.66%
Total Bill on TOU (including OCEB)				**$ 500.50**			**$ 523.79**	**$ 23.29**	**4.65%**
Total Bill on RPP (before Taxes)				**$ 495.68**			**$ 518.58**	**$ 22.90**	**4.62%**
HST		13%		$ 64.44	13%		$ 67.42	$ 2.98	4.62%
Total Bill (including HST)				$ 560.12			$ 586.00	$ 25.88	4.62%
Ontario Clean Energy Benefit [1]				-$ 56.01			-$ 58.60	-$ 2.59	4.62%
Total Bill on RPP (including OCEB)				**$ 504.11**			**$ 527.40**	**$ 23.29**	**4.62%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Unmetered Scattered Load

TOU / non-TOU: non-TOU

Connections 1
Consumption 193 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	$ 6.3400	1	$ 6.34	$ 6.36	1	$ 6.36	$ 0.02	0.32%
Distribution Volumetric Rate	per kWh	$ 0.0089	193	$ 1.71	$ 0.0089	193	$ 1.71	$ -	0.00%
Sub-Total A (excluding pass through)				$ 8.05			$ 8.07	**$ 0.02**	**0.25%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	193	-$ 0.19	$ 0.0015	193	$ 0.28	$ 0.48	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	193	-$ 0.08		193	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		193	$ -	-$ 0.0017	193	-$ 0.32	-$ 0.32	
Low Voltage Service Charge	per kWh	$ 0.0010	193	$ 0.19	$ 0.0015	193	$ 0.29	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0750	9.01	$ 0.68	$ 0.0839	9.26	$ 0.78	$ 0.10	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.65**			**$ 9.10**	**$ 0.45**	**5.15%**
RTSR - Network	per kWh	$ 0.0060	202	$ 1.21	$ 0.0069	202	$ 1.39	$ 0.18	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	202	$ 0.63	$ 0.0035	202	$ 0.72	$ 0.09	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.49**			**$ 11.20**	**$ 0.72**	**6.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	202	$ 0.89	$ 0.0044	202	$ 0.89	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	202	$ 0.24	$ 0.0012	202	$ 0.24	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	193	$ 1.35	$ 0.0070	193	$ 1.35	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	123	$ 8.26	$ 0.0670	123	$ 8.26	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	35	$ 3.61	$ 0.1040	35	$ 3.61	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	35	$ 4.30	$ 0.1240	35	$ 4.30	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	193	$ 14.45	$ 0.0750	193	$ 14.45	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 29.38**			**$ 30.10**	**$ 0.72**	**2.44%**
HST		13%		$ 3.82	13%		$ 3.91	$ 0.09	2.44%
Total Bill (including HST)				$ 33.20			$ 34.01	$ 0.81	2.44%
Ontario Clean Energy Benefit [1]				-$ 3.32			-$ 3.40	-$ 0.08	2.41%
Total Bill on TOU (including OCEB)				**$ 29.88**			**$ 30.61**	**$ 0.73**	**2.45%**
Total Bill on RPP (before Taxes)				**$ 27.66**			**$ 28.38**	**$ 0.72**	**2.59%**
HST		13%		$ 3.60	13%		$ 3.69	$ 0.09	2.59%
Total Bill (including HST)				$ 31.26			$ 32.07	$ 0.81	2.59%
Ontario Clean Energy Benefit [1]				-$ 3.13			-$ 3.21	-$ 0.08	2.56%
Total Bill on RPP (including OCEB)				**$ 28.13**			**$ 28.86**	**$ 0.73**	**2.60%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Unmetered Scattered Load

TOU / non-TOU: non-TOU

Connections 58
Consumption 24,581 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	$ 6.3400	58	$ 367.72	$ 6.36	58	$ 368.88	$ 1.16	0.32%
Distribution Volumetric Rate	per kWh	$ 0.0089	24,581	$ 218.77	$ 0.0089	24,581	$ 218.77	$ -	0.00%
Sub-Total A (excluding pass through)				$ 586.49			$ 587.65	**$ 1.16**	**0.20%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	24,581	-$ 24.58	$ 0.0015	24,581	$ 36.18	$ 60.76	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	24,581	-$ 9.83		24,581	$ -	$ 9.83	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		24,581	$ -	-$ 0.0017	24,581	-$ 41.46	-$ 41.46	
Low Voltage Service Charge	per kWh	$ 0.0010	24,581	$ 24.58	$ 0.0015	24,581	$ 36.87	$ 12.29	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0880	1,150.39	$ 101.23	$ 0.0839	1,182.34	$ 99.22	-$ 2.01	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 677.89**			**$ 718.47**	**$ 40.57**	**5.99%**
RTSR - Network	per kWh	$ 0.0060	25731	$ 154.39	$ 0.0069	25763	$ 177.25	$ 22.87	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	25731	$ 79.77	$ 0.0035	25763	$ 91.39	$ 11.62	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 912.05**			**$ 987.11**	**$ 75.06**	**8.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	25731	$ 113.22	$ 0.0044	25763	$ 113.36	$ 0.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	25731	$ 30.88	$ 0.0012	25763	$ 30.92	$ 0.04	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	24581	$ 172.07	$ 0.0070	24581	$ 172.07	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	15732	$ 1,054.03	$ 0.0670	15732	$ 1,054.03	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	4425	$ 460.16	$ 0.1040	4425	$ 460.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	4425	$ 548.65	$ 0.1240	4425	$ 548.65	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	23981	$ 2,110.32	$ 0.0880	23981	$ 2,110.32	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 3,291.29**			**$ 3,366.54**	**$ 75.24**	**2.29%**
HST		13%		$ 427.87	13%		$ 437.65	$ 9.78	2.29%
Total Bill (including HST)				$ 3,719.16			$ 3,804.19	$ 85.02	2.29%
Ontario Clean Energy Benefit [1]				-$ 371.92			-$ 380.42	-$ 8.50	2.29%
Total Bill on TOU (including OCEB)				**$ 3,347.24**			**$ 3,423.77**	**$ 76.52**	**2.29%**
Total Bill on RPP (before Taxes)				**$ 3,383.78**			**$ 3,459.03**	**$ 75.24**	**2.22%**
HST		13%		$ 439.89	13%		$ 449.67	$ 9.78	2.22%
Total Bill (including HST)				$ 3,823.68			$ 3,908.70	$ 85.02	2.22%
Ontario Clean Energy Benefit [1]				-$ 382.37			-$ 390.87	-$ 8.50	2.22%
Total Bill on RPP (including OCEB)				**$ 3,441.31**			**$ 3,517.83**	**$ 76.52**	**2.22%**

Loss Factor (%) 4.68% 4.81%

ORANGEVILLE HYDRO

Appendix O -

Bill Impacts

100% All Classes

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

File Number:	EB-2013-0160
Exhibit:	8
Tab:	6
Schedule:	1
Page:	1
Date:	12-Feb-14

Appendix 2-W
Bill Impacts

Customer Class: Residential ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

TOU / non-TOU: TOU

Consumption 100 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	100	$ 1.40	$ 0.0138	100	$ 1.38	-$ 0.02	-1.43%
Sub-Total A (excluding pass through)				$ 20.50			$ 18.39	**-$ 2.11**	**-10.29%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	100	-$ 0.13	-$ 0.0002	100	-$ 0.02	$ 0.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	100	-$ 0.03		100	$ -	$ 0.03	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		100	$ -	-$ 0.0016	100	-$ 0.16	-$ 0.16	
Low Voltage Service Charge	per kWh	$ 0.0011	100	$ 0.11	$ 0.0017	100	$ 0.17	$ 0.06	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	4.68	$ 0.39	$ 0.0839	4.81	$ 0.40	$ 0.01	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.63**			**$ 19.58**	**-$ 2.06**	**-9.51%**
RTSR - Network	per kWh	$ 0.0065	105	$ 0.68	$ 0.0075	105	$ 0.78	$ 0.10	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	105	$ 0.36	$ 0.0039	105	$ 0.41	$ 0.05	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.67**			**$ 20.76**	**-$ 1.90**	**-8.40%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	105	$ 0.46	$ 0.0044	105	$ 0.46	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	105	$ 0.13	$ 0.0012	105	$ 0.13	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	64	$ 4.29	$ 0.0670	64	$ 4.29	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	18	$ 1.87	$ 0.1040	18	$ 1.87	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	18	$ 2.23	$ 0.1240	18	$ 2.23	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	100	$ 7.50	$ 0.0750	100	$ 7.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.60**			**$ 30.69**	**-$ 1.90**	**-5.84%**
HST		13%		$ 4.24	13%		$ 3.99	-$ 0.25	-5.84%
Total Bill (including HST)				$ 36.83			$ 34.68	-$ 2.15	-5.84%
Ontario Clean Energy Benefit [1]				-$ 3.68			-$ 3.47	$ 0.21	-5.71%
Total Bill on TOU (including OCEB)				**$ 33.15**			**$ 31.21**	**-$ 1.94**	**-5.85%**
Total Bill on RPP (before Taxes)				**$ 31.71**			**$ 29.80**	**-$ 1.90**	**-6.00%**
HST		13%		$ 4.12	13%		$ 3.87	-$ 0.25	-6.00%
Total Bill (including HST)				$ 35.83			$ 33.68	-$ 2.15	-6.00%
Ontario Clean Energy Benefit [1]				-$ 3.58			-$ 3.37	$ 0.21	-5.87%
Total Bill on RPP (including OCEB)				**$ 32.25**			**$ 30.31**	**-$ 1.94**	**-6.02%**

Loss Factor (%) Current: 4.68% Proposed: 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	per kWh		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	250	$ 3.50	$ 0.0138	250	$ 3.45	-$ 0.05	-1.43%
Sub-Total A (excluding pass through)				$ 22.60			$ 20.46	**-$ 2.14**	**-9.47%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	250	-$ 0.33	-$ 0.0002	250	-$ 0.05	$ 0.28	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	250	-$ 0.08		250	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		250	$ -	-$ 0.0016	250	-$ 0.40	-$ 0.40	
Low Voltage Service Charge	per kWh	$ 0.0011	250	$ 0.28	$ 0.0017	250	$ 0.43	$ 0.15	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	11.70	$ 0.98	$ 0.0839	12.03	$ 1.01	$ 0.03	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.25**			**$ 22.24**	**-$ 2.01**	**-8.28%**
RTSR - Network	per kWh	$ 0.0065	262	$ 1.70	$ 0.0075	262	$ 1.95	$ 0.25	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	262	$ 0.89	$ 0.0039	262	$ 1.02	$ 0.13	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 25.21**	**-$ 1.63**	**-6.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	262	$ 1.15	$ 0.0044	262	$ 1.15	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	262	$ 0.31	$ 0.0012	262	$ 0.31	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	160	$ 10.72	$ 0.0670	160	$ 10.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	45	$ 4.68	$ 0.1040	45	$ 4.68	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	45	$ 5.58	$ 0.1240	45	$ 5.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	250	$ 18.75	$ 0.0750	250	$ 18.75	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 51.28**			**$ 49.66**	**-$ 1.62**	**-3.17%**
HST		13%		$ 6.67	13%		$ 6.46	-$ 0.21	-3.17%
Total Bill (including HST)				$ 57.95			$ 56.11	-$ 1.84	-3.17%
Ontario Clean Energy Benefit [1]				-$ 5.80			-$ 5.61	$ 0.19	-3.28%
Total Bill on TOU (including OCEB)				**$ 52.15**			**$ 50.50**	**-$ 1.65**	**-3.15%**
Total Bill on RPP (before Taxes)				**$ 49.05**			**$ 47.43**	**-$ 1.62**	**-3.31%**
HST		13%		$ 6.38	13%		$ 6.17	-$ 0.21	-3.31%
Total Bill (including HST)				$ 55.43			$ 53.60	-$ 1.84	-3.31%
Ontario Clean Energy Benefit [1]				-$ 5.54			-$ 5.36	$ 0.18	-3.25%
Total Bill on RPP (including OCEB)				**$ 49.89**			**$ 48.24**	**-$ 1.66**	**-3.32%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 500 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	500	$ 7.00	$ 0.0138	500	$ 6.90	-$ 0.10	-1.43%
Sub-Total A (excluding pass through)				$ 26.10			$ 23.91	**-$ 2.19**	**-8.39%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	500	-$ 0.65	-$ 0.0002	500	-$ 0.09	$ 0.56	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	500	-$ 0.15		500	$ -	$ 0.15	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		500	$ -	-$ 0.0016	500	-$ 0.79	-$ 0.79	
Low Voltage Service Charge	per kWh	$ 0.0011	500	$ 0.55	$ 0.0017	500	$ 0.85	$ 0.30	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	23.40	$ 1.96	$ 0.0839	24.05	$ 2.02	$ 0.05	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.60**			**$ 26.68**	**-$ 1.92**	**-6.73%**
RTSR - Network	per kWh	$ 0.0065	523	$ 3.40	$ 0.0075	524	$ 3.91	$ 0.50	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	523	$ 1.78	$ 0.0039	524	$ 2.04	$ 0.26	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.79**			**$ 32.62**	**-$ 1.16**	**-3.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523	$ 2.30	$ 0.0044	524	$ 2.31	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523	$ 0.63	$ 0.0012	524	$ 0.63	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	320	$ 21.44	$ 0.0670	320	$ 21.44	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	90	$ 9.36	$ 0.1040	90	$ 9.36	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	90	$ 11.16	$ 0.1240	90	$ 11.16	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	500	$ 37.50	$ 0.0750	500	$ 37.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 82.43**			**$ 81.27**	**-$ 1.16**	**-1.40%**
HST		13%		$ 10.72	13%		$ 10.56	-$ 0.15	-1.40%
Total Bill (including HST)				$ 93.14			$ 91.83	-$ 1.31	-1.40%
Ontario Clean Energy Benefit [1]				-$ 9.31			-$ 9.18	$ 0.13	-1.40%
Total Bill on TOU (including OCEB)				**$ 83.83**			**$ 82.65**	**-$ 1.18**	**-1.41%**
Total Bill on RPP (before Taxes)				**$ 77.97**			**$ 76.81**	**-$ 1.16**	**-1.49%**
HST		13%		$ 10.14	13%		$ 9.99	-$ 0.15	-1.49%
Total Bill (including HST)				$ 88.10			$ 86.79	-$ 1.31	-1.49%
Ontario Clean Energy Benefit [1]				-$ 8.81			-$ 8.68	$ 0.13	-1.48%
Total Bill on RPP (including OCEB)				**$ 79.29**			**$ 78.11**	**-$ 1.18**	**-1.49%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	800	$ 11.20	$ 0.0138	800	$ 11.04	-$ 0.16	-1.43%
Sub-Total A (excluding pass through)				$ 30.30			$ 28.05	**-$ 2.25**	**-7.43%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	800	-$ 1.04	-$ 0.0002	800	-$ 0.15	$ 0.89	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		800	$ -	-$ 0.0016	800	-$ 1.27	-$ 1.27	
Low Voltage Service Charge	per kWh	$ 0.0011	800	$ 0.88	$ 0.0017	800	$ 1.36	$ 0.48	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	37.44	$ 3.14	$ 0.0839	38.48	$ 3.23	$ 0.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.83**			**$ 32.01**	**-$ 1.83**	**-5.40%**
RTSR - Network	per kWh	$ 0.0065	837	$ 5.44	$ 0.0075	838	$ 6.25	$ 0.81	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	837	$ 2.85	$ 0.0039	838	$ 3.26	$ 0.41	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.12**			**$ 41.52**	**-$ 0.60**	**-1.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	838	$ 3.69	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	838	$ 1.01	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	200	$ 17.60	$ 0.0880	200	$ 17.60	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 119.80**			**$ 119.20**	**-$ 0.60**	**-0.50%**
HST		13%		$ 15.57	13%		$ 15.50	-$ 0.08	-0.50%
Total Bill (including HST)				$ 135.37			$ 134.70	-$ 0.68	-0.50%
Ontario Clean Energy Benefit [1]				-$ 13.54			-$ 13.47	$ 0.07	-0.52%
Total Bill on TOU (including OCEB)				**$ 121.83**			**$ 121.23**	**-$ 0.61**	**-0.50%**
Total Bill on RPP (before Taxes)				**$ 115.26**			**$ 114.66**	**-$ 0.60**	**-0.52%**
HST		13%		$ 14.98	13%		$ 14.91	-$ 0.08	-0.52%
Total Bill (including HST)				$ 130.25			$ 129.57	-$ 0.68	-0.52%
Ontario Clean Energy Benefit [1]				-$ 13.02			-$ 12.96	$ 0.06	-0.46%
Total Bill on RPP (including OCEB)				**$ 117.23**			**$ 116.61**	**-$ 0.62**	**-0.53%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential ○ **May 1 - October 31** ○ **November 1 - April 30 (Select this radio button for applications filed after Oct 31**

TOU / non-TOU: TOU

Consumption 1,000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,000	$ 14.00	$ 0.0138	1,000	$ 13.80	-$ 0.20	-1.43%
Sub-Total A (excluding pass through)				$ 33.10			$ 30.81	**-$ 2.29**	**-6.92%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0002	1,000	-$ 0.19	$ 1.11	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,000	-$ 0.30		1,000	$ -	$ 0.30	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0016	1,000	-$ 1.59	-$ 1.59	
Low Voltage Service Charge	per kWh	$ 0.0011	1,000	$ 1.10	$ 0.0017	1,000	$ 1.70	$ 0.60	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.32**			**$ 35.56**	**-$ 1.76**	**-4.72%**
RTSR - Network	per kWh	$ 0.0065	1047	$ 6.80	$ 0.0075	1048	$ 7.81	$ 1.01	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1047	$ 3.56	$ 0.0039	1048	$ 4.08	$ 0.52	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 47.68**			**$ 47.45**	**-$ 0.23**	**-0.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 144.71**			**$ 144.49**	**-$ 0.23**	**-0.16%**
HST		13%		$ 18.81	13%		$ 18.78	-$ 0.03	-0.16%
Total Bill (including HST)				$ 163.53			$ 163.27	-$ 0.26	-0.16%
Ontario Clean Energy Benefit [1]				-$ 16.35			-$ 16.33	$ 0.02	-0.12%
Total Bill on TOU (including OCEB)				**$ 147.18**			**$ 146.94**	**-$ 0.24**	**-0.16%**
Total Bill on RPP (before Taxes)				**$ 140.99**			**$ 140.77**	**-$ 0.23**	**-0.16%**
HST		13%		$ 18.33	13%		$ 18.30	-$ 0.03	-0.16%
Total Bill (including HST)				$ 159.32			$ 159.07	-$ 0.26	-0.16%
Ontario Clean Energy Benefit [1]				-$ 15.93			-$ 15.91	$ 0.02	-0.13%
Total Bill on RPP (including OCEB)				**$ 143.39**			**$ 143.16**	**-$ 0.24**	**-0.16%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,500 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	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	1,500	$ 21.00	$ 0.0138	1,500	$ 20.70	-$ 0.30	-1.43%
Sub-Total A (excluding pass through)				$ 40.10			$ 37.71	**-$ 2.39**	**-5.96%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,500	-$ 1.95	-$ 0.0002	1,500	-$ 0.28	$ 1.67	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	1,500	-$ 0.45		1,500	$ -	$ 0.45	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,500	$ -	-$ 0.0016	1,500	-$ 2.38	-$ 2.38	
Low Voltage Service Charge	per kWh	$ 0.0011	1,500	$ 1.65	$ 0.0017	1,500	$ 2.55	$ 0.90	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	70.20	$ 5.89	$ 0.0839	72.15	$ 6.05	$ 0.16	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.03**			**$ 44.44**	**-$ 1.59**	**-3.46%**
RTSR - Network	per kWh	$ 0.0065	1570	$ 10.21	$ 0.0075	1572	$ 11.72	$ 1.51	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1570	$ 5.34	$ 0.0039	1572	$ 6.12	$ 0.78	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 61.58**			**$ 62.27**	**$ 0.70**	**1.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1570	$ 6.91	$ 0.0044	1572	$ 6.92	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1570	$ 1.88	$ 0.0012	1572	$ 1.89	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	960	$ 64.32	$ 0.0670	960	$ 64.32	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	270	$ 28.08	$ 0.1040	270	$ 28.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	270	$ 33.48	$ 0.1240	270	$ 33.48	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	900	$ 79.20	$ 0.0880	900	$ 79.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 207.00**			**$ 207.71**	**$ 0.71**	**0.34%**
HST		13%		$ 26.91	13%		$ 27.00	$ 0.09	0.34%
Total Bill (including HST)				$ 233.91			$ 234.71	$ 0.80	0.34%
Ontario Clean Energy Benefit [1]				-$ 23.39			-$ 23.47	-$ 0.08	0.34%
Total Bill on TOU (including OCEB)				**$ 210.52**			**$ 211.24**	**$ 0.72**	**0.34%**
Total Bill on RPP (before Taxes)				**$ 205.32**			**$ 206.03**	**$ 0.71**	**0.34%**
HST		13%		$ 26.69	13%		$ 26.78	$ 0.09	0.34%
Total Bill (including HST)				$ 232.01			$ 232.81	$ 0.80	0.34%
Ontario Clean Energy Benefit [1]				-$ 23.20			-$ 23.28	-$ 0.08	0.34%
Total Bill on RPP (including OCEB)				**$ 208.81**			**$ 209.53**	**$ 0.72**	**0.34%**

Loss Factor (%) 4.68% 4.81%

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 2,000 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	$ 16.2600	1	$ 16.26	$ 15.97	1	$ 15.97	-$ 0.29	-1.78%
Smart Meter Disposition Rider	Monthly	$ 2.8400	1	$ 2.84		1	$ -	-$ 2.84	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.0400	1	$ 1.04	$ 1.04	
Distribution Volumetric Rate	per kWh	$ 0.0140	2,000	$ 28.00	$ 0.0138	2,000	$ 27.60	-$ 0.40	-1.43%
Sub-Total A (excluding pass through)				$ 47.10			$ 44.61	**-$ 2.49**	**-5.29%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0002	2,000	-$ 0.38	$ 2.22	-85.41%
Rate Rider for Tax Change	per kWh	-$ 0.0003	2,000	-$ 0.60		2,000	$ -	$ 0.60	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0016	2,000	-$ 3.18	-$ 3.18	
Low Voltage Service Charge	per kWh	$ 0.0011	2,000	$ 2.20	$ 0.0017	2,000	$ 3.40	$ 1.20	54.55%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.74**			**$ 53.32**	**-$ 1.43**	**-2.61%**
RTSR - Network	per kWh	$ 0.0065	2094	$ 13.61	$ 0.0075	2096	$ 15.62	$ 2.02	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	2094	$ 7.12	$ 0.0039	2096	$ 8.16	$ 1.04	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 75.47**			**$ 77.10**	**$ 1.62**	**2.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 269.29**			**$ 270.92**	**$ 1.64**	**0.61%**
HST		13%		$ 35.01	13%		$ 35.22	$ 0.21	0.61%
Total Bill (including HST)				$ 304.29			$ 306.14	$ 1.85	0.61%
Ontario Clean Energy Benefit [1]				-$ 30.43			-$ 30.61	-$ 0.18	0.59%
Total Bill on TOU (including OCEB)				**$ 273.86**			**$ 275.53**	**$ 1.67**	**0.61%**
Total Bill on RPP (before Taxes)				**$ 269.65**			**$ 271.28**	**$ 1.64**	**0.61%**
HST		13%		$ 35.05	13%		$ 35.27	$ 0.21	0.61%
Total Bill (including HST)				$ 304.70			$ 306.55	$ 1.85	0.61%
Ontario Clean Energy Benefit [1]				-$ 30.47			-$ 30.66	-$ 0.19	0.62%
Total Bill on RPP (including OCEB)				**$ 274.23**			**$ 275.89**	**$ 1.66**	**0.61%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 1,000 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	$ 33.2700	1	$ 33.27	$ 28.45	1	$ 28.45	-$ 4.82	-14.49%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	1,000	$ 10.10	$ 0.0086	1,000	$ 8.60	-$ 1.50	-14.85%
Sub-Total A (excluding pass through)				$ 50.39			$ 41.29	**-$ 9.10**	**-18.06%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	1,000	-$ 1.30	-$ 0.0007	1,000	-$ 0.71	$ 0.59	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	1,000	-$ 0.20		1,000	$ -	$ 0.20	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		1,000	$ -	-$ 0.0009	1,000	-$ 0.91	-$ 0.91	
Low Voltage Service Charge	per kWh	$ 0.0010	1,000	$ 1.00	$ 0.0015	1,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	46.80	$ 3.93	$ 0.0839	48.10	$ 4.04	$ 0.11	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.61**			**$ 45.99**	**-$ 8.61**	**-15.77%**
RTSR - Network	per kWh	$ 0.0060	1047	$ 6.28	$ 0.0069	1048	$ 7.21	$ 0.93	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	1047	$ 3.25	$ 0.0035	1048	$ 3.72	$ 0.47	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.13**			**$ 56.92**	**-$ 7.21**	**-11.24%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1047	$ 4.61	$ 0.0044	1048	$ 4.61	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1047	$ 1.26	$ 0.0012	1048	$ 1.26	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	640	$ 42.88	$ 0.0670	640	$ 42.88	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	180	$ 18.72	$ 0.1040	180	$ 18.72	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	180	$ 22.32	$ 0.1240	180	$ 22.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	400	$ 35.20	$ 0.0880	400	$ 35.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 161.17**			**$ 153.96**	**-$ 7.20**	**-4.47%**
HST		13%		$ 20.95	13%		$ 20.02	-$ 0.94	-4.47%
Total Bill (including HST)				$ 182.12			$ 173.98	-$ 8.14	-4.47%
Ontario Clean Energy Benefit [1]				-$ 18.21			-$ 17.40	$ 0.81	-4.45%
Total Bill on TOU (including OCEB)				**$ 163.91**			**$ 156.58**	**-$ 7.33**	**-4.47%**
Total Bill on RPP (before Taxes)				**$ 157.45**			**$ 150.24**	**-$ 7.20**	**-4.58%**
HST		13%		$ 20.47	13%		$ 19.53	-$ 0.94	-4.58%
Total Bill (including HST)				$ 177.91			$ 169.77	-$ 8.14	-4.58%
Ontario Clean Energy Benefit [1]				-$ 17.79			-$ 16.98	$ 0.81	-4.55%
Total Bill on RPP (including OCEB)				**$ 160.12**			**$ 152.79**	**-$ 7.33**	**-4.58%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 2,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 28.45	1	$ 28.45	-$ 4.82	-14.49%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	2,000	$ 20.20	$ 0.0086	2,000	$ 17.20	-$ 3.00	-14.85%
Sub-Total A (excluding pass through)				$ 60.49			$ 49.89	**-$ 10.60**	**-17.52%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2,000	-$ 2.60	-$ 0.0007	2,000	-$ 1.43	$ 1.17	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		2,000	$ -	-$ 0.0009	2,000	-$ 1.82	-$ 1.82	
Low Voltage Service Charge	per kWh	$ 0.0010	2,000	$ 2.00	$ 0.0015	2,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	93.60	$ 7.85	$ 0.0839	96.20	$ 8.07	$ 0.22	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 68.13**			**$ 58.51**	**-$ 9.63**	**-14.13%**
RTSR - Network	per kWh	$ 0.0060	2094	$ 12.56	$ 0.0069	2096	$ 14.42	$ 1.86	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	2094	$ 6.49	$ 0.0035	2096	$ 7.44	$ 0.95	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 87.19**			**$ 80.37**	**-$ 6.82**	**-7.82%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2094	$ 9.21	$ 0.0044	2096	$ 9.22	$ 0.01	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2094	$ 2.51	$ 0.0012	2096	$ 2.52	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1400	$ 123.20	$ 0.0880	1400	$ 123.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 281.00**			**$ 274.19**	**-$ 6.81**	**-2.42%**
HST		13%		$ 36.53	13%		$ 35.65	-$ 0.88	-2.42%
Total Bill (including HST)				$ 317.53			$ 309.84	-$ 7.69	-2.42%
Ontario Clean Energy Benefit [1]				-$ 31.75			-$ 30.98	$ 0.77	-2.43%
Total Bill on TOU (including OCEB)				**$ 285.78**			**$ 278.86**	**-$ 6.92**	**-2.42%**
Total Bill on RPP (before Taxes)				**$ 281.36**			**$ 274.55**	**-$ 6.81**	**-2.42%**
HST		13%		$ 36.58	13%		$ 35.69	-$ 0.88	-2.42%
Total Bill (including HST)				$ 317.94			$ 310.25	-$ 7.69	-2.42%
Ontario Clean Energy Benefit [1]				-$ 31.79			-$ 31.02	$ 0.77	-2.42%
Total Bill on RPP (including OCEB)				**$ 286.15**			**$ 279.23**	**-$ 6.92**	**-2.42%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

May 1 - October 31

November 1 - April 30 (Select this radio button for applications filed after Oct 31

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	$ 33.2700	1	$ 33.27	$ 28.45	1	$ 28.45	-$ 4.82	-14.49%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	5,000	$ 50.50	$ 0.0086	5,000	$ 43.00	-$ 7.50	-14.85%
Sub-Total A (excluding pass through)				$ 90.79			$ 75.69	**-$ 15.10**	**-16.63%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	5,000	-$ 6.50	-$ 0.0007	5,000	-$ 3.57	$ 2.93	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	5,000	-$ 1.00		5,000	$ -	$ 1.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		5,000	$ -	-$ 0.0009	5,000	-$ 4.54	-$ 4.54	
Low Voltage Service Charge	per kWh	$ 0.0010	5,000	$ 5.00	$ 0.0015	5,000	$ 7.50	$ 2.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	234.00	$ 19.64	$ 0.0839	240.50	$ 20.18	$ 0.55	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 108.72**			**$ 96.05**	**-$ 12.67**	**-11.65%**
RTSR - Network	per kWh	$ 0.0060	5234	$ 31.40	$ 0.0069	5241	$ 36.05	$ 4.65	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	5234	$ 16.23	$ 0.0035	5241	$ 18.59	$ 2.36	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 156.35**			**$ 150.69**	**-$ 5.65**	**-3.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	5234	$ 23.03	$ 0.0044	5241	$ 23.06	$ 0.03	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	5234	$ 6.28	$ 0.0012	5241	$ 6.29	$ 0.01	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5000	$ 35.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	3200	$ 214.40	$ 0.0670	3200	$ 214.40	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	900	$ 93.60	$ 0.1040	900	$ 93.60	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	900	$ 111.60	$ 0.1240	900	$ 111.60	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	4400	$ 387.20	$ 0.0880	4400	$ 387.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 640.51**			**$ 634.89**	**-$ 5.62**	**-0.88%**
HST		13%		$ 83.27	13%		$ 82.54	-$ 0.73	-0.88%
Total Bill (including HST)				$ 723.77			$ 717.43	-$ 6.35	-0.88%
Ontario Clean Energy Benefit [1]				-$ 72.38			-$ 71.74	$ 0.64	-0.88%
Total Bill on TOU (including OCEB)				**$ 651.39**			**$ 645.69**	**-$ 5.71**	**-0.88%**
Total Bill on RPP (before Taxes)				**$ 653.11**			**$ 647.49**	**-$ 5.62**	**-0.86%**
HST		13%		$ 84.90	13%		$ 84.17	-$ 0.73	-0.86%
Total Bill (including HST)				$ 738.01			$ 731.67	-$ 6.35	-0.86%
Ontario Clean Energy Benefit [1]				-$ 73.80			-$ 73.17	$ 0.63	-0.85%
Total Bill on RPP (including OCEB)				**$ 664.21**			**$ 658.50**	**-$ 5.72**	**-0.86%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

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	$ 33.2700	1	$ 33.27	$ 28.45	1	$ 28.45	-$ 4.82	-14.49%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	10,000	$ 101.00	$ 0.0086	10,000	$ 86.00	-$ 15.00	-14.85%
Sub-Total A (excluding pass through)				$ 141.29			$ 118.69	**-$ 22.60**	**-16.00%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	10,000	-$ 13.00	-$ 0.0007	10,000	-$ 7.15	$ 5.85	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	10,000	-$ 2.00		10,000	$ -	$ 2.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		10,000	$ -	-$ 0.0009	10,000	-$ 9.08	-$ 9.08	
Low Voltage Service Charge	per kWh	$ 0.0010	10,000	$ 10.00	$ 0.0015	10,000	$ 15.00	$ 5.00	50.00%
Line Losses on Cost of Power	Monthly	$ 0.0839	468.00	$ 39.27	$ 0.0839	481.00	$ 40.37	$ 1.09	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 176.35**			**$ 158.62**	**-$ 17.74**	**-10.06%**
RTSR - Network	per kWh	$ 0.0060	10468	$ 62.81	$ 0.0069	10481	$ 72.11	$ 9.30	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	10468	$ 32.45	$ 0.0035	10481	$ 37.18	$ 4.73	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 271.61**			**$ 267.91**	**-$ 3.70**	**-1.36%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	10468	$ 46.06	$ 0.0044	10481	$ 46.12	$ 0.06	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	10468	$ 12.56	$ 0.0012	10481	$ 12.58	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10000	$ 70.00	$ 0.0070	10000	$ 70.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	6400	$ 428.80	$ 0.0670	6400	$ 428.80	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	1800	$ 187.20	$ 0.1040	1800	$ 187.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	1800	$ 223.20	$ 0.1240	1800	$ 223.20	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	9400	$ 827.20	$ 0.0880	9400	$ 827.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,239.68**			**$ 1,236.05**	**-$ 3.63**	**-0.29%**
HST		13%		$ 161.16	13%		$ 160.69	-$ 0.47	-0.29%
Total Bill (including HST)				$ 1,400.84			$ 1,396.74	-$ 4.10	-0.29%
Ontario Clean Energy Benefit [1]				-$ 140.08			-$ 139.67	$ 0.41	-0.29%
Total Bill on TOU (including OCEB)				**$ 1,260.76**			**$ 1,257.07**	**-$ 3.69**	**-0.29%**
Total Bill on RPP (before Taxes)				**$ 1,272.68**			**$ 1,269.05**	**-$ 3.63**	**-0.29%**
HST		13%		$ 165.45	13%		$ 164.98	-$ 0.47	-0.29%
Total Bill (including HST)				$ 1,438.13			$ 1,434.03	-$ 4.10	-0.29%
Ontario Clean Energy Benefit [1]				-$ 143.81			-$ 143.40	$ 0.41	-0.29%
Total Bill on RPP (including OCEB)				**$ 1,294.32**			**$ 1,290.63**	**-$ 3.69**	**-0.29%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS < 50kW

TOU / non-TOU: TOU

Consumption 15,000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 33.2700	1	$ 33.27	$ 28.45	1	$ 28.45	-$ 4.82	-14.49%
Smart Meter Disposition Rider	Monthly	$ 7.0200	1	$ 7.02		1	$ -	-$ 7.02	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 4.2400	1	$ 4.24	$ 4.24	
Distribution Volumetric Rate	per kWh	$ 0.0101	15,000	$ 151.50	$ 0.0086	15,000	$ 129.00	-$ 22.50	-14.85%
Sub-Total A (excluding pass through)				$ 191.79			$ 161.69	**-$ 30.10**	**-15.69%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	15,000	-$ 19.50	-$ 0.0007	15,000	-$ 10.72	$ 8.78	-45.04%
Rate Rider for Tax Change	per kWh	-$ 0.0002	15,000	-$ 3.00		15,000	$ -	$ 3.00	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		15,000	$ -	$ 0.3259	15,000	$ 4,888.55	$ 4,888.55	
Low Voltage Service Charge	per kWh	$ 0.0010	15,000	$ 15.00	$ 0.0015	15,000	$ 22.50	$ 7.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	702.00	$ 58.91	$ 0.0839	721.50	$ 60.55	$ 1.64	2.78%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 243.99**			**$ 5,123.36**	**$ 4,879.36**	**1999.81%**
RTSR - Network	per kWh	$ 0.0060	15702	$ 94.21	$ 0.0069	15722	$ 108.16	$ 13.95	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	15702	$ 48.68	$ 0.0035	15722	$ 55.77	$ 7.09	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 386.88**			**$ 5,287.29**	**$ 4,900.41**	**1266.65%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	9600	$ 643.20	$ 0.0670	9600	$ 643.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	2700	$ 280.80	$ 0.1040	2700	$ 280.80	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	2700	$ 334.80	$ 0.1240	2700	$ 334.80	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	14400	$ 1,267.20	$ 0.0880	14400	$ 1,267.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,838.86**			**$ 6,739.38**	**$ 4,900.52**	**266.50%**
HST		13%		$ 239.05	13%		$ 876.12	$ 637.07	266.50%
Total Bill (including HST)				$ 2,077.91			$ 7,615.50	$ 5,537.59	266.50%
Ontario Clean Energy Benefit [1]				-$ 207.79			-$ 761.55	-$ 553.76	266.50%
Total Bill on TOU (including OCEB)				**$ 1,870.12**			**$ 6,853.95**	**$ 4,983.83**	**266.50%**
Total Bill on RPP (before Taxes)				**$ 1,892.26**			**$ 6,792.78**	**$ 4,900.52**	**258.98%**
HST		13%		$ 245.99	13%		$ 883.06	$ 637.07	258.98%
Total Bill (including HST)				$ 2,138.26			$ 7,675.84	$ 5,537.59	258.98%
Ontario Clean Energy Benefit [1]				-$ 213.83			-$ 767.58	-$ 553.75	258.97%
Total Bill on RPP (including OCEB)				**$ 1,924.43**			**$ 6,908.26**	**$ 4,983.84**	**258.98%**

Loss Factor (%)	4.68%		4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 60 kW
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	$ 186.2300	1	$ 186.23	$ 225.10	1	$ 225.10	$ 38.87	20.87%
Distribution Volumetric Rate	per kW	$ 2.1927	60	$ 131.56	$ 2.5929	60	$ 155.57	$ 24.01	18.25%
Sub-Total A (excluding pass through)				$ 317.79			$ 380.67	**$ 62.88**	**19.79%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	60	-$ 30.32	-$ 0.3588	60	-$ 21.53	$ 8.79	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	60	-$ 1.73		60	$ -	$ 1.73	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		60	$ -	-$ 0.1230	60	-$ 7.38	-$ 7.38	
Low Voltage Service Charge	per kW	$ 0.3999	60	$ 23.99	$ 0.5965	60	$ 35.79	$ 11.80	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	702.00	$ 61.78	$ 0.0839	721.50	$ 60.55	-$ 1.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 371.51**			**$ 448.10**	**$ 76.59**	**20.62%**
RTSR - Network	per kW	$ 2.4552	60	$ 147.31	$ 2.8153	60	$ 168.92	$ 21.61	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	60	$ 73.70	$ 1.4057	60	$ 84.34	$ 10.64	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 592.53**			**$ 701.36**	**$ 108.83**	**18.37%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15702	$ 69.09	$ 0.0044	15722	$ 69.17	$ 0.09	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	15702	$ 18.84	$ 0.0012	15722	$ 18.87	$ 0.02	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15000	$ 105.00	$ 0.0070	15000	$ 105.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 785.71**			**$ 894.65**	**$ 108.94**	**13.87%**
HST		13%		$ 102.14	13%		$ 116.30	$ 14.16	13.87%
Total Bill (including HST)				$ 887.85			$ 1,010.96	$ 123.11	13.87%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 101.10	-$ 12.32	13.88%
Total Bill on TOU (including OCEB)				**$ 799.07**			**$ 909.86**	**$ 110.79**	**13.86%**
Total Bill on RPP (before Taxes)				**$ 785.71**			**$ 894.65**	**$ 108.94**	**13.87%**
HST		13%		$ 102.14	13%		$ 116.30	$ 14.16	13.87%
Total Bill (including HST)				$ 887.85			$ 1,010.96	$ 123.11	13.87%
Ontario Clean Energy Benefit [1]				-$ 88.78			-$ 101.10	-$ 12.32	13.88%
Total Bill on RPP (including OCEB)				**$ 799.07**			**$ 909.86**	**$ 110.79**	**13.86%**

Loss Factor (%) 4.68% | 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 100 kW
45,000 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	$ 186.2300	1	$ 186.23	$ 225.10	1	$ 225.10	$ 38.87	20.87%
Distribution Volumetric Rate	per kW	$ 2.1927	100	$ 219.27	$ 2.5929	100	$ 259.29	$ 40.02	18.25%
Sub-Total A (excluding pass through)				$ 405.50			$ 484.39	**$ 78.89**	**19.45%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	100	-$ 50.54	-$ 0.3588	100	-$ 35.88	$ 14.66	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	100	-$ 2.88		100	$ -	$ 2.88	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		100	$ -	-$ 0.1230	100	-$ 12.30	-$ 12.30	
Low Voltage Service Charge	per kW	$ 0.3999	100	$ 39.99	$ 0.5965	100	$ 59.65	$ 19.66	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	2,106.00	$ 185.33	$ 0.0839	2,164.50	$ 181.64	-$ 3.68	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 577.40**			**$ 677.50**	**$ 100.10**	**17.34%**
RTSR - Network	per kW	$ 2.4552	100	$ 245.52	$ 2.8153	100	$ 281.53	$ 36.01	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	100	$ 122.84	$ 1.4057	100	$ 140.57	$ 17.73	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 945.76**			**$ 1,099.60**	**$ 153.84**	**16.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	47106	$ 207.27	$ 0.0044	47165	$ 207.52	$ 0.26	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	47106	$ 56.53	$ 0.0012	47165	$ 56.60	$ 0.07	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	45000	$ 315.00	$ 0.0070	45000	$ 315.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 1,524.80**			**$ 1,678.97**	**$ 154.17**	**10.11%**
HST		13%		$ 198.22	13%		$ 218.27	$ 20.04	10.11%
Total Bill (including HST)				$ 1,723.03			$ 1,897.24	$ 174.21	10.11%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 189.72	-$ 17.42	10.11%
Total Bill on TOU (including OCEB)				**$ 1,550.73**			**$ 1,707.52**	**$ 156.79**	**10.11%**
Total Bill on RPP (before Taxes)				**$ 1,524.80**			**$ 1,678.97**	**$ 154.17**	**10.11%**
HST		13%		$ 198.22	13%		$ 218.27	$ 20.04	10.11%
Total Bill (including HST)				$ 1,723.03			$ 1,897.24	$ 174.21	10.11%
Ontario Clean Energy Benefit [1]				-$ 172.30			-$ 189.72	-$ 17.42	10.11%
Total Bill on RPP (including OCEB)				**$ 1,550.73**			**$ 1,707.52**	**$ 156.79**	**10.11%**

Loss Factor (%) 4.68% | 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 500 kW
200,000 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	$ 186.2300	1	$ 186.23	$ 225.10	1	$ 225.10	$ 38.87	20.87%
Distribution Volumetric Rate	per kW	$ 2.1927	500	$ 1,096.35	$ 2.5929	500	$ 1,296.45	$ 200.10	18.25%
Sub-Total A (excluding pass through)				$ 1,282.58			$ 1,521.55	**$ 238.97**	**18.63%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	500	-$ 252.70	-$ 0.3588	500	-$ 179.42	$ 73.28	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	500	-$ 14.40		500	$ -	$ 14.40	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		500	$ -	-$ 0.1230	500	-$ 61.50	-$ 61.50	
Low Voltage Service Charge	per kW	$ 0.3999	500	$ 199.95	$ 0.5965	500	$ 298.25	$ 98.30	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	9,360.00	$ 823.68	$ 0.0839	9,620.00	$ 807.31	-$ 16.37	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,039.11**			**$ 2,386.19**	**$ 347.08**	**17.02%**
RTSR - Network	per kW	$ 2.4552	500	$ 1,227.60	$ 2.8153	500	$ 1,407.66	$ 180.06	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	500	$ 614.20	$ 1.4057	500	$ 702.83	$ 88.63	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,880.91**			**$ 4,496.68**	**$ 615.77**	**15.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	209360	$ 921.18	$ 0.0044	209620	$ 922.33	$ 1.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	209360	$ 251.23	$ 0.0012	209620	$ 251.54	$ 0.31	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	200000	$ 1,400.00	$ 0.0070	200000	$ 1,400.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 6,453.58**			**$ 7,070.80**	**$ 617.23**	**9.56%**
HST		13%		$ 838.96	13%		$ 919.20	$ 80.24	9.56%
Total Bill (including HST)				$ 7,292.54			$ 7,990.01	$ 697.47	9.56%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 799.00	-$ 69.75	9.56%
Total Bill on TOU (including OCEB)				**$ 6,563.29**			**$ 7,191.01**	**$ 627.72**	**9.56%**
Total Bill on RPP (before Taxes)				**$ 6,453.58**			**$ 7,070.80**	**$ 617.23**	**9.56%**
HST		13%		$ 838.96	13%		$ 919.20	$ 80.24	9.56%
Total Bill (including HST)				$ 7,292.54			$ 7,990.01	$ 697.47	9.56%
Ontario Clean Energy Benefit [1]				-$ 729.25			-$ 799.00	-$ 69.75	9.56%
Total Bill on RPP (including OCEB)				**$ 6,563.29**			**$ 7,191.01**	**$ 627.72**	**9.56%**

Loss Factor (%) 4.68% 4.81%

Customer Class: GS > 50kW

TOU / non-TOU: non-TOU

Consumption 1,000 kW
500,000 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	$ 186.2300	1	$ 186.23	$ 225.10	1	$ 225.10	$ 38.87	20.87%
Distribution Volumetric Rate	per kW	$ 2.1927	1,000	$ 2,192.70	$ 2.5929	1,000	$ 2,592.90	$ 400.20	18.25%
Sub-Total A (excluding pass through)				$ 2,378.93			$ 2,818.00	**$ 439.07**	**18.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5054	1,000	-$ 505.40	-$ 0.3588	1,000	-$ 358.84	$ 146.56	-29.00%
Rate Rider for Tax Change	per kW	-$ 0.0288	1,000	-$ 28.80		1,000	$ -	$ 28.80	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1,000	$ -	-$ 0.1230	1,000	-$ 123.00	-$ 123.00	
Low Voltage Service Charge	per kW	$ 0.3999	1,000	$ 399.90	$ 0.5965	1,000	$ 596.50	$ 196.60	49.16%
Line Losses on Cost of Power	per kWh	$ 0.0880	23,400.00	$ 2,059.20	$ 0.0839	24,050.00	$ 2,018.28	-$ 40.92	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,303.83**			**$ 4,950.94**	**$ 647.11**	**15.04%**
RTSR - Network	per kW	$ 2.4552	1,000	$ 2,455.20	$ 2.8153	1000	$ 2,815.32	$ 360.12	14.67%
RTSR - Line and Transformation Connection	per kW	$ 1.2284	1,000	$ 1,228.40	$ 1.4057	1000	$ 1,405.66	$ 177.26	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,987.43**			**$ 9,171.92**	**$ 1,184.49**	**14.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	523400	$ 2,302.96	$ 0.0044	524050	$ 2,305.82	$ 2.86	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	523400	$ 628.08	$ 0.0012	524050	$ 628.86	$ 0.78	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	FALSE	$ -	$ 0.0670	FALSE	$ -	$ -	
TOU - Mid Peak	per kWh	$ 0.1040	FALSE	$ -	$ 0.1040	FALSE	$ -	$ -	
TOU - On Peak	per kWh	$ 0.1240	FALSE	$ -	$ 0.1240	FALSE	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	FALSE	$ -	$ 0.0750	FALSE	$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0880	FALSE	$ -	$ 0.0880	FALSE	$ -	$ -	
Total Bill on TOU (before Taxes)				**$14,418.72**			**$15,606.85**	**$ 1,188.13**	**8.24%**
HST		13%		$ 1,874.43	13%		$ 2,028.89	$ 154.46	8.24%
Total Bill (including HST)				$16,293.15			$17,635.74	$ 1,342.58	8.24%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,763.57	-$ 134.25	8.24%
Total Bill on TOU (including OCEB)				**$14,663.83**			**$15,872.17**	**$ 1,208.33**	**8.24%**
Total Bill on RPP (before Taxes)				**$14,418.72**			**$15,606.85**	**$ 1,188.13**	**8.24%**
HST		13%		$ 1,874.43	13%		$ 2,028.89	$ 154.46	8.24%
Total Bill (including HST)				$16,293.15			$17,635.74	$ 1,342.58	8.24%
Ontario Clean Energy Benefit [1]				-$ 1,629.32			-$ 1,763.57	-$ 134.25	8.24%
Total Bill on RPP (including OCEB)				**$14,663.83**			**$15,872.17**	**$ 1,208.33**	**8.24%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**3**
Consumption	**215** kWh
	1 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 1.5100	3	$ 4.53	$ 1.76	3	$ 5.28	$ 0.75	16.56%
Distribution Volumetric Rate	per kW	$ 8.3561	1	$ 4.76	$ 9.7162	1	$ 5.54	$ 0.78	16.28%
Sub-Total A (excluding pass through)				$ 9.29			$ 10.82	**$ 1.53**	**16.41%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	1	-$ 0.26	$ 3.0122	1	$ 1.72	$ 1.97	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	1	-$ 0.08		1	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.4079	1	-$ 0.23	-$ 0.23	
Low Voltage Service Charge	per kW	$ 0.3091	1	$ 0.18	$ 0.4611	1	$ 0.26	$ 0.09	49.18%
Line Losses on Cost of Power	per kWh	$ 0.0750	10.04	$ 0.75	$ 0.0839	10.32	$ 0.87	$ 0.11	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 9.89**			**$ 13.43**	**$ 3.54**	**35.83%**
RTSR - Network	per kW	$ 1.8516	1	$ 1.06	$ 2.1232	1	$ 1.21	$ 0.15	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	1	$ 0.54	$ 1.0865	1	$ 0.62	$ 0.08	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.49**			**$ 15.26**	**$ 3.78**	**32.88%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	225	$ 0.99	$ 0.0044	225	$ 0.99	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	225	$ 0.27	$ 0.0012	225	$ 0.27	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	215	$ 1.50	$ 0.0070	215	$ 1.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	137	$ 9.20	$ 0.0670	137	$ 9.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	39	$ 4.02	$ 0.1040	39	$ 4.02	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	39	$ 4.79	$ 0.1240	39	$ 4.79	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	215	$ 16.13	$ 0.0750	215	$ 16.13	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 32.50**			**$ 36.28**	**$ 3.78**	**11.62%**
HST		13%		$ 4.23	13%		$ 4.72	$ 0.49	11.62%
Total Bill (including HST)				$ 36.73			$ 41.00	$ 4.27	11.62%
Ontario Clean Energy Benefit [1]				-$ 3.67			-$ 4.10	-$ 0.43	11.72%
Total Bill on TOU (including OCEB)				**$ 33.06**			**$ 36.90**	**$ 3.84**	**11.61%**
Total Bill on RPP (before Taxes)				**$ 30.62**			**$ 34.40**	**$ 3.78**	**12.34%**
HST		13%		$ 3.98	13%		$ 4.47	$ 0.49	12.34%
Total Bill (including HST)				$ 34.60			$ 38.87	$ 4.27	12.34%
Ontario Clean Energy Benefit [1]				-$ 3.46			-$ 3.89	-$ 0.43	12.43%
Total Bill on RPP (including OCEB)				**$ 31.14**			**$ 34.98**	**$ 3.84**	**12.33%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: **Streetlights**

TOU / non-TOU: non-TOU

Connections	**2,568**
Consumption	**132,737** kWh
	353 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 1.5100	2,568	$ 3,877.68	$ 1.76	2,568	$ 4,519.68	$ 642.00	16.56%
Distribution Volumetric Rate	per kW	$ 8.3561	353	$ 2,946.19	$ 9.7162	353	$ 3,425.74	$ 479.54	16.28%
Sub-Total A (excluding pass through)				$ 6,823.87			$ 7,945.42	**$ 1,121.54**	**16.44%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4492	353	-$ 158.38	$ 3.0122	353	$ 1,062.04	$ 1,220.42	-770.57%
Rate Rider for Tax Change	per kW	-$ 0.1366	353	-$ 48.16		353	$ -	$ 48.16	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		353	$ -	-$ 0.4079	353	-$ 143.80	-$ 143.80	
Low Voltage Service Charge	per kW	$ 0.3091	353	$ 108.98	$ 0.4611	353	$ 162.57	$ 53.59	49.18%
Line Losses on Cost of Power	per kWh	$ -	6,212.11	$ -	$ 0.0839	6,384.67	$ 535.80	$ 535.80	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,726.73**			**$ 9,562.44**	**$ 2,835.71**	**42.16%**
RTSR - Network	per kW	$ 1.8516	353	$ 652.84	$ 2.1232	353	$ 748.59	$ 95.76	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9495	353	$ 334.77	$ 1.0865	353	$ 383.08	$ 48.31	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7,714.34**			**$10,694.11**	**$ 2,979.78**	**38.63%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	138949	$ 611.38	$ 0.0044	139122	$ 612.14	$ 0.76	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	138949	$ 166.74	$ 0.0012	139122	$ 166.95	$ 0.21	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	132737	$ 929.16	$ 0.0070	132737	$ 929.16	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	84952	$ 5,691.78	$ 0.0670	84952	$ 5,691.78	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	23893	$ 2,484.84	$ 0.1040	23893	$ 2,484.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	23893	$ 2,962.70	$ 0.1240	23893	$ 2,962.70	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	132137	$11,628.08	$ 0.0880	132137	$11,628.08	$ -	0.00%
Total Bill on TOU (before Taxes)				**$20,561.18**			**$23,541.93**	**$ 2,980.74**	**14.50%**
HST		13%		$ 2,672.95	13%		$ 3,060.45	$ 387.50	14.50%
Total Bill (including HST)				$23,234.14			$26,602.38	$ 3,368.24	14.50%
Ontario Clean Energy Benefit [1]				-$ 2,323.41			-$ 2,660.24	-$ 336.83	14.50%
Total Bill on TOU (including OCEB)				**$20,910.73**			**$23,942.14**	**$ 3,031.41**	**14.50%**
Total Bill on RPP (before Taxes)				**$21,094.95**			**$24,075.69**	**$ 2,980.74**	**14.13%**
HST		13%		$ 2,742.34	13%		$ 3,129.84	$ 387.50	14.13%
Total Bill (including HST)				$23,837.29			$27,205.53	$ 3,368.24	14.13%
Ontario Clean Energy Benefit [1]				-$ 2,383.73			-$ 2,720.55	-$ 336.82	14.13%
Total Bill on RPP (including OCEB)				**$21,453.56**			**$24,484.98**	**$ 3,031.42**	**14.13%**
Loss Factor (%)		4.68%			4.81%				

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**1**	
Consumption	**180**	**kWh**
	1	kW

	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	$ 3.3200	1	$ 3.32	$ 4.27	1	$ 4.27	$ 0.95	28.61%
Distribution Volumetric Rate	per kW	$ 12.9468	1	$ 12.95	$ 16.6482	1	$ 16.65	$ 3.70	28.59%
Sub-Total A (excluding pass through)				$ 16.27			$ 20.92	**$ 4.65**	**28.59%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	1	-$ 0.28	$ 2.5804	1	$ 1.47	$ 1.75	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	1	-$ 0.14		1	$ -	$ 0.14	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		1	$ -	-$ 0.7715	1	-$ 0.44	-$ 0.44	
Low Voltage Service Charge	per kW	$ 0.3156	1	$ 0.18	$ 0.4709	1	$ 0.27	$ 0.09	49.21%
Line Losses on Cost of Power	per kWh	$ 0.0750	8.42	$ 0.63	$ 0.0839	8.66	$ 0.73	$ 0.09	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 16.66**			**$ 22.94**	**$ 6.28**	**37.69%**
RTSR - Network	per kW	$ 1.8609	1	$ 1.86	$ 2.1339	1	$ 2.13	$ 0.27	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	1	$ 0.97	$ 1.1095	1	$ 1.11	$ 0.14	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19.49**			**$ 26.19**	**$ 6.69**	**34.34%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	188	$ 0.83	$ 0.0044	189	$ 0.83	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	188	$ 0.23	$ 0.0012	189	$ 0.23	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	180	$ 1.26	$ 0.0070	180	$ 1.26	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	115	$ 7.72	$ 0.0670	115	$ 7.72	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	32	$ 3.37	$ 0.1040	32	$ 3.37	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	32	$ 4.02	$ 0.1240	32	$ 4.02	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	180	$ 13.50	$ 0.0750	180	$ 13.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 37.16**			**$ 43.86**	**$ 6.69**	**18.01%**
HST		13%		$ 4.83	13%		$ 5.70	$ 0.87	18.01%
Total Bill (including HST)				$ 42.00			$ 49.56	$ 7.57	18.01%
Ontario Clean Energy Benefit [1]				-$ 4.20			-$ 4.96	-$ 0.76	18.10%
Total Bill on TOU (including OCEB)				**$ 37.80**			**$ 44.60**	**$ 6.81**	**18.00%**
Total Bill on RPP (before Taxes)				**$ 35.56**			**$ 42.25**	**$ 6.69**	**18.83%**
HST		13%		$ 4.62	13%		$ 5.49	$ 0.87	18.83%
Total Bill (including HST)				$ 40.18			$ 47.75	$ 7.57	18.83%
Ontario Clean Energy Benefit [1]				-$ 4.02			-$ 4.77	-$ 0.75	18.66%
Total Bill on RPP (including OCEB)				**$ 36.16**			**$ 42.98**	**$ 6.82**	**18.85%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **Sentinel Lights**

TOU / non-TOU: non-TOU

Connections	**30**	
Consumption	**2,780**	**kWh**
	7	kW

	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	$ 3.3200	30	$ 99.60	$ 4.27	30	$ 128.10	$ 28.50	28.61%
Distribution Volumetric Rate	per kW	$ 12.9468	7	$ 94.19	$ 16.6482	7	$ 121.12	$ 26.93	28.59%
Sub-Total A (excluding pass through)				$ 193.79			$ 249.22	**$ 55.43**	**28.60%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4833	7	-$ 3.52	$ 2.5804	7	$ 18.77	$ 22.29	-633.92%
Rate Rider for Tax Change	per kW	-$ 0.2444	7	-$ 1.78		7	$ -	$ 1.78	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kW		7	$ -	-$ 0.7715	7	-$ 5.61	-$ 5.61	
Low Voltage Service Charge	per kW	$ 0.3156	7	$ 2.30	$ 0.4709	7	$ 3.43	$ 1.13	49.21%
Line Losses on Cost of Power	per kWh	$ 0.0880	130.10	$ 11.45	$ 0.0839	133.72	$ 11.22	-$ 0.23	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 202.24**			**$ 277.02**	**$ 74.78**	**36.98%**
RTSR - Network	per kW	$ 1.8609	7	$ 13.54	$ 2.1339	7	$ 15.52	$ 1.99	14.67%
RTSR - Line and Transformation Connection	per kW	$ 0.9696	7	$ 7.05	$ 1.1095	7	$ 8.07	$ 1.02	14.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 222.83**			**$ 300.62**	**$ 77.79**	**34.91%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2910	$ 12.80	$ 0.0044	2914	$ 12.82	$ 0.02	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2910	$ 3.49	$ 0.0012	2914	$ 3.50	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2780	$ 19.46	$ 0.0070	2780	$ 19.46	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1779	$ 119.21	$ 0.0670	1779	$ 119.21	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	500	$ 52.04	$ 0.1040	500	$ 52.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	500	$ 62.05	$ 0.1240	500	$ 62.05	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	2180	$ 191.84	$ 0.0880	2180	$ 191.84	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 492.14**			**$ 569.94**	**$ 77.81**	**15.81%**
HST		13%		$ 63.98	13%		$ 74.09	$ 10.11	15.81%
Total Bill (including HST)				$ 556.11			$ 644.04	$ 87.92	15.81%
Ontario Clean Energy Benefit [1]				-$ 55.61			-$ 64.40	-$ 8.79	15.81%
Total Bill on TOU (including OCEB)				**$ 500.50**			**$ 579.64**	**$ 79.13**	**15.81%**
Total Bill on RPP (before Taxes)				**$ 495.68**			**$ 573.49**	**$ 77.81**	**15.70%**
HST		13%		$ 64.44	13%		$ 74.55	$ 10.11	15.70%
Total Bill (including HST)				$ 560.12			$ 648.04	$ 87.92	15.70%
Ontario Clean Energy Benefit [1]				-$ 56.01			-$ 64.80	-$ 8.79	15.69%
Total Bill on RPP (including OCEB)				**$ 504.11**			**$ 583.24**	**$ 79.13**	**15.70%**

Loss Factor (%) 4.68% 4.81%

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: non-TOU

Connections	**1**	
Consumption	**193**	**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	$ 6.3400	1	$ 6.34	$ 5.30	1	$ 5.30	-$ 1.04	-16.40%
Distribution Volumetric Rate	per kWh	$ 0.0089	193	$ 1.71	$ 0.0074	193	$ 1.43	-$ 0.29	-16.85%
Sub-Total A (excluding pass through)				$ 8.05			$ 6.73	**-$ 1.33**	**-16.50%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	193	-$ 0.19	$ 0.0015	193	$ 0.28	$ 0.48	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	193	-$ 0.08		193	$ -	$ 0.08	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		193	$ -	-$ 0.0017	193	-$ 0.32	-$ 0.32	
Low Voltage Service Charge	per kWh	$ 0.0010	193	$ 0.19	$ 0.0015	193	$ 0.29	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0750	9.01	$ 0.68	$ 0.0839	9.26	$ 0.78	$ 0.10	15.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.65**			**$ 7.75**	**-$ 0.90**	**-10.43%**
RTSR - Network	per kWh	$ 0.0060	202	$ 1.21	$ 0.0069	202	$ 1.39	$ 0.18	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	202	$ 0.63	$ 0.0035	202	$ 0.72	$ 0.09	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.49**			**$ 9.86**	**-$ 0.63**	**-6.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	202	$ 0.89	$ 0.0044	202	$ 0.89	$ 0.00	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	202	$ 0.24	$ 0.0012	202	$ 0.24	$ 0.00	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	193	$ 1.35	$ 0.0070	193	$ 1.35	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	123	$ 8.26	$ 0.0670	123	$ 8.26	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	35	$ 3.61	$ 0.1040	35	$ 3.61	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	35	$ 4.30	$ 0.1240	35	$ 4.30	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	193	$ 14.45	$ 0.0750	193	$ 14.45	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 29.38**			**$ 28.75**	**-$ 0.63**	**-2.15%**
HST		13%		$ 3.82	13%		$ 3.74	-$ 0.08	-2.15%
Total Bill (including HST)				$ 33.20			$ 32.49	-$ 0.71	-2.15%
Ontario Clean Energy Benefit [1]				-$ 3.32			-$ 3.25	$ 0.07	-2.11%
Total Bill on TOU (including OCEB)				**$ 29.88**			**$ 29.24**	**-$ 0.64**	**-2.15%**
Total Bill on RPP (before Taxes)				**$ 27.66**			**$ 27.03**	**-$ 0.63**	**-2.28%**
HST		13%		$ 3.60	13%		$ 3.51	-$ 0.08	-2.28%
Total Bill (including HST)				$ 31.26			$ 30.54	-$ 0.71	-2.28%
Ontario Clean Energy Benefit [1]				-$ 3.13			-$ 3.05	$ 0.08	-2.56%
Total Bill on RPP (including OCEB)				**$ 28.13**			**$ 27.49**	**-$ 0.63**	**-2.25%**

Loss Factor (%)	4.68%	4.81%

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: non-TOU

Connections	**58**	
Consumption	**24,581**	**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	$ 6.3400	58	$ 367.72	$ 5.30	58	$ 307.40	-$ 60.32	-16.40%
Distribution Volumetric Rate	per kWh	$ 0.0089	24,581	$ 218.77	$ 0.0074	24,581	$ 181.90	-$ 36.87	-16.85%
Sub-Total A (excluding pass through)				$ 586.49			$ 489.30	**-$ 97.19**	**-16.57%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0010	24,581	-$ 24.58	$ 0.0015	24,581	$ 36.18	$ 60.76	-247.18%
Rate Rider for Tax Change	per kWh	-$ 0.0004	24,581	-$ 9.83		24,581	$ -	$ 9.83	-100.00%
Rate Rider Calculation for Accounts 1575 and 1576	per kWh		24,581	$ -	-$ 0.0017	24,581	-$ 41.46	-$ 41.46	
Low Voltage Service Charge	per kWh	$ 0.0010	24,581	$ 24.58	$ 0.0015	24,581	$ 36.87	$ 12.29	50.00%
Line Losses on Cost of Power	per kWh	$ 0.0880	1,150.39	$ 101.23	$ 0.0839	1,182.34	$ 99.22	-$ 2.01	-1.99%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 677.89**			**$ 620.11**	**-$ 57.78**	**-8.52%**
RTSR - Network	per kWh	$ 0.0060	25731	$ 154.39	$ 0.0069	25763	$ 177.25	$ 22.87	14.81%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	25731	$ 79.77	$ 0.0035	25763	$ 91.39	$ 11.62	14.57%
Sub-Total C - Delivery (including Sub-Total B)				**$ 912.05**			**$ 888.76**	**-$ 23.29**	**-2.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	25731	$ 113.22	$ 0.0044	25763	$ 113.36	$ 0.14	0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	25731	$ 30.88	$ 0.0012	25763	$ 30.92	$ 0.04	0.12%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	24581	$ 172.07	$ 0.0070	24581	$ 172.07	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	15732	$ 1,054.03	$ 0.0670	15732	$ 1,054.03	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	4425	$ 460.16	$ 0.1040	4425	$ 460.16	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	4425	$ 548.65	$ 0.1240	4425	$ 548.65	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	23981	$ 2,110.32	$ 0.0880	23981	$ 2,110.32	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 3,291.29**			**$ 3,268.18**	**-$ 23.11**	**-0.70%**
HST		13%		$ 427.87	13%		$ 424.86	-$ 3.00	-0.70%
Total Bill (including HST)				$ 3,719.16			$ 3,693.05	-$ 26.11	-0.70%
Ontario Clean Energy Benefit [1]				-$ 371.92			-$ 369.30	$ 2.62	-0.70%
Total Bill on TOU (including OCEB)				**$ 3,347.24**			**$ 3,323.75**	**-$ 23.49**	**-0.70%**
Total Bill on RPP (before Taxes)				**$ 3,383.78**			**$ 3,360.67**	**-$ 23.11**	**-0.68%**
HST		13%		$ 439.89	13%		$ 436.89	-$ 3.00	-0.68%
Total Bill (including HST)				$ 3,823.68			$ 3,797.56	-$ 26.11	-0.68%
Ontario Clean Energy Benefit [1]				-$ 382.37			-$ 379.76	$ 2.61	-0.68%
Total Bill on RPP (including OCEB)				**$ 3,441.31**			**$ 3,417.80**	**-$ 23.50**	**-0.68%**

Loss Factor (%)	4.68%	4.81%

ORANGEVILLE HYDRO

Appendix P -

MS1 Valuation

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

YOU HAVE A FAX!

ROYAL LEPAGE

RCR Realty, Brokerage
Independently Owned & Operated

75 First Street, Suite 14
Orangeville, ON, L9W 2E7

Phone: 519-941-5151
905-450-3355
800-268-2455
Fax: 519-941-5432

Date: April 2, 13 **Fax #:** 519-941-6061

To: George Dick

From: David Maguire

Re: 40 Mill Street

Message:

There are 18 page(s) including this cover page.

Please contact sender immediately if there are missing pages.

ROYAL LEPAGE

RCR Realty, Brokerage
Independently Owned & Operated

To: Orangeville Hydro
Attention: George Dick, Manager
Date: April 2, 2013

Dear Mr. Dick,

Please find attached the letter of opinion Re: 40 Mill Street, Orangeville, Ontario as requested. Thank you very much for considering me in this matter. Feel free to call me with any further questions you may have in regards to this letter.

Sincerely,

David Maguire
Sales Representative
Royal LePage RCR Realty

75 First Street, Suite 14, Orangeville, Ontario, L9W 2E7
Bus: (519) 941-5151 or (800) 268-2455 Fax: (519) 941-5432

ROYAL LEPAGE
RCR Realty, Brokerage
Independently Owned & Operated

LETTER OF OPINION

April 2, 2013
Orangeville Hydro
Attention: George Dick
400 C Line, Box 400
Orangeville, ON L9W 2Z7

Dear Mr. Dick

In accordance with your request for an opinion of the market value of lease rate of the property commonly known as:

40 Mill Street, Orangeville, Ontario

and more particularly described as follows:

Vacant lot measuring 118.01 feet front by 100.5 feet deep.

I hereby certify that I have inspected the property and all data gathered in my investigation is from sources believed to be reliable and on the basis of comparative sales and development potential, it is the opinion of the writer that as of: **April 2, 2013** the market value for the purpose of sale of the property above described would be:

$100,000.00 (ONE HUNDRED THOUSAND DOLLARS)

I further certify that I am a registered Real Estate Broker/Salesperson under the Real Estate and Business Brokers Act, 2002 of the Province of Ontario, and that I have no interest nor do I contemplate having any interest, directly or indirectly in the ownership of the subject property.

The opinion of value in no way may be construed as binding on the signer or his firm for any court appearances, correspondence or appearances before any body, unless prior arrangements have been made.

Yours very truly,

David Maguire
Sales Representative
ROYAL LEPAGE RCR REALTY, Brokerage
Independently Owned & Operated

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

39 Church St **Sold: $36,000**
Orangeville, Ontario L9W1N7 Dufferin Orangeville **List:** $38,000
Pts Lot 8&9 Blk 5* 95 % List
SPIS: 404-46-J **DOM:** 130 **Taxes:** $1,055.61/1995 **Last Status:** Sld

Vacant Land **Fronting On:** **Rooms:**
Acreage: **Bedrooms:**
Dir/Cross St: Townline To William **Washrooms:** 0
Lot: 50X66.13 Feet **Irreg:**

MLS#: WA4544 **Seller:** Trisha L. Coffey **Contact After Exp:** **Holdover:** 90
PIN#: **Occupancy:** Owner

Kitchens:	**Exterior:**	**Zoning:**
Fam Rm:		**Cable TV:** **Hydro:**
Basement:	**Drive:**	**Gas:** **Phone:**
	GarType/Spaces:	**Water:** Municipal
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** Sewers
	Pool:	**Spec Desig:**
A/C:	Level	**Farm/Agr:**
Apx Age:	**Energy Cert:**	**Waterfront:**
Apx Sqft:	**Cert Level:**	**Retirement:**
Assessment:	**GreenPIS:**	
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

Room Level Dimensions (ft)

Extras: *Pts Lot 8&9 Blk 5 Reg Plan 216

Remarks for Brokerages: In Town Property In Established Residential Area.Centrally Located Close To All Amenities. Recently Severed 1993 Survey. Accessible To All Town Services.Nicely Treed Property. See Lbo Re: Levies.

Mortgage Comments: Treat As Clear

List: NIEUWENHUIS, BERT, R.E. (519) 942-3777 **Fax:**
? INCOMPLETE LISTING (905) 454-0944
Co-Op: CB Comm: 3%-$11

Contract Date: 10/1/1995 **Sold Date:** 2/8/1996 **Leased Terms:**
Expiry Date: 3/31/1996 **Closing Date:** 3/4/1996 **Original Price:** $38,000
Last Update: 2/8/1996

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

26 Church St — **Sold: $42,500**
Orangeville, Ontario L9W1N5 Dufferin Orangeville — **List:** $42,900
E.1/2 Lot 1 Con "E" — 99 % List
SPIS: None 404-46-J **DOM:** 18 **Taxes:** — **Last Status:** Sld

Vacant Land — **Fronting On:** N — **Rooms:**
Acreage: < .49 — **Bedrooms:**
Dir/Cross St: Wellington/Church — **Washrooms:** 0
Lot: 56X168 Feet **Irreg:**

MLS#: LJ8605 Incomplete **Seller:** Robert Stewart & Mary C. Stewart **Contact After Exp:** **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:** Res
Fam Rm:		**Cable TV:** Y **Hydro:** Y
Basement:	**Drive:** Private	**Gas:** Y **Phone:** Y
	GarType/Spaces:	**Water:** Municipal
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** Sewers
	Pool:	**Spec Desig:** Unknown
A/C:	Level	**Farm/Agr:**
Apx Age:	Park	**Waterfront:**
Apx Sqft:	Public Transit	**Retirement:**
Assessment:	**Energy Cert:**	
Addl Mo Fee:	**Cert Level:**	
Elev/Lift: **Laundry Lev:**	**GreenPIS:**	
Phys Hdcap-Equip:		

Room Level Dimensions (ft)

Extras: Be Sold "As Is". All Offers Appreciated Today. Development Charges May Apply.

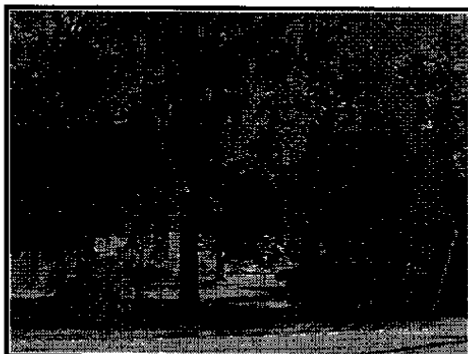
Remarks for Brokerages: Good Size Building Lot Wit Hin Close Proximity To Dow Ntown Amenities. Lot May Need A New Survey.Condemne D House Will Need To Be Re Moved. Please Use Extreme Caution When Showing. Area Cordoned Off - May Ne Ed Permission! Property To

Mortgage Comments: Treat As Clear

List: SALLY FRANCO R.E. INC. (519) 928-5723 **Fax:**
SARAH SALLY FRANCO (519) 928-3339
Co-Op: FRANCO, SALLY, R.E. INC. **CB Comm:** 3%

Contract Date:	4/15/1999	**Sold Date:**	5/3/1999	**Leased Terms:**	
Expiry Date:	6/30/1999	**Closing Date:**	6/1/1999	**Original Price:**	$42,900
Last Update:	5/3/1999				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM



L58 Sarah St
Orangeville, Ontario Dufferin Orangeville
Lt58 Ptlt57Bl7Pl138
SPIS: None -- **DOM:** 162 **Taxes:**

Sold: $34,000
List: $44,900
76 % List
Last Status: Sld

Vacant Land
Fronting On: E
Acreage: < .49
Dir/Cross St: Sarah & Wellington
Lot: 18.39X28.92 Metres **Irreg:** X19.89 Irreg.

Rooms:
Bedrooms:
Washrooms: 0

MLS#: LP8877 **Seller:** Dwight Trafford And Hennie Trafford **Contact After Exp:** **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:
Fam Rm:
Basement:
Fireplace/Stv: **Central Vac:**
Heat:
A/C:
Apx Age:
Apx Sqft:
Assessment:
Addl Mo Fee:
Elev/Lift: **Laundry Lev:**
Phys Hdcap-Equip:

Exterior:
Drive:
GarType/Spaces:
Parking Spaces:
UFFI:
Pool:
Energy Cert:
Cert Level:
GreenPIS:

Zoning: Res
Cable TV: A **Hydro:** A
Gas: A **Phone:** A
Water: Municipal
Water Supply:
Sewers: Sewers
Spec Desig: Unknown
Farm/Agr:
Waterfront:
Retirement:

# Room	Level	Dimensions (ft)

Remarks for Brokerages: Vacant Lot In Quiet Older Section Of Orangeville. Services Are At Street And Would Need To Be Connected By Purchaser. Subject To Development Charges, And Gst May Apply At Purchasers Expense.

Mortgage Comments: Treat As Clear

List: ROYAL LEPAGE RCR REALTY (905) 450-3355 **Fax:**
RALPH RUTLEDGE (905) 450-3355
Co-Op: COLDWELL BANKER PINNACLE RE CB **Comm:** 3%

Contract Date: 9/26/2000 **Sold Date:** 3/5/2001
Expiry Date: 12/31/2000 **Closing Date:** 5/19/2001
Last Update: 3/5/2001

Leased Terms:
Original Price: $44,900

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

47 John St
Orangeville, Ontario L9W2P6 Dufferin Orangeville
L19 Pl195 Rp7R4490
SPIS: 404-46-J **DOM:** 28 **Taxes:**

Sold: $40,000
List: $49,000
82 % List
Last Status: Sld

Vacant Land
Fronting On:
Acreage:
Dir/Cross St: John St/Henry St.
Lot: 66X76 Feet **Irreg:**

Rooms:
Bedrooms:
Washrooms: 0

MLS#: LG4310 **Seller:** Carollee Neil **Contact After Exp:** **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:**
Fam Rm:		**Cable TV:** **Hydro:**
Basement:	**Drive:**	**Gas:** **Phone:**
	GarType/Spaces:	**Water:** Municipal
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** Sewers
	Pool:	**Spec Desig:**
A/C:	**Level**	**Farm/Agr:**
Apx Age:	**Energy Cert:**	**Waterfront:**
Apx Sqft:	**Cert Level:**	**Retirement:**
Assessment:	**GreenPIS:**	
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks for Brokerages: Vacant Building Lot Locate D In Established Area Of O Rangeville. Water & Sewer Is To The Lot Line. Purcha Ser Is Responsible For Lot Levies And Development Ch Arges. See Lb For Conditio Ns In Offer. (*3%-$12.00)

Mortgage Comments: Treat As Clear

List: RE/MAX SELECT REALTY LTD. (905) 454-0944 **Fax:**
DOUGLAS SCHILD (519) 942-8700
Co-Op: CENTURY 21 MILLENNIUM INC. **CB Comm:** *3%

Contract Date:	5/11/1998	**Sold Date:**	6/8/1998	**Leased Terms:**	
Expiry Date:	8/15/1998	**Closing Date:**	6/22/1998	**Original Price:**	$49,000
Last Update:	6/8/1998				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

Photo Not Available

18-20 Mill St
Orangeville, Ontario L9W2M3 Dufferin Orangeville
Pt Lots 2&3 ,Block 8 Plan 138 Orangevill
SPIS: Y 404-46-J **DOM:** 187 **Taxes:** $1,732.85/2007

Sold: $73,000
List: $79,000
92 % List
Last Status: Sld

Vacant Land
Dir/Cross St: Broadway/Mill
Lot: 24X91 Feet **Irreg:**
Fronting On: W
Acreage: < .49
Rooms:
Bedrooms:
Washrooms: 0

MLS#: W1259920 **Seller:** Dino Facin, Rita De Zen **Contact After Exp:** N **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:
Fam Rm:
Basement:
Fireplace/Stv: **Central Vac:**
Heat:
A/C:
Apx Age:
Apx Sqft:
Assessment:
Addl Mo Fee:
Elev/Lift: **Laundry Lev:**
Phys Hdcap-Equip:

Exterior:
Drive:
GarType/Spaces:
Parking Spaces:
UFFI:
Pool:
Energy Cert:
Cert Level:
GreenPIS:

Zoning:
Cable TV: A **Hydro:** A
Gas: A **Phone:** A
Water: Municipal
Water Supply:
Sewers: None
Spec Desig: Unknown
Farm/Agr:
Waterfront:
Retirement:

# Room	Level	Dimensions (ft)

Remarks For Clients: Don't Miss This Great Investment Opportunity In Downtown Core. Only Available Vacant Land On Mls In Core Location, Strategically Located On Street, Less Than 400 Ft South Of Broadway, Zoning Allows Many Uses, Hook Up For Utilities Available (Gas, Water, Sewers, Hydro)

Extras: Call For Available Survey.

Mortgage Comments:

List: ROYAL LEPAGE RCR REALTY, BROKERAGE 905-857-0651 **Fax:** 905-857-4566
ANNE C COBHAM, Salesperson 1-800-748-6789
Co-Op: ROYAL LEPAGE RCR REALTY, BROKERAGE **CB Comm:** 2.5
Anne C Cobham, Salesperson
Contract Date: 11/11/2007 **Sold Date:** 5/16/2008 **Leased Terms:**
Expiry Date: 4/3/2008 **Closing Date:** 6/3/2008 **Original Price:** $79,000
Last Update: 5/16/2008

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:36:45 PM

16 Sherbourne St
Orangeville, Ontario L9W2A6 Dufferin Orangeville
Lt 14, Pl 256; Orangeville
SPIS: N 404-47-J **DOM:** 146 **Taxes:** $1,415/2010

Sold: $160,000
List: $175,000
91 % List
Last Status: Sld

Vacant Land
Fronting On: W
Acreage: < .49
Dir/Cross St: Broadway/ Sherbourne
Lot: 63.5X132 Feet **Irreg:**

Rooms:
Bedrooms:
Washrooms: 0

MLS#: W2076313 **Seller:** Gus Litz Contracting & Massive Peat Inc. **Contact After Exp:** N **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:** Rm 1
Fam Rm:		**Cable TV:** A **Hydro:** A
Basement:	**Drive:**	**Gas:** A **Phone:** A
	GarType/Spaces:	**Water:** None
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** None
	Pool:	**Spec Desig:** Unknown
A/C:	**Energy Cert:**	**Farm/Agr:**
Apx Age:	**Cert Level:**	**Waterfront:** None
Apx Sqft:	**GreenPIS:**	**Retirement:**
Assessment:		
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks For Clients: Attention Investors & Builders. Fabulous In Town Vacant Lot Zoned Rm1 That Has Potential For 3 Town Homes. Many Of The Studies, Survey, Drawings And Reports Have Already Been Completed.

Extras: Please Contact Listing Agent For List Of All Studies/Reports That Have Been Done To Date And Will Be Forwarded To The New Owners.

Remarks for Brokerages: Fax Or Email All Offers As Per Sellers Directions. Hst In Addition To Purchase Price. Taxes To Be Confirmed By Buyer.

Mortgage Comments:

List: RE/MAX REAL ESTATE CENTRE INC., BROKERAGE 519-942-8700 **Fax:** 519-943-0550
MIKE MULLIN, Salesperson 519-942-8700
Co-Op: SUTTON WEST REALTY INC., BROKERAGE **CB Comm:** 2.5% Plus Hst
Gurdial Bal, Salesperson

Contract Date:	4/6/2011	**Sold Date:**	8/30/2011	**Leased Terms:**	
Expiry Date:	9/30/2011	**Closing Date:**	9/30/2011	**Original Price:**	$175,000
Last Update:	9/1/2011				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:36:45 PM

Photo Not Available	Pt L3B5 Armstrong St E $178,000 For Sale Orangeville, Ontario L9W3G4 Dufferin Orangeville Pt.L3, Blk 5, Plan 138 & Part Lot 1, Continued Taxes: $1,275.08/2013 SPIS: N -- Last Status: New
	Vacant Land Fronting On: N Rooms: Acreage: < .49 Bedrooms: Dir/Cross St: Mill St And Armstrong St Washrooms: 0 Lot: 41.84X96.32 Feet Irreg: Legal Desc Cont'd..Pts 10 To 17 7R2865

MLS#: W2593416 Seller: Barbara Pambianchi Contact After Exp: N Occup: Vacant
Open House: From: To: DOM: 8 Holdover: 90 Possession: 30 Days
Open House Notes: PIN#:

Kitchens:	Exterior:	Zoning: Central Business District Cbd
Fam Rm:		
Basement:	Drive:	Cable TV: A Hydro: A
	GarType/Spaces:	Gas: A Phone: A
Fireplace/Stv: Central Vac:	Parking Spaces:	Water: None
Heat:	UFFI:	Water Supply:
	Pool:	Sewers: None
A/C: None	Energy Cert:	Spec Desig: Unknown
Apx Age:	Cert Level:	Farm/Agr:
Apx Sqft:	GreenPIS:	Waterfront: None
Assessment:		Retirement:
Addl Mo Fee:		
Elev/Lift: Laundry Lev:		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks For Clients: Highly Visable Location Historical Core Of Downtown Orangeville. Vacant Lot Uses, Commercial, Commercial Residential Or Multi Residential Use. Seller Can Build To Suit, Plans For A 7 Unit Residential Building. Lot Is Ashphalt, Wqith 10 Parking Spots. Good Value For A Rare Prime Development Lot In Downtown Orangeville. Vendor May Consider A Mortgage. Vendor Take Back On Approved Credit, 30% Down 8% To Be Confirmed On Credit Approval

Extras: Survey Available, Buyer To Verify Use Compliance, Zoning. Buyer Will Be Responsible For Development Charges. Cbdistrict Has Reduced Parking Requirements. Lot Desc Pt.L3, Blk 5, Plan 138 & Part Lot 1, Conc E Pts 10 To 17 7R2865

Remarks for Brokerages: Plans For 7 Unit Building Had Been Submitted To Town For Approval, Buyer Must Verify Acceptability To Lot And Zoning. Seller Willing To Build To Suit. Vendor May Consider Vtb On Approved Credit. Great Opportunity. Attached Schedule 'B' Verify Lot Description On Offer

Mortgage Comments: Vendor May Consider A Mortgage. Vendor Take Back On Approved Credit, 30% Down 8% To Be Confirmed On Credit Approval

ROYAL LEPAGE RCR REALTY, BROKERAGE 519-925-2761 Fax: 519-926-6160
136 Main Street, Shelburne L0N1S0
MARG MCCARTHY, Salesperson 1-800-360-5821
519-216-1756 Appts:
Contract Date: 3/25/2013 Condition: Ad: Y
Expiry Date: 12/11/2013 Cond Expiry: Escape:
Last Update: 4/2/2013 CB Comm: 2.5% Original $: $178,000

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

0 Henry St
Orangeville, Ontario L9W2R6 Dufferin Orangeville
See Listing Agent For Legal Description
SPIS: N -- **DOM:** 39 **Taxes:** $0/2009

Sold: $53,000
List: $79,900
66 % List
Last Status: Sld

Vacant Land
Fronting On: W
Acreage: < .49
Dir/Cross St: William And Henry
Lot: 19.52X17.93 Metres **Irreg:**

Rooms:
Bedrooms:
Washrooms: 0

MLS#: W1737834 **Seller:** Shirley Gerlach **Contact After Exp:** N **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:**
Fam Rm:		**Cable TV:** A **Hydro:** A
Basement:	**Drive:**	**Gas:** A **Phone:** A
	GarType/Spaces:	**Water:** None
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** None
	Pool:	**Spec Desig:** Unknown
A/C:	**Energy Cert:**	**Farm/Agr:**
Apx Age:	**Cert Level:**	**Waterfront:** None
Apx Sqft:	**GreenPIS:**	**Retirement:**
Assessment:		
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks For Clients: Fantastic Opportunity To Build Your Brand New Home In A Mature And Sought After Neighbourhood In Orangeville. This Newly Severed Lot Is Situated Just Steps From Shops, Boutiques, Restaurants, Live Theatre, The Library And Much More!

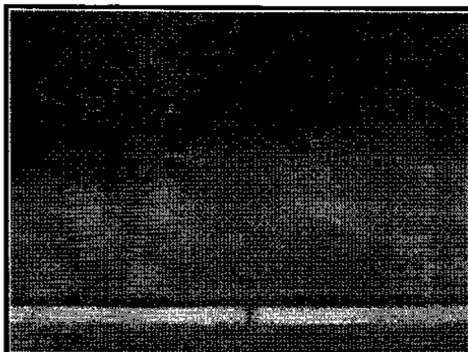
Remarks for Brokerages: When Building On Lot The House Style Must Conform With Existing Subdivision And Damage To Municipal Property Must Be Repaired At Expense Of Owner. Please Contact La For More Info. Agent To Accompany All Prospective Buyers To Property.

Mortgage Comments:

List: ROYAL LEPAGE RCR REALTY, BROKERAGE 519-941-5151 **Fax:** 519-941-5432
LISA FELICE, Salesperson 519-941-5151
Co-Op: ROYAL LEPAGE RCR REALTY, BROKERAGE **CB Comm:** 2.5%
Lisa Felice, Salesperson

Contract Date:	11/5/2009	**Sold Date:**	12/14/2009	**Leased Terms:**	
Expiry Date:	1/4/2010	**Closing Date:**	12/21/2009	**Original Price:**	$79,900
Last Update:	12/14/2009				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM



98 John St
Orangeville, Ontario L9W Dufferin Orangeville
Part Lot 20 & 21, Block 8, Plan 233 (See Below)
SPIS: N -- **DOM:** 9 **Taxes:** $0/2009

Sold: $82,000
List: $89,900
91 % List
Last Status: Sld

Vacant Land
Fronting On: W
Acreage: < .49
Dir/Cross St: John South Of Townline
Lot: 49X124 Feet **Irreg:** Slightly Irregular

Rooms:
Bedrooms:
Washrooms: 0

MLS#: W1674443 **Seller:** Marian Edna May Noble **Contact After Exp:** N **Holdover:** 120
PIN#: **Occupancy:** Vacant

Kitchens:
Fam Rm:
Basement:
Fireplace/Stv: **Central Vac:**
Heat:
A/C:
Apx Age:
Apx Sqft:
Assessment:
Addl Mo Fee:
Elev/Lift: **Laundry Lev:**
Phys Hdcap-Equip:

Exterior:
Drive:
GarType/Spaces:
Parking Spaces:
UFFI:
Pool:
Energy Cert:
Cert Level:
GreenPIS:

Zoning:
Cable TV: N **Hydro:** N
Gas: N **Phone:** N
Water: None
Water Supply:
Sewers: None
Spec Desig: Unknown
Farm/Agr:
Waterfront: None
Retirement:

# Room	Level	Dimensions (ft)

Remarks For Clients: Rare Opportunity! Attention All Builders And Those That Want To Build Their Own Custom Home. Lovely In Town Lot, Put Your Dream Home Here.

Extras: All Fees To Develop/Build Are To Be Paid By The Buyer. Please Contact Listing Agent Prior To Any Offers For Additional Schedules. Please Do Not Walk The Property On John St Unless You Have Called Re/Max To Advise. Thanks

Remarks for Brokerages: Legal Description Continued *Designated As Pt 3 On 7R5253.Pin # 340160484. Please Download Schedule 'C'and Schedule 'D' And Attach With Any Offers. Offers Are To Have A 48 Hour Irrevocable.

Mortgage Comments:

List: RE/MAX REAL ESTATE CENTRE INC., BROKERAGE 519-942-8700 **Fax:** 519-942-2284
CINDY ANN NESS, Salesperson 519-942-8700
Co-Op: SUTTON GROUP - PROFESSIONAL REALTY INC., BROKERAGE **CB Comm:** 2.5% + Gst
Marge Cotton, Salesperson

Contract Date: 7/28/2009 **Sold Date:** 8/6/2009 **Leased Terms:**
Expiry Date: 12/31/2009 **Closing Date:** 8/31/2009 **Original Price:** $89,900
Last Update: 8/7/2009

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM

Photo Not Supplied

49 William St — **Sold: $122,000**
Orangeville, Ontario L9W2R8 Dufferin Orangeville — **List:** $119,900
Plan 216 Blk 1 Lt5 — 102 % List
SPIS: None 404-46-J **DOM:** 16 **Taxes:** $2,111.47/1999 **Last Status:** Sld

Vacant Land — **Fronting On:** E — **Rooms:**
Other — **Acreage:** < .49 — **Bedrooms:**
Dir/Cross St: Townline & William — **Washrooms:** 0
Lot: 66X133 Feet **Irreg:**

MLS#: LO2441 **Seller:** Karen Anne Mashford And Andrew Shane Mashford **Contact After Exp:** **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:		**Exterior:**	Other	**Zoning:**	Res
Fam Rm:	N			**Cable TV:**	A **Hydro:** Y
Basement:	None	**Drive:**	Private	**Gas:**	A **Phone:** A
		GarType/Spaces:	/4	**Water:**	Municipal
Fireplace/Stv: N **Central Vac:**		**Parking Spaces:**		**Water Supply:**	
Heat:		**UFFI:**	No	**Sewers:**	Sewers
		Pool:	None	**Spec Desig:**	Unknown
A/C:		Level		**Farm/Agr:**	
Apx Age:		Public Transit		**Waterfront:**	
Apx Sqft:		**Energy Cert:**		**Retirement:**	
Assessment:		**Cert Level:**			
Addl Mo Fee:		**GreenPIS:**			
Elev/Lift: **Laundry Lev:**					
Phys Hdcap-Equip:					

Room Level Dimensions (ft)

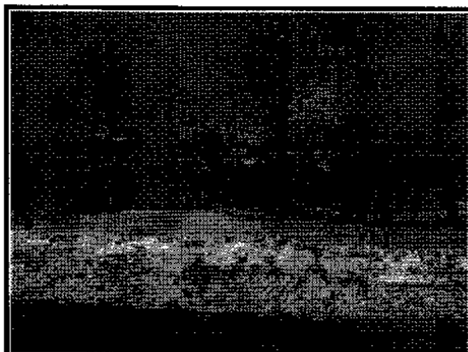
Remarks for Brokerages: Potential Living Quarters. 1 Bedroom/2 Bedroom Apts. Being Sold As Is. Premium Lot! Allow 48Hr Irrevocab Le.

Mortgage Comments: Treat As Clear

List: RE/MAX SELECT REALTY LTD. (800) 461-2686 **Fax:**
DONNA DAVISON (800) 461-2686
Co-Op: FORALL REALTY-BTR HMS & GRD CB **Comm:** 2.5%

Contract Date:	5/15/2000	**Sold Date:**	5/31/2000	**Leased Terms:**	
Expiry Date:	9/30/2000	**Closing Date:**	6/30/2000	**Original Price:**	$119,900
Last Update:	5/31/2000				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM



16 Sherbourne St | **Sold: $115,000**
Orangeville, Ontario L9W2A6 Dufferin Orangeville | **List:** $139,900
Lt 14, Pl 256; Orangeville | 82 % List
SPIS: N 404-47-J **DOM:** 81 **Taxes:** $0/2007 | **Last Status:** Sld

Vacant Land | **Fronting On:** W | **Rooms:**
Acreage: < .49 | **Bedrooms:**
Dir/Cross St: Broadway/ Sherbourne | **Washrooms:** 0
Lot: 63.5X132 Feet **Irreg:**

MLS#: W1303650 **Seller:** 71113 Ontario Inc. **Contact After Exp:** N **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:** Rm 1
Fam Rm:		**Cable TV:** N **Hydro:** N
Basement:	**Drive:**	**Gas:** N **Phone:** N
	GarType/Spaces:	**Water:** None
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** None
	Pool:	**Spec Desig:** Unknown
A/C:	**Energy Cert:**	**Farm/Agr:**
Apx Age:	**Cert Level:**	**Waterfront:**
Apx Sqft:	**GreenPIS:**	**Retirement:**
Assessment:		
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

 # Room **Level** **Dimensions (ft)**

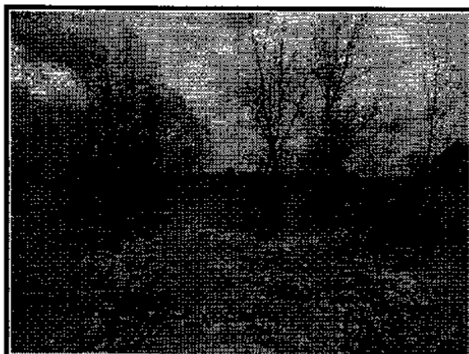
Remarks For Clients: Attention All Investors, Builders! Great Parcel Of Land Available. Zoning On This Property Is Rm 1. Please See Faxed Attached Sheet With Permitted Uses.

Mortgage Comments: Tac

List: ROYAL LEPAGE RCR REALTY, BROKERAGE 519-941-5151 **Fax:** 519-941-5432
FRANK GRAY JR., Salesperson 519-941-5151 519-941-5151
Co-Op: ROYAL LEPAGE RCR REALTY, BROKERAGE **CB Comm:** 2.5%
Frank Gray Jr., Salesperson

Contract Date:	2/3/2008	**Sold Date:**	4/24/2008	**Leased Terms:**	
Expiry Date:	4/30/2008	**Closing Date:**	5/15/2008	**Original Price:**	$139,900
Last Update:	4/24/2008				

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:44:03 PM



16 Sherbourne St — **Sold: $160,000**
Orangeville, Ontario L9W2A6 Dufferin Orangeville — **List:** $175,000
Lt 14, Pl 256; Orangeville — 91 % List
SPIS: N 404-47-J **DOM:** 146 **Taxes:** $1,415/2010 **Last Status:** Sld

Vacant Land — **Fronting On:** W — **Rooms:**
Acreage: < .49 — **Bedrooms:**
Dir/Cross St: Broadway/ Sherbourne — **Washrooms:** 0
Lot: 63.5X132 Feet **Irreg:**

MLS#: W2076313 **Seller:** Gus Litz Contracting & Massive Peat Inc. **Contact After Exp:** N **Holdover:** 90
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:** Rm 1
Fam Rm:		**Cable TV:** A **Hydro:** A
Basement:	**Drive:**	**Gas:** A **Phone:** A
	GarType/Spaces:	**Water:** None
Fireplace/Stv: **Central Vac:**	**Parking Spaces:**	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** None
	Pool:	**Spec Desig:** Unknown
A/C:	**Energy Cert:**	**Farm/Agr:**
Apx Age:	**Cert Level:**	**Waterfront:** None
Apx Sqft:	**GreenPIS:**	**Retirement:**
Assessment:		
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks For Clients: Attention Investors & Builders. Fabulous In Town Vacant Lot Zoned Rm1 That Has Potential For 3 Town Homes. Many Of The Studies, Survey, Drawings And Reports Have Already Been Completed.

Extras: Please Contact Listing Agent For List Of All Studies/Reports That Have Been Done To Date And Will Be Forwarded To The New Owners.

Remarks for Brokerages: Fax Or Email All Offers As Per Sellers Directions. Hst In Addition To Purchase Price. Taxes To Be Confirmed By Buyer.

Mortgage Comments:

List: RE/MAX REAL ESTATE CENTRE INC., BROKERAGE 519-942-8700 **Fax:** 519-943-0550
MIKE MULLIN, Salesperson 519-942-8700
Co-Op: SUTTON WEST REALTY INC., BROKERAGE **CB Comm:** 2.5% Plus Hst
Gurdial Bal, Salesperson

Contract Date: 4/6/2011	**Sold Date:** 8/30/2011	**Leased Terms:**	
Expiry Date: 9/30/2011	**Closing Date:** 9/30/2011	**Original Price:**	$175,000
Last Update: 9/1/2011			

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
14 - 75 First Street, Orangeville, ON L9W2E7
519 941-5151
4/2/2013 12:36:45 PM

2 Margaret St
Orangeville, Ontario L9W2N2 Dufferin Orangeville
Pt Lot 28 Pl 195 Des Pt 2, 3, 4 Pl 7R6080
SPIS: N 404-46-J **DOM:** 62 **Taxes:** $1/2012

Sold: $75,000
List: $99,995
75 % List
Last Status: Sld

Vacant Land
Fronting On: W
Acreage: < .49
Dir/Cross St: John/Church/Margaret
Lot: 49.5X70 Feet **Irreg:**
Rooms:
Bedrooms:
Washrooms: 0

MLS#: W2504408 **Seller:** Denise Charlene Wheaton **Contact After Exp:** N **Holdover:** 120
PIN#: **Occupancy:** Vacant

Kitchens:	**Exterior:**	**Zoning:** Residential
Fam Rm:		**Cable TV:** A **Hydro:** A
Basement:	**Drive:** Pvt Double	**Gas:** A **Phone:** A
	GarType/Spaces:	**Water:** Municipal
Fireplace/Stv: **Central Vac:**	**Parking Spaces:** 2	**Water Supply:**
Heat:	**UFFI:**	**Sewers:** Sewers
	Pool:	**Spec Desig:** Unknown
A/C: None	**Energy Cert:**	**Farm/Agr:**
Apx Age:	**Cert Level:**	**Waterfront:** None
Apx Sqft:	**GreenPIS:**	**Retirement:**
Assessment:		
Addl Mo Fee:		
Elev/Lift: **Laundry Lev:**		
Phys Hdcap-Equip:		

# Room	Level	Dimensions (ft)

Remarks For Clients: Recently Severed 49.5 X 70 Foot Lot. Ideally Situated Great Mature Location. Outstanding Building Lot In The Centre Of Town!! Located In A Quiet Neighbourhood Close To All Amenities This Single Family Building Lot Is Perfect For The Investor Or For Someone Looking For An Opportunity To Build And Live In A Custom Home.

Extras: Please Do Not Walk On Property Without Appointment With An Agent. Easements For Sanitary And Sewer Shown On Survey.

Remarks for Brokerages: Buyer Is Responsible For Hst If Applicable, Lot Levies, Permits And All Development Charges. Taxes To Be Confirmed By Buyer As Not Yet Assessed Seperately.Please Register All Showings With Listing Office.

Mortgage Comments:

List: RE/MAX REALTY ONE INC., BROKERAGE 866-279-6638 **Fax:** 905-277-0086
MARTIN ANDREW BALL, Salesperson 519-941-2255; ELLIE BALL, Salesperson 519-941-2255
Co-Op: RE/MAX REALTY SPECIALISTS INC., BROKERAGE **CB Comm:** 2.5% + Hst
Jennifer Lynne Horne, Salesperson

Contract Date: 11/6/2012	**Sold Date:** 1/7/2013	**Leased Terms:**	
Expiry Date: 4/6/2013	**Closing Date:** 4/30/2013	**Original Price:**	$99,995
Last Update: 1/9/2013			

Residential Freehold Unavailable Sale

Prepared by DAVID MAGUIRE, Salesperson
ROYAL LEPAGE RCR REALTY, BROKERAGE
519 941-5151
4/2/2013 12:39:37 PM

Area Code: Dufferin
Municipality Code: Orangeville
Last Status: Sld
Type: Vacant Land

LSC	EC	St#	Street Name	Abbr	Dir	Municipality	Community	List Price	Sold Price	Type	Style	Br	+	Wr	Fam	Kit	GarTyp	A/C	Heat	Contract Date	Sold Date	List Brokerage	Co-Op Brokerage	MLS#
Sld		Lot 28	East Luthe	St	W	Orangeville	Orangevill	$27,700	$23,000	Vacant Lan				0						8/10/2006	1/29/2007	REALTY EXEC	REALTY EXECUT	X964759
Sld		39	Church	St		Orangeville	Orangevill	$38,000	$36,000	Vacant Lan				0						10/1/1995	2/8/1996	NIEUWENHUIS		WA4544
Sld	N	26	Church	St		Orangeville	Orangevill	$42,900	$42,500	Vacant Lan				0						4/15/1999	5/3/1999	SALLY FRANC	FRANCO, SALLY	LJ8605
Sld	N	L58	Sarah	St		Orangeville	Orangevill	$44,900	$34,000	Vacant Lan				0						9/26/2000	3/5/2001	ROYAL LEPAG	COLDWELL BANK	LP8877
Sld	N	47	John	St		Orangeville	Orangevill	$49,000	$40,000	Vacant Lan				0						5/11/1998	6/8/1998	RE/MAX SELE	CENTURY 2: MI	LG4310
Sld	N	L1	Buena Vist	Dr		Orangeville	Orangevill	$73,500	$55,000	Vacant Lan				0						8/28/1998	2/22/1999	FORALL REAL	FORALL REALTY	X23769
Sld	N	L1	Buena Vist	Dr		Orangeville	Orangevill	$73,500	$55,000	Vacant Lan				0						8/28/1998	2/22/1999	FORALL REAL	FORALL REALTY	X23770
Sld	N	18-20	Mill	St		Orangeville	Orangevill	$79,000	$73,000	Vacant Lan				0						11/11/2007	5/16/2008	ROYAL LEPAG	ROYAL LEPAGE	W1259920
Sld		0	Henry	St		Orangeville	Orangevill	$79,900	$53,000	Vacant Lan				0						11/5/2009	12/14/2009	ROYAL LEPAG	ROYAL LEPAGE	W1737834
Sld	N	L4	C	Line		Orangeville	Orangevill	$85,000	$70,000	Vacant Lan				0			Attach		Gas	4/10/1998	3/2/1999	ROYAL CITY	ROYAL LEPAGE	WB6928
Sld	N	428A	College	Ave		Orangeville	Orangevill	$89,900	$80,000	Vacant Lan				0						8/8/2008	9/15/2008	ROYAL LEPAG	SUTTON GROUP	W1442262
Sld	N	98	John	St		Orangeville	Orangevill	$89,900	$82,000	Vacant Lan				0						7/28/2009	8/6/2009	RE/MAX REAL	SUTTON GROUP	W1674443
Sld		L10	Starview	Cres		Orangeville	Orangevill	$94,990	$87,000	Vacant Lan				0						9/21/1998	11/5/1998	ROYAL CITY	ROYAL LEPAGE	LH7931
Sld	N	12	Sherbourne	St		Orangeville	Orangevill	$99,900	$71,000	Vacant Lan				0						1/16/1998	10/7/1998	SUTTON GRP-	RE/MAX YORK G	LF0780
Sld	N	L92	C	Line		Orangeville	Orangevill	$99,900	$93,000	Vacant Lan				0						10/7/2002	11/22/2002	ROYAL LEPAG	ROYAL LEPAGE	W147934
Sld		2	Margaret	St		Orangeville	Orangevill	$99,995	$75,000	Vacant Lan				0				None		11/6/2012	1/7/2013	RE/MAX REAL	RE/MAX REALTY	W2504408
Sld		L6	Fifth	Line		Orangeville	Orangevill	$103,500	$86,000	Vacant Lan				0						9/16/1999	1/13/2000	SUTTON GRP-	ROYAL LEPAGE	X29632
Sld		L1	Fifth	Line		Orangeville	Orangevill	$109,900	$104,500	Vacant Lan	Other			0						7/24/2002	8/14/2002	RE/MAX IN T	ROYAL LEPAGE	X112356
Sld		L1	Fifth	Line		Orangeville	Orangevill	$109,900	$100,000	Vacant Lan	Other			0						1/17/2002	2/21/2002	RE/MAX IN T	LAWLOR REALTY	X42416
Sld		Lot 26	Rayburn Me			Orangeville	Orangevill	$117,000	$117,000	Vacant Lan				0						2/7/2004	5/26/2004	ROYAL LEPAG	ROYAL LEPAGE	W396247
Sld	N	L21	Fifth	Line		Orangeville	Orangevill	$119,000	$100,000	Vacant Lan				0						6/18/2002	1/30/2003	RE/MAX BRAM	ROYAL LEPAGE	X45283
Sld		Lot 1	Highway 9	Rd		Orangeville	Orangevill	$119,000	$115,000	Vacant Lan				0						10/27/2004	7/12/2005	COUNTRY LIV	COUNTRY LIVIN	X562910
Sld	N	49	William	St		Orangeville	Orangevill	$119,900	$122,000	Vacant Lan	Other			0	N					5/15/2000	5/31/2000	RE/MAX SELE	FORALL REALTY	LO2441
Sld	N	3	Starview	Cres		Orangeville	Orangevill	$120,000	$80,000	Vacant Lan				0						5/16/1997	7/1/1997	RE/MAX NORT	PRUDENTIAL EL	LC9020
Sld	N	L14	Blind	Line		Orangeville	Orangevill	$130,000	$130,000	Vacant Lan				0						5/3/2004	10/5/2004	RE/MAX SELE	RE/MAX SELECT	X449243
Sld		31	C	Line		Orangeville	Orangevill	$139,000	$117,500	Vacant Lan				0						1/26/2000	12/13/2002	ROYAL LEPAG	ROYAL LEPAGE	LM7229
Sld	N	31	C	Line		Orangeville	Orangevill	$139,000	$117,500	Vacant Lan				0						5/17/2002	9/1/2002	ROYAL LEPAG	ROYAL LEPAGE	LX5714
Sld	N	16	Starview	Cres		Orangeville	Orangevill	$139,000	$125,000	Vacant Lan	Other			0			Other			4/3/2001	7/5/2001	ROYAL LEPAG	ROYAL LEPAGE	X37793
Sld	N	16	Sherbourne	St		Orangeville	Orangevill	$139,900	$115,000	Vacant Lan				0						2/3/2008	4/24/2008	ROYAL LEPAG	ROYAL LEPAGE	W1303650
Sld		L16	Starview	Cres		Orangeville	Orangevill	$139,900	$135,000	Vacant Lan				0						7/8/1999	2/2/2000	RE/MAX SELE	RE/MAX SELECT	X28625
Sld		L16	Starview	Cres		Orangeville	Orangevill	$139,900	$135,000	Vacant Lan				0						12/14/1999	3/2/2000	RE/MAX SELE	RE/MAX SELECT	X30710
Sld	N	Pt Lt 6	Con 2			Orangeville	Orangevill	$169,000	$160,000	Vacant Lan	Other			0						1/12/2006	3/3/2006	RE/MAX SELE	ROYAL LEPAGE	X816451
Sld	N	16	Sherbourne	St		Orangeville	Orangevill	$175,000	$160,000	Vacant Lan				0						4/6/2011	8/30/2011	RE/MAX REAL	SUTTON WEST R	W2076313
Sld	N	0	Hurontario	St		Orangeville	Orangevill	$189,900	$170,000	Vacant Lan				0						6/2/2010	8/6/2010	RE/MAX REAL	PRUDENTIAL RO	X1888336
Sld	N	L16	Concession			Orangeville	Orangevill	$199,000	$170,000	Vacant Lan				0				None		7/28/2011	8/9/2011	RE/MAX WEST	ROYAL LEPAGE	W2163681
Sld		L10*	Sherbourne	St		Orangeville	Orangevill	$199,900	$190,000	Vacant Lan				0						3/22/2000	4/26/2000	ROYAL LEPAG	RE/MAX YORK G	LN4825
Sld	N	Pt Lt 2	St. Andrew	Rd		Orangeville	Orangevill	$200,000	$200,000	Vacant Lan				0						12/9/2008	12/17/2008	HOMELIFE RE	RE/MAX 2000 R	W1526111
Sld	N	Lot 16	Hurontario	St		Orangeville	Orangevill	$217,000	$205,000	Vacant Lan				0						2/9/2004	5/3/2004	COUNTRY LIV	EXIT REALTY H	X396414
Sld		Lot 16	Hurontario	St		Orangeville	Orangevill	$229,000	$220,000	Vacant Lan				0						3/1/2005	5/2/2005	COUNTRY LIV	COUNTRY LIVIN	X621912
Sld	N	L23	St Andrew'	Rd		Orangeville	Orangevill	$239,900	$225,900	Vacant Lan				0						5/26/2003	11/26/2003	RE/MAX BRAM	SUTTON GROUP	W266366
Sld	Y	Lot 11	Hurontario	St		Orangeville	Orangevill	$239,900	$230,000	Vacant Lan				0						4/15/2006	5/4/2006	COUNTRY LIV	COUNTRY LIVIN	X881380
Sld	N	Lot 30	Hurontario	St		Orangeville	Orangevill	$259,900	$195,000	Vacant Lan				0						11/26/2005	12/14/2005	RE/MAX REAL	RE/MAX REALTY	X800681
Sld	Y	Lot 13	Blind	Line		Orangeville	Orangevill	$310,000	$295,000	Vacant Lan				0						7/7/2007	10/1/2007	COUNTRY LIV	SUTTON GROUP	X1179323
Sld		9-35	Woodvale	Crt		Orangeville	Orangevill	$325,000	$310,000	Vacant Lan				0						6/15/2002	8/12/2002	RE/MAX SELE	RE/MAX SELECT	LY0342
Sld	N	1	Chisholm	St		Orangeville	Orangevill	$419,900	$375,000	Vacant Lan				0				None		9/6/2011	11/30/2011	RE/MAX REAL	SUTTON WEST R	W2190476

Property Details | Neighbourhood Sales | Demographics | Plan List By PIN

40 MILL ST

N/A | ACTIVE | PIN 340110044

Search By Block | Enhanced Report | GeoWarehouse Store

Land Registry Information - PIN: 340110044

Print Store Parcel Register

Address:	40 MILL ST				
Municipality:	N/A	LRO:	07	Area:	1,092 m2
Land Registry Status:	ACTIVE	Registration Type:	LT	Perimeter:	133 m
Description:	PT LTS 23 & 25, BLK 6, PL 138 AS IN MF223973 (FIRSTLY) (SECONDLY) ; ORANGEVILL				
Party To:	THE HYDRO-ELECTRIC COMMISSION OF THE TOWN OF ORANGEVILLE;				

Assessment Information

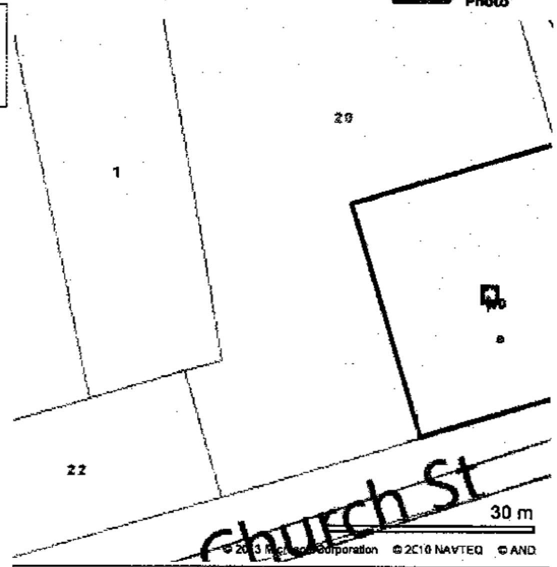
Assessment Roll Number	221403000907700				
2013 Tax Year, Phased In Assessment:	$68,750	Depth:	100.05 F	Frontage:	118.04 F
Assessed Value based on January 1, 2012:	$83,000	Property Type:	560 MEU Transformer Station		

Sales History Information

Store Insurance Claims History

DATE:	TYPE:	AMOUNT:
05/16/1996	T	$2
PARTY TO:	THE HYDRO-ELECTRIC COMMISSION OF THE TOWN OF ORANGEVILLE;	

MAP VIEW STREET VIEW Store Aerial Photo



Ownership	Assessment	Municipality	Lot/Con
LRO	Search Result	Subject Property	Subject Property
Address	Plan	Subject ARN	Neighbourhood Sale

Appendix Q -

GEA Plan

PO BOX 400, 400 C LINE ORANGEVILLE, ON L9W 2Z7
Telephone 519-942-8000 Fax 519-941-6061

Orangeville Hydro Limited Plan to Enable the Green Energy Act

2009

The purpose of this enabler plan is to identify Orangeville Hydro's proposed plan of implementation for aspects of the Green Energy Act that would apply to Orangeville Hydro Limited and its customers. Orangeville Hydro is seeking general approval from the Ontario Energy Board to carry out its plan.

Orangeville Hydro Ltd.
400 C Line, Orangeville, ON L9W 2Z7
Telephone: (519) 942-8000
Fax: (519) 941-6061

TABLE OF CONTENTS

List of Figures....4

List of Tables....4

List of Acronyms 5

Executive Summary 7

1 Overview.... 9

- 1.1 The Green Energy Act 9
- 1.2 Situational Analysis 11
- 1.3 Environmental Analysis.... 12
- 1.4 Company Strategy.... 14
- 1.5 Recent Company Successes 14

2 Vision 16

3 Proposed Strategy 17

- 3.1 Assumptions and Constraints 17
- 3.2 Prioritization Criteria for Strategic Goals 17
- 3.3 Short Term Strategic Goals (Years 1-5) 19
  - Goal 1: Develop Smart Grid Infrastructure and Installation of Smart Meters.... 19
  - Goal 2: Distribution Upgrades to enable Distributed Generation and FIT pricing 21
  - Goal 3: Evolution of CDM 24
  - Goal 4: Marketing Campaign 26
  - Goal 5: Small-Scale Renewable Resource Generation Installations 28
  - Goal 6: Large Renewables 30
- 3.4 Risk Profiles of Investments.... 32
- 3.5 Long-Term Strategic Goals (Years 6-11).... 33
  - Cap and Trade.... 33
  - Combined Heat and Power.... 33
  - Waste Energy Options 33
  - Electric Vehicles.... 33
  - Setup Generation Arm.... 34

4 Work Plan, Milestones, and Timeline.... 35

- 4.2 Execution of GEA Initiatives 37

5 Budget and Resources 38

6 Corporate Evolution 39

Appendix1....40

LIST OF FIGURES

Figure 1 - Opportunities in Energy Supply Chain 9

Figure 2 - Feeder Infrastructure 12

Figure 3 - Proposed timeline for activities 37

LIST OF TABLES

Table 1 –Current Generating Capacity 22

Table 2 – High level financial, regulatory, and operational implications of strategic goals 32

Table 3 – Work Plan, Milestones & Timelines 35

Table 4 - Costs associated with implementing Smart Grid 38

LIST OF ACRONYMS

AMI	Advanced Metering Infrastructure
CDM	Conservation and Demand Management
CHEC	Cornerstone Hydro Electric Concepts
CMI	Count Me In
DG	Distributed Generation
DR	Demand Response
ERIP	Electricity Retrofit Incentive Program
FIT	Feed-in Tariffs
GAM	Global Adjustment Mechanism
GEA	Green Energy Act
GHG	Green House Gas
GIS	Global Information System
LDC	Local Distribution Company
OEB	Ontario Energy Board
OHL	Orangeville Hydro Limited
OPA	Ontario Power Authority
PS	Peak Saver
PSB	Power Savings Blitz
PURE	Power Up Renewable Energy
RC	Renewable Connection
RESOP	Renewable Energy Standard Offer Program
ROI	Return on Investment
SCADA	Supervisory Control and Data Acquisition
SG	Smart Grid
SM	Smart Meter
TGRR	The Great Refrigeration Round Up
TOU	Time-of-Use

EXECUTIVE SUMMARY

The purpose of this Green Energy Act (GEA) enabler plan for Orangeville Hydro (OHL) is to:

1. Identify OHL's proposed activities to implement aspects of the GEA applicable to OHL Limited and its customers; and,
2. Seek approval and funding from the Ontario Energy Board (OEB) to carry out the activities set forth in this document to implement the proposed plan;

The next steps will result in the creation of documents that will:

1. Provide the positions available to OHL;
2. Frame the choices available to OHL that will require Board of Directors approval;
3. Document the elements that will be required to gain approval from the OEB, specially accounting orders; and;
4. Assist in developing the Business Case for 'green' jobs primarily in Orangeville and Grand Valley.

To position OHL as a leader in GEA compliance, an ambitious set of strategic goals are being proposed. The timeline for proposed implementation of the goals is based on activities that take place during two timeframes; Years 1-5 and Years 6-11. While this plan begins January 1, 2010, it is based on underlying assumptions about GEA framework, and it reserves the right for the relative timing and value of the projects to be revisited as regulations and directives are issued or become available.

Based on strategic fit, constraints, risk and reward considerations, an ambitious list of goals under the GEA has been developed. There is a unique set of activity requirements that must be carried out to achieve each respective goal. OHL has a high degree of knowledge for the 6 short term strategic goals and the activities required to achieve them are generally known. High priority strategic goals include:

1. Commissioning of the Smart Grid through the large-scale, yet prudent investment in T&D infrastructure aimed at enabling, and improving, advanced metering, Demand Response, asset management, and system reliability;
2. Installing and connecting Distribution Generation systems to residential and commercial customers;
3. Continuing to support and enhance OEB, Ministry, and Ontario Power Authority (OPA) Conservation and Demand Management objectives. In particular, we will evolve Conservation Demand Management (CDM) opportunities by promoting Demand Response initiatives to residential customers through OPA and custom programs;
4. Promoting, educating and packaging renewable energy resource based solutions through our affiliate Green Pathways Inc. and become the "One-Stop-Energy-Shop". A marketing campaign will be used to engage and inform the various market segments throughout Orangeville and Grand Valley;
5. Launching programs that will support the installation and operation by residential and small business customers of (less than 10 kW) green electrical power generating systems on their properties; and,
6. Installing and operating a large renewable system within the 10MW limit at OHL's corporate office. This installation will also serve as a technology demonstration site, particularly of Ontario and Canadian renewable electricity generation technology;

The lower priority strategic goals are long term visions that OHL will investigate. These include:

- Cap and Trade;
- Combined Heat and Power;
- Waste Energy;
- Electric Vehicles; and,
- Generation Activities.

This Enabler Plan includes the proposed activity, benefits of the activity, timeframe for activity, risk assessment and estimated cost. Benefits of various projects are grouped to realize cross-functional gains.

During the Period of Performance of this proposed plan, it is estimated that 11.5 jobs will be created, 7 of which will be skilled, full-time and long-term positions. The goal is to create "green collar" jobs in the design, manufacturing, installation, CDM, service and education sectors.

The investment/cost of executing this proposed plan in its entirety is conservatively estimated at $3.04 million over 5 years, with an annual average expenditure of $303,344.56 (Capital ($334,800) + Expenses ($271,889.12). The first three years will require $1.91 million (Capital ($1.07 million) + Expenses ($840,000). Partially offsetting these capital expenditures will be the cost avoidance associated with the reduction in electricity demand through our CDM programs.

1 OVERVIEW

1.1 THE GREEN ENERGY ACT

On February 2009, Minister Smitherman announced Bill 150, Green Energy and Green Economy Act, 2009. The GEA has now received Royal Assent. The vision of the GEA is "to make Ontario a global leader in the development of renewable energy, clean distributed energy and conservation, creating thousands of jobs, economic prosperity, energy security, and climate protection". The Ministry plans on achieving its vision by "facilitating the development of a sustainable energy economy that protects the environment while streamlining the approvals process, mitigates climate change, engages communities and builds a world-class green industry sector" (Minister Smitherman, 2009). The Act addresses all forms of 'green' power production and conservation of all forms of energy and is designed to address opportunities in all three areas of the energy supply chain.

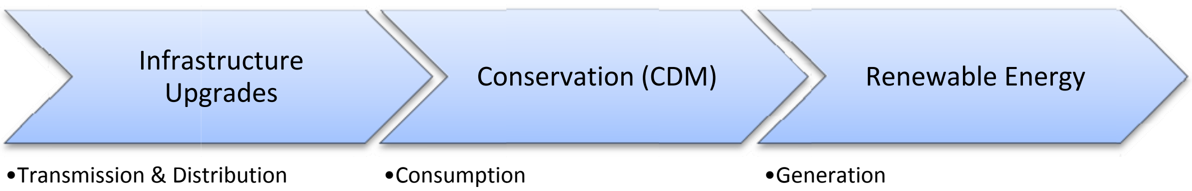


Figure 1 - Opportunities in Energy Supply Chain

The GEA delivers a Climate Change Strategy, positioning Ontario as a world-leader in clean technology. The GEA is intended to foster the growth of renewable energy projects, remove barriers to and promote opportunities for renewable energy projects and to promote a green economy and thereby create a significant number of well paying, long term jobs.

The Act also encourages everybody, whether homeowners, businesses or institutions, to engage in and practice energy conservation and use energy in an efficient manner. Both industry and public support is strong, creating optimism for local economies. Municipalities and utilities are investigating ways to expand core lines of business to take advantage of opportunities created by the Act.

SMART GRID

The Smart Grid enables a two way flow of data and information in the electricity system. The Smart Grid uses "sensors, monitoring, communications, automation and computers to improve flexibility, security, reliability, efficiency, and safety of electrical system" (Ontario Smart Grid Forum, February 2009). The benefits of the Smart Grid are as follows:

- Enhanced reliability of distribution system;
- Reduced outages;
- Quicker response times;
- Better integration of renewables and Distributed Generation (DG);
- Grid optimization;
- Electric vehicle support;
- More efficient use of energy infrastructure; and
- Allows consumers to make consumption choices (I.e. Demand Response).

Smart Meters automatically record when electricity is used and make Time-of-use (TOU) rates possible. TOU pricing through Smart Meters, provides Demand Response, price information, and load control to electricity consumers.

CONSERVATION AND DEMAND MANAGEMENT

Conservation and Demand Management (CDM) has been given a higher profile in the Ministry of Energy. Within the context of the GEA, CDM is defined in terms of the following:

- **Conservation Behaviour** – changing habits or processes to reduce energy consumption;
- **Energy Efficiency** – gain from using more efficient appliance and equipment;
- **Demand Management** – occurs when customers reduce their electricity demand during peak hours (load shifting);
- **Fuel Switching** – customers elect to use other energy sources in place of electricity; and,
- **Distributed Generation** – generates electricity from many small energy sources.

RENEWABLES

The GEA also facilitates the installation of relatively small scale renewable energy based electricity generators that can be grid-tied. The Ministry has shown strong support for renewable energy policy initiatives under the GEA, some of which include:

- Enhancing commitment to renewables ;
- Enabling Feed-in Tariffs (FIT) to procure renewables ;
- Guaranteeing and prioritizing connection of renewables; and,
- Streamlining approvals.

1.2 SITUATIONAL ANALYSIS

A SWOT analysis was developed at a Strategic Planning session held with the Board of Directors in December 2008. The SWOT analysis excludes implications under the GEA and its purpose is to provide insights into the general pulse of the organization.

STRENGTHS

The following were identified as strengths of the organization:

- Strong management team (for size of the organization);
- Productive labour force, and supportive union (local membership);
- Foresight to establish Green Pathways Inc. as a One-Stop-Energy-Shop which provides high level of service and customer satisfaction, based on survey results; and,
- Good relationship with Town, including Town CAO, Home Builders Association, Dufferin Manufacturing Association and Chamber of Commerce.

PROACTIVE RESPONSES TO PERCEIVED WEAKNESSES

The following were identified as weaknesses of the organization:

- Limited land for development – bound by Hydro One
    - Grow business through green opportunities;
- Aging labour force – 5 year retirement window
    - Succession plan is in place;
- Risk averse Shareholder
    - Build business cases that provide shareholder comfort with acceptable risk;
- No formal asset management strategy
    - Formalized asset management strategy is being completed with assistance from Hatch Engineering; and,
- Organization populated with generalist, few opportunities to specialize;
    - Access to specialized resources through organizations such as Cornerstone Hydro Electric Concepts (CHEC), Green Pathways Inc., Power Up Renewable Energy (PURE), Rodan Energy and Metering Services.

OPPORTUNITIES

The following were identified as opportunities for the organization:

- Leverage CHEC membership
    - Cost savings and resource sharing;
- Green Pathways Inc.
    - Broader scope of business opportunities;
- Operation integration of Grand Valley
    - Expanded customer base allows for greater cost effectiveness; and,
- Rate design
    - Creating a model for better rate allocation.

THREATS

The following were identified as threats to the organization:

- **Government Policies** – risk and uncertainty increasing, as changes in role of regulator and increased expectation from individual LDCs; and,
- **Regulatory risk** – rate rebasing is more than a financial exercise, it is the foundation for future revenue – expectations and requirements continue to change.

1.3 ENVIRONMENTAL ANALYSIS

OHL is a municipally owned Local Distribution Utility, servicing the town of Orangeville and the former Village of Grand Valley. The LDC services almost 11,000 customers and has a strong, highly skilled management team, many of whom are long serving employees with the utility. With over 90 years of supplying the region, OHL has an intimate knowledge of the utility and its operations.

The Town of Orangeville and the Township of East Luther Grand Valley have been identified by the province as places of growth. This means that unless Conservation and Renewable Generation activities are proactively pursued, the ability to service the anticipated growth will be compromised. OHL expects a minimum of 9% growth in customer numbers overall. Normally, this would relate to an approximate increase of 14% in demand when commercial and industry customers are taken into account. However, due to economic conditions, Orangeville has lost a couple of industries with another major industry to close down soon. We are therefore forecasting our demand to decrease in comparison to 2009 demand. The proposed conservation programs will further improve our demand. OHL together with its affiliate, Green Pathways Inc., chooses to be responsive rather than reactive to the evolving energy environment.

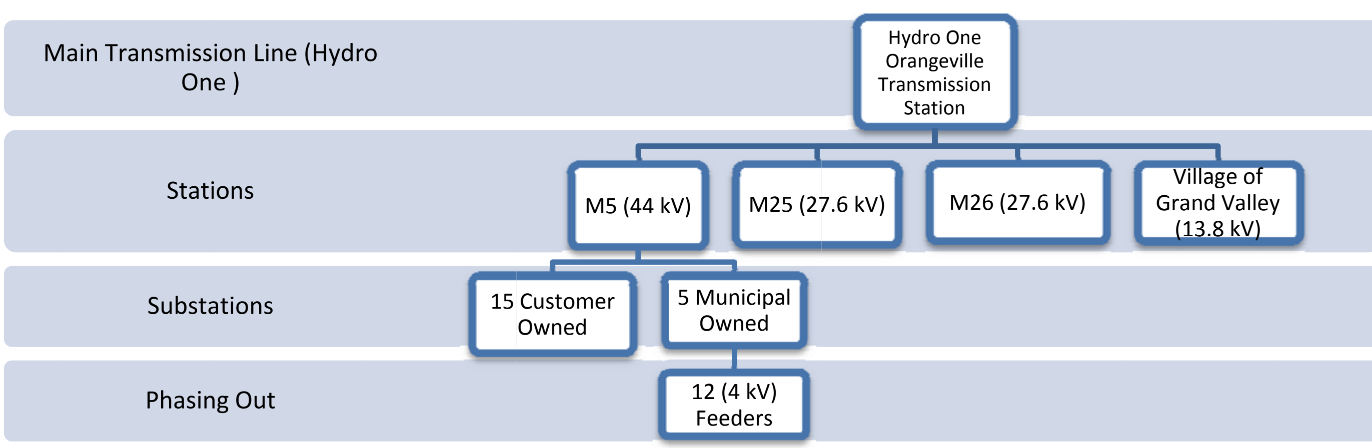
OHL has 3 feeders which are fed from the Hydro One Orangeville Transmission Station.

The M5 is a 44kV feeder which feeds 5 municipal substations and 15 customer owned substations. An older 4kV system of 12 feeders is then fed from the 5 municipal substations. OHL has been gradually, over the past 20 years, converting load from the older 4kV system to a newer standardized 27.6kV system. There are 2 - 27.6kV feeders, the M25 & the M26.

OHL also looks after the Village of Grand Valley. There is only one 13.8kV feeder which is fed from a Hydro One Distribution Station.

Both Orangeville and Grand Valley are fed from the same Hydro One transmission station. The allowable distributed generation that Hydro One has set for this station is 53.1 MW on the 27.6kV portion and 34 MW on the 44kV portion.

Figure 2 - Feeder Infrastructure



In going forward with any new set of initiatives, it is prudent to have a common understanding of the environment in which you are operating. The political, economic, social, and technological implications of the GEA on OHL are included below.

POLITICAL

- OHL believes that the greatest single risk is linked to uncertainty of regulatory and political climate; and,
- As a provincially regulated entity, changing requirements create risk to the company, which is directly linked to risk to the town in both rates (customers) and dividends (municipality).

ECONOMIC

- Ontario's economy stalled in 2008 and is likely to see nothing more than slow growth in 2009;
- Although the current economic climate will have implications for OHL, its customers and the local community – many participants of the strategic planning session feel it will be no greater than the impact felt by other similar industry players and mostly beyond the control of OHL;
- The recession may limit the number and type of opportunities, creating a shorter time horizon than other similar plans; and,
- It should be recognized that during the implementation of this Plan, a number of significant events and activities will occur that will affect the supply and demand of electricity power and thus will influence its execution.

SOCIAL

- Relates largely to ratepayers and taxpayers, and their perceptions of what is happening in their local community;
- Perceptions could be affected by future rate increases brought about by factors beyond the company's control (Global Rate Adjustment); and,
- OHL's customer base is anticipated by 2020 to grow to 13,000 residential and commercial customers.

TECHNOLOGICAL

- Generally concerned with emerging trends in the use of the new green technologies by either the company or its customers – the impact of Smart Meters needs to be considered and could be seen as a structural change in the energy industry.

1.4 COMPANY STRATEGY

The strategic goals OHL is proposing to enable the GEA must be aligned with the company's overall strategy. The top four priorities for OHL (in no particular order) include:

- Growing the business to benefit the community and through green business opportunities;
- Leveraging the benefits of CHEC membership – Continue to encourage CHEC to lobby to reduce response requirements by the regulatory entities;
- Possible mergers to grow the company. It is of paramount importance to OHL that they be the majority shareholder – investigating growth with same size or smaller businesses ; and,
- Investigating opportunities to utilize renewable energy, and pursue potential partnerships with renewable energy companies.

Other notable strategies include:

- We will stay current with industry, sector, and regulatory changes;
- We will continue to comply with all legislation related to our industry, as well as all other government regulations that are required of us;
- We will investigate areas that are within our control to reduce or curtail costs, or to better utilize resources;
- We will develop a formal asset management plan to enhance the overall value of the organization;
- We will network with other boards to develop and share best practices; and,
- We will keep the board informed but our main focus will be on the customer's needs.

1.5 RECENT COMPANY SUCCESSES

ORANGEGILLE HYDRO

- **Peak Buster Award, October 2008 -** OHL is one of seven Ontario electric utilities that have won a Peak Buster Award for keeping the summer peak power demands below the provincial average;

- **Ontario Clean Air Alliance Award, 2007 -** OHL received one of eight "Peak Buster" awards for reducing peak electricity demand this past summer below the provincial average. OHL collaborated with Orangeville Sustainability Committee to Create the Orangeville Energy Calculator which calculated averages of OHL usage to be used for comparative purposes against the average Orangeville home;

- **Reduce the Juice** – Promoted conservation programs on behalf of the Ontario Power Authority through direct interaction with our community by way of door-to-door canvassing, participation in the Farmers Market and Founders Fair. Reduce the Juice worked in conjunction with local businesses offering energy audits and discounted energy retrofits to help promote energy conservation;

- **Green Pathways Inc. has run 2 programs; Power Savings Blitz (PSB) and Electricity Retrofit Incentive Program (ERIP)** – Green Pathways Inc. has been a delivery agent in 2008 & 2009, promoting the PSB and ERIP program on behalf of OHL;

- **Network** – OHL has worked with various organizations such as Reduce the Juice, PURE, Green Pathways Inc. and other LDCs through its CHEC affiliation to help develop a culture of conservation within the community; and,

- **Home Shows** – OHL showcased the Hazard Hamlet for kids that helped explain the dangers of live electricity. OHL also promoted OPA programs within the community.

GREEN PATHWAYS INC.

Green Pathways Inc. was established in May 2008, in partnership with the non-profit group PURE. Although relatively new, this One-Stop-Energy-Shop is gaining tremendous credibility in the community by virtue of its efforts and customer responsiveness. OHL has had excellent success working in conjunction with Green Pathways Inc., in delivering various sets of programs. The demonstrated passion and desire to find total solutions of Green Pathways Inc. strongly positions it to execute and further the proposed GEA activities, in conjunction with OHL, as they relate to CDM and Renewable Energy Generation.

While the current demand for electricity has diminished due to the economic down turn, this plan recognizes the need to consider long-term planning because of the ultimate state of generation in the province (decommissioning of coal fired generators and nuclear life expectancy). Green Pathways Inc. will continue to support its initiative to be known as the One-Stop-Energy-Shop in the Orangeville area and beyond.

2 VISION

OHL, together with its affiliate service company Green Pathways Inc., aspires to establish itself in the minds and actions of its customers as the preferred source of unbiased, credible and authentic information for CDM and Renewable Generation. OHL aspires to be recognized as the source of reliable and excellent quality Small-Scale Renewable energy based equipment together with its installation in all aspects – a competent, dependable facilitator and total solutions provider. OHL's vision under the GEA for Smart Grid, CDM, and Renewable Generation is set out below.

SMART TECHNOLOGY

- To build a Smart Grid that will meet the technical needs of our customers and is economically prudent; and,
- Exercise vigilance with respect to the size and makeup of the OHL's Smart Grid as smart meter functionality increases.

CONSERVATION

- To reduce its per capita consumption by a minimum of 7% in the next five years (based on 2009 consumption); and,
- To use aggressive conservation practices to cap the increase in demand, caused by customer growth at 5 MW in 2020 - the forecasted demand is 6MW, based upon current usage and generation.

RENEWABLE GENERATION

- To install renewable energy based generation capability to service its Orangeville and Grand Valley customers – connecting 800 premises with small scale renewable energy based generation capabilities with a total capacity of 2,400 kWs.

COMPLIMENTARY VISIONS

In addition to government mandated/driven initiates, OHL also has the vision to:

- Deliver, educate, and provide training in programs that will in partnership with Green Pathways Inc. meet the needs of OHL's customers; residential, low income, seniors and commercial;
- Establish Green Pathways Inc. as a recognized and integral part of the delivery of services and products associated with OHL's enabling of the Green Energy Act;
- Implement facilities to support servicing electric vehicles with emphasis on converting the Town's buses to electric; and,
- Create 7 long-term sustainable "green collar jobs" within OHL.

3 PROPOSED STRATEGY

3.1 ASSUMPTIONS AND CONSTRAINTS

The strategic goals proposed in this plan are premised on assumptions and supporting facts including but not limited to:

- LDCs will be allowed to invest in Renewable Generation assets under the GEA legislation;
- Any investment inside the LDC will be considered a utility asset and eligible for Regulated Rate of Return (Generation Adjustment Mechanism (GAM) or distribution rates for customers);
- A significant number of Small-Scale Renewable energy based Distributed Generation projects will make a positive contribution to lower electricity deliveries by OHL;
- OHL will partner with private sector and 3rd party delivery channels to gain expertise in areas that are not currently core strengths;
- The replacement/refurbishment of much of the province's existing generating capability will be well underway (Note: all coal-fired generators decommissioned by 2012);
- All customers using Smart Meters will be subjected to Time-of-Use (TOU) billing;
- The "conservation culture" being promoted under the CDM plans will encourage customers to reduce electricity consumption;
- OHL will continue its voltage conversion program as opposed to modifying the five existing municipal substations (estimated cost: 1 million dollars per station);
- There are areas of the province where the transmission system has limited or no ability to accept new generation. OPA will be prudent and not procure new generation that will exceed the capacity limit (based on approved or allocated projects); and,
- Hydro One will develop a transmission plan that outlines system upgrades and reinforcements to overcome some known constraints.

3.2 PRIORITIZATION CRITERIA FOR STRATEGIC GOALS

It is the overarching goal of OHL to fully embrace and comply with the Green Energy Act, to the best of our ability, in an economically prudent manner. This will protect our customers and our shareholders.

The strategic goals with respect to the GEA are consistent with the strengths of the organization. Our objectives are to be a promoter and installer of renewable energy devices and equipment and an effective deliverer of a comprehensive selection of conservation programs. In addition to complying with legislation and orders of the regulatory, OHL will achieve its strategic goals by setting realistic and feasible short goals as well as a long term vision. The strategic goals are consistent with OHL's vision and are directed by the core strengths within the organization.

The proposed timelines are based on underlying assumptions about GEA framework. As regulations and directives become known, relative timing and value of projects will need to be revisited. OHL is seeking clarification of approval requirements to ensure cost recovery. OHL recognizes change continues to occur (regulatory oversight) and that re-assessments will be required.

SHORT- TERM (YEAR 1-5)

The short-term strategic goals are provided in Part 3 of this document and are Goals 1-6. They are of high priority and their achievement commences at the start of Year 1 (January 1, 2010). OHL has already begun the planning and implementation phases for these. An estimate of the capital and operating costs associated with implementing the short-term goals are shown in Table 3 in section 5.

However, some of the proposed activities under the short-term goals will require additional time to plan and implement due to the regulatory, operational, and the technological nature of the activities (I.e. some of the business cases have not been completed, capital and operating costs and respective return on investment are unknown).

LONG TERM 6-11 YEAR GOALS

The long-term strategic goals are the proposed objectives to be achieved during the 6-11 year period. Achieving these goals, are dependent on feasibility studies or business cases that will be completed at a later date or as opportunities arise. These goals provide long term direction for OHL.

3.3 SHORT TERM STRATEGIC GOALS (YEARS 1-5)

GOAL 1: DEVELOP SMART GRID INFRASTRUCTURE AND INSTALLATION OF SMART METERS

SITUATION

The provincial mandate for installing Smart Meters and implementing an advanced metering infrastructure is considered the first step in realizing the Smart Grid. OHL's current system requires upgrading to improve its performance and efficiency and to deploy a Smart Grid to the benefit of its customers.

Presently, OHL does not have a SCADA system because the benefits did not warrant the cost. In order to implement a Smart Grid, OHL will need to install SCADA (i.e. by sharing costs with other CHEC group members). OHL has had preliminary discussions with a neighbouring LDC regarding the costs of sharing a SCADA system.

STRATEGY

OHL recognizes that there are many functionalities of the Smart Grid as previously identified in section 1.1. As a first step, OHL would like to allow TOU billing to enable Demand Response and Load Control during critical peak periods to immediately assist the customers in a more efficient use of their energy.

The next steps in this progression will be advancement of metering technologies and the integration of functionalities to realize new enabled services. OHL plan is to make investments with respect to Advanced Metering Infrastructure (AMI) include:

- Retrofits or add-on equipment of first generation meters in strategic areas; and,
- Expansion and leverage of the advanced metering infrastructure – data analytics, outage reporting, theft detection, remote disconnects, power quality monitoring, spot price settlement for generation, etc.

In order to optimize the implementation of the Smart Grid, OHL will continue to convert older 4kV feeders to the newer standardized 27.6kV distribution system over time through our normal capital works program. However, the equipment necessary to make the grid smart has not been included in our normal capital works. In addition, there are a number of components of our distribution system that have been converted and will require upgrades to make them 'Smart', including:

- Installation of Remote Sensing and SCADA;
- Motorized Switches;
- Engineering Design; and
- PME Upgrades.

SUCCESS INDICATORS AND TARGETS

- Enhanced reliability of the electricity system;
- New Distribution Generation facilities attached to grid and enhanced efficiency of distributed network;
- Job creation; and,
- A fully integrated Smart Grid capable of facilitating all forms of generation, and reduction in energy consumption per capita, based on 2009.

FINANCIAL IMPLICATIONS

Implementing Smart Grid infrastructure is a long-term investment. OHL will make prudent decisions taking into account the needs of its customers and capital providers (i.e. shareholders). It recognizes that the objective will have a very significant financial impact on the organization.

Rather than modifying the five existing 4kV municipal substations at an estimated cost of 1 million dollars each, OHL will continue its voltage conversion program – not a financial implication, rather a cost minimization decision.

The implementation of a fully functional Smart Grid would also create 1 new full-time job, with an annual salary of $80,000 per year plus benefits ($100,000 total in 2009 dollars).

To enable the Demand Response and Load Control, it is estimated that the in-home information system would cost approximately $420 per customer and will utilize the Smart Meter infrastructure.

GOAL 2: DISTRIBUTION UPGRADES TO ENABLE DISTRIBUTED GENERATION AND FIT PRICING

SITUATION

Under the GEA, the connection of Renewable Generation requires priority access to the electricity grid, as well as an obligation by utilities to connect such generation into their system.

OHL will prepare a streamlined process to connect Renewable Generation. This will include financing, installing, maintaining, and billing for small Renewable Generation installations. Capital and operating costs in the area of renewable energy generation connection administration include:

- Contract administration;
- Customer service;
- Billing and Settlement – include an automated process for settlement between LDC interval meter data with IESO spot price;
- CIS upgrades;
- Promotion/communication;
- Connection Contracts;
- Standardized contracts, financial/legal/commercial involvement; and,
- Online self-assessment portal, including tracking application and project status.

OHL is committed to cooperating fully with commercial generators to give Orangeville a competitive advantage over other locations. To facilitate a streamlined connection amongst utilities, standards development in the areas of engineering, communication and operation is required. The plans for standards development include:

- Development of additional standards;
- Convergence of standards as appropriate;
- Pre-qualified contractors; and,
- Safety standards.

Metering is an essential component in the facilitation of renewable energy connection. This includes:

- Meter base/meter technology;
- ESA requirements for meter locations – minimize meter relocations; and,
- Leveraging the advanced metering infrastructure for check metering and verification of generation source.

The amount of generation capacity from distributed generation allowed to be fed back into the grid is constrained by a variety of engineering factors, such as short circuit capacity, ampacity, power quality, and protection and control. It is anticipated that in the initial rollout, the connection of inverter-based Renewable Generation will not impose many limitations, though larger scale synchronous generation will be more constrained.

Additional investments required to enable Distributed Generation include:

- Studies to determine existing capacity to accommodate Renewable Generation of various types and methods/actions required to eliminate constraints;
- Determination and publication of guidelines to be used for initial planning purposes for sizing generation capacity within the distribution system (i.e. by voltage, station, feeder or geographical location);
- Description of plans to mitigate constraints on an as needed basis, to the maximum extent technically possible;
- Coordination amongst distributors and transmitter, to remove regulatory barriers to expand infrastructure in supporting Distributed Generation; and,
- Appropriate protection of confidential or commercially sensitive information.

OHL's new Distribution Generating capacity will enhance and expand on its current capacity (shown in Table 1, below).

Table 1 - Current Generating Capacity

	Voltage	2008 Peak	2008 Low Pt.
M5	44 kV Delta	18.6 MW	11.7 MW
M25	27.6 kV Wye	10.7 MW	4.4 MW
M26	27.6 kV Wye	11.1 MW	4.8 MW
Grand Valley	13.8 kV Wye	2.2 MW	0.9 MW

ASSET MANAGEMENT PLAN

OHL is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. OHL distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of OHL's physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. OHL does not have a formal asset management plan. For this first stage in developing an asset management plan, we contracted Hatch and Associates to assist by doing a comprehensive review and analysis of current asset condition. Accompanying this proposal in the Rate Application as Appendix A is a September 8, 2009 document titled "Asset Management Executive Summary Report". The findings of the Asset Management Condition Assessment Report will be used as a guideline to determine the short-term capital expenditure levels until there is more work completed on the data and asset management strategies contained within an Asset Management Plan. This report contains analysis of overall asset condition and assisted OHL in determining our 2010 and 2011 capital expenditures. It is important to note that OHL's formal Asset Management Plan is in its early development stage and in 2010 we will implement a GIS system and will perform a system optimization study. OHL will use the results of our future study along with the recent condition assessment to help us effectively plan capital and maintenance sustainment work programs.

There is no requirement for a short-term strategy to replace meters as the Smart Meter Initiative will likely result in the replacement all of OHL's meter assets in the next few years.

The plan for Substation assets is currently under investigation by OHL to determine its context with respect to the strategy for the conversion of distribution system overhead and underground 4.16 kV line assets to 27.6 kV thus allowing for a further reduction of the four remaining municipal substations.

STRATEGY

Our strategy is to complete all the necessary distribution upgrades required to enable Renewable Generation connection to the grid. Non –Renewable Generators must still be connected to the distribution grid and will be connected to the grid in a similar fashion as the renewable generators.

GOAL 3: EVOLUTION OF CDM

SITUATION

OHL delivers electricity conservation and energy efficiency programs to both commercial and residential consumers through programs offered by the Ontario Power Authority (i.e. Every Kilowatt Counts). OHL will continue to support these programs, and will develop customized programs to create a culture of conservation - to encourage reduction of consumption while building awareness within its communities.

Since the establishment of the Conservation Bureau, within the Ontario Power Authority, as included in the Electricity Act, 1998, there have been a number of primary electricity conservation programs undertaken, both as community initiatives and as programs offered by the Ontario Power Authority. “Every Kilowatt Counts” is a branded initiative that encompasses all of the OPA programs: Its objective is to focus the consumer on one theme when they think of energy conservation. Under this program, OHL has gained experience delivering both community initiatives and individual programs. An example of the former is the highly successful “Reduce the Juice” program. This program involved having a team of trained high school students, under the supervision and oversight of professional staff, go door-to-door in both residential and commercial sectors, obtaining pledges of electricity reduction, and, offering a selection of more energy efficient light bulbs for purchase by the premises owner/occupier. This resulted in a minimum of a 5% reduction in electricity consumption.

Examples of the latter are the Power Savings Blitz-Direct Install program and the Electricity Retrofit Incentive Program. Both these programs have recently been awarded to Green Pathways Inc. who will act as Delivery Agent, and both these programs are on-going.

However, the Green Energy Act proposes the dissolution of the Conservation Bureau and vests the execution of energy conservation programs in the Ontario Energy Board. This would be an opportune time for OHL, in collaboration with Green Pathways Inc., to review the various electricity conservation programs for effectiveness. Subsequent to this review, initiatives, programs and projects considered to be most effective and consistent with our electricity conservation and demand reduction goals, will be proposed. During this review period the existing programs would continue to be offered.

STRATEGY

OHL will continue to support and enhance OEB, Ministry, and OPA objectives and ensure access to province wide programs and work with retailers, businesses, and associations to help promote this agenda.

With respect to OPA Programs, OHL plans to explore opportunities for promoting Demand Response initiatives involving all OHL customers. The Demand Response programs that OHL will explore include:

- **DR 1**- Encourage short term Demand Response capacity in response to the IESO Three-Hour Ahead Pre-Dispatch signal in the electricity market;
- **DR 2** - Participants can contract to reduce a pre-determined amount of load for a minimum period of four consecutive hours up to a maximum of 12 consecutive hours; and,
- **DR 3** - Participants make themselves available during scheduled hours for potential notices to reduce load.

OHL will also explore the commercial applications through OPA incentive based programs to help reduce peak demand for electricity in the Orangeville area and the burden on currently constrained areas. In rolling out existing OPA programs, funding should be available through OPA; however some additional local promotion and customer incentives will be required.

With respect to Utility-specific Programs, OHL proposes to enhance the overall customer base by acknowledging that a great deal has already been accomplished through Demand Management; however existing programs may not be enough to reach provincially allocated targets.

Any new programs will require additional funding and may not initially be cost effective according to existing metrics.

GOAL 4: MARKETING CAMPAIGN

SITUATION

The Green Energy Act states: “The Government is committed to fostering the growth of renewable energy projects….and to removing the barriers to and promoting, the opportunities for renewable energy projects and to promoting a green economy.”

It has been determined that there is a significant lack of knowledge in the consumer community with regard to the various aspects addressed by the Green Energy Act. OHL, in collaboration with Green Pathways Inc. and qualified experts, intends to address this situation by developing consistent vehicles of communication upon which our communities can rely upon to obtain current information regarding all aspects of conservation and renewable energy.

STRATEGY

To accomplish our proposed goals in response to the GEA, OHL in partnership with Green Pathways Inc., recommends introducing customized programs to foster a “grassroots” customer understanding of CDM. We will lean heavily on education and awareness activities. In the execution of our education and awareness plan, we will work together with our subsidiary Green Pathways Inc.. The marketing plan will commence January 1, 2010. The first 6 months will be used to assess current activities and properly construct the Marketing Plan. Our strategy is to educate and encourage the following market segments:

- **Business/Industry Institutions and Associations:** OHL and Green Pathways Inc. will continue to capitalize on their excellent relationships with The Greater Dufferin Area Chamber of Commerce, The Dufferin Area Manufacturers Association, The Business Improvement Association, The Dufferin Builders Association, The Headwaters Tourism Association, and the Dufferin Farmers Association. We will foster relationships with any company or association that furthers our CDM agenda. Our current activities include ERIP and PSB participation. Past activities include participation in the Eco Energy, Home & Lifestyle show, and Reduce the Juice. The main goal is to:
    - Introduce energy conservation information, programs and products on CDM and renewables to all new and existing commercial businesses.
- **Schools and Educational Facilities:** Educating students may be our best channel for communicating awareness and inspiring further reaching activity. Any proposed programs will encompass all children from JK-G12. Within the timeframe of our short and long term goals, many students will graduate, join the work force, and become home-owners/renters. The goals are to:
    - Work with schools boards and schools through the Grade 5 pilot project, to educate students on consumption, the environment and green energy so they can contribute to the realization of the long term goals and objectives of the GEA, with respect to CDM and the introduction of renewables;
    - Complete our proposed 6 month assessment which will include:
        - Assessing viability of holding a local “Green Science Fair & Expo” (If successful, it may be expanded to Regional or Provincial levels).

- **Residential Homeowners:** This is a diverse age group of varying socio-economic circumstances and levels of education. OHL and Green Pathways Inc. will extensively educate this segment with regards to Smart Metering, CDM, and Renewables. Our current activities include The Great Refrigerator Round Up (TGRR) and Peak Saver (PS) participation. Past activities include participation in the Eco Energy, Home & Lifestyle show, and Reduce the Juice. Our goals are to:
    - Introduce energy conservation products and information on CDM and renewables to all new and existing residents within Orangeville and Grand Valley with our Welcome Wagon Program;
    - Conduct a feasibility study to consider residential programs modeled after ERIP and PSB; and,
    - Determine financial viability during the 6 month prior to implementation of proposed activities,
- **Low Income & Seniors:** This is an excellent channel to promote awareness/education since they are a diverse age group of varying socio-economic circumstances and levels of education with a similar goal or focus to cut costs
    - Introduce energy conservation products and information on CDM and renewables to all new and existing low income residents within Orangeville and Grand Valley with our Welcome Wagon Program;
    - Implement residential programs modeled after ERIP and PSB; and,
    - Address the needs of our community for those who are on a fixed income, who cannot afford to purchase energy saving products;

PROPOSED RESOURCES

Engagement and information delivery techniques and practices will be those that are found to be the most effective for the particular group. The following actions are suitable for enhancing awareness:

- It is proposed that OHL's current facility become a technology and practices 'flagship' and be a demonstration site for Ontario and Canadian green technology;
- Develop a strong information and responsive website for OHL, with an emphasis on conservation, renewables, energy efficiencies, incentives and links to programs, suppliers, governments and agencies, including assessment tools;
- Create a common vehicle for communicating energy saving programs and news to the community through an online newsletter and "Community Conservation Lending Library" within Green Pathways Inc. office. It is our view that Green Pathways Inc. will develop an extensive resource library specific to the green world, including renewables, conservation and energy efficiency;
- OHL in conjunction with Green Pathways Inc. will provide information sessions and workshop seminars to the various segments of our communities;
- Explore the viability of a 'high impact' alternative-fueled green vehicle to serve as a mobile display and demonstrator. All systems and furnishings within this vehicle would be examples of green technology, and could be utilized for both education and training.

Programs and Technical Training: As this Plan is executed there will be a demonstrable need for both program training and technical training. These methods will act as a consistent vehicle for our community and staff to rely on regardless of the program being implemented.

GOAL 5: SMALL-SCALE RENEWABLE RESOURCE GENERATION INSTALLATIONS

SITUATION

The GEA encourages and facilitates small scale distributed generation installations. These will be executed under the auspices of the MicroFIT Program.

OHL wishes to take full advantage of this opportunity and views small-scale renewable generation /distributed generation as residential and small business owned wind and solar projects. Other technologies may also be included.

STRATEGIES

OHL envisions being the 'one-stop-energy-shop' for all of our customers as well as residents in the rural area surrounding Orangeville and Grand Valley. OHL would like for customers to be able to purchase their systems from, have them installed and maintained by, financed through, and billed by OHL.

Since this is not currently allowed by our license, we anticipate initially conducting these activities through our affiliate Green Pathways Inc. (Note: this arrangement may prove to be the most efficient and effective vehicle by which to conduct this aspect of the business).

OHL and Green Pathways intend to develop a viable arrangement with suppliers and installers of Renewable Energy packages, have them complete the installation, certification and commissioning and provide after sales, in-service/product support. OHL and Green Pathways Inc. would perform initial suitability and viability assessments. It would also make the prospective participant aware of issues such as installation specific insurance requirements.

OHL proposes that every effort and preference will be given to sourcing Ontario and Canadian designed and manufactured products since it is known that such sources exist for both solar powered and wind powered products.

OHL anticipates there will be a market for approximately 800 small-scale generation installations. This potential demand would create full-time jobs for 2 installation / maintenance technicians, 1 engineer, 1 administration person, and 1 marketing person.

There are two candidate acquisition and installation scenarios. 'Get you Started' and Lease to own/rent to own installations:

The goal of these Programs is to achieve the maximum number of residential and small business installations of less than 10 kWs (MicroFIT Program) and thereby have a significant influence on future electricity demand. i.e. its reduction. Initially this might be restricted to solar PV since it will be offered only in the towns of Orangeville and Grand Valley. It could then be expanded to include wind turbines for more rural installations with suitable wind conditions.

GET YOU STARTED INSTALLATION

The system would be offered as an installed 'starter kit' package of modest size, e.g. single panel – 160W, but would have provision to be scaled up incrementally, should the Participant wish, at their cost and could then conform to the terms and conditions of the Lease to Own/Rent to Own program . The Program would be marketed, managed, delivered and installed similarly to the PSB program. i.e. a Provincial government sponsored and funded program, offered by the OEB/OPA and delivered by OHL and or its Agent. The program application and installation permit application would be made by the prospective participant as identified in the MicroFIT Program.

LEASE TO OWN / RENT TO OWN INSTALLATION

In this program, the applicant identifies the size/capacity of the system of interest and makes application through the MicroFIT Program. Any costs or charges associated with the determination of site suitability and viability would be borne by the proponent. Green Pathways will co-ordinate the installation, grid-tie and commissioning of a system of defined capacity.

SUCCESS INDICATORS AND TARGETS

- Growth of sales in DG packages;
- Positive customer feedback and favourable ROI; and,
- Smooth integration of DG into Smart Grid.

FINANCIAL IMPLICATIONS

All detail materials, installation and tie-in labor, certification and commissioning costs would be transparent to the participant. These costs would be recovered through FIT's. This could be in the form of an interest bearing loan and the transaction conducted as part of the monthly billing process.

GOAL 6: LARGE RENEWABLES

SITUATION/STRATEGY

In partnering and investing in small renewables generation with commercial or industrial businesses, OHL will be supporting the local industry and furthering its objective of becoming a "green" leader amongst similar sized communities.

Presently there are no large-scale generation projects planned for our service territory. However, there are large-scale projects planned in Hydro One's territory adjacent to our service areas that have already allocated all of the available capacity through RESOP. Some developers of these projects have requested direct connection to OHL. Should a large-scale project emerge, we may have to expedite voltage conversion plan and /or build additional 3 phase circuits.

Partnering with commercial or industrial customers to develop solar or wind projects fits in our long range Year 6-11 year plan. Business cases for investing in Renewable Generation jointly with Commercial/Industrial customers are required before they begin. This may include analysis of opportunities for sharing of risk and LDC financing of projects which might not otherwise be developed. The main reason this goal is within the 2-5 year time horizon is because the grid is currently constrained – the time of project commencement assumes transmission constraint will be resolved by Hydro One and new capacity will be accessible.

STRATEGY

As a first step for large renewables we propose building and operating our own Distributed Generation facility and feeding electricity back to the grid. We would like to build and own our own Distributed Generation System to pilot the renewable distributed generation concept. A renewable generation system with the maximum allowed generating capacity under the Green Energy Act will be considered. OHL will conduct a feasibility study for the project to determine the optimal generating capacity (which may be significantly less than 10 MW).

After OHL has successfully completed and connected its large Distributed Generation project, it anticipates having the necessary infrastructure in place to start connecting other Distributed Generation to its grid. OHL will continue growing its distribution system and make the administrative, standards, metering, and generating capacity investments while it is developing its own Distributed Generation facility. Additionally, we would like to create a business case for creating a "green" commercial park.

OTHER COLLABORATIVE LARGE SCALE RENEWABLE PROJECTS

There are a number of possible collaborative projects, some of which may qualify as 'community' that are of interest to OHL, collaborating with Green Pathways Inc. and OHL customers. It is OHL's intention, together with Green Pathways Inc., to be pro-active in communicating potential projects within the community and identifying prospective candidate partners who can take advantage of and benefit from programs facilitated by the GEA.

Apart from wind and solar based electricity generating systems, OHL is now aware of a small-scale bio-waste system (suitable for hospitals, schools, nursing homes, hotels for example) which would significantly reduce the requirement to landfill waste products that cannot be recycled or are not suitable for composting.

Examples of Potential Collaborative/Partnership Projects include:

School Premises – Participating in the grade 5 Green Schools Pilot Initiative; a collaborative project/program that is attractive to Orangeville Hydro and Green Pathways, is the recently announced Green Schools Pilot Initiative. This Initiative has a number of aspects, green electricity generation being just one, where we could participate in an effective and constructive way. By working with both the Upper Grand District School Board and the Catholic School Board together and a team of competent 'partners', we can help deliver significant benefits to the School Boards and school premises in the area.

The next step is to contact the Schools Boards to determine whether they are interested in participating in a Science Fair Event and whether they have indicated this to the Ministry of Education.

Flat Roofed Buildings: There are a significant number of buildings in Orangeville with flat or shallow rise roofs. The potential exists to install a solar PV system designed specifically for these types of roofs.

This could be under 3 scenarios:

- OHL rents or leases the roof area and installs, owns and operates the system;
- OHL, in partnership with the building owner installs, owns and operates the system; and,
- The building owner installs, owns and operates the system. (The building owner contracts with OHL/Green Pathways Inc. to procure, install, grid-tie and commission the system).

"Total Solution" Type Opportunities: The potential exists to propose a renewable energy based generation system that could conceivably comprise elements of wind, solar and bio-waste and be supplemented by solar water heating and drain water heat recovery. Examples include:

- Headwaters Healthcare Centre, Best Western Hotel and Elizabeth Street Seniors Residence.

FINANCIAL IMPLICATIONS

Although these renewable projects will be funded through the LDC, any investment through partnerships will increase the risk profile and reduce control. Furthermore, since these are strategic partnerships, the wise choice of partners is critical to ensuring that achieve the benefits identified in the applicable business case.

3.4 RISK PROFILES OF INVESTMENTS

With limiting resources and competing priorities, risks and constraints are an essential factor. It is critically important that risk and return be balanced with the likelihood of success for the project initiatives. In exploring a projects risk profile, it is important to consider the regulatory, financial, and operation implications of each investment.

Table 2 - High level financial, regulatory, and operational implications of strategic goals

Goals & Activities	Financial Implications	Regulatory Implications	Operational Implications
Goal 1 Activities: SCADA; Remote Sensing; Motorized Switches; Engineering Design; PME Installs; In Home Controls; Remote Disconnect	Investments in infrastructure recoverable through rates application	Smart Meters and TOU are mandatory; system upgrades and the replaced of 4 kV feeder will need to be phased in	Increased complexity and new full time employees
Goal 2 Activities: FIT Enablement; CIS Upgrades and other essential components	Distribution upgrades will be submitted to OEB for approval. Any transmission upgrades are to be developed with Hydro One Support	Main control mechanism for FIT program under OPA is project readiness, need for T&D connection upgrades, and deposits	LDCs have established a working group for FIT developed through EDA; used to educate LDCs regarding their role roles and responsibilities under FIT program
Goal 3 Activities: Continue to support current OEB, Ministry and OPA objectives. Proposed DR programs OHL will explore include: • DR1 • DR2 • DR3	Recovery of capital investment must be ensured	Verifiable results can be achieved through LRAM incentive	Customer communications implications
Goal 4 Activities: Educate the following market segments: • Business/Industry Institutions and Associations • Schools and Educational Facilities • Residential Homeowners • Low Income and Seniors	Ongoing capital and operational expenditure	N/A	Marketing campaigns and seminars will be delivered through OHL in conjunction with its affiliate, Green Pathways Inc.
Goal 5 Activities: In conjunction with Goal 2 Activities Above	There will be minimal financial risk to OHL since price will be known in advance and main revenue will come from FIT contracts and not at the expense of the LDC	Grid currently constrained; pending additional Hydro One capacity	Strong relationship with customers is critical in selling renewables through turnkey operations
Goal 6 Activities: OHL owned large renewable (On-site); Other large renewables	Partner with third party to share financial risk	Ensure approval to include in rate base	Not a core competency; employee expertise and knowledge transfer required

3.5 LONG-TERM STRATEGIC GOALS (YEARS 6-11)

CAP AND TRADE

The objective of the Cap-and-Trade program is to reduce emissions at the lowest possible cost. Green House Gas (GHG) emissions from large emitters or sources are capped at a designated level. Parties that emit GHGs above a threshold (25,000 tonnes/ yr CO2) are called regulated emitters. OHL is not a regulated emitter therefore CDM activities may create opportunities to develop Carbon Offsets.

Our plan is to Investigate which type of baselines need to be established and which type of metering equipment will be required. Using this information we can determine which type of initiatives can be aggregated and sold depending on the market value in that point in time - choose to hold until opportune time to sell.

Potential markets for carbon offsets are assumed to be $12-15/tonnes, meaning it could be a significant revenue stream. The Cap-and-Trade revenues could offset CDM costs or promote further investment and other strategic goals.

COMBINED HEAT AND POWER

The combined Heat and Power projects will be completed in partnership with Commercial and Industrial Customers. Eligible FIT programs can be completed, either separately, or in combination with heat and power. OHL's Commercial/Industrial customers do not have the expertise to carry out the projects.

With a sufficient feed stock, combined heat and power is an efficient and productive method to produce energy for and recycle the heat of an industrial commercial application. This solves the feed stock problem - as long as the customer continues to use the facility.

In partnership, there are risk and control implications for the Commercial or Industrial business. For example, the plant could shut down or relocate and the feed stock could disappear.

WASTE ENERGY OPTIONS

The waste energy Renewable Generation source is not a high priority for Municipal Governments since generating energy from waste does not support their diversion targets - this will need to be resolved between the Ministries of Energy and Environment. OHL will explore opportunities with local municipalities when the government policy is identified.

ELECTRIC VEHICLES

The Green Energy Act is essentially silent on green or electrically powered vehicles but does mention transportation fuels in the context of reduction of use. There are issues that must be addressed if "Green" electric and hybrid electric vehicles are to be made widely available to the public in the next few years, including:

- Communication and billing;
- Impact assessment;
- Incenting customers;
- Preparing and upgrading the grid;
- Establishing commercial fueling stations;
- Policy development for the transport sector; and,
- Provision of training for the above.

OHL wishes to commence a study in 2010 that will address all the issues above as well as the following modes of transportation, shown below.

- **Scooters and Motorcycles:** Electric scooters and motorcycles are now becoming more prominent. Dealerships are being established and model and type availability is quite diverse. Orangeville has two sales outlets for these types of vehicles;

- **Personal Vehicles:** Currently, there is much publicity regarding the development by virtually every vehicle manufacturer of electric personal vehicles. Various technical challenges and issues still need to be addressed and solved and the vehicles need to be approved to operate on the roads of Ontario;

- **Commercial Vehicles:** Less is publicized about electric commercial vehicles but as with electric passenger vehicles they are being developed. One company that comes to mind is Smith located in the U.K which has an affiliation with the Ford Motor Company. Smith has recently established an assembly plant in the United States and will offer electric commercial vehicles under the Ford badge and through selected Ford dealerships. This, further, reinforces the OHL interest in developing a charging and battery regeneration system for electric vehicles; and,

- **Public Transit Vehicles:** Orangeville operates a small fleet of public transit vehicles. During years 2 - 4 of this Plan OHL would like to conduct research and investigation of the cost / benefit of converting the town's buses to electric propulsion.

It is anticipated that Green vehicles such as electric, solar/electric, hydrogen and air, will become available for consumers to purchase during the long term period of performance of this Plan. OHL proposes to investigate the requirement for and if appropriate establish a service/support capability for these types of vehicles. It also has identified a small knowledge and experience acquisition project that would be suitable for high schools and community colleges to undertake.

Overall, as these vehicles increase in popularity and availability, this market/business sector will represent both business and job creation opportunities in the area of sales, product support/maintenance and training.

SETUP GENERATION ARM

As OHL develops expertise in Renewable Generation, through partnerships with generators and Commercial/Industrial customers, it may become a relative competitive advantage. At this point OHL may choose to setup an affiliate devoted to Renewable Generation and remove any future projects from utility rate base. This is an opportunity for Orangeville to diversify shareholder business.

4 WORK PLAN, MILESTONES, AND TIMELINE

Upon submission of this enabler plan, OHL anticipates OEB approval within 1 month. The 3-6 months following approval, OHL anticipates OEB will begin funding and resolving resourcing issues. Once funding and resolving issues have been addressed, OHL will begin commencing execution.

In the months leading up to January 1, 2010, OHL will do the following:

- Name/identify internal Champions and Proponents;
- Seek unanimous buy-in and support from the OHL Board as well as Orangeville Town Council (*This action will informally be achieved prior to Plan submission to OEB however upon OEB approval we will seek official support);*
- Finalize budgets (both capital and operating) to enable execution of plan, specifically:
  - Within 90 days of receiving Plan approval there are funds available to cover Year 1 capital and operating expenses, and with source of funds determined for Years 2 to 5;
  - Within 90 days of receiving Plan approval a detailed operating budget has been developed and approved for Year 1;
- Form its Management Teams required to implement the strategic goals; and,
- Begin initial discussion with key strategic partners.

A proposed Work Plan has been completed for the short-term (Year 1-5) strategic goals. The plan is subject to change, in accordance to regulatory, operational, or financial developments.

The Activities under each goal and our proposed Work Plan and Timeframe with respect to each, is shown in Table 3, below.

Table 3 – Work Plan, Milestones, and Timeline

	Activities	Work Plan, Timeframe and Milestones
Goal 1 - Develop Smart Grid Infrastructure and Installation of Smart Meters:	Install and implement the following: • SCADA; Remote Sensing; Motorized Switches • Engineering Design; PME Installs; In Home Controls; Remote Disconnect • Review and update work Safety Manuals, Operating Policies and Practices	Year 1 -Have engaged the resources necessary to commence the design and engineering of a Smart Grid infrastructure and begin procurement of Smart Meters for Orangeville and Grand Valley.

Goal 2 - Distribution Upgrades to enable DG	Install and implement the following:
	• FIT Enablement
	• CIS Upgrades and other essential components including:
	  • Meter technology
	  • ESA requirements for meter locations
		Our strategy is to complete a feasibility study in Year 1 to determine if the project is viable. If the project is feasible, construction of the project would begin at year 2. By the 2nd quarter of Year 3 construction of the distributed generation will commence.

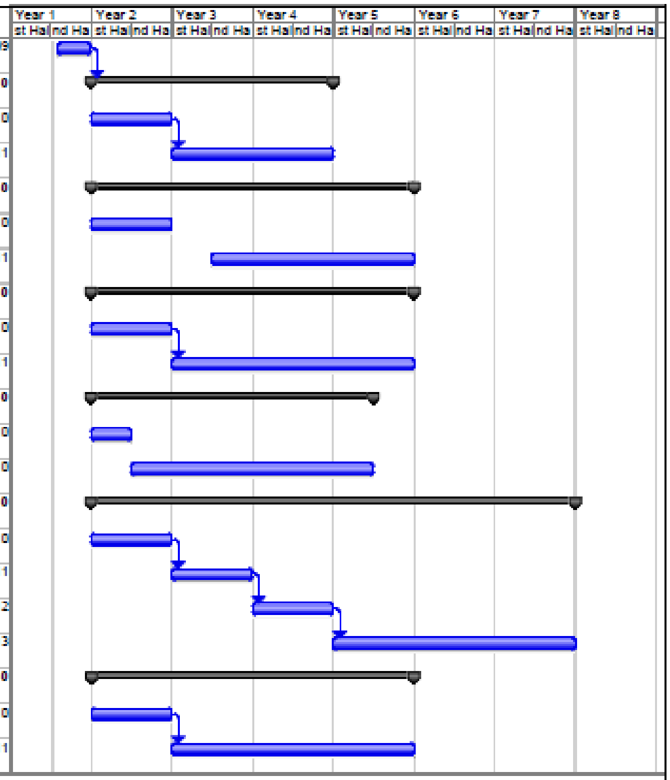
Goal 3 – Evolution of CDM	Continue to support current OEB, Ministry and OPA objectives. Proposed DR programs OHL will explore include: • DR1 • DR2 • DR3	Time is spent in Year 1 to properly review the effectiveness of existing programs and Initiatives as they are being participated in, by OHL's customers to determine whether they are achieving their desired goals. The existing programs and initiatives would, of course, continue while this task is being conducted. The rollout of the new CDM initiatives is proposed to occur during the five years following the review of existing programs.

Goal 4 – Marketing Campaign	Educate the following market segments: • Business/Industry Institutions and Associations • Schools and Educational Facilities • Residential Homeowners • Low Income and Seniors	This will require the services of a professional website developer and access to subject matter experts. Planning will commence in Year 1 with incremental completion milestones over an 18 month period. In order to educate the customers on Smart Meters, CDM, and Renewable Generation we propose running seminars for the next two years. By the end of Year 2, all customers of OHL will have been made aware of what is contained within this Plan, how they will be affected and what's in it for them.
Goal 5 – Small-Scale Renewables Installation	See Goal 2 Activities Above	The work plan for Small-Scale Renewable Generation can be summed up by the number of new small renewables being proposed in consecutive timeframes: • By the end of Year 2 to have up to 300 <10kW solar PV installations in place with up to 5 of those including wind power; • By the end of Year 3 to have a further 200 <10kW solar PV installations in place with 20% including wind power; • By the end of Year 4 to have a further 100 <10kW solar PV installations in place with 20% including wind power; and, • Between Year 5 and 11 have installations increase year over year in order that the goal of a minimum of 800 installations is achieved. Note: This represents an estimated installation rate of approximately 3 per week.
Goal 6 – Large-Scale Renewables Installation	• OHL owned large renewable (On-site) • Other large renewables	Large Renewables - By the end of Year 2 we will have completed the business case study for an up to 10MW (size optimized) distributed generation facility owned and operated by OHL. Once the business case has been completed and approved, OHL anticipates that the installation will require 2-3 years to complete.

EXECUTION OF GEA INITIATIVES

Figure 3 - Proposed timeline for activities

ID	Task Name	Duration	Start
1	OEB and Orangeville Stakeholder Approval of Plan	107 days?	Mon 03/08/09
2	**Goal 1 - Develop Smart Grid Infrastructuren and Smart Meter Installatio**	**783 days?**	**Fri 01/01/10**
3	Infrastructure and Smart Meter Design & Procurement	261 days?	Fri 01/01/10
4	Building and Installation of Infrastructure and Meters, Respectively	522 days?	Mon 03/01/11
5	**Goal 2 – Distribution Upgrades to Enable DG**	**1044 days?**	**Fri 01/01/10**
6	Feasibility Study and Procurement	261 days?	Fri 01/01/10
7	Construction of DG System	654 days?	Fri 01/07/11
8	**Goal 3 - Evolution of CDM**	**1043 days?**	**Fri 01/01/10**
9	Review Effectiveness of Existing Programs	261 days?	Fri 01/01/10
10	Roll out OPA Demand Response Programs and Enhanced CDM Effort	782 days?	Mon 03/01/11
11	**Goal 4 – Education and Marketing**	**912 days?**	**Fri 01/01/10**
12	Development of Marketing Plan	130 days?	Fri 01/01/10
13	Seminars (Bi-Weekly)	783 days?	Thu 01/07/10
14	**Goal 5 - Small- Scale Renewable Installation**	**1566 days?**	**Fri 01/01/10**
15	20 (<10kW) Solar PV Installations	261 days?	Fri 01/01/10
16	40 (<10kW) Solar PV Installations	260 days?	Mon 03/01/11
17	50 (<10kW) Solar PV Installations	261 days?	Mon 02/01/12
18	Additional 700 (<10kW) Solar PV Installation	784 days?	Tue 01/01/13
19	**Goal 6 - Large Renewables**	**1043 days?**	**Mon 04/01/10**
20	Business Case for DG Facility at Orangeville Hydro	260 days?	Mon 04/01/10
21	Build DG Facility	783 days?	Mon 03/01/11



Project: Orangeville Timeline
Date: Fri 10/07/09

Task		Milestone		External Tasks	
Split		Summary		External Milestone	
Progress		Project Summary		Deadline	

Page 1

5 BUDGET & RESOURCES

Table 4 - Costs associated with implementing Smart Grid

Strategic Goal	Activity		Year One - 2010		Year Two – 2011		Year Three - 2012		Year Four – 2013		Year Five - 2014		Total Summary
			Capital	Expense	Capital	Expense	Capital	Expense	Capital	Expense	Capital	Expense	
	INFRASTRUCTURE UPGRADES - Included in Budget and Rate Application												
1	**SCADA**	RC							$ 10,000.00	$ 5,000.00	$ 10,000.00	$ 5,000.00	
		SG	$ 35,000.00	$ 5,000.00		$ 5,000.00		$ 5,000.00	$ 10,000.00	$ 5,000.00	$ 10,000.00	$ 5,000.00	
	Remote Sensing	RC											
		SG	$ 50,000.00		$ 30,000.00		$ 30,000.00		$ 10,000.00		$ 10,000.00		
	Motorized Switches	RC											
		SG			$ 63,000.00		$ 63,000.00		$ 63,000.00		$ 63,000.00		
	PME Installs	RC											
		SG			$ 63,000.00		$ 63,000.00		$126,000.00		$126,000.00		
	In Home Controls	RC	$ 22,000.00		$ 44,000.00		$ 44,000.00		$ 22,000.00		$ 22,000.00		
		SG											
2 & 5	**MicroFIT Enablement**	RC	$ 50,000.00		$100,000.00		$100,000.00		$ 50,000.00		$ 50,000.00		
	(small-scale renewables)	SG											
	CIS Upgrades	RC	$ 60,000.00		$ 10,000.00		$ 10,000.00		$ 10,000.00		$ 10,000.00		
		SG											
4	**Marketing**	RC		$ 16,000.00		$ 16,000.00		$ 16,000.00		$ 16,000.00		$ 16,000.00	
		SG											
6	**Large Renewable others**	RC	$135,000.00										
	SMART GRID TOTAL		**$352,000.00**	**$ 21,000.00**	**$310,000.00**	**$ 21,000.00**	**$310,000.00**	**$ 21,000.00**	**$301,000.00**	**$ 26,000.00**	**$301,000.00**	**$ 26,000.00**	**$ 1,689,000.00**
	RENEWABLE ENERGY GENERATION - Non Utility Business												
6	**Large Renewable LDC - Solar Roof Panels**	RC			$100,000.00								
	RENEWABLE ENERGY GENERATION TOTAL				**$100,000.00**								**$ 100,000.00**
	CONSERVATION DEMAND MANAGEMENT - Funded through OPA												
4	Customer / Program Analysis			$ 15,264.00		$ 15,721.92		$ 16,179.84		$ 16,637.76		$ 17,095.68	
	Workshops & Marketing for Conservation			$ 20,483.00		$ 17,284.28		$ 17,232.56		$ 17,728.84		$ 17,638.12	
	Education & Awareness			$ 191,034.79		$ 161,815.75		$ 117,241.86		$ 116,634.69		$ 119,659.52	
	Green Energy Act - Staff Educating & Training			$ 50,920.00		$ 71,872.00		$ 81,454.00		$ 76,249.00		$ 86,298.00	
	CONSERVATION TOTAL			**$ 277,701.79**		**$ 266,693.95**		**$ 232,108.26**		**$ 227,250.29**		**$ 240,691.32**	**$ 1,244,445.62**
	Grand Total		**$352,000.00**	**$ 298,701.79**	**$410,000.00**	**$ 287,693.95**	**$310,000.00**	**$ 253,108.26**	**$301,000.00**	**$ 253,250.29**	**$301,000.00**	**$ 266,691.32**	**$ 3,033,445.62**
	SG	Smart Grid											
	RC	Renewable Connection											

RC = Renewable Connection

SG = Smart Grid

See Appendix 1 for a breakdown of CDM Budget Estimates

6 CORPORATE EVOLUTION

It is believed that during the Work Plan, OHL will need to change its corporate structure to effectively execute the various activities described in the Plan. In fundamental terms, over time, the functions will evolve into three areas: distribution, generation, and services. These are a variety of corporate structures – from operating divisions of OHL to affiliated stand alone entities – that may be suitable.

The distribution function will be similar to the prevailing business mandate with the added responsibility of designing, engineering, developing, installing, operating and maintaining the Smart Grid. It will be responsible for the adequate supply of secure, reliable and quality electricity to its ever-growing customer base. It will also be responsible for billing customers, settlement and collecting monies.

A potentially new function will be that of electricity generation, primarily using renewable resources such as solar, wind and, perhaps, bio-waste/bio-mass. To execute this effectively it may be appropriate to establish a separate business entity with a unique mandate to provide reliable, quality electricity up to the capacity of 10 MW.

A third function would be that of provision of services to a 40,000 customer base. However, the core customer base would be that of OHL. This business division would be similar in function to and could incorporate Green Pathways Inc. subsidiary. It would be the One-Stop-Shop. This entity would perhaps assume the responsibility for maintaining the street lighting. Its other activities would include conservation program delivery, conservation and energy management programs, consumer education and awareness, green power installations outside of the 10 MW system and other green energy related consumer products and services.

APPENDIX

Appendix 1 - CDM Budget Estimates

CDM Program Budget																
Activity	**Year 1 - 2010**			**Year 2 - 2011**			**Year 3 - 2012**			**Year 4 - 2013**			**Year 5 - 2014**			
Estimating Note: Dollar values shown are 'then year'																
Annual inflation of 3% applied																
Estimating Detail - Level 0			**Total**			**Total**			**Total**			**Total**			**Total**	**Level 0 Total**
Customer / Program Analysis			$ 15,264.00			$ 15,721.92			$ 16,179.84			$ 16,637.76			$ 17,095.68	
Workshops & Marketing for Conservation			$ 20,483.00			$ 17,284.28			$ 17,232.56			$ 17,728.84			$ 17,638.12	
Education & Awareness			$ 191,034.79			$ 161,815.75			$ 117,241.86			$ 116,634.69			$ 119,659.52	
Green Energy Act - Staff Educating & Training			$ 50,920.00			$ 71,872.00			$ 81,454.00			$ 76,249.00			$ 86,298.00	
GRAND TOTAL			**$ 277,701.79**			**$ 266,693.95**			**$ 232,108.26**			**$ 227,250.29**			**$ 240,691.32**	**$ 1,244,445.62**
Estimating Detail - Level 1	**Category**	**Maintenance & Administration**	**Total**	**Category**	**Maintenance & Administration**	**Total**	**Category**	**Maintenance & Administration**	**Total**	**Category**	**Maintenance & Administration**	**Total**	**Category**	**Maintenance & Administration**	**Total**	**Level 1 Total**
Customer / Program Analysis	$ -	$ 15,264.00	$ 15,264.00	$ -	$ 15,721.92	$ 15,721.92	$ -	$ 16,179.84	$ 16,179.84	$ -	$ 16,637.76	$ 16,637.76	$ -	$ 17,095.68	$ 17,095.68	
Workshops & Marketing for Conservation	$ 1,350.00	$ 19,133.00	$ 20,483.00	$ 1,398.00	$ 15,886.28	$ 17,284.28	$ 1,440.00	$ 15,792.56	$ 17,232.56	$ 1,482.00	$ 16,246.84	$ 17,728.84	$ 1,527.00	$ 16,111.12	$ 17,638.12	
Education & Awareness	$ 103,607.00	$ 87,427.79	$ 191,034.79	$ 105,554.46	$ 56,261.29	$ 161,815.75	$ 67,118.67	$ 50,123.19	$ 117,241.86	$ 65,086.88	$ 51,547.81	$ 116,634.69	$ 66,684.09	$ 52,975.43	$ 119,659.52	
Green Energy Act - Staff Educating & Training	$ 12,000.00	$ 38,920.00	$ 50,920.00	$ 12,360.00	$ 59,512.00	$ 71,872.00	$ 14,857.00	$ 66,597.00	$ 81,454.00	$ 13,113.00	$ 63,136.00	$ 76,249.00	$ 15,757.00	$ 70,541.00	$ 86,298.00	
Category Totals	**$ 116,957.00**			**$ 119,312.46**			**$ 83,415.67**			**$ 79,681.88**			**$ 83,968.09**			
Maintenance & Administration Totals		**$ 160,744.79**			**$ 147,381.49**			**$ 148,692.59**			**$ 147,568.41**			**$ 156,723.23**		
GRAND TOTAL			**$ 277,701.79**			**$ 266,693.95**			**$ 232,108.26**			**$ 227,250.29**			**$ 240,691.32**	**$ 1,244,445.62**

RC = Renewable Connection
SG = Smart Grid

CDM Program Budget

Activity	Year 1 - 2010	Year 2 - 2011	Year 3 - 2012	Year 4 - 2013	Year 5 - 2014	
Estimating Note: Dollar values shown are 'then year' Annual inflation of 3% applied						
Estimating Detail - Level 2	**Total**	**Total**	**Total**	**Total**	**Total**	**Level 2 Total**
Customer / Program Analysis						
Reporting & Analysis	$ 15,264.00	$ 15,721.92	$ 16,179.84	$ 16,637.76	$ 17,095.68	
Workshops & Marketing for Conservation						
Business / Industry Institutions and Associations	$ 8,347.00	$ 6,420.76	$ 6,047.52	$ 6,222.28	$ 6,400.04	
Residential	$ 6,068.00	$ 5,431.76	$ 5,592.52	$ 5,753.28	$ 5,619.04	
Low Income & Seniors	$ 6,068.00	$ 5,431.76	$ 5,592.52	$ 5,753.28	$ 5,619.04	
Education & Awareness						
Science Fair	$ 10,960.00	$ 11,478.80	$ 12,000.60	$ 12,524.40	$ 13,050.20	
Trade / Event Show (s) Participation	$ 11,200.00	$ 11,536.00	$ 11,872.00	$ 12,208.00	$ 12,544.00	
Website Upgrades	$ 15,728.96	$ 7,904.52	$ 8,136.39	$ 8,368.26	$ 8,600.13	
Residential	$ 22,191.62	$ 11,939.36	$ 12,287.11	$ 12,634.86	$ 12,982.61	
Business / Industry Institutions and Associations	$ 18,625.22	$ 8,265.97	$ 8,506.73	$ 8,747.49	$ 8,988.24	
Low Income & Seniors	$ 71,904.00	$ 68,903.59	$ 21,674.28	$ 22,004.68	$ 22,335.09	
Community Communication	$ 16,500.00	$ 16,995.00	$ 17,490.00	$ 17,985.00	$ 18,480.00	
LDC Conservation Fund	$ 12,875.00	$ 13,647.50	$ 14,033.75	$ 14,420.00	$ 14,806.25	
Resource Lending Library	$ 11,050.00	$ 11,145.00	$ 11,241.00	$ 7,742.00	$ 7,873.00	
Green Energy Act - Staff Educating & Training						
Opportunities Pursuit and Capture	$ 18,070.00	$ 18,612.00	$ 19,171.00	$ 19,745.00	$ 20,199.00	
FIT and microFIT Customer Assistance	$ 32,850.00	$ 53,260.00	$ 62,283.00	$ 56,504.00	$ 66,099.00	
GRAND TOTAL	**$ 277,701.79**	**$ 266,693.95**	**$ 232,108.26**	**$ 227,250.29**	**$ 240,691.32**	**$ 1,244,445.62**
Management & Administration Category - to be included in Level 1 Category	$ 27,620.43	$ 25,686.60	$ 24,806.36	$ 24,525.72	$ 26,027.53	

RC = Renewable Connection
SG = Smart Grid

CDM Program Budget						
Activity	**Year 1 - 2010**	**Year 2 - 2011**	**Year 3 - 2012**	**Year 4 - 2013**	**Year 5 - 2014**	
Estimating Note: Dollar values shown are 'then year' Annual inflation of 3% applied						
Estimating Detail - Level 3						
Customer / Program Analysis	**Total**	**Total**	**Total**	**Total**	**Total**	**Level 3 Total**
Reporting and Analysis						
Prepare and deliver reporting & analysis						
Administration - Reporting & Analysis 24x12x$53.00	$ 15,264.00	$ 15,721.92	$ 16,179.84	$ 16,637.76	$ 17,095.68	
Analysis Sub-total	**$ 15,264.00**	**$ 15,721.92**	**$ 16,179.84**	**$ 16,637.76**	**$ 17,095.68**	
Workshops & Marketing for Conservation						
Business / Industry Institutions and Associations						
Prepare and deliver information sessions on a regular basis						
Prepare material 60 x $53.00	$ 3,180.00	$ 1,092.00	$ 562.00	$ 579.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc. 25 x 1 x $53	$ 1,325.00	$ 1,365.00	$ 1,406.00	$ 1,448.00	$ 1,491.00	
Materials	$ 200.00	$ 210.00	$ 216.00	$ 222.00	$ 229.00	
Travel	$ 250.00	$ 260.00	$ 268.00	$ 276.00	$ 284.00	
Business Sub-total	**$ 8,347.00**	**$ 6,420.76**	**$ 6,047.52**	**$ 6,222.28**	**$ 6,400.04**	
Residential						
Prepare and deliver information sessions on a regular basis						
Prepare material 30 x $53.00	$ 1,590.00	$ 819.00	$ 844.00	$ 869.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc. 12 x 1 x $53	$ 636.00	$ 655.00	$ 675.00	$ 695.00	$ 716.00	
Materials	$ 200.00	$ 206.00	$ 212.00	$ 218.00	$ 225.00	
Travel	$ 250.00	$ 258.00	$ 266.00	$ 274.00	$ 282.00	
Residential Sub-total	**$ 6,068.00**	**$ 5,431.76**	**$ 5,592.52**	**$ 5,753.28**	**$ 5,619.04**	
Low Income & Seniors						
Prepare and deliver information sessions on a regular basis						
Prepare material 30 x $53.00	$ 1,590.00	$ 819.00	$ 844.00	$ 869.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc 12 x1 x $53	$ 636.00	$ 655.00	$ 675.00	$ 695.00	$ 716.00	
Material	$ 200.00	$ 206.00	$ 212.00	$ 218.00	$ 225.00	
Travel	$ 250.00	$ 258.00	$ 266.00	$ 274.00	$ 282.00	
Low Income Sub-total	**$ 6,068.00**	**$ 5,431.76**	**$ 5,592.52**	**$ 5,753.28**	**$ 5,619.04**	
Education & Awareness						
Science Fair						
Host Science Fair - annual event						
Administration - investigate, organize and support - 120 hrs x $53	$ 6,360.00	$ 6,550.80	$ 6,741.60	$ 6,932.40	$ 7,123.20	
Premises rental	$ 600.00	$ 618.00	$ 637.00	$ 656.00	$ 675.00	
Catering etc	$ 500.00	$ 515.00	$ 530.00	$ 546.00	$ 563.00	
Materials	$ 1,000.00	$ 1,030.00	$ 1,061.00	$ 1,093.00	$ 1,126.00	
Publicity	$ 500.00	$ 515.00	$ 531.00	$ 547.00	$ 563.00	
Awards	$ 2,000.00	$ 2,250.00	$ 2,500.00	$ 2,750.00	$ 3,000.00	
Science Fair Sub-total	**$ 10,960.00**	**$ 11,478.80**	**$ 12,000.60**	**$ 12,524.40**	**$ 13,050.20**	
Trade / Event Show (s) Participation						
Attend trade shows / events to promote conservation programs and educate community						
Premises rental / fees $500 x 4	$ 2,000.00	$ 2,060.00	$ 2,120.00	$ 2,180.00	$ 2,240.00	
Travel $100 x 4	$ 400.00	$ 412.00	$ 424.00	$ 436.00	$ 448.00	
Labour ($1500 per event)	$ 6,000.00	$ 6,180.00	$ 6,360.00	$ 6,540.00	$ 6,720.00	
Material & Training	$ 2,800.00	$ 2,884.00	$ 2,968.00	$ 3,052.00	$ 3,136.00	
Trade Show / Event Sub-total	**$ 11,200.00**	**$ 11,536.00**	**$ 11,872.00**	**$ 12,208.00**	**$ 12,544.00**	

RC = Renewable Connection
SG = Smart Grid

CDM Program Budget					
Activity	**Year 1 - 2010**	**Year 2 - 2011**	**Year 3 - 2012**	**Year 4 - 2013**	**Year 5 - 2014**
Estimating Note: Dollar values shown are 'then year'					
Annual inflation of 3% applied					
Estimating Detail - Level 3					
Website Upgrades					
Upgrade / update website to reflect programs and CDM information					
Develop & test content and functionality requirements / upgrades 80 hrs x $23.46	$ 1,876.80	$ 938.40	$ 966.55	$ 994.70	$ 1,022.86
Website upgrades- sub-contract 80hrs x $100	$ 8,000.00	$ 938.40	$ 966.55	$ 994.70	$ 1,022.86
Labour and Administration $23.46 x 8 x 12	$ 2,252.16	$ 2,319.72	$ 2,387.29	$ 2,454.85	$ 2,522.42
Website Maintenance 3hrs per month x $100	$ 3,600.00	$ 3,708.00	$ 3,816.00	$ 3,924.00	$ 4,032.00
Website Sub-total	**$ 15,728.96**	**$ 7,904.52**	**$ 8,136.39**	**$ 8,368.26**	**$ 8,600.13**
Residential					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 300 hrs x $53	$ 15,900.00	$ 5,459.00	$ 5,618.00	$ 5,777.00	$ 5,936.00
Welcome Wagon - Material 800 cx X $4 per package	$ 4,000.00	$ 4,120.00	$ 4,240.00	$ 4,360.00	$ 4,480.00
Welcome Wagon - Maintenance & Administration ($23.46 x 4hrs x12 mths at 80% for residents)	$ 791.62	$ 815.36	$ 839.11	$ 862.86	$ 886.61
Welcome Wagon - Marketing & Distribution	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Residential - Sub-total	**$ 22,191.62**	**$ 11,939.36**	**$ 12,287.11**	**$ 12,634.86**	**$ 12,982.61**
Business / Industry Institutions and Associations					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 300 hrs x $53	$ 15,900.00	$ 5,459.00	$ 5,618.00	$ 5,777.00	$ 5,936.00
Welcome Wagon - Material	$ 1,000.00	$ 1,030.00	$ 1,060.00	$ 1,090.00	$ 1,120.00
Welcome Wagon - Maintenance & Administration ($23.46 x 4hrs x12 mths at 20% for business)	$ 225.22	$ 231.97	$ 238.73	$ 245.49	$ 252.24
Welcome Wagon - Marketing	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Business - Sub-total	**$ 18,625.22**	**$ 8,265.97**	**$ 8,506.73**	**$ 8,747.49**	**$ 8,988.24**
Low Income & Seniors					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 100 hrs x $53	$ 5,300.00	$ 1,801.47	$ 1,909.56	$ 1,963.60	$ 2,017.65
Labour (2 x 8 x 84 x $11)	$ 14,784.00	$ 15,227.52	$ 7,835.52	$ 8,057.28	$ 8,279.04
Training (Techincal / Program) 2 x 2 x $11 + 12 hrs @ $53.00	$ 988.00	$ 1,017.64	$ 1,047.28	$ 1,076.92	$ 1,106.56
Travel	$ 832.00	$ 856.96	$ 881.92	$ 906.88	$ 931.84
Material	$ 50,000.00	$ 50,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00
Low Income & Seniors Sub-total	**$ 71,904.00**	**$ 68,903.59**	**$ 21,674.28**	**$ 22,004.68**	**$ 22,335.09**
Community Communication					
Methods of communication to educate and promote CDM programs and create conservation awareness					
Newspaper	$ 7,500.00	$ 7,725.00	$ 7,950.00	$ 8,175.00	$ 8,400.00
Radio	$ 2,500.00	$ 2,575.00	$ 2,650.00	$ 2,725.00	$ 2,800.00
Transit	$ 1,400.00	$ 1,442.00	$ 1,484.00	$ 1,526.00	$ 1,568.00
Bill Messages / Inserts 4 bill inserts per year	$ 2,000.00	$ 2,060.00	$ 2,120.00	$ 2,180.00	$ 2,240.00
On Hold Phone Messages	$1,600	$ 1,648.00	$ 1,696.00	$ 1,744.00	$ 1,792.00
Bill envelope advertising (85,000 envelopes)	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Community Communication - Sub-total	**$ 16,500.00**	**$ 16,995.00**	**$ 17,490.00**	**$ 17,985.00**	**$ 18,480.00**
Conservation Fund					
This fund is to help assist Orangeville Hydro with adhoc CDM activities					
LDC Conservation Fund	$ 12,875.00	$ 13,647.50	$ 14,033.75	$ 14,420.00	$ 14,806.25
LDC Conservation Sub-total	**$ 12,875.00**	**$ 13,647.50**	**$ 14,033.75**	**$ 14,420.00**	**$ 14,806.25**

RC = Renewable Connection

SG = Smart Grid

CDM Program Budget

Activity	Year 1 - 2010	Year 2 - 2011	Year 3 - 2012	Year 4 - 2013	Year 5 - 2014	
Estimating Note: Dollar values shown are 'then year'						
Annual inflation of 3% applied						
Estimating Detail - Level 3						
Resource Lending Library						
Note: Topics and subject matter held in the library: 'Green" building design, construction and renovation; systems design and installation; heating, cooling and ventilating; energy and conservation management and best practices, green power generation; green vehicles; green living- best practices. Sources. Engage in a 3 year incremental procurement program with low level acquisition in later years						
Books: 25 x $100.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 1,250.00	$ 1,250.00	
DVDs: 25 x $50	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 500.00	$ 500.00	
Periodicals and Magazines: 10 x $50	$ 500.00	$ 500.00	$ 500.00	$ 525.00	$ 525.00	
Technical Papers and Documents: 25 x $100	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 1,000.00	$ 1,000.00	
Directories: 4 x $100	$ 400.00	$ 400.00	$ 400.00	$ 200.00	$ 200.00	
Misc. materials	$ 250.00	$ 250.00	$ 250.00	$ 280.00	$ 290.00	
Advertising: pro-rated with other advertising	$ 500.00	$ 500.00	$ 500.00	$ 546.00	$ 563.00	
Operating expenses	$ 500.00	$ 515.00	$ 530.00	$ 546.00	$ 563.00	
Adminstrative labour: 50hrs x $53	$ 2,650.00	$ 2,730.00	$ 2,811.00	$ 2,895.00	$ 2,982.00	
Library sub-total	**$ 11,050.00**	**$ 11,145.00**	**$ 11,241.00**	**$ 7,742.00**	**$ 7,873.00**	
Green Energy Act - Staff Educating & Training						
Opportunities Pursuit and Capture						
Attending conferences/seminars etc.						
Labour 2 x 40 x $53	$ 4,240.00	$ 4,367.00	$ 4,498.00	$ 4,633.00	$ 4,633.00	
Labour 2 x 30 x $53	$ 3,180.00	$ 3,275.00	$ 3,373.00	$ 3,474.00	$ 3,578.00	
2 delegates x 2 Domestic	$ 5,000.00	$ 5,150.00	$ 5,305.00	$ 5,464.00	$ 5,628.00	
Labour 2 x 25 x $53	$ 2,650.00	$ 2,730.00	$ 2,812.00	$ 2,896.00	$ 2,983.00	
Public Relations	$ 3,000.00	$ 3,090.00	$ 3,183.00	$ 3,278.00	$ 3,377.00	
GEA Opportunities Pursuit Sub-total	**$ 18,070.00**	**$ 18,612.00**	**$ 19,171.00**	**$ 19,745.00**	**$ 20,199.00**	
FIT and microFIT Customer Assistance						
Pre and post implementation customer support						
Labour 20 hrs x 45wks x $53	$ 23,850.00	$ 49,140.00	$ 50,614.00	$ 52,133.00	$ 53,697.00	
Non-labour - travel	$ 2,000.00	$ 4,120.00	$ 4,244.00	$ 4,371.00	$ 4,502.00	
Software and tools	$ 2,000.00		$ 2,125.00		$ 2,250.00	
Training	$ 5,000.00		$ 5,300.00		$ 5,650.00	
FIT and MicroFIT Sub-total	**$ 32,850.00**	**$ 53,260.00**	**$ 62,283.00**	**$ 56,504.00**	**$ 66,099.00**	
Note: Estimate for installs, commisioning, post-install support contained in OH Estimates						
GRAND TOTAL	**$277,701.79**	**$266,693.95**	**$232,108.26**	**$227,250.29**	**$240,691.32**	**$ 1,244,445.62**
Management and Administration						
Labour 15% of labour component	$ 24,111.72	$ 22,107.22	$ 22,303.89	$ 22,135.26	$ 23,508.48	
Non-labour - pro-rated $ allocation.- 3%	$ 3,508.71	$ 3,579.37	$ 2,502.47	$ 2,390.46	$ 2,519.04	
Total	**$ 27,620.43**	**$ 25,686.60**	**$ 24,806.36**	**$ 24,525.72**	**$ 26,027.53**	
Summary						
Labour	$160,744.79	$147,381.49	$148,692.59	$147,568.41	$156,723.23	
Non Labour	$116,957.00	$119,312.46	$ 83,415.67	$ 79,681.88	$ 83,968.09	

OPA Funded Core Programs						
Orangeville Hydro would like to include these programs into our CDM budget should the OPA remove it from the slate of funded core programs after the 2009 season						
ERIP Program						**Total**
Fixed Funding	$ 36,191.00	$ 37,276.73	$ 38,362.46	$ 39,448.19	$ 40,533.92	
Variable Funding	$ 5,800.00	$ 6,300.00	$ 6,800.00	$ 6,800.00	$ 9,700.00	
ERIP Sub-total	**$ 41,991.00**	**$ 43,576.73**	**$ 45,162.46**	**$ 46,248.19**	**$ 50,233.92**	
PSB Program Execution						
Fixed Funding	$ 22,379.00	$ 23,050.37	$ 23,721.74	$ 24,393.11	$ 25,064.48	
Variable Funding	$ 22,715.00	$ 23,600.00	$ 25,075.00	$ 26,550.00	$ 28,025.00	
PSB Sub-total	**$ 45,094.00**	**$ 56,114.28**	**$ 57,702.42**	**$ 59,290.56**	**$ 60,878.70**	**$ 111,112.62**

Note: Orangeville Hydro is requesting these funds be provided on a quarterly basis