Response to Board Staff Interrogatories
2014 Electricity Distribution Rates
Niagara-on-the-Lake Hydro Inc.
EB-2013-0155

Board Staff Interrogatories
2014 Cost of Service Rate Application Niagara-on-the-Lake Hydro Inc. ("NOTL Hydro") EB-2013-0155
January 10, 2013

1. Foundation

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

1.1-Staff-1
Ref: Ex.2/App.2A/pg. 20 and 21
Ref: E -2/T-3/S-2/p.1, Table 2.3.1 - Summary of Capital Expenditures Ref: Ex.2/App.2A/pg. 81-84, C. Category-specific requirements for each project/activity/System Renewal for Overhead System and for Underground System

In regard to NOTL's Asset Management Tool, found on page 21 of the first reference, NOTL Hydro states:

> In the summer of 2012, it became apparent that a software program would be required to assist us with developing our Asset Management Plan. The software would need to integrate the ACA data to assist with the compilation of our 2013 Capital Expenditure Plan and ultimately, our long-term Capital Expenditure Plan. After a selection process, NOTL Hydro purchased 'Optimizer' [..], which has proven to be invaluable tool. This tool allows NOTL Hydro to factor in public and employee safety, service quality, community/corporate goals, legal implications, regulatory, environmental concerns and financial objectives (investment priorities, risk aversion) and budget allocations. See Attachments 12a and 12b.

Table 2.3.1 Summary of Capital Expenditures, summarizes the investments including System Access, System Renewal, and System Service for the historical period since 2009, the bridge year, and the planned forecast period including the test year.

Table 2.3.1 Summary of Capital Expenditures

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		44	--		334	--		246	--		1,850	--		37	--	100	100	100	100	100
System Renewal		1,339	--		721	--		397	--		1,745	--		516	--	970	4,030	1,030	935	1,030
System Service		15	--		23	--		19	--		96	--		238	--	95	55	55	55	55
General Plant		407	--		449	--		397	--		491	--		85	--	120	65	65	160	65
TOTAL EXPENDITURE	-	1,805	--	-	1,527	--	-	1,059	--	-	4,182	--	-	876	--	1,285	4,250	1,250	1,250	1,250
System O&M		$ 839	--		$ 745	--		$ 817	--		$ 949	--		$ 522	--	$ 964	$ 979	$ 995	$1,011	$ 1,027
														7						

In the third reference NOTL included a listing of various projects under System Renewal for both Overhead and Underground Systems.

Please provide further details regarding the "Optimizer" program. Specifically:

a) Please summarize the inputs provided to the Optimizer tool including any quantitative or qualitative data that was assessed by NOTL staff for each project.
b) Please summarize the range of projects (e.g. all projects in the distributor's 5- year plan) that are provided to the Optimizer tool for determination of the capital budget each year.
c) Using a specific example, please explain how a particular overhead and underground infrastructure project would be prioritized or deferred over another.
d) Was the Optimizer tool used to forecast capital investments for the years 2015 through 2018? If so, please provide details on how the tool assisted NOTL Hydro in accomplishing that task.
e) Please explain how the Optimizer tool factors NOTL Hydro's strategic objectives in determining the capital expenditure plan including how the tool achieves the weightings assigned to each objective, as shown in Exhibit 2, Appendix 2A, Attachment 12b. If applicable, please explain how the strategic objectives are quantified for each capital project?

Response to 1.1-Staff-1

a) With the exception of newer line sections, all other overhead system line segments (approximately 60) underwent a thorough asset condition assessment of which samples are provided in Exhibit 2, Attachment 10. The 60 line sections were individually recorded in the Optimizer program in a rating type system that aided in prioritizing (ranking) capital projects based on our company's strategic objectives

(Exhibit 2, Attachment 12b). The Optimizer program developed a Risk Matrix (Exhibit 2, Attachment 12a) which positions each potential project relative to probability and consequence

b) We found that the program was efficient in the prioritization of overhead distribution line projects but not as effective for other projects such as our garage area roof replacement and software upgrades etc. The Optimizer program was utilized to prioritize overhead System Renewal projects only for the years 2014-2018.

c) As indicated in b) above, approximately 60 overhead line sections were originally entered in the Optimizer program. Several line sections constructed in the last 20 years for example were not considered. As an example, please consider proposed Rural Overhead Project #1(2014), Concession 2, Line 7 to Line 9. The field asset condition assessment documentation is in Exhibit 2, Attachment 10 (page 380 of the application). The field staff evaluated the line section and recorded pole ages of up to 63 years and old style cross-arm and pin construction with glass insulators. An 'Orange' risk was assigned in the field indicating a higher risk of failure and impending future maintenance issues. This information was entered in to the Optimizer program (different personnel) with our corporate objectives as explained above. The resulting risk matrix positioned this particular project as high priority prompting NOTL Hydro to proceed with the project in 2014.

NOTL Hydro has found it more economical to complete our overhead capital projects in-house with the exception of a few specific tasks. Past experience has also determined that our personnel can effectively and efficiently complete approximately $600,000 in construction annually. Our 5 year capital overhead plan presented in this application utilizes the highest priority projects identified in the Optimizer risk matrix and positions projects in increments of approximately $600k over the period. The relative importance of overhead projects that were not selected in our 5 Year program have been documented and will be added to our rolling 5 Year capital program developed each year. We should note that this annual re-evaluation is necessary as new government initiatives or unexpected customer growth projects can occasionally push specific projects back in the replacement schedule.

The prioritization of underground projects is more complex and quite different from overhead. With the removal of the 60+ year old King Street substation in the Old Town (our last), temporary 27.6 kV to 4 kV step down units have been strategically placed to supply the residual 4 kV load during the final conversion. The prioritization of underground conversion projects is determined by a combination of current urban renewal projects scheduled by the Town (coordinated/joint construction), condition of the specific overhead assets, budget, logistics of step down supply and quantity of old 4 kV overhead facilities that can be removed as a result of completing the project.

d) As explained above, the Optimizer tool was integral to the development and prioritization of overhead capital projects for the period of 2014-2018. Multiple employees contributed to the inputs to the Optimizer program, perhaps removing the possibility of subjectivity from the capital project selection process. The program also allowed us to prioritize and save projects beyond 2018 for future reference.

e) Exhibit 2, Appendix 12b illustrates the corporate weighting factors applied to prioritize all of our 5 Year Capital projects. The weighting amounts were originally proposed by senior management to reflect our corporate values and objectives and then endorsed by the NOTL Hydro Board at a regular meeting. You will note that the most significant factor is public and employee safety (26%) followed by reliability 16% and environmental concerns and financing requirements at 15%. Customer complaints, regulatory and customer claims have lower weightings. The values remained 'fixed' for the duration of the capital plan preparation process.

1.1-Staff-2

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

a) 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).
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?
c) Please identify any cost impacts that the December 2013 ice storm has had on capital and OM&A spending in 2013 and 2014 which were recorded in Account 1572, Extraordinary Event Costs.

Response to 1.1-Staff-2

a) The Niagara Region was less seriously impacted by the December 2013 ice storm than the GTA region. We do not expect that the storm's impact will have any notable impact on the test year capital or OM&A budgets.

b) No

c) This will confirm that no capital and OM&A expenses were recorded in Account 1572 related to the December 2013 ice storm

2. Performance Measures

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

2.1-Staff-3
Ref: Ex.2/T.3/Sch.5/pg. 1 and 2
Ref: Ex.2/App.2A/pg. 9

Table 2.3.3 and Table 2.3.4 of Ex. 2/T. 3/Sch. 5 show NOTL Hydro's historical reliability and projected reliability indices, respectively. They are reproduced below for reference.

Table 2.3.3 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2009	0.33	0.28	1.2
2010	0.06	0.03	1.62
2011	15.39	4.36	3.53
2012	1.54	0.95	1.63
Excluding Loss of Supply			
2009	0.21	0.13	1.58
2010	0.06	0.03	1.62
2011	15.39	4.36	3.53
2012	0.94	0.95	0.99

Table 2.3.4 - Target Indices for 2013 and 2014

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2013	0.62	0.40	1.55
2014	0.60	0.39	1.54
Excluding Loss of Supply			
2013	0.40	0.40	1.00
2014	0.38	0.38	1.00

On page 9 of the Consolidated Distribution System Plan ("CDSP"), NOTL Hydro states:

> Storms and inclement weather have an adverse impact on outage indices and the frequency of storms can vary year to year. Therefore, complex interpretation of annual results is required. In April 2011, a tornado like windstorm swept through Niagara causing serious damage to our system. Meanwhile, 2010 was referred to as the 'quiet year' when we experienced relatively few weather related outages. With information suggesting that our MTS#2 transformer units would be approaching the end of the their useful life in the next 5-10 years, we moved a significant amount of load off MTS#2 over to the newer MTS#1 station. The MTS#1 M2 Feeder picked up the lion's

share of the MTS#2 load and in doing so, doubled the length (and exposure) of this rural feeder. We accept the higher outage indices on the M2 as temporary until 2015 when the MTS#2 transformer unit is place on line and the M2 can be restored to a normal configuration.

a) Does NOTL Hydro expect that its reliability indices will return to levels exhibited in 2009 and 2010 when the new MTS#2 transformer unit is installed and in use?
b) Was the decision to shift the load from the MTS#2 station to the MTS#1 station driven solely by the asset condition assessment of the MTS#2 station? Had NOTL Hydro been experiencing issues with increased outages for customers fed by the MTS#2 station prior to that point?
c) Please provide NOTL Hydro's best estimate of its outage indices in 2011, excluding the impacts of the windstorm.

Response to 2.1-Staff-3

a) Yes

b) Yes. The resulting configuration supply results in a great deal more exposure of the M2 feeder as it picks up the MTS#2 F1 load. Effectively, the M2 feeder length doubled along with its customer count. Therefore, the risk of outages on the M2 feeder also doubles. The F1 feeder was primarily a long rural feeder prior to the reconfiguration but did not exhibit an increase outage tendency.

c) The April windstorm outage was the only outage in April 2011. We have calculated our 2011 outage indices excluding the impact of the April windstorm as follows:

SAIDI - 1.05; SAIFI - 1.31; CAIDI - 0.80

4. Operational Effectiveness

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

4.1-Staff-4
Ref: Ex.2/App.2A/pg. 4

On page 4 of the CDSP, NOTL Hydro states that "a recent consultant's study suggests that the two transformer units at MTS#2 will approach the end of their useful life in the next 5-10 years and replacement/refurbishment should be addressed."

a) Please provide a copy of the consultant's study mentioned in the reference above.

Response to 4.1-Staff-4

a) A copy of the report by the consultant (Ascent) is attached as Attachment A to these IRRs.

4.1-Staff-5
Ref: Ex.2/App.2A/pg. 16
Ref: Ex.2/App.2A/ Attachment 11 - Equipment Failure Analysis

On page 16 of the CDSP, NOTL Hydro states:

> On an ongoing basis, each individual outage is recorded and includes time, duration, location/feeder, cause and the need for follow-up (see Attachment 11). This information is summarized by month and year and provides data for our reliability indices as well as our worst performing feeder analysis (Attachment 3). This information is particularly scrutinized during budget time and factors in to the need to make the necessary improvements to the worst performing feeders. This process is described in more detail under 'Feeder Analysis' on page 9.

At Attachment 11, of the same reference, the 2012 Outage Summary is shown. Under the "Summary of Causes" heading there is reference to "Equipment Failure".

a) Please indicate whether under "Equipment Failure", NOTL keeps track of the type of equipment that has failed whenever an incident is logged (e.g., "Poles", "Pole Mounted transformers", "Overhead Line Switches", "Pad Mounted Transformers" etc.)? If yes, are the outage and failure information for each type of asset used as input to the Asset Management Process?
b) If the response to a) above is negative, please indicate whether steps are planned to include such analysis in the Asset Management Process.

Response to 4.1-Staff-5

a) Our Asset Management process includes the requirement for an annual assessment of outages and their causes with the intent of analyzing potential trends. In 2012, we recorded 11 equipment failures and the recording documents provide adequate details to determine the specific device and potential causes of the failure. The annual analysis would determine if a specific manufacturer has a higher than average risk of failure or whether we perhaps need to adjust our P&C settings for example.

b) N/a

4.1-Staff-6
Ref: Ex.2/App.2A/p. 20
Ref: Ex.2/App.2A/p. 18, section 5.3.2 "Overview of Assets Managed", item b)

At the first reference, NOTL in describing its Asset Condition Assessment (ACA) process stated that:

> Our ACA process did not involve the recording of specific data such as transformer name plate data and age. This direction was intentional as a means of completing the process more quickly and with the knowledge that the oldest assets (4 kV system and previous Ontario Hydro assets) would be replaced in the next 5-7 years leaving our entire system with assets less than 35 years old.

At the second reference, NOTL indicated that it owned two 115/27.6 kV supply stations with 6 -27.6 kV feeders in total.

a) Given NOTL's stated intention to convert the 4.16 kV distribution system to the higher voltage 27.6 kV, please indicate whether or not NOTL intends to commence recording, for the existing 27.6 higher voltage distribution system, specific data for each system element covering asset categories such as Overhead Line Switches, Pad Mounted Transformers, Pad Mounted Switchgear, and Underground Cables etc.? If the response is yes, please indicate when it will start to do so. If the response is no, please provide the rationale.

Response to 4.1-Staff-6

a) NOTL Hydro currently records and retains pertinent information on major assets (primarily those with a serial number) for the tracking of depreciation. The GIS system has traditionally been the data base for information on all distribution assets. For example, our GIS system will currently identify a set of overhead line switches with an identifying number, switch type and ampacity rating. Our 2014 IT integration project proposes to utilize the GIS system as the primary data base for all departments to source operational, billing, financial and engineering-related information by linking the FIS and CIS systems to the GIS system. Our goal when completed is to have detailed information on all distribution system components including poles, wires, transformers, switches and cables etc. easily accessible on the GIS system.

- ***Issue 4.2:** Are the applicant's proposed OM&A expenses clearly driven by appropriate objectives and do they show continuous improvement in cost performance?*

4.2-Staff-7

Ref: Ex.4/T.1/Sch.2/pg. 2, Table 4.1.4

Ref: EB-2012-0036, Draft Rate Order, Smart Meter Model, filed on June 11, 2012

On Table 4.1.4, NOTL Hydro provides a summary of the main drivers for increases to OM&A from the last Board approved rebasing year (2009) to the 2014 test year. The table is reproduced below, for reference.

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Combined 2009 to 2014
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance (2009=Board Approved)	$ 1,844,140	$ 1,817,894	$ 1,769,548	$ 1,904,187	$ 2,141,405	$ 2,180,742	$ 1,844,140
Driver #1 - IBEW contract rates	$ -	$ 22,999	$ 29,222	$ 27,007	$ 33,739	$ 27,119	$ 140,085
Driver #2 - Non-labour Inflation (IPI)	$ -	$ 12,334	$ 12,334	$ 18,976	$ 15,181	$ 15,181	$ 74,006
Driver #3 - LEAP donations	$ -	$ -	$ 3,000	$ -	$ 2,500	$ -	$ 5,500
Driver #4 - Smart Meters - DVA disposition	$ -	$ -	$ -	$ 184,671	-$ 184,671	$ -	$ -
Driver #5 - Smart Meters - Meter Reading	$ -	$ -	$ -	$ 42,269	$ 21,731	$ 1,000	$ 65,000
Driver #6 - Smart Meters - Meter Maintenance	$ -	$ -	$ -	$ 27,539	$ 12,361	$ 800	$ 40,700
Driver #7 - Smart Meters - UCS Billing services	$ -	$ 61,124	$ 14,554	$ 2,025	$ 5,565	$ 1,280	$ 84,548
Driver #8 - Distribution System Plan - Teleworks	$ -	$ -	$ -	$ -	$ -	$ 11,800	$ 11,800
Driver #9 - File Nexus Document Management System	$ -	$ -	$ -	$ -	$ -	$ 13,700	$ 13,700
Driver #10 - Ontario One Call / Locate Services	$ -	$ 1,053	$ 3,501	$ 23,235	-$ 1,081	$ -	$ 26,708
All other costs	-$ 26,246	-$ 145,856	$ 72,029	-$ 88,505	$ 134,013	-$ 20,915	-$ 75,481
Closing Balance	$ 1,817,894	$ 1,769,548	$ 1,904,187	$ 2,141,405	$ 2,180,742	$ 2,230,707	$ 2,230,707

Included in the table are 3 items related to the ongoing operation and maintenance of smart meters: i) Meter Reading, ii) Meter Maintenance and iii) UCS Billing Services.

Sheet 5 "SM_Rev_Reqt" from the Smart Meter Model, filed with NOTL Hydro's Draft Rate Order for its Smart Meter Cost Recovery Application (EB-2012-0036), indicates $39,667 in incremental OM&A expenses related to smart meters in NOTL Hydro's service territory.

In its Smart Meter cost recovery application, NOTL Hydro had received approval to recover approximately $40k in incremental operating expenses for smart meters as part of its Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR). The combined increase in OM&A related to smart meters requested from NOTL Hydro's last rebasing year to the 2014 test year is $190,248.

a) Please explain why the proposed increase in OM&A expenses related to smart meters is significantly higher than the estimated incremental OM&A approved for recovery in the SMIRR in NOTL Hydro's Smart Meter cost recovery application.
b) Please comment on whether or not the proposed OM&A expenditures for the 2014 test year are reflective of any efficiencies/savings achieved with respect to meter reading costs.

Response to 4.2-Staff-7

a) The $39,667 in estimated 2012 costs filed and approved in the smart meter rate application comprised the following:

Meter reading (Sensus)	$27,147
Meter maintenance functions	$45,940
Meter reading savings (internal)	($33,420)
Total	$39,667
Combined increase	$190,248
Difference	$150,581

The combined increase of $190,248 referred to in the interrogatory comprises the Drivers shown below. The requested explanations are provided for each Driver:

- **Driver #5 – Smart Meters – Meter Reading $65,000**
    - Of the $39,667 incremental OM&A referred to in the interrogatory, $27,147 was the estimated amount for the Sensus TGB and base station service in 2012. At the time of filing our smart meter rate recovery application, our AMI vendor (Sensus) had yet to achieve the minimum system performance outlined in our joint contract. Sensus installed an additional TGB device (at their capital cost) to boost the read rate percentage but in accordance with the contract, the monthly operating cost of the additional TGB is passed on to NOTL Hydro. The resulting total Sensus smart meter reading cost in 2012 including both TGBs was $64,247 as shown in the Table in b) below.
    - Difference explained is $65,000 - $27,147 = $37,853
- **Driver #6 – Smart Meters – Meter Maintenance $40,700**
    - Of the $39,667 incremental OM&A referred to in the interrogatory, $45,942 was for estimated meter maintenance functions. The $40,700 reflects an updated estimate for 2014.
    - Difference explained is $40,700 - $45,940 = ($5,240)
- **Driver # 7 – Smart Meters – UCS Billing Services $84,548**

- UCS[1] billing costs were not included in the smart meter rate application. As noted by the Board in its decision (EB-2012-0036), NOTL Hydro moved to a higher cost CIS system due to concerns with the existing CIS vendor and the need to implement time-of-use pricing once smart meters were implemented. The Board approved the CIS upgrade costs on this basis. However, at the time of moving to the Harris Northstar CIS through the UCS group in February 2010, time-of-use billing was not yet in place. Consequently, billing using UCS services was therefore treated by NOTL Hydro in the preparation of the smart meter application as an ongoing billing process thought not to be eligible for consideration as incremental OM&A. Thus, this Driver cost of $84,548 should not be included in the combined increase to be compared with the proposed increase with the estimated incremental OM&A approved for recovery.
- Difference explained is $84,548 - $Nil = $84,548

- **In summary, the differences are:**

Function	SMIRR	Drivers Table	Difference
Meter Reading	$ 27,147	$ 65,000	$ 37,853
Meter maintenance	$ 45,940	$ 40,700	$ (5,240)
Meter reading savings	$ (33,420)	$ -	$ 33,420
UCS billing services	$ -	$ 84,548	$ 84,548
Totals	$ 39,667	$ 190,248	$ 150,581

- **Meter readings savings**, though not separately listed in the Drivers Table, are estimated as provided in b) below. Such savings are subsumed in the "all other costs" line in the Drivers Table.

b) The following Table is also provided in response to VECC-18b:

[1] Information regarding UCS can be found at www.ucsportal.ca

5310 Meter Reading	Vendor	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual (unaudited)	2014 Forecast
Manual reads	Collective Utility Services >> Niagara Field Services*	$ 30,570	$ 30,697	$ 27,026	$ 8,874	$ 5,171	$ 5,237	$ 5,200
	Internal NOTL Hydro	$ 14,628	$ 12,741	$ 14,853	$ 6,016	$ 45,937	$ 6,115	$ 3,068
Interval meter reads	Enerconnect >> Utilismart	$ 4,570	$ 6,923	$ 7,945	$ 9,795	$ 13,139	$ 13,851	$ 14,100
Subtotals exc. Smart meters		$ 49,768	$ 50,361	$ 49,824	$ 24,685	$ 64,247	$ 25,203	$ 22,368
Smart Meter reads	Sensus	From variance account				$ 76,514		
		Direct to 5310				$ 42,269	$ 64,207	$ 65,000
Totals		$ 49,768	$ 50,361	$ 49,824	$ 24,685	$ 140,761	$ 89,411	$ 87,368

Disposition from Smart Meter OM&A Variance Acct:

Smart Meter reads	Sensus		$ 4,371	$ 26,333	$ 26,770	$ 19,040
	Total 2009 to April 2012 moved to Acct 5310 in 2012					$ 76,514

The subtotals exc. Smart meters show savings of $49,768 in 2009 minus $22,368 in 2014 = $27,400 savings in manual and interval meter reading costs from 2009 rebasing to the 2014 forecast.

4.2-Staff-8
Ref: Ex.4/T.2/Sch.1/pg. 6 and 8

On page 6 of Ex.4/T.2/Sch.1, NOTL Hydro states:

> Increase in engineering staff time allocated to meters operation and maintenance from the 2009 estimate of 284 hours in the 2009 rebasing to the current ongoing level of staff time, forecast at 660 hours for 2014, combined with pay-rate increases since 2009.

On page 8, NOTL states:

> Increase in staff time allocated to billing from the 2009 estimate of 1,882 hours in the 2009 rebasing to the current ongoing level of staff time, forecast at 3,599 hours for 2014, combined with pay-rate increases since 2009.

The combined increase in OM&A since NOTL Hydro last rebased for the two activities mentioned above is $114,921 from the 2014 test year.

a) Please provide further explanation for the significant increases in staff time allocated to meter operation and maintenance, as well as billing.
b) Please comment on whether or not NOTL Hydro expects the increases in staff time allocated to meter operation and maintenance and billing to maintain throughout the IRM term. Additionally, please comment on any measures NOTL Hydro is taking to reduce the amount of time spent on these activities in the future.

Response to 4.2-Staff-8

a) **Meter Operation and Maintenance**

The increase in staff time is due to increase in smart meter activities such as tuning, troubleshooting, meter sampling, meter seal extensions, meter activities for FIT and mFIT which did not exist in 2009. There are variable hours associated with communication problems with TGB, firmware upgrade verification and investigation of failures. More staff hours are budgeted towards meter re-verification compared to 2009 as we have a plan to re-verify all our out-of-seal meters which is very important as we are obliged to comply with Measurement Canada's rules. To keep up to pace with the new technology and train young engineering staff, training hours have gone up which are charged to this account.

Billing

As stated in the responses to VECC-18a and Energy Probe-13a, the billing department staff (Billing Supervisor and 3 Customer Account Representatives in 2009, Business Manager and 3 Customer Account Representatives in 2014) has remained at 3 FTEs from 2009 to 2014. However, the proportion of their time among the functions of billing, retail services, collecting and services provided to the affiliate ESNI (for water heater billing and water billing for the Town of NOTL) has changed from 2009 to 2014. A summary is provided below, showing that the proportion of their time for billing increased from 28.4% in the 2009 Board approved to 58.6% in the 2014 forecast.

Billing Staff Hours*	Hours		% of Hours	
	2009 Board Approved	2014 Forecast	2009 Board Approved	2014 Forecast
Billing	1,712	3,451	28.4%	58.6%
Collecting	1,621	847	26.9%	14.4%
Retail	468	197	7.8%	3.3%
Sub-total to OM&A	3,801	4,495	63.0%	76.3%
ESNI - Water Heaters	570	-	9.4%	0.0%
ESNI - Water Billing	1,664	1,398	27.6%	23.7%
Total	6,035	5,893	100%	100%
**** Including all Departments, billing hours are as follows:***				
Billing Department	*1,712*	*3,451*		

b) **<u>Meter Operation and Maintenance</u>**

Since smart meters are relatively new, we expect the amount of meter operation and activities to be the same throughout the IRM. As always we try our best to find efficiencies and reduce the number of hours spent on every activity however with the re-verification plan and smart meter activities mentioned above, it will be hard to reduce the amount of time spent on these activities during the IRM period. Once all our out-of-seal meters are re-verified and we have less smart meter troubleshooting, the number of hours spent will is expected to come down.

<u>Billing</u>

NOTL Hydro believes the 2014 forecast mix of hours is reflective of current business processes and does not expect any further increase in staff time allocated to billing during the IRM term.

Board staff are requested to refer to the response to Staff-9ci for a description of initiatives being undertaken to manage billing costs.

4.2-Staff-9

a) Please identify the percentage of customers on e-billing as of December 31, 2013.
b) Please describe the Applicant's efforts to promote e-billing to its customers.
a) Please confirm whether or not NOTL Hydro has moved to monthly billing. If so:
   i. Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.
   ii. As part of the decision making process, has the applicant determined the impact of the change to monthly billing on its working capital? If so, how is the working capital impacted by this change? If not, why not?

Response to 4.2-Staff-9

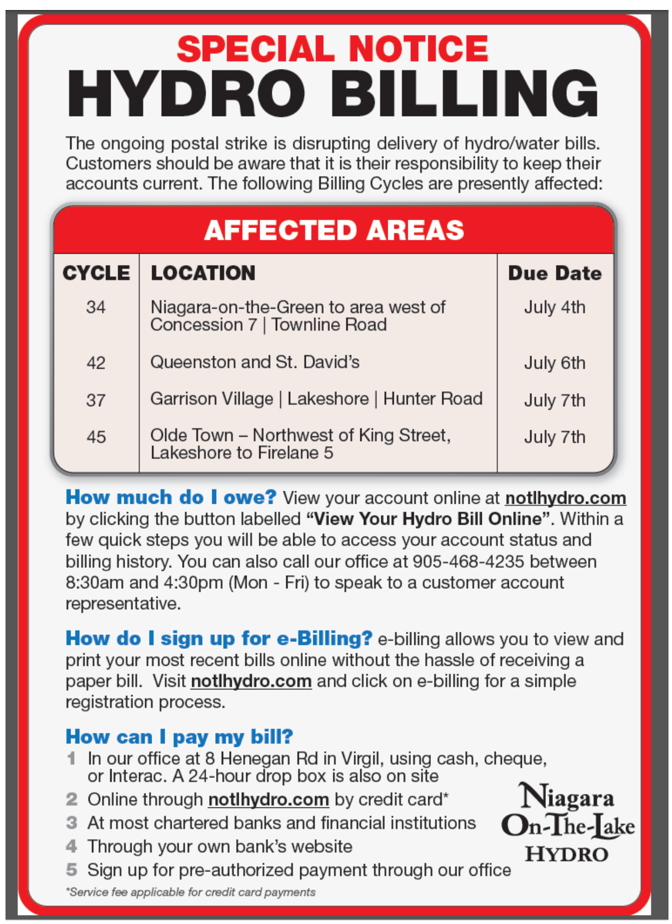
a) As of December 31, 2013, approximately 18% of customers were on e-billing.

b) NOTL Hydro has actively promoted e-billing to its customer base via many channels for some time, including:

- Customer Account Representative staff's engagement with customers at the front counter or on the telephone
- community contest to win a Dyson Fan:

- promotion on the back of our billing envelopes:

- local Newspaper, e.g. prior to potential postal strike in 2011:



- on our website:

- through social media, such as Twitter and Facebook:

c) NOTL Hydro's Board decided to implement monthly billing almost 13 years ago, effective March 12, 2001. Prior to that date, billing was every two months.

i. NOTL manages costs through software solutions.

Included in our rate application is the purchase of FileNexus, an integrated document management solution, allowing us to more easily save and locate e-documents saving time with the retrieval of records for account information and analysis. In addition to the purchase of FileNexus, NOTL Hydro intends to purchase part of a group licence for Teleworks, an IVR system designed for both pull and push customer notification, allowing customers to pay invoices and query account information while allowing NOTL Hydro to notify customers of emergency outages, account reminders, and other outgoing telephone communications that were formally completed by a staff member. Finally, in this next period NOTL Hydro is moving to a new version of our CIS with promises of reducing time taken to complete many billing calculations and functions. The processing of microFITs at NOTL Hydro has long been done manually and a software solution is underway to automate the entire process.

NOTL manages costs through innovative business models that respect community diversity.

NOTL Hydro has long been a member of the Utility Collaborative Services (UCS Group), membership with this group continues to save NOTL Hydro costs through purchasing a group licence for our CIS, FileNexus and Teleworks and continuing to take advantage of reduced group costs on premium software. Using the same principles that guided NOTL Hydro to the UCS Group, NOTL Hydro is a founding member of the Customer First group (formerly the G8 group) and expects to see savings by sharing larger standardized products and services purchased at a bulk rate instead of purchasing smaller batches of goods at a higher cost as an individual utility. In addition to sharing costs over a larger group, NOTL Hydro makes regular effort when reordering supplies to approach multiple vendors to elicit the best price for our customers.

NOTL manages costs through understanding our areas of expertise.

The number of connections in the NOTL Hydro service area, from municipal projections, is expected to grow by approximately 10% in this next rate period. NOTL Hydro has taken into consideration expected gained efficiencies over the next period and is forecasting an ability to operate with the same number of staff. Based on our unique and close relationship with our customers, NOTL Hydro continues to encourage e-billing through education, discussion, and incentives for existing customers and new customer connections. The potential increase in postal rates coupled with the uncertainty that this change may bring are both motivating factors driving NOTL Hydro to evaluate outsourcing all mailed billing reducing the cost of postage, bill paper, envelopes, and time worked on these tasks. With the infrastructure in place mandated from the SME, NOTL Hydro is migrating larger demand meters requiring a physical read to a smart meter that will integrate with our existing smart meter architecture resulting in a decrease in the cost of meter reading.

ii. In 2001, NOTL Hydro's Board decision to move to monthly billing involved an assessment of other possible initiatives such as internet billing and payment, and the combined billing of water and hydro, as well as consideration of cash flow effects. A detailed calculation of the impact on working capital was not done, as at that time the setting of rates by the OEB, to the best of our understanding, did not involve a working capital allowance calculation.

- ***Issue 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-10
Ref: Ex.2/App.2A/pg. 9

On page 9 of the CDSP, NOTL Hydro states that "with information suggesting that our MTS#2 transformer units would be approaching the end of their useful life in the next 5-10 years, we moved a significant amount of load off MTS#2 over to the newer MTS#1 station."

NOTL Hydro then states "as a means of extending the useful life of the MTS#2 transformer units, we offloaded a majority of the F1 feeder on to the MTS#1 M2 feeder in early 2012. As we fully expect to upgrade one MTS#2 unit in 2015, the normal M2/F1 configuration will be restored."

a) Given that the expected remaining useful life of the MTS#2 station is 5-10 years and that NOTL Hydro has taken measures to rebalance loads between transformer stations in order to increase the useful life of the MTS#2 station, please explain why NOTL Hydro believes it is necessary to perform the replacement of the MTS#2 station as early as 2015.

Response to 4.3-Staff-10

a) NOTL Hydro received engineering reports indicating shorter than expected life expectancy for the two MTS#2 units in 2012. Our decision to immediately commence the process to replace the first unit as early as 2015 was based on the following;

- In order to better ensure that the two units do not fail before we can reasonably replace them, their load was reduced - not to exceed 50% of capacity at the first stage cooling at peak load or approximately 12 mVA.

- Typical peak system load of 50 mVA exceeds the 42 mVA rating of MTS#1. In the event of a loss of supply, failure of MTS#1 or emergency maintenance requirement, MTS#2 would be required to supply over 100% of rated capacity of the both MTS#2 units which presents a high risk situation

- NOTL Hydro is expecting continued load growth which magnifies the potential risk

- Professional advice indicates that the process to replace and increase the capacity of a unit at MTS#2 will require 3-4 years

- One of the units at MTS#2 has a slightly higher failure potential as confirmed by ongoing gas-in-oil analysis

4.3-Staff-11
Ref: Ex.8/T.1/Sch.2/pg. 1
Ref: Ex.8/T.1/Sch.8/pg. 5

The bill impact calculation, on page 5 of Ex. 8/T. 1/Sch. 8, indicates a $4.48 (or 30.37%) increase in the total bill for the Street Lighting class. On page 1 of Ex. 8/T. 1/Sch. 2, NOTL Hydro states:

> It is NOTL Hydro's understanding that in order to address the significant under recovery of cost in this class, a significant change to the revenue-to-cost ratio has occurred in many other cases and the bill impacts for these classes have been higher than 10%. Based on the aforementioned information, it is NOTL Hydro's understanding that in the past the Board has not been concerned with bill impacts greater than 10% for Street Lighting and as a result a mitigation plan was not developed.

a) Has NOTL Hydro contacted its Street Lighting customer(s) to get feedback on the proposed bill increase? If so, please summarize the customer(s)' comments.
b) NOTL Hydro's current proposed Revenue-to-Cost ratio adjustments would bring the Street Lighting class from a ratio of 57.9% to 90.3%. If NOTL Hydro's Street Lighting customer(s) have posed any objections to the proposed bill impacts or have not been approached about the proposed bill impacts, please provide the estimated bill impacts for the Street Lighting class if NOTL Hydro were to use a phased adjustment to the revenue-to-cost ratios for the Street Lighting class under the following scenarios:

    i. A 2-year phase-in period (74.1% in 2014 and 90.3% in 2015).
    ii. A 3-year phase-in period (68.7% in 2015, 79.5% in 2015 and 90.3% in 2016).

Response to 4.3-Staff-11

a) About 95% of the streetlight connections are those of The Town of Niagara-on-the-Lake. The other 5% belong to the Region of Niagara (2%) and the Cities of Niagara Falls (<1%) and St. Catharines (2%). NOTL Hydro notified the Town, as its main customer, of the proposed increase in rates on October 31, 2013. On the same day, the Town of Niagara-on-the-Lake acknowledged the notification as received but has not provided any comment or objection.

b) The estimated 2014 bill impacts per the original application (Table 8.1.16 of Exhibit 8) are as follows[2]:

[2] The line loss volumes in the application linked in error to the kW volume. The yellow-highlighted values in the Table

Impacts Per Application										
Customer Class:	Street Lighting									
TOU / non-TOU:	non-TOU									
	Consumption	50	kWh		May 1 - October 31					
		0.14	kW							
		Current Board-Approved			Proposed			Impact		
		Rate	Volume	Charge	Rate	Volume	Charge			
	Charge Unit	($)		($)	($)		($)	$ Change	% Change	
Monthly Service Charge	Monthly	$ 4.9800	1	$ 4.98	$ 7.6700	1	$ 7.67	$ 2.69	54.02%	
Distribution Volumetric Rate	per kW	$19.4795	0.14	$ 2.73	$29.9987	0.14	$ 4.20	$ 1.47	54.00%	
Sub-Total A (excluding pass through)				$ 7.71			$11.87	**$ 4.16**	**54.01%**	
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	$(0.02)	-$ 1.1086	0.14	$ (0.16)	-$ 0.13	588.16%	
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	$ (0.11)	-$ 0.37	-140.53%	
DVA 1562 disposition	per kW	-$ 2.4982	0.14	$(0.35)	$ -	0.14	$ -	$ 0.35	-100.00%	
Tax change rider	per kW	-$ 0.9793	0.14	$(0.14)	$ -	0.14	$ -	$ 0.14	-100.00%	
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	$ (0.05)	-$ 0.05		
Line Losses on Cost of Power		$ 0.0880	2.32	$ 0.20	$ 0.0880	1.90	$ 0.17	-$ 0.04	-18.14%	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.66**			**$ 11.73**	**$ 4.06**	**52.99%**	
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 1.9242	0.14	$ 0.27	-$ 0.00	-1.59%	
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3254	0.14	$ 0.05	-$ 0.00	-2.46%	
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.99**			**$ 12.04**	**$ 4.06**	**50.79%**	
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%	
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	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%	
Energy - Non RPP	per kWh	$ 0.0880	50	$ 4.40	$ 0.0880	50	$ 4.40	$ -	0.00%	
Total Bill (before Taxes)				**$13.27**			**$ 17.32**	**$ 4.06**	**30.58%**	
HST		13%		$ 1.72	13%		$ 2.25	$ 0.53	30.58%	
Total Bill (including HST)				$14.99			$ 19.57	$ 4.58	30.58%	
Total Bill				**$14.99**			**$ 19.57**	**$ 4.58**	**30.58%**	
	Loss Factor (%)		4.63%			3.79%				

i. The estimated 2014 bill impacts per a 2-year phase-in period are as follows:

below link correctly to the kWh volume, slightly reducing the estimated impacts.

Impacts Per Staff IR11bi - 2-year phase in

Customer Class: **Street Lighting**

TOU / non-TOU: non-TOU

Consumption 50 kWh ○ May 1 - October 31
0.14 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	$ 4.9800	1	$ 4.98	$ 6.1301	1	$ 6.13	$ 1.15	23.09%
Distribution Volumetric Rate	per kW	$ 19.4795	0.14	$ 2.73	$ 23.9781	0.14	$ 3.36	$ 0.63	23.09%
Sub-Total A (excluding pass through)				$ 7.71			$ 9.49	**$ 1.78**	**23.09%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	$ (0.02)	-$ 1.1086	0.14	$ (0.16)	-$ 0.13	588.16%
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	$ (0.11)	-$ 0.37	-140.53%
DVA 1562 disposition	per kW	-$ 2.4982	0.14	$ (0.35)	$ -	0.14	$ -	$ 0.35	-100.00%
Tax change rider	per kW	-$ 0.9793	0.14	$ (0.14)	$ -	0.14	$ -	$ 0.14	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	$ (0.05)	-$ 0.05	
Line Losses on Cost of Power		$ 0.0880	2.32	$ 0.20	$ 0.0880	1.90	$ 0.17	-$ 0.04	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.66**			**$ 9.34**	**$ 1.68**	**21.90%**
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 1.9242	0.14	$ 0.27	-$ 0.00	-1.59%
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3254	0.14	$ 0.05	-$ 0.00	-2.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.99**			**$ 9.66**	**$ 1.67**	**20.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%
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	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0880	50	$ 4.40	$ 0.0880	50	$ 4.40	$ -	0.00%
Total Bill (before Taxes)				**$ 13.27**			**$ 14.94**	**$ 1.67**	**12.61%**
HST		13%		$ 1.72	13%		$ 1.94	$ 0.22	12.61%
Total Bill (including HST)				$ 14.99			$ 16.88	$ 1.89	12.61%
Total Bill				**$ 14.99**			**$ 16.88**	**$ 1.89**	**12.61%**
Loss Factor (%)			4.63%			3.79%			

ii. The estimated 2014 bill impacts per a 3-year phase-in period are as follows:

Impacts Per Staff IR11bii - 3-year phase in

Customer Class: Street Lighting

TOU / non-TOU: non-TOU

Consumption 50 kWh ; 0.14 kW — May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 4.9800	1	$ 4.98	$ 5.6458	1	$ 5.65	$ 0.67	13.37%
Distribution Volumetric Rate	per kW	$ 19.4795	0.14	$ 2.73	$ 22.0839	0.14	$ 3.09	$ 0.36	13.37%
Sub-Total A (excluding pass through)				$ 7.71			$ 8.74	**$ 1.03**	**13.37%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	$ (0.02)	-$ 1.1086	0.14	$ (0.16)	-$ 0.13	588.16%
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	$ (0.11)	-$ 0.37	-140.53%
DVA 1562 disposition	per kW	-$ 2.4982	0.14	$ (0.35)	$ -	0.14	$ -	$ 0.35	-100.00%
Tax change rider	per kW	-$ 0.9793	0.14	$ (0.14)	$ -	0.14	$ -	$ 0.14	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	$ (0.05)	-$ 0.05	
Line Losses on Cost of Power		$ 0.0880	2.32	$ 0.20	$ 0.0880	1.90	$ 0.17	-$ 0.04	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.66**			**$ 8.59**	**$ 0.93**	**12.12%**
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 1.9242	0.14	$ 0.27	-$ 0.00	-1.59%
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3254	0.14	$ 0.05	-$ 0.00	-2.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.99**			**$ 8.91**	**$ 0.92**	**11.57%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%
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	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0880	50	$ 4.40	$ 0.0880	50	$ 4.40	$ -	0.00%
Total Bill (before Taxes)				**$ 13.27**			**$ 14.19**	**$ 0.92**	**6.96%**
HST		13%		$ 1.72	13%		$ 1.84	$ 0.12	6.96%
Total Bill (including HST)				$ 14.99			$ 16.03	$ 1.04	6.96%
Total Bill				**$ 14.99**			**$ 16.03**	**$ 1.04**	**6.96%**
Loss Factor (%)			4.63%			3.79%			

5. Public Policy Responsiveness

- ***Issue 5.1:*** *Do the applicant's proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations?*

5.1-Staff-12
Ref: Ex.2/App.2A/pg. 45 and 46
Ref: Ex.2/App.2A/ pg. 84
Ref: Ex.2/App.2A/Attachment 6 – Customer Engagement Survey

In the first reference on page 46, first paragraph- item c), NOTL Hydro states:

> […] A Town bilaw prohibits the installation of new overhead plant as a means of preserving the original ambiance of the historic town and we have accepted that burial of facilities is in the best interest of the community. The design and project management of the project will be handled by our Engineering Department while construction will be completed by contracted services during the calendar year of 2014. [emphasis added]

In the second reference, it is stated in part that:

> [..] A long standing Town by-law requires that new infrastructure in the urban limits of the Old Town be installed underground. NOTL Hydro agrees with the principle of the by-law and has readily complied with the by-law since 1987. The replacement of the aging legacy 4 kV distribution network with 27.6 kV has continued for the past 25 years and is reflected in our 5 year Capex plan. With the completion of the Simcoe 600 amp feeder in 2013 and decommissioning of the last 4 kV sub-station this autumn, the renewal plan for the urban limits has become clear. We estimate that the entire historic Old Town will be converted to 27.6 kV and buried within 15 years.

a) Please provide a copy of the town by-law mentioned in the first reference.
b) In making the decision to convert the distribution infrastructure in Old Town from overhead to underground, did NOTL Hydro consider that the Board, under section 78 of the Ontario Energy Board Act, in reviewing and approving an application by an electricity distributor for the purpose of setting just and reasonable rates, is not restricted by any by-law if the Board determines that such a by-law is not in the best interest of the distributors' rate payers.
c) Please confirm that replacement of the existing 4 kV system with a 27.6 kV overhead system is merely a replacement of existing infrastructure with a more efficient infrastructure and that the replacement is not a new installation as referred to in item c) of the first reference.
d) Did NOTL compare the cost of a 27.6 kV overhead system with the cost of a 27.6 kV underground system? If the answer is yes, please provide any and all documents which set out the cost comparison including all assumptions and

sources of the cost estimates, as well as, installation costs and the expected annual OM&A.

e) If the answer to d) above is “no” please explain why no comparison of the costs of an overhead vs. underground line was completed.
f) Did NOTL investigate the use of an overhead design for the 27.6 kV option such as a “Hendrix Cable System” which utilizes an overhead configuration with reduced dimensions and overhead attachment techniques but with conductors insulated to a degree that significantly reduces outages from tree branch and animal/bird contact and also reduces weather related outages? If not, why not?
g) Please indicate whether NOTL received any feedback from its customers regarding NOTL’s 10 year plan to convert the old 4 kV overhead system to an underground 27.6 kV system. If so, did NOTL Hydro outline the cost comparison and advantages and disadvantages of the two options?

Response to 5.1-Staff-12

a) The Town's Official Plan which was adopted by By-law 2735-94. Section 6: General Development Policies - Public Utilities states:

"(4) The Town shall require that in Urban Areas gas lines, hydro lines and other public services be located underground along road allowances and/or easements, where appropriate. In rural areas the Town may require that such facilities be underground. Suitable setbacks from all such utilities will be required."

b) NOTL Hydro is cognizant of the fact that a Town by-law may not restrict our ability to install new overhead facilities in the Old Town. However, we choose to bury facilities in the Old Town because we believe it is the right thing to do. This 'underground' practice commenced over 25 years ago with the Niagara-on-the-Lake Hydro Commission and has continued with NOTL Hydro. Our previous rate applications and Conditions of Service also clearly outline(d) our plans to bury facilities in the Old Town. Customers living in the Old Town have for over 25 years been required to pay the additional cost of burying their supply cables to their homes when modifying their service. Customers have willingly accepted this additional cost and we have never had a related dispute.

The Old Town's historic significance is unique to Ontario and perhaps anywhere in Canada and has often been compared to Williamsburg Virginia. The municipality's economy is highly dependent on the estimated 1 million annual visitors that are attracted to the ambiance found in this quaint Old Town. An estimated 100 Bed and Breakfast establishments in early 1800's and Victorian houses and 200 year old oak trees surround the downtown core. These annual visitors contribute to parking revenues and successful local businesses that result in NOTL boasting the lowest tax mill rate in the Region. NOTL Hydro's current rate application will also position our company with perhaps the lowest electricity rates in the Niagara Region. We fully believe that the burial of facilities in the Old Town is a justifiable additional cost and the only reasonable proposal.

c) This will confirm that NOTL Hydro is merely replacing the outdated legacy 4 kV overhead system with a basic but efficient 27.6kV underground system.

d) no

e) As described in b) above, the practice of burying facilities in the Old Town commenced in 1988 with the installation of a major underground supply to the new Queens Landing hotel. Since that time, all new facilities in the historic town area have been buried. In our 2009 rate application, a very large multi-phase burial of facilities in the historic Chautauqua area was proposed and accepted by the Board and intervenors alike. Replacing the ageing 4 kV overhead system in the Old town with an overhead 27.6 kV system has therefore, not been considered in this application.

f) The existing 4 kV system is generally positioned on old 35 foot wood poles and the primary lines are carved through 200 year old trees. Several sections of the existing primary consists of hendrix cable systems. We fully expect that to meet current ESA safety standards for a new overhead 27.6 kV system utilizing a hendrix cable system, taller poles (45 foot) will be required especially for transformer locations. These taller poles will result in extensive tree trimming. The hendrix system does reduce bird/animal contacts but we would disgree (based on our experience) with the weather related advantage. During ice build ups similar to what the GTA experienced in December 2013, the heavier bundled cables tend to cause additional problems.

g) NOTL Hydro has been burying all facilities in the Old Town for over 25 years. We hold an annual 'AGM' and invite all customers at which time our current and long term plans are presented. As previously mentioned, our Conditions of Service document was recently updated and included a public consultation process which confirmed the continuance of an underground servicing policy in the Old Town. In all situations listed above, we have never received a dissenting comment from a single customer. Cost comparisons and advantages/disadvantages of an overhead option were not presented.

5.1-Staff-13

Ref: Ex.1/T.1/Sch.2/pg. 10
Ref: Ex.9/T.2/Sch.1/pg. 18 and 19
Ref: Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence, March 25, 2010, Revised May 17, 2012 (EB-2009-0397)

At the first reference, it is stated that:

> NOTL Hydro is requesting approval to include $237,952 as a 2013 capital addition to be included in the 2014 rate base, resulting from smart grid demonstration project capital costs incurred in 2009, 2010 and 2011 and recorded in Account 1534.

At the second reference, NOTL stated in part that:

> The Old Town area of Niagara-on-the-Lake is currently supplied via two 27.6 kV feeders that originate several kilometres south at MTS#2. The feeders have always been susceptible to animal contacts and lightning etc. as they pass through a predominantly rural area. In order to minimize the impact of these outages on the Old Town, NOTL Hydro turned to a Smart Grid solution. Smart switches were installed that effectively transfer the Old Town supply to the alternative feeder in seconds when automatically determined that the fault is not present in the Old Town. The switches are integrated to our SCADA system to provide intelligence and load information. The system has performed flawlessly since placed in operation in 2011. The success prompted Hydro Quebec to invite our Operations Manager to speak at a Regional conference in 2011.

The third reference at pages 20 and 22 describes eligible smart grid activities, namely, Smart Grid Demonstration Projects, Smart Grid Studies and Planning Exercises, and Smart Grid Education and Training.

a) Please comment on the view that installation of switches to transfer Old Town supply to another feeder to address reliability issues is not new and is part of the ongoing responsibility of any distributor to investigate and address such issues, and that any capital investment in that regard is part of its normal activities, and does not meet the Filing requirement criteria as prescribed in the noted third reference.

Response to 5.1-Staff-13

a) At the time when we decided to proceed with the installation of the Old Town Smart Switch arrangement, we had been inspired by the Energy Minister's Green Energy vision and prompted by the O.E.B.'s creation of Green Energy/Smart Grid variance accounts. We carefully studied the criteria established for the variance accounts and were convinced that the project qualified and we were advancing Smart Grid public policy established by the government. In 2010, the switches were considered leading edge and utilized smart grid technology to solve a complex situation. Upon completing the system installation in 2011, NOTL Hydro was invited (and accepted) to speak at a North American technical conference in Montreal hosted by Hydro Quebec and share our experience with the audience. We also note that this project was recognized by Canada Revenue as a valid Science Research and Experimental Data (SRED) project in a 2012 application for a SRED tax credit[3]. With today's technological advancements, one can argue that by the time new technology implemented, it is yesterday's technology.

[3] The initiative qualified as "Experimental Development" with the purpose "To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes

5.1-Staff-14

Ref: E-9/T-2/S-1/pp. 20 – 21/1535 Smart Grid OM&A Deferral Account
Ref: Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence, March 25, 2010, Revised May 17, 2012 (EB-2009-0397)

In the first reference, NOTL Hydro refers to the following Primary projects contributing to the Smart Grid OM&A account:

- $ 46,000 : unfunded portion of the Residential Load Control Pilot project This refers to the 2010/2011 Pilot Program partially funded by the OPA;
- Industry smart grid training courses;
- Maintaining/tuning the Smart Grid self-healing system; and
- Participating in an EDA delegation that visited Denmark to study smart grid connection of renewable generation.

In that same first reference NOTL stated in part that:

> NOTL Hydro's audited balance in this account at December 31, 2012, including principal and interest to that date, is $86,258, reflecting OM&A expenses incurred in the years 2009 to 2012. As stated above with regard to Account 1534, NOTL Hydro had not yet recorded the depreciation and accumulated depreciation to December 2012 prior to the 2012 audit[1]. The resulting principal balance after adjustments in Account #1535 for expenses up to December 31, 2012 including depreciation is $130,500.
>
> For 2014, NOTL Hydro is requesting disposition of the December 31, 2012 adjusted balance plus the forecasted interest through April 30, 2014. The claim is a debit balance of $133,025.

a) If the Board does not approve NOTL's request of adding $237,952 as a 2013 capital addition to be included in the 2014 rate base, as outlined earlier in the Board staff interrogatory in regard to "1534 Smart Grid Capital Deferral Account", please confirm that only the $86,258 would be eligible for consideration in regard to the 1535 Smart Grid OM&A Deferral Account

Response to 5.1-Staff-14

a) NOTL Hydro's best understanding of the Board's possible decision scenarios for this item is that either:

   I. The Board approves the request as submitted, i.e. recognizes the installation of the switches as an eligible smart grid activity, approves $237,952 as a 2013 capital addition to be included in the 2014 rate base and approves recovery of the depreciation expenses in account #1535; or

II. The Board decides that the installation of the switches is part of the normal capital investment activities (as referenced for comment in 5.1-Staff-13).

Under Scenario II, NOTL Hydro's understanding is that because the capital investment did occur with net book value of $237,952 at December 2012, then this amount would still move into account #1980 from account #1534 and thereby go into the 2014 rate base, similar to what would have happened if the investment had been treated by NOTL Hydro as "normal capital activity" and recorded in account #1980 originally. However, under Option II, the associated depreciation expense to December 2012 would be considered to have been within rates approved in the 2009 COS. If this understanding is correct, then NOTL Hydro accepts and confirms that, under Scenario II, the associated depreciation should not be included for consideration in disposition of account #1535, i.e. only $86,258 plus carrying charges to April 2014 would be eligible.

5.1-Staff-15
Ref: Ex.9/T.2/Sch.1/pg. 15 - 17

On pages 15-17 of Ex.9/T.2/Sch.1, NOTL Hydro outlines its claim for the recovery of start-up OM&A costs related to enabling the connection of renewable generation under Ontario Regulation 330/09.

On page 15, NOTL Hydro states:

> $12,572 for consulting costs. NOTL Hydro along with nine local distribution companies in the Niagara-Erie Region ("NEPA") jointly employed a consultant to prepare a Green Energy Act (GEA) Roadmap. The GEA Roadmap was critical for the NEPA members to understand the legislation and to participate and support the Minister's objectives outlined in the GEA. The Act focused not only on renewable energy initiatives, but also on opportunities for Demand Response programs, impacts of building codes, updates to smart grid and smart appliance regulations and also impacted plans for the future expansion of LDC transmission and distribution infrastructure. The GEA Roadmap outlined potential opportunities for NEPA to pool resources to potentially launch innovative new projects. NOTL Hydro's share of the Report cost was $12,000 plus out-of-pockets costs of $572.

a) Please explain why NOTL Hydro believes that the cost of the GEA Roadmap report is appropriate for recovery under Ontario Regulation 330/09 given the description above.
b) If the Board does not approve the recovery of the $12,572 in consulting costs, please confirm that the total claim under Ontario Regulation 330/09 would be the $6,000 in costs for an electrical engineer to complete a CIA and commission three (3) new FIT customers.
c) As the requested recovery under Ontario Regulation 330/09 is for start-up OM&A only, please confirm that NOTL Hydro will apply in its 2015 rate application to update the amount for recovery from the IESO to $nil.

Response to 5.1-Staff-15

a) As explained in our response to your previous question #13, NOTL Hydro and a majority of our fellow LDCs met the passage of the Green Energy Act with both enthusiasm and some anxiety. We felt compelled to explore opportunities by which to assist the promotion of public policy. Nine other NEPA members also agreed to procure the assistance of an industry professional to advise us on preparing our system for renewable energy generators, installing our own local renewable generation facilities, exploring demand response initiatives and generally developing an intelligent grid beyond our operating areas in to larger regional districts. These activities were well outside the traditional activities of an LDC and were truly Public Policy Responsiveness. We remain of the opinion that it is appropriate to recover the cost of the GEA Roadmap study under Ontario Regulation 330/09.

b) This will confirm that less the consulting costs for a) our total claim would be $6000 for CIA/commissioning of 3 new FIT customers.

c) This will confirm that our requested recovery from the IESO under Ontario Regulation 330/09 in our 2015 rate application will be $nil.

5.1-Staff-16
Ref: CDSP/Attachment 17-OPA letter/pg. 2/2nd last paragraph
Ref: CDSP/p. 37/1st paragraph
Ref: Report of the Board- Framework for Determining the Direct Benefits Accruing to Consumers of a Distributor under Ontario Regulation 330/09 – June 10, 2010 (EB-2009-0349)/Section 1.1/p. 3

At the first reference, the OPA letter states in part that:

> In fact, NOTL Hydro has not identified any renewable generation enabling capital expansion expenditures, although its 5 year capital expenditure program has planned renewable generation enabling expenditures for the continued development of an outage management system and various smart grid-related technological components.

At the second reference, the evidence provides under “System Service”, a description for 2014 investment of $95,000 for Capex project titled “System Integration GIS/FIS/CIS/ODS”, and states in part that:

> Not long after implementing our AMI network, we realized the vast potential of the system. Integrated data from our AMI, ODS, CIS, FIS and GIS systems can be utilized to develop an outage management system and various other tools to improve our efficiency and customer service. Integration of these systems commenced in 2012 and is proposed to be largely complete in 2014. Utilizing the GIS as a central data base, customer information from the CIS, asset information from the AM system and FIS as well as AMI load information from our ODS system will be integrated. An outage management system is our final outcome and is currently well under development. […] We are confident based on development to date, that the desired project will be completed. Our 2013 forecasted Capex expense is $100,000 but we have budgeted $95,000 in 2014 with the expectation that the project will be completely functional before year end. Funding for this project will be from general revenues. [emphasis added]

The third reference is the Report of the Board outlining the framework for determining the direct benefits accruing to customers of a distributor under Ontario Regulation 330/09.

a) Please comment whether or not Renewable Generation would benefit from the proposed outage management system as described in the second reference? If yes please describe in detail how Renewable Generation would benefit from this system.

b) If indeed there are benefits to the Renewable Energy in the NOTL system, how would that share of the benefit be allocated between NOTL's load customers and NOTL's Renewable Generator customers?

Response to 5.1-Staff-16

a) We understand that a renewable generator`s protective equipment is designed to interrupt the flow of the generated power to the distributor`s grid during an outage. Therefore, the renewable generator would in fact benefit from an Outage Management system that restores power more quickly, thus allowing the customer to maximize the revenue potential from increased generation supplied to the grid.

b) NOTL Hydro`s SOP and FIT customers are currently assessed a monthly service charge at the GS<50 kW rate class as a means of recovering our fixed charges. Conceptually, if NOTL Hydro`s 2014 rates are approved, they will reflect the provision of the outage management system in the monthly service charge. As the Board continues to fix a provincial service charge for microFIT customers, there is no way to allocate this rate group with a share of such a benefit. NOTL Hydro is of the opinion that the provincial microFIT service charge already represents a subsidized rate for a vast majority of LDCs in the province.

5.1-Staff-17
Ref: Ex.9/T.3/Sch.3/pg. 2

On page 2 of Ex.9/T.3/Sch.3, NOTL Hydro states that the “allocated weighting (%) of the stranded meter costs was based on the relative proportions of the residential and GS < 50 kW weighted meter capital cost allocations in NOTL Hydro’s 2009 rate application, which used the 2006 cost allocation model.”

a) What were the installation costs for each of the meter types of the removed stranded meters?
b) How many meters of each type were removed from service?
c) Using the responses to a) and b) please provide an allocation of the remaining net book value of stranded meter costs for each class using a weighted average of the installation costs for the associated meters. Please provide updated calculations of the Stranded Meter Rate Rider using this allocation.

Response to 5.1-Staff-17

a) NOTL Hydro did not track the specific installation costs of residential and GS<50 meter classes. Additionally, a number of the GS<50 installations included instrument transformers that were not stranded and remain in place today.

b) As per Table 9.3.12 in Exhibit 9, 6,666 residential meters and 1,253 GS<50kW meters were removed from service.

c) Although specific installation costs are not available, NOTL Hydro offers an approach using a snapshot of historical purchase prices (circa 2006) which would be reflective of the comparability of installation costs. Using this approach, the allocated weighting of stranded meters would be 44.2% residential, 55.8% GS<50kW as follows:

Allocation Based on Historical Price Snapshot				
Meter Type	**Cost**	**Res**	**GS<50**	**Total**
Regular Residential	$ 39.00	6,597		6,597
Central Meters	$ 99.00	69	187	256
7 Jaw GS<50	$ 295.00		1,066	1,066
Total		6,666	1,253	7,919
Weighted Average Cost		$ 39.62	265.73	
Total Cost		$ 264,133	$ 332,957	$ 597,089
Percentage of Total Cost / Allocated Weighting		**44.2%**	**55.8%**	**100.0%**

Table 9.3.12 is updated below to reflect this weighting and to provide updated calculations of the rate rider.

	Stranded Meters Calculation				
	Capital cost	$ 349,266	*Actual*		
	Accumulated depreciation to Dec 31, 2011	$ 237,184	*Actual*		
	2012 Depreciation	$ 9,836	*Actual*		
	2013 depreciation	$ 9,462	*Forecast*		
A	Net Book Value @ Dec 31, 2013	$ 92,784	*Forecast*		
		Residential	GS< 50 kW	Total	
B	Weighted meter capital -per Staff IR17c	$ 264,133	$ 332,957	$ 597,089	
C = % of B	Allocated weighting of stranded meters	44.2%	55.8%	100.0%	
D = C x A	Net Book Value Segregated by Rate Class	$ 41,045	$ 51,740	$ 92,784	
E	Forecast average customers in 2014	7,040	1,304	8,345	
F = D / E /12	Rate rider to recover stranded meter costs per Staff IR17c	$ 0.49	$ 3.31	per month	
	Recovery period (years)	1	1		
	Number of meters stranded	6,666	1,253	7,919	

7. Revenue Requirement

- ***Issue 7.7:*** *Has the proposed revenue requirement been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues?*

7.7-Staff-18

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Response to 7.7-Staff-18

An updated RRWF is provided as a separate Excel file and also as attachment B to these responses. Similar to the response to Energy Probe-33, a listing of the changes is provided below.

Topic	Interrogatory Response	RRWF reference
Specific Service Charges increase	7.1-VECC-22	See RRWF 3. Data Input Sheet, Note 13
O&M reduction	4.2-VECC-15	See RRWF 3. Data Input Sheet, Note 14
1576 update	9.1-Staff-27	n/a
Capital Parameters update	7.5-Energy Probe-31	-
Truck disposals update	7.1-Energy Probe-22	See RRWF 3. Data Input Sheet, Note 10
Capital Contributions update	7.1-Energy Probe-20	-
FA Continuity update	7.1-Energy Probe-20	See RRWF 3. Data Input Sheet, Note 10 and Note 15
Cost of Power update	7.1-Energy Probe-24	See RRWF 3. Data Input Sheet, Note 12
RTSR update	8.5-VECC-38	n/a

7.7-Staff-19

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).

Response to 7.7-Staff-19

The updated bill impacts are provided as Attachment C and as a separate Excel file. These impacts reflect the following data entries:

- Updated monthly service charges and distribution volumetric rates are entered in the "proposed" column.
- Updated RTSR network and line connection rates are entered in the "proposed" column.
- Updated non-RPP energy prices per the Navigant report dated October 17, 2013 are entered in both the "current" and "proposed" columns as these prices are independent of the decision on the application.
- Updated RPP rates per the Navigant report dated October 17, 2013 are entered in both the "current" and "proposed" columns as these prices are independent of the decision on the application..

The radio button "November 1 – April 30" is selected as this IR response is submitted after October 31.

8. Load Forecast, Cost Allocation and Rate Design

- ***Issue 8.1:*** *Is the proposed load forecast, including billing determinants an appropriate reflection of the energy and demand requirements of the applicant?*

8.1-Staff-20
Ref: Ex.3/T.1/Sch.1/pg. 1[4]

On page 1 of Ex. 3/T. 1/Sch. 1, NOTL Hydro states that it "found that the available data on numbers of customers [and] monthly billed/accrued revenue data by rate class would not support a reliable regression modelling process for rate class load forecasts."

a) Please provide further details regarding the approaches undertaken by NOTL Hydro to complete class-specific load forecasts. Please include descriptions of the variables used and why they were rejected.
b) Where available, please provide the results of the regressions that were ultimately rejected including descriptions for the variables that were used.

Response to 8.1-Staff-20

a) Details of NOTL Hydro's findings when it considered how class-specific load forecasts might be done are provided on Pages 1 and 2 of Exhibit 1, Tab 5, Schedule 21 of the application.

   NOTL Hydro collected and reviewed the available historical monthly billed/accrued revenue data and customer numbers by rate class to determine whether it would be possible to conduct a regression on a rate class basis.

   Additional data on customer numbers was obtained from archives of Hydro One rate applications for the NOTL Hydro Commission related to the period before incorporation in 2000. However, this data provided only the total number of customers of all classes combined by year, not monthly. For the period from 2000 to mid-2003, customer numbers were available by rate class, but only as annual figures.

[4] NOTL Hydro assumes this reference is to Tab 2

Estimates of monthly billed/accrued revenue data by rate class have only been done since mid-2004. Up until February 2010, these estimates were calculated by pro-ration of billings by rate classes as a whole; since March 2010, with the implementation of a new CIS system, the calculations have been done on a customer-by-customer basis. Consequently, it was felt that the limited monthly billed/accrued revenue data availability (8 ½ years from mid-2004 to December 2012) and questionable quality of this data prior to 2010 would not support a reliable regression modeling process for rate class load forecasts.

As a result, specific rate class regression analyses were not conducted. Because of the limitedness and questionability of this data, there did not appear to be any good alternative but to focus efforts on the purchased power regression modelling approach that has been accepted by the Board in previous cost of service applications and was approved in NOTL Hydro's 2009 COS case.

b) All the following variables that were considered possible and reasonable predictors of Kwh were used at the start of this process:

Heating Degree Days (as defined in Exhibit 3, Tab 2, Schedule 1, Page 7)
Cooling Degree Days (as defined in Exhibit 3, Tab 2, Schedule 1, Page 7)
Peak Hours (Per IESO definition)
Days in Month (per calendar)
Spring Fall Flag (Mar/Apr/May/Sep/Oct/Nov = 1)
Summer Tourist Flag (Jul/Aug/Sep = 1)
Spring Flag (Mar/Apr/May = 1)
Fall Flag (Sep/Oct/Nov =1)
Total Customers (various sources – see DATA-Customers sheet in load forecast model)
Population (Statistics Canada Census data)
CDM Activity (as calculated in load forecast model sheet DATA-CDM from OPA data)
Ontario Real GDP Monthly (Q) % (monthly GDP estimated from quarterly GDP)
Ontario Real GDP Monthly (A) % (monthly GDP calculated from annual GDP)
Local Employed-seasonally adjusted (000s) (Statistics Canada for St. Catharines/Niagara)
Local Employed-unadjusted (000s) (Statistics Canada for St. Catharines/Niagara)
Local Unemployed-seasonally adjusted (000s) (Statistics Canada for St. Catharines/Niagara)
Local Unemployed-unadjusted (000s) (Statistics Canada for St. Catharines/Niagara)

Variables were then eliminated one by one, using the XLSTAT statistical add-in for

Excel and a multiple stepwise backward regression in which the variable with the highest p-value was eliminated, until all variables passed the 5% significance test. Model 10a[5] was the first model where all variables p-values were less than 0.05. From this model onwards, variables were added and eliminated in order to view and compare the statistical results of different models.

Further explanations of the regression results are provided as follows, with reference to the sheets in the Excel files provided:

1. File – NOTL_Regression Models_Bdstaff_IR20_1.xlsx

   Raw Data_1992 – Monthly data for each variable used, from January 1992 to December 2012

   Raw Data_1996 – Monthly data for each variable used, from March 1996 to December 2012. Data was not available for Local Employed and Local Unemployed variables (Columns P to S), from January 1992 to February 1996.

   Model Summary – This table shows the variables that were used in each model, as well as high p-values. An “x” is shown when the variable is no longer used.

   Model Evaluation – This table summarizes the statistical results of each model, in order to compare and decide which variables to include in the final model. The coefficient value is shown in the columns beside each variable. Clicking on the cell shows the formula linking to the origin of the information shown on the chart.

   Models 1 through 20 – Shows detailed output results from each regression model using the XLSTAT add-in.

2. File – NOTL_Regression Models_Bdstaff_IR20_2.xlsx

   This file was created because, during the preparation of the rate application, an error was spotted in the data entries for the Summer Tourist Flag Variable for a small number of months. In order to ensure correct results.

   The tab, “Raw Data_Jan 1996,” includes all data used in the final model in the Rate Application submission. Tabs in this file have the same function as those explained in 1) above. Model 11 in the “Model evaluation” sheet is the final model selected.

3. Notes on Differences between Regression Files in 1) and 2) above

[5] Please refer to the Excel file provided “NOTL_Regression Models_Bdstaff_IR20_1.xlsx”, “Model Summary” sheet

- The ending result from both regression files included the same sets of variables, as in the regression models 11 and 11a in File 1 and 10 and 11 in File 2. Model 11 in File 2 was ultimately chosen for the submission, based on the full set of 204 observations from January 1996 to December 2012. Also see 4. below.
- Further models, using XLSTAT in File 1), were "experiments" to view the resulting statistics.
- The same variables were removed in sequence, except minor differences. Such as, the GDP Monthly (Q) was taken out before the employment variables in File 1) and after the employment variables in File 2).
- In File 1, the Fall Flag variable was automatically removed by the XLSTAT add-in calculations due to multi-colinearity. Thus, the Fall Flag variable was excluded altogether in File 2) because of the multi-co-linearity issue in the first set of models in File 1).
- In File 1), models were run with both 252 and 202 observations as the full set of data was not available for the employment variables. Employment data was available beginning March of 1996.
- As the employment variables were removed, we were able to run regression results for the full set of data that was available from January 1996.
- We found the statistical results were improved when regression models were run using 1996 data, as opposed to starting in 1992.
- There is a variance between the resulting models with the same variables and observations in Files 1) and 2), due to the repair in File 2) of the small error in the Summer Tourist Flag as mentioned above.

4. <u>Final Model</u>

In September 2013, the load forecast regression (File 2- Model 11), which had reflected the draft 2012 CDM results provided by the OPA, was updated to reflect the final 2012 CDM results that had been recently received. The predicted 2014 purchases decreased by 211,898 kWh or 0.11% as follows:

- Based on draft 2012 CDM results 193,418,655 kWh
- Application based on final 2012 CDM results 193,206,757 kWh

8.1-Staff-21

Ref: Ex.3/T.2/Sch.1/pg. 16

On page 16 of Ex. 1/T. 2/Sch. 1, NOTL Hydro states:

> For the Residential and General Service < 50 kW classes, it has been assumed in previous cost of service rate applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. NOTL Hydro agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, NOTL Hydro has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 76.4%, i.e. 88.2%.

a) Did NOTL Hydro consider any other methods of estimating the weather sensitivity of the Residential and General Service < 50 kW classes? If so, please describe what methods were investigated and why they were not used. If not, please explain why NOTL Hydro feels the proposed approach is reasonable.

Response to 8.1-Staff-21

a) NOTL Hydro did not consider any other methods of estimating the weather sensitivity of the Residential and General Service < 50 kW classes. The approach of systematically assessing each customer one-by-one was clearly impractical due to the numbers of customers involved in each of these classes.

In the absence of such a systematic approach, NOTL Hydro felt it was reasonable to gauge the overall sensitivity of these classes relative to the GS>50kW class sensitivity of 76.4% and the maximum possible of 100%. A sensitivity of 100% is too high as there are drivers of electricity consumption by these two classes that are not sensitive to weather, such as lighting and appliances or equipment not used for heating or cooling. On the other hand, a larger proportion of consumption by customers in these two classes is for heating or cooling than would be the case on average for the GS>50kW class customers that were individually assessed. An accurate gauging of the overall sensitivity % combined or separately for these two classes is not feasible, but the average of 100% and 76.4%, i.e. 88.2%, appears to be a reasonable sensitivity % to be used for both classes.

- ***Issue 8.2:*** *Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?*

8.2-Staff-22
Ref: Ex.7/T.1/Sch.1/pg. 4, Table 7.1.2

On Table 7.1.2, NOTL Hydro indicates the weighting factors for each of the 30 cost components it identifies as being related to billing and collection.

a) Please provide descriptions for the activities/functions that comprise the labels in Table 7.1.2 noted below. Where the weighting factors differ between classes for an identified function/activity, please explain the rationale for the difference.

i. B&C Customer Billing - Systems stuff
ii. B&C Collecting – Truck

Response to 8.2-Staff-22

a) Descriptions of the two referenced items are provided below:

i. B&C Customer Billing – "Systems stuff"

- Settlement system support by Kinetiq Canada Ltd., such as to provide pricing and the net system load shape.
- Month-end data-base archiving, revenue reporting and OCEB reporting by the ITM Group Inc., who host the Harris Northstar server for the UCS group of LDCs.
- Use of the File Nexus document management system (planned for 2014 as indicated in the Distribution System Plan)

ii. B&C Collecting – Truck

- The vehicle expenses resulting from use of a company pick-up truck by line department staff to disconnect or reconnect customers in the event of non-payment of accounts

With regard to functions where there are differences in weighting factors between classes, the rationales are provided below the following Table (derived from Table 7.1.2 of the application) which groups functions to which the same weights were assigned. The Table below excludes functions where the weights for the classes do not differ.

	A	B	C	D	E	F	G	H	I
2	**USoA**	**Function**	**2014 Test**	**Function Weighting Factors**					
3				Residential	GS<50	GS>50 Interval	GS>50 Non-Interval	Streetlights	USL
4	**5315**	**B&C - CUSTOMER BILLING**							
5	**Group 1**								
6	PURCHASES	RCVA adjustment (-ve)	-$ 3,343	1	1.65	2.85	7	0	0
7	PURCHASES	Expenses	$ 1,653	1	1.65	2.85	7	0	0
8	LABOUR	Billing Sup	$ 1,030	1	1.65	2.85	7	0	0
9	LABOUR	Billing - Office	$ 7,818	1	1.65	2.85	7	0	0
10	PURCHASES	RCVA adjustment (-ve)	-$ 19,299	1	1.65	2.85	7	0	0
11	LABOUR	Billing - Office	$ 10,450	1	1.65	2.85	7	0	0
12									
13	**Group 2**								
14	LABOUR	Billing - Management	$ 74,845	1	1	1.25	1.25	0.75	0.75
15									
16	**Group 3**								
17	LABOUR	Billing -crew	$ 97,216	1	0.95	0.95	0.9	0.75	0.75
18									
19	**Group 4**								
20	PURCHASES	Systems stuff	$ 12,330	1	1	0.71	0.71	1	1
21									
22	**5320**	**B&C - COLLECTING**							
23	**Group 5**								
24	LABOUR	Collecting -B&C Crew	$ 33,210	1	1	0.25	0.25	0	0
25	LABOUR	Billing - Line Crew Regular	$ 443	1	1	0.25	0.25	0	0
26	LABOUR	Collecting - Eng. Labour	$ 337	1	1	0.25	0.25	0	0
27	TRUCK	Truck	$ 600	1	1	0.25	0.25	0	0
28									
29	**Group 6**								
30	LABOUR	Collecting - Management	$ 5,150	1	1	0	0	0	0
31	LABOUR	Admin crew	$ 2,216	1	1	0	0	0	0
32	PURCHASES	Credit Bureau	$ 500	1	1	0	0	0	0
33	SUBCONTRACT	Admin - Temp agency (Hamm)	$ 1,873	1	1	0	0	0	0

Group 1

These functions and costs are those carried out by NOTL Hydro to serve retailer customers.

The costs for these functions are allocated according to the %-age of the total number of retailer customers that are in each class, shown as line B in the Table below. To obtain this result using the “weight” methodology requires the weights to be the relative %-ages of the classes that are retail customers (lines D and E in the Table below). Line F in the Table is shown to verify that the correct allocation result is achieved, i.e. lines F and B are the same.

.

			Residential	GS<50	GS>50 Interval	GS>50 Non-Interval	Streetlights	USL	Total
A		No. of Retailer Customers	161	47	2	14	0	0	224
B	% of Allocated Cost =	% of Retailer Customers	71.88%	20.98%	0.89%	6.25%	0.0%	0.0%	100.0%
Weight Derivation									
C		No. of Customers in Class	7,115	1,256	31	88	5	22	8,517
D = A / C		% of class that are retailer customers	2.3%	3.7%	6.5%	15.9%	0.0%	0.0%	
E = D scaled to residential as 1		**Weight**	**1**	**1.65**	**2.85**	**7.0**	**0**	**0**	
F verified to be same as B		Weight x number of customers in class / sumproduct of weights and nos. of customers in class	71.88%	20.98%	0.89%	6.25%	0.0%	0.0%	100.0%

Group 2

This function is the billing work carried out by the Business Manager (supervisor of the billing department). The weights assigned across all classes reflect a subjective assessment of the relative complexity of dealing with matters for customers in each class, such as the type of research involved (e.g. conversations with technologists, etc.) and the collection of relevant billing information. Thus, it is felt that 25% more work (i.e. a weight of 1.25) would be required for GS>50kW issues than for residential, and 25% less (i.e. a weight of 0.75) for streetlights and USL than residential.

Group 3

This function is the billing work carried out by the 3 Customer Account Representatives in the billing department. The weights assigned across all classes reflect a subjective assessment of the relative complexity of dealing with matters for customers in each class. For example, LEAP complexity and communication with agencies is a factor that increases the component for residential customers relative to other classes; GS>50kW customers' collection of data, loading of data, and billing of data is no more onerous than requesting billing quantities from the MDMR; GS>50kW Non-Interval is an even less onerous task as the readings are taken directly from the readings gun and imported into the NorthStar billing system; streetlight and USL customers require the least effort. Thus, weights of 95% for GS<50kW and GS>50kW interval, 90% for GS>50kW non-interval and 75% for streetlights and USL were felt to be reasonable.

Group 4

These functions are the items referred to in the response to 8.2-Staff-22 a) above. Best efforts were made to assess the applicability of the systems items to each class to determine an appropriate cost allocation, such as net system load shape is not applicable to the GS>50kW interval customers and unbilled revenue reports are not required for GS>50kW customers as they are billed for usage from the 1st to the end of the month. The result is shown in the Table below, with the weights set equal to the rounded ratio % of costs to % of customers in order to achieve the cost allocation required.

	Systems Items	Cost	Residential	GS<50	GS>50	Streetlights	USL	Total
	All other	$ 4,130	$ 3,450	$ 609	$ 57	$ 2	$ 11	$ 4,130
	Kinetiq/ITM	$ 6,400	$ 5,366	$ 947	$ 66.37	$ 4	$ 17	$ 6,400
	ITM monthend	$ 1,800	$ 1,525	$ 269		$ 1	$ 5	$ 1,800
	Total	$ 12,330	$ 10,341	$ 1,826	$ 123	$ 7	$ 32	$ 12,330
A	% of cost		83.87%	14.81%	0.998%	0.06%	0.26%	100.0%
	# of Customers		7,115	1,256	119	5	22	8,517
B	% of customers		83.54%	14.75%	1.397%	0.06%	0.26%	100.00%
C = A / B	Ratio % of cost to % of customers		1.00396	1.00396	0.71458	1.00396	1.00396	
C Rounded	Weight = scaled ratio		1	1	0.71	1	1	

Group 5

These collection functions do not normally occur for the streetlight and USL classes as they are typically owned by assured payers such as municipal/regional governments in the case of streetlights, or owned by assured payers such as Bell Canada and Cogeco in the case of USL, or are small accounts in the case of other USL customers. Thus, to avoid any allocation of cost to these two classes in the calculations for Table 7.1.3, their weights were set to zero.

When collections do occur for GS>50kW class, the methodology is similar to the residential and GS<50kW classes, However, experience has shown that the overall likelihood of the occurrence of collections for a GS>50kW customer is lower than it would be for a residential or a GS<50kW customer. A weight of 25% for GS>50kW relative to weights of 1 for Residential and GS<50 was felt to reasonably represent this situation.

Group 6

These functions normally occur only for the residential and GS<50kW classes. Thus, to avoid any allocation of cost to the other classes in the calculations for Table 7.1.3, the weights for the other classes were set to zero. Weights of 1 for residential and GS<50kW reflect that there is no difference between the functions for these two classes.

8.2-Staff-23

Ref: Ex.7/T.1/Sch.1/pg. 6, Table 7.1.6

On Table 7.1.6, NOTL Hydro provides the weights for meter reads for each class. NOTL Hydro indicates a weighting of 50.51 for interval metered customers in the GS > 50 kW class.

a) Please provide further details as to how the weighting factor for interval metered customers in the GS > 50 kW class was derived and what factors contribute to the weighting factor that is indicated.

Response to 8.2-Staff-23

a) The cost allocation Excel file submitted with the application contains in Sheet I7.2 the following per meter per month reading costs and the resulting weight factors:

Philip Wormwell:
These are previous OEB default. Must develop own.

	A	B	C
18		Allocation Percentage Weighted Factor	
19		Cost Relative to Residential Cost	
20			Total
21		Per meter per month	Factor
22	Residential - Urban - Outside		
23	Residential - Urban - Outside with other services		
24	Residential - Urban - Inside		
25	Residential - Urban - Inside - with other services		
26	Residential - Rural - Outside		
27	Residential - Rural - Outside with other services		
28	Smart Meter		
29	Smart Meter with Demand		
30	GS - Walking		
31	GS - Walking - with other services		
32	GS - Vehicle with other services --- TOU Read		
33	GS - Vehicle with other services		
34	Residential Smart Meter	$ 0.65	1.00
35	GS<50 kW Smart Meter	$ 0.65	1.00
36	GS>50 kW Interval	$ 32.83	50.51
37	GS>50 kW non-interval	$ 4.87	7.49
38	Streetlights accounts	$ 16.25	25.00

In responding to this interrogatory, details of the analysis that was done to derive the weights for all classes are provided:

<u>Residential and GS<50kW Smart Meters</u>

Sensus monthly invoices:

Base station	$2,263	
Metro	$2,041	
Subtotal [6]	$4,304 for 8,100 customers =>	$0.5300 per meter per month
Plus Customer reading charge[7]		<u>$0.1145</u> per meter per month
Total per meter per month		<u>$0.6445</u> rounded to $0.65
Weight		**1.00**

[6] For gathering of radio reads and directing them to the Sensus server, located in the GTA

[7] Sensus charge per customer read

GS>50kW Interval

Utilismart monthly invoices[8]:

31 customer phone-lines at $16.25 per month		$503.75
26 of the 31 – GPRS cell-phone add-on at $14.00		$364.00
Monthly demand report per month		$150.00
Total		$1,017.75
Weighted average cost per month per read		$1,017.75 / 31 customers
	=	$32.83 per meter per month
Weight = 32.83 / 0.65 =		**50.51**

GS>50kW non-interval

Niagara Field Services invoices:

January 2013 invoice (91 meters)		$443.02
Cost per monthly read		$443.02 / 91
	=	$4.87
Weight = 4.87 / 0.65 =		**7.49**

Streetlights

[NOTL Hydro has 5 streetlight accounts:

Town of NOTL urban
Town of NOTL rural
Region of Niagara
City of St. Catharines
City of Niagara Falls]

Utilismart monthly invoices:

Same price as GS>50kW MV90 service	$16.25 per acct per month
Weight = 16.25 / 0.65 =	**25.00**

[8] For remote MV90 meter reading service

- ***Issue 8.3:*** *Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?*

8.3-Staff-24
Ref: Ex.8/T.1/Sch.1/pg. 3
Ref: Ex.3/T.2/Sch.1/pg. 23

The customer/connection numbers from NOTL Hydro's load forecast, shown on pg. 23 of Ex.3/T.2/Sch.1/pg.23, do not match the values that are used to calculate the proposed fixed charges on Table 8.1.4 of Ex.8/T.1/Sch.1.

a) Please explain why NOTL Hydro is using values for customers/connections that do not match the values shown in the adjusted load forecast.
b) If any changes are required, please provide updated calculations for the proposed fixed charges for each class.

Response to 8.3-Staff-24

a) The customer/connection numbers in the load forecast on Page 23 of Exhibit 3, Tab 2 Schedule 1 are all year-end numbers. The calculation of the fixed charges uses average numbers for 2014, calculated as average of the year-end 2013 and year-end 2014 numbers. This approach results in a fixed charge which, when applied to the changing numbers of customers month-by-month during 2014, would generate fixed charge revenue during 2014 closer to the required fixed revenue amount than would use of the 2014 year-end numbers alone. This use of average numbers is also shown in Tables 8.1.10, 8.1.11 and 8.1.12.

b) No changes are required.

- ***Issue 8.5:*** *Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?*

8.5-Staff-25
Ref: RTSR Workform – Sheet 6

On Sheet 6 of the RTSR Workform, NOTL Hydro has not provided any billed quantities for Transformation Connection charges.

a) Please confirm that NOTL Hydro does not pay Transformation Connection charges.

Response to 8.5-Staff-25

a) NOTL Hydro confirms that it does not pay Transformation Connection Charges, as it owns its own transformer stations.

9. Accounting

- ***Issue 9.1:*** *Are the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders appropriate?*

9.1-Staff-26
Ref: Ex.9/T.2/Sch.1/page 1, Table 9.2.1 and page 10

The evidence with respect to the claim for account 1508 – Sub-account Financial Assistance Payment and Recovery Variance – Ontario Clean Energy Benefit Act is not consistent in the evidence referenced above. Table 9.2.1 on page 1 shows that the amount requested for disposition is $144, but page 10 of the evidence shows that the claim is a debit balance of $170,381.

a) Please clarify and confirm the amount requested for disposition in this proceeding.
b) If NOTL Hydro is requesting disposition of the $170,381 debit balance, please reconcile this balance to NOTL Hydro's RRR filing and explain any variances. Please file an updated version of the 2014 Deferral/Variance Account Workform including updated deferral and variance account rate rider calculations.

Response to 9.1-Staff-26

a) In writing Exhibit 9, Tab 2, Schedule 1, Page 10, "1508 – Other Regulatory Assets – OCEB", an embedded linkage to Table 9.2.1 was inadvertently linked to the RSVA – GA cell, instead of the 1508-OCEB cell. The amount of $170,381 on Line 10 of Page 10 should be replaced by the actually claimed amount for disposition of $144. No corrections are required to any calculations in Exhibit 9 as a result of this error.

b) N/a

9.1-Staff-27
Ref: Appendix 2-EE

Board staff notes that the NOTL filed the evidence regarding Accoun1576 in September 2013, which includes the forecast figures for Account 1576 in Appendix 2-EE.

a) Please update 2013 forecast figures based on actual figures, if possible, for Account 1576 and provide the reasons of the update (i.e. adjustments identified, audited by external auditor, etc.).

Response to 9.1-Staff-27

a) The calculation of Account 1576 has been updated in the Table on the next page based on the actual (unaudited) 2013 capital expenditures and disposals. The reasons for the update are to provide a more accurate estimate of Account 1576 using actual results than was possible with the capital forecast done in mid-2013 for the application and to reflect OEB's updated cost of capital parameters in the "WACC" rate (regulated rate of return) issued on November 25, 2013.

   The updated closing balance in Account 1576 is $671,921. With the updated WACC rate of 6.65%, the amount to be included in the rate rider calculation is $895,192.

Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				21,557,141					
Net Additions - Note 4				1,094,857					
Net Depreciation (amounts should be negative) - Note 4				-1,396,227					
Closing net PP&E (1)				21,255,771					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				21,557,141					
Net Additions - Note 4				1,098,857					
Net Depreciation (amounts should be negative) - Note 4				-728,305					
Closing net PP&E (2)				21,927,693					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-671,921					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	- 671,921	**WACC**	6.65%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 223,271	**# of years of rate rider disposition period**	5
Amount included in Deferral and Variance Account Rate Rider Calculation	- 895,192		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

9.1-Staff-28

Ref: Ex.9/T.2/Sch.1/pg. 28, Table 9.2.8 – 2011 and 2012 Expected Savings for LRAM

NOTL Hydro has requested the disposition of its LRAMVA – Account 1568, of a total amount of $27,662, which includes $726 in carrying charges through April 30, 2014. NOTL Hydro is requesting the disposition of the lost revenues related to its 2011 CDM savings in both 2011 and 2012 and its 2012 CDM savings in 2012.

a) Please expand Table 9.2.8 and include all the appropriate OPA CDM Initiatives that produced net CDM savings which were used in NOTL's LRAMVA calculations. For each rate class, please list all relevant CDM initiatives and provide the subsequent net CDM savings for each. An example is provided below:

Residential	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
GS<50	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
GS>50	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		

Response to 9.1-Staff-28

a) The requested Table is provided below.

2011		
RESIDENTIAL	**Net kWh**	**Net KW**
Appliance Retirement	46,772	7
Appliance Exchange	289	0
HVAC Incentives	86,998	49
Conservation Instant Coupon Initiative	32,225	2
Bi-Annual Retailer Event	46,602	3
TOTAL	212,886	60
GS < 50	**Net kWh**	**Net KW**
Pre-2011 Retrofit completed in 2011	50,693	9
Retrofit	61,073	12
Direct Install Lighting	451,696	171
New Construction	22,211	5
TOTAL	585,673	197
GS > 50	**Net kWh**	**Net KW**
Pre-2011 Retrofit completed in 2011	114,925	22
Pre-2011 New Constuction completed in 2011	92,390	18
Retrofit	17,001	3
TOTAL	224,316	42
	Net kWh	**Net KW**
2011 TOTAL	1,022,875	299

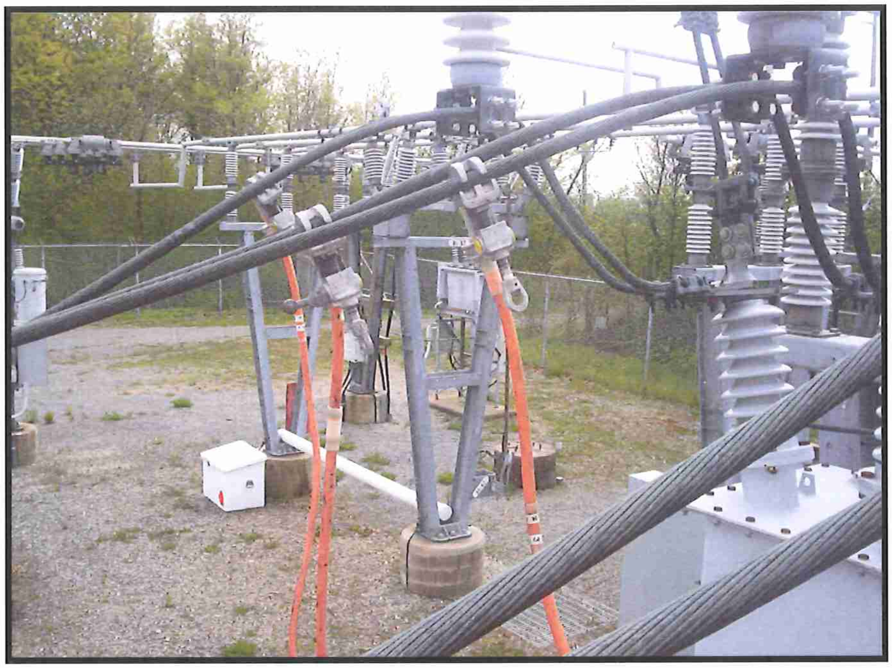
2012		
RESIDENTIAL	**Net kWh**	**Net KW**
Appliance Retirement	27,029	5
Appliance Exchange	683	0
HVAC Incentives	42,025	26
Conservation Instant Coupon Initiative	2,654	0
Bi-Annual Retailer Event	45,932	2
Low Income	1484	0
TOTAL	119,807	33
GS < 50	**Net kWh**	**Net KW**
Retrofit	12,339	11
Direct Install Lighting	287,393	72
Energy Audit	25,176	5
TOTAL	324,908	88
GS > 50	**Net kWh**	**Net KW**
Pre-2011 New Constuction completed in 2011	21711	4
Retrofit	398,954	65
New Construction	13,146	4
TOTAL	433,811	73
	Net kWh	**Net KW**
2012 TOTAL	878,526	194

- End of document -

Attachment A

2012 Maintenance Inspection Report

Ascent™



Project Ref. #: 24743LSP

Customer: Niagara on the Lake Hydro
Site: NOTL DS – 801 Concession 5, Virgil

2012 Maintenance Inspection Report

June 13, 2012

R.R. #3 - 14719 BAYHAM DRIVE
TILLSONBURG, ONTARIO N4G 4G8

TEL : 519-842-6458
FAX : 519-842-2496

Date: June 25, 2012

To: Niagara on the Lake Hydro
PO Box 460
8 Henegan Road
Virgil, Ontario
L0S 1T0

Attention: Hassan Syed

Re: NOTL DS T1 and T2 Condition

Dear Hassan,

Thank you for providing us with the opportunity to assess the condition of your transformers at NOTL DS.

Introduction:

We have performed a review of our archived oil samples and test reports for T1 and T2 at Niagara on the Lake DS. We have also reviewed previous insulation resistance and power factor tests.

A frequency response analysis (FRA) was performed on May 9, 2012. Frequency response analysis is a useful tool to evaluate shifts in transformer windings over time due to through faults and/or deterioration. Since no baseline FRA test data was available, the FRA test results of the two virtually identical units at NOTL DS have been compared to each other.

Although only incomplete loading data was available, available information was reviewed as part of this assessment. Available loading data included periodic meter readings by Ascent and averaged monthly demand. Averaged monthly demand data was provided by NOTL Hydro.

14719 Bayham Drive, RR #3, Tillsonburg, ON N4G 4G8 Tel: 519-842-6458 Fax: 519-842-3775 Toll Free: 1-800-565-6790

Summary of Findings:

Oils:

Both units appear to be fit for continued service, although it is evident from the test data that the replacement of both transformers should be considered and budgeted for within the next five years, as both transformers are approaching end of life age, regardless of their current condition. Seasonal overloading is a concern – dissolved gas analysis (DGA) indicates that degradation of the cellulose insulation of both transformer cores has occurred in the past and will continue to occur under current operating conditions, although the rate of degradation has remained static.

The oil analysis of NOTL DS-T1 shows elevated levels of ethylene, which can be formed when metal parts of the transformer overheat under oil. Interfacial tension of the insulating oil of NOTL DS-T1 is barely within acceptable limits. For a detailed analysis of oil conditions for both transformers, please refer to Oil Analysis Report 24643LSP dated June 25, 2012. Furan analysis indicates that the mechanical strength of the solid insulation of the core of NOTL DS-T1 is close to that which would be found in a new transformer.

The oil analysis of NOTL DS-T2 shows levels of hydrogen just below IEEE condition 1 limits. This is potentially an indication of corona discharge occurring under oil. Furan analysis indicates that the mechanical strength of the solid insulation of the core of NOTL DS-T2 is close to that which would be found in a new transformer.

FRA Analysis:

The provided plots should be placed side by side to compare the frequency responses of NOTL DS-T1 to NOTL DS-T2

It is not possible to reach a definitive conclusion regarding the condition of either transformer from the FRA plots alone. The magnitude and phase response for the same test configurations for the two transformers are remarkably similar. Variations were observed in magnitude and phase response for the primary side (115kV) windings in the 1 kHz-10 kHz range for NOTL DS-T1. Test instrument probes were attached between phases B and A with the ground attached to phase A. This could be indicative of a primary winding shift due to a through fault, or shifting of the windings due to age and insulation degradation.

NOTL DS-T2 shows a variation of magnitude and phase response when the test instrument probes are attached between phases B (115kV) and b1 (27.6kV) with the ground attached to the neutral point of the secondary winding (27.6kV) of the transformer. It is difficult to guess what the cause of this variation might be, especially given the relatively better health of NOTL DS-T2 when compared to NOTL DS-T1. Winding shift or an anomaly in the solid insulation or core ground may be the cause. This result should not be cause for concern without baseline FRA data for this transformer.

Load:

Load information provided to Ascent by NOTL Hydro reveals that the transformers may loaded beyond their respective 30MVA capacities during the summer months. Overloading may be partly to blame for elevated carbon dioxide levels in the insulating oil.

Other Tests:

Insulation resistance tests showed that the insulation resistance of both units is within NETA limits. Insulation power factor is below 0.5%, which is within the recommended limits for new equipment. Winding ratio tests showed no indication of shorted windings. Winding resistance is within acceptable limits.

Further Recommendations:

Both NOTL DS-T1 and NOTL DS-T2 are fit for continued service – although there are indications of overloading. Since the transformers will continue to be overloaded, and are approaching the end of their design life, the following measures should be taken to ensure continued trouble free service.

Perform a Detailed Load Study for NOTL DS:

A detailed load study will show the duration and magnitude of transformer overloading, and will help determine whether or not elevated dissolved gas levels are due to overloading or hot spot activity. A detailed load study will also be helpful from a system planning perspective. Such a study would consist of collected and graphed amperage and/or kVA readings at intervals of several minutes over a period of several days each month. This information may be available from existing monitoring systems.

Oil Sampling Frequency:

Quarterly oil sampling is recommended for both transformers, to ensure that rapid deterioration of insulation is not occurring. This is recommended in the most recent Weidmann oil sample test report for NOTL DS-T2 (please refer to Oil Analysis Report 24743LSP dated June 25, 2012).

We hope that our comments will be helpful to NOTL Hydro. We look forward to being of continued service. Please contact me if you have any questions regarding this letter.

Yours sincerely,

Ben White
Ascent Solutions Inc.

Email: bwhite@ascent.ca
Phone: (519) 842-6458 x256
Cell: (519) 521-1170

June 7, 2012

Niagara on the Lake Hydro
8 Henegan Road
Virgil, ON
L0S 1T0

Attention: Hassan Syed

Re: Maintenance Inspection Report - Our Ref: 24743LSP
Site: NOTL DS – 801 Concession 5, Virgil

Dear Hassan,

Please find the attached report for the maintenance work and inspections completed May 8, 2012 at the NOTL DS substation.

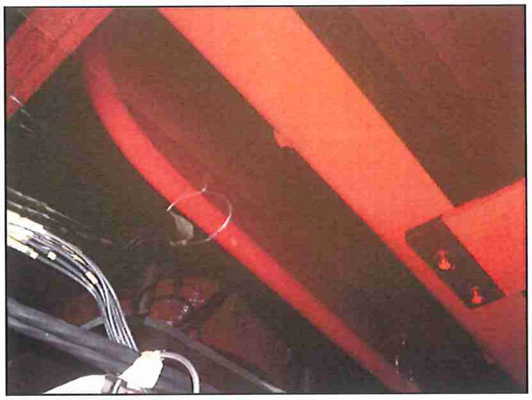
Ascent Solutions inspected and tested T1 and T2 as required. A summary of the site findings is listed below for your review. All findings are referenced to the Ontario Electrical Safety Code (OESC).

T1

Findings/Repairs:

- All test results found satisfactory

- Oil found to be very clear in tank, non-visible in transformer on internal inspection



- Replaced lock washers as three were found broken

- Transformer showing signs of rust

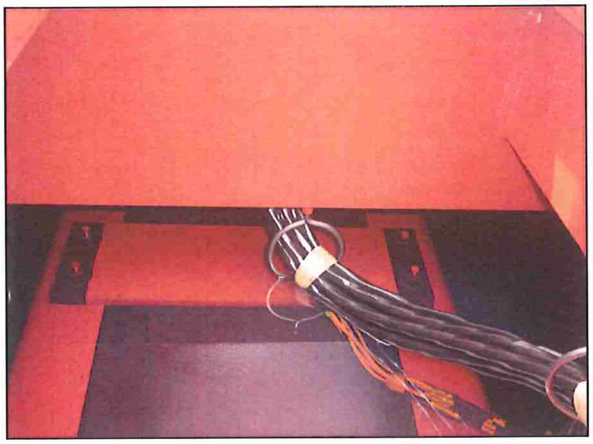
Recommendations:

- Continue with regular maintenance inspections to keep equipment clean and in good working condition
- Repaint transformer to prevent further rusting

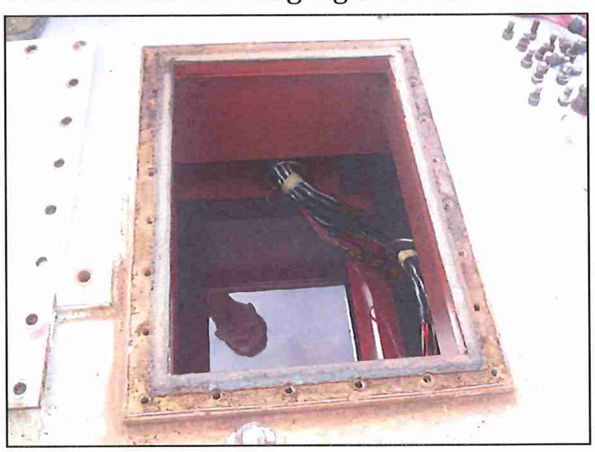
T2

Findings/Repairs:

- All test results found satisfactory
- Oil found very clear in tank with none visible on the transformer



- Transformer showing signs of rust



Recommendations:

- Continue with regular maintenance inspections to keep equipment clean and in good working condition
- Repaint transformer to prevent further rusting

All other equipment that we tested appears in satisfactory condition, suitable for continued service.

Please give us a call should you wish us to provide you pricing and services for any or all of the recommended repairs listed in this report.

If you have any questions/concerns please do not hesitate to contact us. We look forward to being of continued service to Niagara on the Lake Hydro.

Sincerely,
ASCENT

Doug Charron
E.E. Technician, Master Electrician
Maintenance & Technical Services
Phone: (519) 842-6458
Fax: (519) 842-2496
Cell: (519) 521-2600

May 8, 2012

Niagara on the Lake Hydro
8 Henegan Road
P.O. Box 460
Virgil, ON
L0S 1T0

Attention: Mr. Craig McLean

Re: Oil Analysis Report – Our Ref: 24570LSP
Transformer: Westinghouse, Serial No. A3S5671

Dear Craig,

Attached are the results of the oil analysis of samples recently taken from the 3 Transformers and 3 LTC's located at your substations by Niagra-on-the-Lake.

- **Transformer – T1, Westinghouse, Serial No. A3S5671**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be reasonably satisfactory. With the exception of Ethylene (C2H4) and Carbon Dioxide (CO2), all of the other gases remained within the IEEE recommended limits. **Ethylene increased to *57 ppm* compared with results almost a year ago (*50 ppm*) (exceeding the IEEE limit of *50 ppm*), while Carbon Dioxide jumped to *5749 ppm* compared with *4864 ppm* (exceeding IEEE limit of *4000 ppm*).** Trending shows there may be **a small hot spot slowly developing inside the transformer, possibly due to a bad connection inside.** Ethylene is usually accompanied by Ethane, together they sometimes called the "hot metal gases", however since levels of Ethane are not currently elevated, **no action is recommended at this time, but levels of Ethylene should be closely monitored.**

    Carbon Dioxide is a byproduct associated with the decomposition of the cellulose insulation, heat being a major factor of its rate produced, usually attributed to overloading. A transformer will also produce this gas along with Carbon Monoxide as it ages, and depending on the manufacturer type/model, varies in amounts produced, with Westinghouse models prone to having higher levels. **Concentrations in the key gases however have not made significant increases to warrant cause for any concern at this time, so no action is required. We do however recommend continued annual sampling to more accurately assess trends such as these.**

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, remaining clear with trace amounts of sediments, and a slight amount of water content (*6 ppm*). All measured parameters remained within the IEEE recommended limits for acceptable in-service operation, however the **Interfacial Tension at *32.62 dynes/cm* was only slightly above the IEEE acceptable minimum limit of *30 dynes/cm*.**

- **Transformer – T2, Westinghouse, Serial No. A3S5672**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be satisfactory, and with the exception of Carbon Monoxide (CO) and Carbon Dioxide (CO2), all other gases remained within the IEEE recommended limits. **Carbon Monoxide increased to *881 ppm* from *773 ppm* almost a year ago (exceeding the IEEE limit of *570 ppm*), while Carbon Dioxide jumped to *5615 ppm* compared with *4509 ppm* (exceeding IEEE limit of *4000 ppm*).** Carbon Monoxide and Carbon Dioxide are produced through the decomposition to the paper insulation through overheating. A transformer will normally produce these gases over its lifespan with Westinghouse models typically producing excess levels of these gases. Through trending analysis we can also see that levels have been building up over time, thus no action is required at this time.

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, it remains clear and with no sediments and no appreciable amount of water content. All measured parameters remained within the IEEE recommended limits for acceptable in-service operation.

- **Transformer – York DS, Ferranti Packard, Serial No. 5016910101**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be satisfactory, with levels for all of the key gases within the currently recommended IEEE limits, thus no action is required at this time.

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, remaining clear and with no sediments and having a slight amount of water content (*7 ppm*). All measured parameters remained within the IEEE recommended limits for acceptable in-service operation.

- **Load Tap Changer – LTC T1, ABB, Serial No. 8380980**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be satisfactory, with levels for all of the key gases within the currently recommended IEEE limits, thus no action is required at this time.

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, remaining clear and with no sediments, having a moderate amount of water content (*19 ppm*). All measured parameters remained within the IEEE recommended limits for acceptable in-service operation.

- **Load Tap Changer – LTC T2, ASEA, Serial No. 2285139**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be satisfactory, with levels for all of the key gases within the currently recommended IEEE limits, thus no action is required at this time.

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, remaining clear and with no sediments, having a moderate amount of water content (*15 ppm*). All measured parameters remained within the IEEE recommended limits for acceptable in-service operation.

- **Load Tap Changer – York TS LTC, Reinhausen, Serial No.C014959**

  - ***Dissolved Gas Analysis (DGA) (Resample)***

    The gas in oil analysis indicates that the oil appears to be satisfactory, with levels for all of the key gases within the currently recommended IEEE limits, thus no action is required at this time.

  - ***Chemical Analysis (ASTM/Water)***

    The chemistry (ASTM) tests show that the oil is in satisfactory condition, remaining clear and with no sediments, having a moderate amount of water content (*17 ppm*). All measured parameters remained within the IEEE recommended limits for acceptable in-service operation.

Please call us if you have any questions regarding this analysis. We look forward to being of continued service to Niagara on the Lake Hydro in the future.

Sincerely,
ASCENT

Doug Charron
Electrical Technician/Master Electrician
Maintenance & Technical Services
Phone: (519) 842-6458
Fax: (519) 842-2496
Mobile: (519) 521-2600

WEIDMANN

WEIDMANN DIAGNOSTIC SOLUTIONS
919 FRASER DR. UNIT 13 + BURLINGTON, ON + L7L 4X8
905-632-8697 + 905-632-8698
WWW.WEIDMANN-DIAGNOSTICS.COM

TEST REPORT
01-6406014-388493-00

;CENT SOLUTIONS INC.	**Serial#:** A3S5671	**Mfr:** WESTINGHOUSE	**Control#:** 6406014
14719 BAYHAM DR, RR#3	**Location:** NOTL DS-T1	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 25000	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 1983	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** SEAL	**Syringe ID:** 8000107	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA**Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MINUS**Gal:** 20473	**Sampled By:** DB	
Customer ID: T1			

	Lab Control Number:	6406014	6381969	6271839	6138757	6003571
	Date Sampled:	04/02/2012	01/18/2012	03/24/2011	04/06/2010	02/10/2009
	Order Number:	388493	383108	359663	332091	300050
	Oil Temp:	20		15	40	20
Dissolved Gas Analysis (DGA)	**Hydrogen (H2) (ppm):**	12		12	7	2.7
ASTM	**Methane (CH4) (ppm):**	5		4	4	4.0
D-3612	**Ethane (C2H6) (ppm):**	7		6	6	5.0
	Ethylene (C2H4) (ppm):	**57**		**50**	**64**	**58**
	Acetylene (C2H2) (ppm):	<1		<1	<1	<1
	Carbon Monoxide (CO) (ppm):	202		170	129	135
	Carbon Dioxide (CO2) (ppm):	**5749**		**4864**	**4910**	**5070**
	Nitrogen (N2) (ppm):	66401		64472	67003	71788
	Oxygen (O2) (ppm):	28579		26057	34132	23586
	Total Dissolved Gas (TDG) (ppm):	101012		95635	106255	10.3
	Total Dissolved Combustible Gas (TDCG) (ppm):	283		242	210	205
	Equivalent TCG (%):	0.2087		0.1874	0.1286	

DGA Diagnostics	**DGA Keys Gas / Interpretive Method: PER IEEE C57.104-2008** (most recent sample)	Hydrogen within condition 1 limits (100 ppm). Methane within condition 1 limits (120 ppm). Ethane within condition 1 limits (65 ppm). Ethylene: Condition 2 Indications of overheated (>350°C) oil (50 ppm). Acetylene within condition 1 limits (1 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Carbon Dioxide: Condition 3 Significant Indications of overheated cellulose insulation (4000 ppm). TDCG within condition 1 limits (720 ppm).
	DGA TDCG Rate Interpretive Method: PER IEEE C57.104-2008 (two most recent sample)	Retest Annually. 1-Continue normal operation.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	WDS DGA Condition Code:	CAUTION
	WDS Recommended Action:	Resample within 6 months for testing.

Comment:

General Oil Quality (GOQ)								
D-1533	**Moisture in Oil**	**(ppm):**	6		4	4	3.5
D-971	**Interfacial Tension**	**(dynes/cm):**	32.62		34.8	34.0	36.1
D-974	**Acid Number**	**(mg KOH/g):**	0.043		0.032	0.031	0.02
D-1500	**Color Number**	**(Relative):**	L2.0		L2.0	L2.0	2.0
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK		CLR&SPRK	CLR&SPRK	Clear
D-1524	**Sediment Exam.**	**(Relative):**	TRACE		ND	ND	
D-877	**Dielectric Breakdown**	**(kV):**	41		43	44	58
D-1298	**Specific Gravity**	**(Relative):**	0.8649		0.868	0.867	0.863

GOQ Diagnostics	**Moisture in Oil:**	Acceptable for in-service oil (25 ppm max).
PER IEEE C57.106-2006	**Interfacial Tension:**	Acceptable for in-service oil (30 dynes/cm min).
(most recent sample)	**Acid Number:**	Acceptable for in-service oil (0.15 mg KOH/g max).

;tations: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT
01-6406014-388493-00

,CENT SOLUTIONS INC.	**Serial#:** A3S5671	**Mfr:** WESTINGHOUSE	**Control#:** 6406014
14719 BAYHAM DR, RR#3	**Location:** NOTL DS-T1	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 25000	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 1983	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** SEAL	**Syringe ID:** 8000107	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA**Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MINUS**Gal:** 20473	**Sampled By:** DB	
Customer ID: T1			

	Lab Control Number:	6406014	6381969	6271839	6138757	6003571
	Date Sampled:	04/02/2012	01/18/2012	03/24/2011	04/06/2010	02/10/2009
	Order Number:	388493	383108	359663	332091	300050
	Oil Temp:	20		15	40	20
	Color Number and Visual:	Diagnostic not applicable. Diagnostic not applicable.				
	Dielectric Breakdown D-877:	Diagnostic not applicable.				
Comment:						
PCB	**Concentration (ppm):**		< 1.0 PPM			
ASTM Method D-4059	**PCB Type (Arocolor):**		ND			
	Reporting Limit:		1.0			
Comment:						

End of Test Report

Authorized By: K Hughes

.tations: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT
01-6406012-388493-00

SCENT SOLUTIONS INC.	**Serial#:** A3S5672	**Mfr:** WESTINGHOUSE	**Control#:** 6406012
ı4719 BAYHAM DR, RR#3	**Location:** NOTL DS-T2	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 25000	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 1983	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** SEAL	**Syringe ID:** 8003857	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA **Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN **USGal:** 20473	**Sampled By:** DB	
Customer ID: T2			

	Lab Control Number:	6406012	6381970	6271835	6138752	6003570
	Date Sampled:	04/02/2012	01/11/2012	03/24/2011	04/06/2010	02/10/2009
	Order Number:	388493	383108	359663	332091	300050
	Oil Temp:	20		15	20	20
Dissolved Gas Analysis (DGA)	**Hydrogen (H2) (ppm):**	83		96	118	93
ASTM	**Methane (CH4) (ppm):**	18		17	18	18
D-3612	**Ethane (C2H6) (ppm):**	15		13	15	14
	Ethylene (C2H4) (ppm):	26		20	31	28
	Acetylene (C2H2) (ppm):	<1		<1	<1	<1
	Carbon Monoxide (CO) (ppm):	**881**		**733**	**858**	**813**
	Carbon Dioxide (CO2) (ppm):	**5615**		**4509**	**4984**	**4994**
	Nitrogen (N2) (ppm):	76615		71174	83529	71482
	Oxygen (O2) (ppm):	3226		2549	5534	<500
	Total Dissolved Gas (TDG) (ppm):	86479		79111	95087	7.9
	Total Dissolved Combustible Gas (TDCG) (ppm):	**1023**		**879**	**1040**	**967**
	Equivalent TCG (%):	0.993		0.9574	0.9512	

DGA Diagnostics	**DGA Keys Gas / Interpretive Method: PER IEEE C57.104-2008** (most recent sample)	Hydrogen within condition 1 limits (100 ppm). Methane within condition 1 limits (120 ppm). Ethane within condition 1 limits (65 ppm). Ethylene within condition 1 limits (50 ppm). Acetylene within condition 1 limits (1 ppm). Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570 ppm). Carbon Dioxide: Condition 3 Significant Indications of overheated cellulose insulation (4000 ppm). TDCG: Condition 2 Levels exceed normal concentrations. Fault may be present (720 ppm).
	DGA TDCG Rate Interpretive Method: PER IEEE C57.104-2008 (two most recent sample)	Retest Quarterly. Exercise caution. Analyze for individual gases. Determine load dependence.
	DGA Cellulose (Paper) Insulation:	Normal decomposition of cellulose insulation.
	WDS DGA Condition Code:	NORMAL
	WDS Recommended Action:	Continue normal operation. Resample for testing within one year.

Comment:

General Oil Quality (GOQ)							
D-1533	**Moisture in Oil**	**(ppm):**	5		4	4	2.7
D-971	**Interfacial Tension**	**(dynes/cm):**	38.98		41.3	39.7	42.8
D-974	**Acid Number**	**(mg KOH/g):**	0.026		0.015	0.012	
D-1500	**Color Number**	**(Relative):**	1.0		L1.5	L1.5	1.5
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK		CLR&SPRK	CLR&SPRK	Clear
D-1524	**Sediment Exam.**	**(Relative):**	ND		ND	ND	
D-877	**Dielectric Breakdown**	**(kV):**	45		42	50	58
D-1298	**Specific Gravity**	**(Relative):**	0.8636		0.867	0.867	0.861

GOQ Diagnostics	**Moisture in Oil:**	Acceptable for in-service oil (25 ppm max).
PER IEEE C57.106-2006	**Interfacial Tension:**	Acceptable for in-service oil (30 dynes/cm min).

ıtions: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

SCENT SOLUTIONS INC.	**Serial#:** A3S5672	**Mfr:** WESTINGHOUSE	**Control#:** 6406012
ı4719 BAYHAM DR, RR#3	**Location:** NOTL DS-T2	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 25000	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 1983	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** SEAL	**Syringe ID:** 8003857	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA **Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN **USGal:** 20473	**Sampled By:** DB	
Customer ID: T2			

	Lab Control Number:	6406012	6381970	6271835	6138752	6003570
	Date Sampled:	04/02/2012	01/11/2012	03/24/2011	04/06/2010	02/10/2009
	Order Number:	388493	383108	359663	332091	300050
	Oil Temp:	20		15	20	20
(most recent sample)	**Acid Number:**	Acceptable for in-service oil (0.15 mg KOH/g max).				
	Color Number and Visual:	Diagnostic not applicable. Diagnostic not applicable.				
	Dielectric Breakdown D-877:	Diagnostic not applicable.				
Comment:						
PCB	**Concentration (ppm):**		< 1.0 PPM			
ASTM Method D-4059	**PCB Type (Arocolor):**		ND			
	Reporting Limit:		1.0			
Comment:						

End of Test Report

Authorized By: K Hughes

ıtions: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT
01-6406015-388493-00

3CENT SOLUTIONS INC.	**Serial#:** 5016910101	**Mfr:** FERRANTI PACKARD	**Control#:** 6406015
14719 BAYHAM DR, RR#3	**Location:** NOTL YORK DS	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 41700	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 2003	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** FB	**Syringe ID:** 8000160	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA **Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN **USGal:** 28172	**Sampled By:** DB	
Customer ID:			

	Lab Control Number:	6406015	6271842	6138760	5659838	6003572
	Date Sampled:	04/02/2012	03/24/2011	04/06/2010	04/07/2009	02/10/2009
	Order Number:	388493	359663	332091	225747	300050
	Oil Temp:	20	12	40		16
Dissolved Gas Analysis (DGA)	**Hydrogen (H2) (ppm):**	5	12	6	<2	6.1
ASTM	**Methane (CH4) (ppm):**	2	2	2	2	2.2
D-3612	**Ethane (C2H6) (ppm):**	<1	<1	<1	<1	1.1
	Ethylene (C2H4) (ppm):	<1	<1	<1	1	1
	Acetylene (C2H2) (ppm):	<1	<1	<1	<1	<1
	Carbon Monoxide (CO) (ppm):	81	96	104	2	126
	Carbon Dioxide (CO2) (ppm):	739	677	608	589	811
	Nitrogen (N2) (ppm):	61899	56758	62290	60817	61860
	Oxygen (O2) (ppm):	30766	25334	34509	34320	28492
	Total Dissolved Gas (TDG) (ppm):	93492	82879	97519	95731	9.2
	Total Dissolved Combustible Gas (TDCG) (ppm):	88	110	112	5	134
	Equivalent TCG (%):	0.0865	0.129	0.1066	0.0025	

DGA Diagnostics	**DGA Keys Gas / Interpretive Method:** **PER IEEE C57.104-2008** (most recent sample)	Hydrogen within condition 1 limits (100 ppm). Methane within condition 1 limits (120 ppm). Ethane within condition 1 limits (65 ppm). Ethylene within condition 1 limits (50 ppm). Acetylene within condition 1 limits (1 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Carbon Dioxide within condition 1 limits (2500 ppm). TDCG within condition 1 limits (720 ppm).
	DGA TDCG Rate Interpretive Method: **PER IEEE C57.104-2008** (two most recent sample)	Retest Annually. 1-Continue normal operation.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	WDS DGA Condition Code:	NORMAL
	WDS Recommended Action:	Continue normal operation. Resample for testing within one year.

Comment:

General Oil Quality (GOQ)								
D-1533	**Moisture in Oil**	**(ppm):**	7	5	3	5	<2
D-971	**Interfacial Tension**	**(dynes/cm):**	39.59	41.5	39.9	29.7	43.5
D-974	**Acid Number**	**(mg KOH/g):**	0.018	0.009	0.005	0.005	
D-1500	**Color Number**	**(Relative):**	L1.	L1.0	1.0	L1.0	1.0
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK	CLR&SPRK	CLR&SPRK	CLR&SPRK	Clear
D-1524	**Sediment Exam.**	**(Relative):**	ND	ND	ND	ND	
D-877	**Dielectric Breakdown**	**(kV):**	43	47	47	42	60
D-1298	**Specific Gravity**	**(Relative):**	0.8907	0.893	0.894	0.893	0.877

GOQ Diagnostics	**Moisture in Oil:**	Acceptable for in-service oil (25 ppm max).
PER IEEE C57.106-2006	**Interfacial Tension:**	Acceptable for in-service oil (30 dynes/cm min).
(most recent sample)	**Acid Number:**	Acceptable for in-service oil (0.15 mg KOH/g max).

…itions: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT
01-6406015-388493-00

3CENT SOLUTIONS INC.	**Serial#:** 5016910101	**Mfr:** FERRANTI PACKARD	**Control#:** 6406015
14719 BAYHAM DR, RR#3	**Location:** NOTL YORK DS	**kV:** 115.5	**Order#:** 388493
	Equipment: TRANSFORMER	**kVA:** 41700	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** MAIN(BOTTOM)	**Year Mf'd:** 2003	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** FB	**Syringe ID:** 8000160	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA **Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN **USGal:** 28172	**Sampled By:** DB	
Customer ID:			

Lab Control Number:	6406015	6271842	6138760	5659838	6003572
Date Sampled:	04/02/2012	03/24/2011	04/06/2010	04/07/2009	02/10/2009
Order Number:	388493	359663	332091	225747	300050
Oil Temp:	20	12	40		16
Color Number and Visual:	Diagnostic not applicable.				
Dielectric Breakdown D-877:	Diagnostic not applicable.				
Comment:					

End of Test Report

Authorized By: K Douglas

ıtions: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT
01-6406018-388493-00

ƷCENT SOLUTIONS INC.	**Serial#:** 8380980	**Mfr:** ABB	**Control#:** 6406018
14719 BAYHAM DR, RR#3	**Location:** NOTL-T1 LTC	**kV:** 115	**Order#:** 388493
	Equipment: LTC	**kVA:**	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** SELECTOR	**Year Mf'd:** 1998	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** FB	**Syringe ID:** 8003818	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NA**Phase:** 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN	**Sampled By:**	
Customer ID:	**Model:** UZERN		

	Lab Control Number:	6406018	6381969	6354003	6331511	6271854
	Date Sampled:	04/02/2012	01/18/2012	10/28/2011	08/17/2011	03/24/2011
	Order Number:	388493	383108	376959	371979	359663
	Oil Temp:	20				
Dissolved Gas Analysis (DGA)	**Hydrogen (H2) (ppm):**	22	<2	63	156	35
ASTM	**Methane (CH4) (ppm):**	7	1	23	31	18
D-3612	**Ethane (C2H6) (ppm):**	<1	<1	3	<1	4
	Ethylene (C2H4) (ppm):	9	<1	77	61	63
	Acetylene (C2H2) (ppm):	85	<1	694	672	616
	Carbon Monoxide (CO) (ppm):	5	2	20	28	11
	Carbon Dioxide (CO2) (ppm):	428	220	483	708	657
	Nitrogen (N2) (ppm):	60991	62328	62833	55106	59164
	Oxygen (O2) (ppm):	31327	28738	31679	25669	29115
	Total Dissolved Gas (TDG) (ppm):	92874	91289	95875	82431	89683
	Total Dissolved Combustible Gas (TDCG) (ppm):	128	3	880	948	747
	Equivalent TCG (%):	0.0649	0.0022	0.2348	0.5109	0.1666
DGA Diagnostics	**Ratio Analysis:**	Acetylene exceeds normal limits. Further analysis is recommended.				
ɔmment:						

ɢeneral Oil Quality (GOQ)							
D-1533	**Moisture in Oil**	**(ppm):**	19	16	43	22	25
D-971	**Interfacial Tension**	**(dynes/cm):**	47.52	47.8	45.44	46.9	46.7
D-974	**Acid Number**	**(mg KOH/g):**		0.006	0.013		
D-1500	**Color Number**	**(Relative):**	L0.5	L0.5	L0.5	L0.5	L0.5
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK	CLR&SPRK	CLR&SPRK	CLR&SPRK	CLR&SPRK
D-1524	**Sediment Exam.**	**(Relative):**	ND	ND	ND	ND	ND
D-877	**Dielectric Breakdown**	**(kV):**		48	34		
D1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	34 (1-23C)			18 (1-24C)	25 (1-23C)
D-1298	**Specific Gravity**	**(Relative):**		0.8715	0.883		

GOQ Diagnostics	**Moisture in Oil:**	Acceptable for in-service oil (25 ppm max).
PER IEEE C57.106-2006	**Interfacial Tension:**	Diagnostic not applicable.
(most recent sample)	**Color Number and Visual:**	Diagnostic not applicable. Diagnostic not applicable.
	Dielectric Breakdown D-1816:	Acceptable for in-service oil (28 kV min @ 1mm).
Comment:		

End of Test Report

Authorized By: K Hughes

ations: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

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TEST REPORT

01-6406020-388493-00

ƆCENT SOLUTIONS INC.	**Serial#:** 2285139	**Mfr:** ASEA	**Control#:** 6406020
14719 BAYHAM DR, RR#3	**Location:** NOTL-T2 LTC	**kV:** 115	**Order#:** 388493
	Equipment: LTC	**kVA:**	**Account:** 6312
TILSONBURG, ON N4G 4G8 CA	**Compartment:** COMMON	**Year Mf'd:**	**Received:** 04/11/2012
ATTN: WARNER ARDELT	**Breathing:** SEALED	**Syringe ID:** 8002246	**Reported:** 04/23/2012
PO#: AS1-128502	**Bank:** NAPhase: 3	**Bottle ID:**	
Project ID: 24570LSP	**Fluid:** MIN	**Sampled By:** DB	
Customer ID:	**Model:** UZERN		

		Lab Control Number:	6406020	6381969	6354004	6331512	6271856
		Date Sampled:	04/02/2012	01/18/2012	10/28/2011	08/17/2011	03/24/2011
		Order Number:	388493	383108	376959	371979	359663
		Oil Temp:	20				
Dissolved Gas Analysis (DGA)		**Hydrogen (H2) (ppm):**	37	<2	170	208	47
ASTM		**Methane (CH4) (ppm):**	6	1	39	44	31
D-3612		**Ethane (C2H6) (ppm):**	<1	<1	2	<1	4
		Ethylene (C2H4) (ppm):	6	<1	107	88	84
		Acetylene (C2H2) (ppm):	60	<1	1065	984	880
		Carbon Monoxide (CO) (ppm):	6	2	30	47	16
		Carbon Dioxide (CO2) (ppm):	422	220	622	941	784
		Nitrogen (N2) (ppm):	61465	62328	64109	56408	60289
		Oxygen (O2) (ppm):	30311	28738	32514	27164	29913
		Total Dissolved Gas (TDG) (ppm):	92313	91289	98658	85884	92048
		Total Dissolved Combustible Gas (TDCG) (ppm):	115	3	1413	1371	1062
		Equivalent TCG (%):	0.0962	0.0022	0.5061	0.6806	0.2275
DGA Diagnostics		**Ratio Analysis:**	Heating to arcing gas ratios within normal limits.				
ɔmment:							
General Oil Quality (GOQ)							
D-1533	**Moisture in Oil**	**(ppm):**	15	16		30	18
D-971	**Interfacial Tension**	**(dynes/cm):**	46.98	47.8		45.98	47.1
D-974	**Acid Number**	**(mg KOH/g):**		0.006		0.013	
D-1500	**Color Number**	**(Relative):**	L0.5	L0.5		L0.5	L0.5
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK	CLR&SPRK		CLR&SPRK	CLR&SPRK
D-1524	**Sediment Exam.**	**(Relative):**	ND	ND		TRACE	ND
D-877	**Dielectric Breakdown**	**(kV):**		48		33	
D1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	34 (1-23C)				11 (1-24C)
D-1298	**Specific Gravity**	**(Relative):**		0.8715		0.883	
GOQ Diagnostics		**Moisture in Oil:**	Acceptable for in-service oil (25 ppm max).				
PER IEEE C57.106-2006		**Interfacial Tension:**	Diagnostic not applicable.				
(most recent sample)		**Color Number and Visual:**	Diagnostic not applicable. Diagnostic not applicable.				
		Dielectric Breakdown D-1816:	Acceptable for in-service oil (28 kV min @ 1mm).				
Comment:							

End of Test Report

Authorized By: K Hughes

ations: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

WEIDMANN

WEIDMANN DIAGNOSTIC SOLUTIONS
919 FRASER DR. UNIT 13 + BURLINGTON, ON + L7L 4X8
905-632-8697 + 905-632-8698
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TEST REPORT
01-6406024-388493-00

ƆENT SOLUTIONS INC.
14719 BAYHAM DR, RR#3

TILSONBURG, ON N4G 4G8 CA
ATTN: WARNER ARDELT
PO#: AS1-128502
Project ID: 24570LSP
Customer ID:

Serial#: C014959
Location: NOTL (YORK TS)
Equipment: LTC
Compartment: SELECTOR
Breathing: VACUUM
Bank: NA **Phase:** 3
Fluid: MIN **USGal:** 268
Model: RMV-II

Mfr: REINHAUSEN
kV:
kVA:
Year Mf'd: 2003
Syringe ID: 8001091
Bottle ID:
Sampled By: DB

Control#: 6406024
Order#: 388493
Account: 6312
Received: 04/11/2012
Reported: 04/23/2012

	Lab Control Number:	6406024	6331513
	Date Sampled:	04/02/2012	08/16/2011
	Order Number:	388493	371979
	Oil Temp:	20	
Dissolved Gas Analysis (DGA)	**Hydrogen (H2) (ppm):**	4	10
ASTM	**Methane (CH4) (ppm):**	1	2
D-3612	**Ethane (C2H6) (ppm):**	<1	<1
	Ethylene (C2H4) (ppm):	<1	<1
	Acetylene (C2H2) (ppm):	<1	<1
	Carbon Monoxide (CO) (ppm):	3	10
	Carbon Dioxide (CO2) (ppm):	590	543
	Nitrogen (N2) (ppm):	59545	53721
	Oxygen (O2) (ppm):	30891	25052
	Total Dissolved Gas (TDG) (ppm):	91034	79338
	Total Dissolved Combustible Gas (TDCG) (ppm):	8	22
	Equivalent TCG (%):	0.0122	0.0372
DGA Diagnostics	**Ratio Analysis:**	Acetylene within normal limits.	
ɔmment:			

General Oil Quality (GOQ)				
D-1533	**Moisture in Oil**	**(ppm):**	17	21
D-971	**Interfacial Tension**	**(dynes/cm):**	30.42	30.72
D-974	**Acid Number**	**(mg KOH/g):**		0.016
D-1500	**Color Number**	**(Relative):**	1.0	L1.0
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK	CLR&SPRK
D-1524	**Sediment Exam.**	**(Relative):**	ND	ND
D-877	**Dielectric Breakdown**	**(kV):**		31
D1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	38 (1-23C)	
D-1298	**Specific Gravity**	**(Relative):**		0.893

GOQ Diagnostics	**Moisture in Oil:**	Acceptable for equipment > 69 kV for in-service oil - kV not provided (25 ppm max).
PER IEEE C57.106-2006	**Interfacial Tension:**	Diagnostic not applicable.
(most recent sample)	**Color Number and Visual:**	Diagnostic not applicable. Diagnostic not applicable.
	Dielectric Breakdown D-1816:	Acceptable for equipment > 69 kV for in-service oil - kV not provided (28 kV min @ 1mm).
Comment:		

End of Test Report

Authorized By: K Douglas

ıotations: 2. This test is conducted by a subcontracted laboratory. 3. Subcontracted laboratory has received ISO Standard 17025 accreditation for this test.

Attachment B

RRWF (Updated)

Response to 7.7-Staff-18

Revenue Requirement Workform

Version 4.00

Utility Name	Niagara-on-the-Lake Hydro Inc.
Service Territory	*Niagara-on-the-Lake*
Assigned EB Number	EB-2013-0155
Name and Title	Philip Wormwell, Directoir of Corporate Services
Phone Number	905-468-4235- Ext 380
Email Address	pwormwell@notlhydro.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

Row			Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	stm	Per Board Decision	
15	1	**Rate Base**								
16		Gross Fixed Assets (average)	$45,176,948	**See Note 10**	$165,171.23	$ 45,342,119			$45,342,119	
17		Accumulated Depreciation (average)	($22,963,012)	**(5)**	($326,730.12)	($23,289,742)			($23,289,742)	
18		Allowance for Working Capital:								
19		Controllable Expenses	$2,259,303	**See Note 11**	($15,445)	$ 2,243,859			$2,243,859	
20		Cost of Power	$19,138,712	**See Note 12**	$821,843	$ 19,960,556			$19,960,556	
21		Working Capital Rate (%)	13.00%	**(9)**		13.00%	**(9)**		13.00%	**(9)**
23	2	**Utility Income**								
24		Operating Revenues:								
25		Distribution Revenue at Current Rates	$4,844,096		$0	$4,844,096				
26		Distribution Revenue at Proposed Rates	$4,545,964		$42,335	$4,588,299				
27		Other Revenue:								
28		Specific Service Charges	$58,300	See Note 13	$18,030	$76,330				
29		Late Payment Charges	$38,000		$0	$38,000				
30		Other Distribution Revenue	$112,751		$0	$112,751				
31		Other Income and Deductions	$33,700		$0	$33,700				
33		Total Revenue Offsets	$242,751	**(7)**						
35		Operating Expenses:								
36		OM+A Expenses	$2,230,707	**See Note 14**	($15,444.81)	$ 2,215,262			$2,215,262	
37		Depreciation/Amortization	$929,588	**See Note 15**	($18,478.32)	$ 911,109			$911,109	
38		Property taxes	$28,596		$ -	$ 28,596			$28,596	
40		Other expenses								
42	3	**Taxes/PILs**								
43		Taxable Income:								
44		Adjustments required to arrive at taxable income	($642,662)	**(3)**		($656,048)				
45		Utility Income Taxes and Rates:								
46		Income taxes (not grossed up)	$27,553			$31,038				
47		Income taxes (grossed up)	$32,607			$36,732				
49		Federal tax (%)	11.00%			11.00%				
50		Provincial tax (%)	4.50%			4.50%				
51		Income Tax Credits	($12,000)			($12,000)				
53	4	**Capitalization/Cost of Capital**								
54		Capital Structure:								
55		Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
56		Short-term debt Capitalization Ratio (%)	4.0%	**(8)**		4.0%	**(8)**			**(8)**
57		Common Equity Capitalization Ratio (%)	40.0%			40.0%				
58		Prefered Shares Capitalization Ratio (%)	0.0%			0.0%				
59			100.0%			100.0%				
61		Cost of Capital								
62		Long-term debt Cost Rate (%)	4.63%			5.03%				
63		Short-term debt Cost Rate (%)	2.07%			2.11%				
64		Common Equity Cost Rate (%)	8.98%			9.36%				
65		Prefered Shares Cost Rate (%)	0.00%			0.00%				

Notes:

General	Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.
(1)	All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2)	Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I
(3)	Net of addbacks and deductions to arrive at taxable income.
(4)	Average of Gross Fixed Assets at beginning and end of the Test Year
(5)	Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6)	Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.
(7)	Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement
(8)	4.0% unless an Applicant has proposed or been approved for another amount.
(9)	Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

NOTL Notes

(10)	The actual (unaudited) net of additions and disposals in 2013 is more than in the initial application. The net of additions and disposals in 2014 is unchanged. Accumulated depreciation changed based on 2013 actuals (unaudited) and re-allocation ($30,000) from trucks to software in 2014.
(11)	Reduction referenced in 4.2-VECC-15
(12)	To reflect the OEB's Regulated Price Plan Price Report dated October 17, 2013
(13)	Increase referenced in 7.1-VECC-22
(14)	See Note 11
(15)	Effect of actual (unaudited) 2013 capital additions and disposals and re-allocation ($30,000) from trucks to software in 2014

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$45,176,948	$165,171	$45,342,119	$ -	$45,342,119
2	Accumulated Depreciation (average)	(3)	($22,963,012)	($326,730)	($23,289,742)	$ -	($23,289,742)
3	Net Fixed Assets (average)	(3)	$22,213,936	($161,559)	$22,052,377	$ -	$22,052,377
4	Allowance for Working Capital	(1)	$2,781,742	$104,832	$2,886,574	$ -	$2,886,574
5	**Total Rate Base**		$24,995,678	($56,727)	$24,938,951	$ -	$24,938,951

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$2,259,303	($15,445)	$2,243,859	$ -	$2,243,859
7	Cost of Power		$19,138,712	$821,843	$19,960,556	$ -	$19,960,556
8	Working Capital Base		$21,398,016	$806,399	$22,204,414	$ -	$22,204,414
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$2,781,742	$104,832	$2,886,574	$ -	$2,886,574

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$4,545,964	$42,335	$4,588,299	$ -	$4,588,299
2	Other Revenue	(1)	$242,751	$18,030	$260,781	$ -	$260,781
3	Total Operating Revenues		$4,788,716	$60,365	$4,849,080	$ -	$4,849,080
	Operating Expenses:						
4	OM+A Expenses		$2,230,707	($15,445)	$2,215,262	$ -	$2,215,262
5	Depreciation/Amortization		$929,588	($18,478)	$911,109	$ -	$911,109
6	Property taxes		$28,596	$ -	$28,596	$ -	$28,596
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$3,188,891	($33,923)	$3,154,968	$ -	$3,154,968
10	Deemed Interest Expense		$669,372	$54,294	$723,666	($55,813)	$667,853
11	Total Expenses (lines 9 to 10)		$3,858,263	$20,371	$3,878,635	($55,813)	$3,822,821
12	**Utility income before income taxes**		$930,452	$39,994	$970,446	$55,813	$1,026,259
13	Income taxes (grossed-up)		$32,607	$4,124	$36,732	$ -	$36,732
14	**Utility net income**		$897,845	$35,870	$933,714	$55,813	$989,528

Notes

Other Revenues / Revenue Offsets

Note	Item	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$58,300	$18,030	$76,330		$76,330
	Late Payment Charges	$38,000	$ -	$38,000		$38,000
	Other Distribution Revenue	$112,751	$ -	$112,751		$112,751
	Other Income and Deductions	$33,700	$ -	$33,700		$33,700
	Total Revenue Offsets	$242,751	$18,030	$260,781	$ -	$260,781

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$897,845	$933,714	$895,807
2	Adjustments required to arrive at taxable utility income	($642,662)	($656,048)	($642,662)
3	Taxable income	$255,183	$277,666	$253,145
	Calculation of Utility income Taxes			
4	Income taxes	$27,553	$31,038	$31,038
6	Total taxes	$27,553	$31,038	$31,038
7	Gross-up of Income Taxes	$5,054	$5,693	$5,693
8	Grossed-up Income Taxes	$32,607	$36,732	$36,732
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$32,607	$36,732	$36,732
10	Other tax Credits	($12,000)	($12,000)	($12,000)
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$13,997,580	4.63%	$648,676
2	Short-term Debt	4.00%	$999,827	2.07%	$20,696
3	**Total Debt**	60.00%	$14,997,407	4.46%	$669,372
	Equity				
4	Common Equity	40.00%	$9,998,271	8.98%	$897,845
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,998,271	8.98%	$897,845
7	**Total**	100.00%	$24,995,678	6.27%	$1,567,217
	Interrogatory Responses				
	Debt				
1	Long-term Debt	56.00%	$13,965,813	5.03%	$702,618
2	Short-term Debt	4.00%	$997,558	2.11%	$21,048
3	**Total Debt**	60.00%	$14,963,371	4.84%	$723,666
	Equity				
4	Common Equity	40.00%	$9,975,580	9.36%	$933,714
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,975,580	9.36%	$933,714
7	**Total**	100.00%	$24,938,951	6.65%	$1,657,381
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$13,965,813	4.63%	$647,203
9	Short-term Debt	4.00%	$997,558	2.07%	$20,649
10	**Total Debt**	60.00%	$14,963,371	4.46%	$667,853
	Equity				
11	Common Equity	40.00%	$9,975,580	8.98%	$895,807
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,975,580	8.98%	$895,807
14	**Total**	100.00%	$24,938,951	6.27%	$1,563,660

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		($298,131)		($255,796)		($356,470)
2	Distribution Revenue	$4,844,096	$4,844,096	$4,844,096	$4,844,096	$4,844,096	$4,944,770
3	Other Operating Revenue Offsets - net	$242,751	$242,751	$260,781	$260,781	$260,781	$260,781
4	**Total Revenue**	$5,086,847	$4,788,716	$5,104,877	$4,849,080	$5,104,877	$4,849,080
5	Operating Expenses	$3,188,891	$3,188,891	$3,154,968	$3,154,968	$3,154,968	$3,154,968
6	Deemed Interest Expense	$669,372	$669,372	$723,666	$723,666	$667,853	$667,853
8	**Total Cost and Expenses**	$3,858,263	$3,858,263	$3,878,635	$3,878,635	$3,822,821	$3,822,821
9	**Utility Income Before Income Taxes**	$1,228,583	$930,452	$1,226,242	$970,446	$1,282,056	$1,026,259
10	Tax Adjustments to Accounting Income per 2013 PILs model	($642,662)	($642,662)	($656,048)	($656,048)	($656,048)	($656,048)
11	**Taxable Income**	$585,921	$287,790	$570,194	$314,398	$626,007	$370,211
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	$90,818	$44,607	$88,380	$48,732	$97,031	$57,383
14	**Income Tax Credits**	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)
15	**Utility Net Income**	$1,149,766	$897,845	$1,149,862	$933,714	$1,197,025	$989,528
16	**Utility Rate Base**	$24,995,678	$24,995,678	$24,938,951	$24,938,951	$24,938,951	$24,938,951
17	Deemed Equity Portion of Rate Base	$9,998,271	$9,998,271	$9,975,580	$9,975,580	$9,975,580	$9,975,580
18	Income/(Equity Portion of Rate Base)	11.50%	8.98%	11.53%	9.36%	12.00%	9.92%
19	Target Return - Equity on Rate Base	8.98%	8.98%	9.36%	9.36%	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	2.52%	0.00%	2.17%	0.00%	3.02%	0.94%
21	Indicated Rate of Return	7.28%	6.27%	7.51%	6.65%	7.48%	6.65%
22	Requested Rate of Return on Rate Base	6.27%	6.27%	6.65%	6.65%	6.27%	6.27%
23	Deficiency/Sufficiency in Rate of Return	1.01%	0.00%	0.87%	0.00%	1.21%	0.38%
24	Target Return on Equity	$897,845	$897,845	$933,714	$933,714	$895,807	$895,807
25	Revenue Deficiency/(Sufficiency)	($251,921)	($0)	($216,148)	($0)	($301,217)	$93,721
26	**Gross Revenue Deficiency/(Sufficiency)**	($298,131) **(1)**		($255,796) **(1)**		($356,470) **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$2,230,707		$2,215,262		$2,215,262	
2	Amortization/Depreciation	$929,588		$911,109		$911,109	
3	Property Taxes	$28,596		$28,596		$28,596	
5	Income Taxes (Grossed up)	$32,607		$36,732		$36,732	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$669,372		$723,666		$667,853	
	Return on Deemed Equity	$897,845		$933,714		$895,807	
8	**Service Revenue Requirement (before Revenues)**	$4,788,716		$4,849,080		$4,755,360	
9	Revenue Offsets	$242,751		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,545,964		$4,849,080		$4,755,360	
11	Distribution revenue	$4,545,964		$4,588,299		$4,588,299	
12	Other revenue	$242,751		$260,781		$260,781	
13	**Total revenue**	$4,788,716		$4,849,080		$4,849,080	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	$93,721	(1)

Notes

(1) Line 11 - Line 8

Attachment C

Bill Impacts

Appendix 2W updated

Customer Class:	**Residential**								
TOU / non-TOU:	TOU								
	Consumption	800	**kWh**	May 1 - October 31		November 1 - April 30 (Select this radio button for applications filed after Oct 3			
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 18.3100	1	$ 18.31	$ 18.6700	1	$ 18.67	$ 0.36	1.97%
Smart Meter Disposition	Monthly	$ 1.1900	1	$ 1.19	$ -	1	$ -	-$ 1.19	-100.00%
SMIRR Recovery	Monthly	$ 2.8400	1	$ 2.84	$ -	1	$ -	-$ 2.84	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 0.9000	1	$ 0.90	$ 0.90	
Distribution Volumetric Rate	per kWh	$ 0.0129	800	$ 10.32	$ 0.0132	800	$ 10.56	$ 0.24	2.33%
Sub-Total A (excluding pass through)				$ 32.66			$ 30.13	**-$ 2.53**	**-7.75%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	800	$ (0.48)	-$ 0.0005	800	$ (0.40)	$ 0.08	-16.67%
DVA 1562 disposition	per kWh	-$ 0.0011	800	$ (0.88)	$ -	800	$ -	$ 0.88	-100.00%
Tax change rider	per kWh	-$ 0.0006	800	$ (0.48)	$ -	800	$ -	$ 0.48	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	800	$ -	-$ 0.0010	800	$ (0.77)	-$ 0.77	
Line Losses on Cost of Power		$ 0.0889	37.04	$ 3.29	$ 0.0889	30.32	$ 2.70	-$ 0.60	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.90**			**$ 32.44**	**-$ 2.46**	**-7.05%**
RTSR - Network	per kWh	$ 0.0070	837	$ 5.86	$ 0.0072	830	$ 5.98	$ 0.12	2.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	837	$ 1.00	$ 0.0013	830	$ 1.08	$ 0.07	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.77**			**$ 39.50**	**-$ 2.27**	**-5.43%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	830	$ 3.65	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	830	$ 1.00	-$ 0.01	-0.80%
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	$ 0.0720	512	$ 36.86	$ 0.0720	512	$ 36.86	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	144	$ 15.70	$ 0.1090	144	$ 15.70	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	144	$ 18.58	$ 0.1290	144	$ 18.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	800	$ 66.40	$ 0.0830	800	$ 66.40	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	0	$ -	$ 0.0970	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 123.44**			**$ 121.14**	**-$ 2.30**	**-1.87%**
HST			13%	$ 16.05	13%		$ 15.75	-$ 0.30	-1.87%
Total Bill (including HST)				$ 139.49			$ 136.88	-$ 2.60	-1.87%
Ontario Clean Energy Benefit [1]				-$ 13.95			-$ 13.69	$ 0.26	-1.86%
Total Bill on TOU (including OCEB)				**$ 125.54**			**$ 123.19**	**-$ 2.34**	**-1.87%**
Total Bill on RPP (before Taxes)				**$ 118.70**			**$ 116.40**	**-$ 2.30**	**-1.94%**
HST			13%	$ 15.43	13%		$ 15.13	-$ 0.30	-1.94%
Total Bill (including HST)				$ 134.14			$ 131.53	-$ 2.60	-1.94%
Ontario Clean Energy Benefit [1]				-$ 13.41			-$ 13.15	$ 0.26	-1.94%
Total Bill on RPP (including OCEB)				**$ 120.73**			**$ 118.38**	**-$ 2.34**	**-1.94%**
Loss Factor (%)		4.63%			3.79%				

Customer Class:	**General Service Less than 50kW**								
TOU / non-TOU:	TOU								
	Consumption	**2,000**	**kWh**	May 1 - October 31					
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 45.9700	1	$ 45.97	$ 37.1600	1	$ 37.16	-$ 8.81	-19.16%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Disposition	Monthly	$ 3.1500	1	$ 3.15	$ -	1	$ -	-$ 3.15	-100.00%
SMIRR Recovery	Monthly	$ 4.8500	1	$ 4.85	$ -	1	$ -	-$ 4.85	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 1.0600	1	$ 1.06	$ 1.06	
Distribution Volumetric Rate	per kWh	$ 0.0138	2000	$ 27.60	$ 0.0112	2000	$ 22.40	-$ 5.20	-18.84%
Sub-Total A (excluding pass through)				$ 81.57			$ 60.62	**-$ 20.95**	**-25.68%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	2000	$ (1.20)	-$ 0.0020	2000	$ (4.00)	-$ 2.80	233.33%
DVA 1562 disposition	per kWh	-$ 0.0011	2000	$ (2.20)	$ -	2000	$ -	$ 2.20	-100.00%
Tax change rider	per kWh	-$ 0.0005	2000	$ (1.00)	$ -	2000	$ -	$ 1.00	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	2000	$ -	-$ 0.0010	2000	$ (2.00)	-$ 2.00	
Line Losses on Cost of Power		$ 0.0889	92.60	$ 8.23	$ 0.0889	75.80	$ 6.74	-$ 1.49	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 86.19**			**$ 62.15**	**-$ 24.04**	**-27.90%**
RTSR - Network	per kWh	$ 0.0064	2093	$ 13.39	$ 0.0066	2076	$ 13.70	$ 0.31	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0013	2076	$ 2.70	$ 0.19	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 102.10**			**$ 78.55**	**-$ 23.55**	**-23.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2093	$ 9.21	$ 0.0044	2076	$ 9.13	-$ 0.07	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0012	2076	$ 2.49	-$ 0.02	-0.80%
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	$ 0.0720	1280	$ 92.16	$ 0.0720	1280	$ 92.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	360	$ 39.24	$ 0.1090	360	$ 39.24	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	360	$ 46.44	$ 0.1290	360	$ 46.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	1250	$ 121.25	$ 0.0970	1250	$ 121.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 305.91**			**$ 282.26**	**-$ 23.64**	**-7.73%**
HST			13%	$ 39.77	13%		$ 36.69	-$ 3.07	-7.73%
Total Bill (including HST)				$ 345.67			$ 318.96	-$ 26.72	-7.73%
Ontario Clean Energy Benefit [1]				-$ 34.57			-$ 31.90	$ 2.67	-7.72%
Total Bill on TOU (including OCEB)				**$ 311.10**			**$ 287.06**	**-$ 24.05**	**-7.73%**
Total Bill on RPP (before Taxes)				**$ 311.57**			**$ 287.92**	**-$ 23.64**	**-7.59%**
HST			13%	$ 40.50	13%		$ 37.43	-$ 3.07	-7.59%
Total Bill (including HST)				$ 352.07			$ 325.35	-$ 26.72	-7.59%
Ontario Clean Energy Benefit [1]				-$ 35.21			-$ 32.54	$ 2.67	-7.58%
Total Bill on RPP (including OCEB)				**$ 316.86**			**$ 292.81**	**-$ 24.05**	**-7.59%**
Loss Factor (%)			4.63%		3.79%				

Customer Class:	**General Service 50 to 4,999 kW**								
TOU / non-TOU:	non-TOU								
	Consumption	**56,000**	**kWh**	May 1 - October 31					
		150	**kW**						
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 328.4100	1	$ 328.41	$ 276.0400	1	$ 276.04	-$ 52.37	-15.95%
Distribution Volumetric Rate	per kW	$ 2.5664	150	$ 384.96	$ 2.1747	150	$ 326.20	-$ 58.76	-15.26%
Sub-Total A (excluding pass through)				$ 713.37			$ 602.24	**-$ 111.13**	**-15.58%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1856	150	$ (27.84)	-$ 1.3909	150	$ (208.63)	-$ 180.79	649.38%
DVA Rate Rider Non-RPP	per kW	$ 2.1024	150	$ 315.36	-$ 0.8249				
DVA 1562 disposition	per kW	-$ 0.1744	150	$ (26.16)	$ -	150	$ -	$ 26.16	-100.00%
Tax change rider	per kW	-$ 0.0802	150	$ (12.03)	$ -	150	$ -	$ 12.03	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	150	$ -	-$ 0.3760	150	$ (56.40)	-$ 56.40	
Line Losses on Cost of Power		$ 0.0876	2,592.80	$ 227.13	$ 0.0876	2,122.40	$ 185.92	-$ 41.21	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,189.83**			**$ 523.13**	**-$ 666.70**	**-56.03%**
RTSR - Network	per kW	$ 2.5928	150	$ 388.92	$ 2.6853	150	$ 402.80	$ 13.87	3.57%
RTSR - Line and Transformation Connection	per kW	$ 0.4315	150	$ 64.73	$ 0.4602	150	$ 69.03	$ 4.31	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,643.47**			**$ 994.96**	**-$ 648.52**	**-39.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	56000	$ 246.40	$ 0.0044	56000	$ 246.40	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	56000	$ 67.20	$ 0.0012	56000	$ 67.20	$ -	0.00%
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	56000	$ 392.00	$ 0.0070	56000	$ 392.00	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	56000	$ 4,905.60	$ 0.0876	56000	$ 4,905.60	$ -	0.00%
Total Bill (before Taxes)				**$ 2,349.32**			**$ 1,700.81**	**-$ 648.52**	**-27.60%**
HST		13%		$ 305.41	13%		$ 221.11	-$ 84.31	-27.60%
Total Bill (including HST)				$ 2,654.74			$ 1,921.91	-$ 732.82	-27.60%
***Ontario Clean Energy Benefit* [1]**				-$ 265.47			-$ 192.19	$ 73.28	-27.60%
Total Bill (including OCEB)				**$ 2,389.27**			**$ 1,729.72**	**-$ 659.54**	**-27.60%**
Total Bill (before Taxes)				**$ 7,254.92**			**$ 6,606.41**	**-$ 648.52**	**-8.94%**
HST		13%		$ 943.14	13%		$ 858.83	-$ 84.31	-8.94%
Total Bill (including HST)				$ 8,198.06			$ 7,465.24	-$ 732.82	-8.94%
***Ontario Clean Energy Benefit* [1]**								$ -	
Total Bill				**$ 8,198.06**			**$ 7,465.24**	**-$ 732.82**	**-8.94%**
Loss Factor (%)		4.63%			3.79%				

Customer Class:	**Street Lighting**								
TOU / non-TOU:	non-TOU								
	Consumption	**50**	**kWh**	May 1 - October 31					
		0.14	**kW**						
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9800	1	$ 4.98	$ 7.6700	1	$ 7.67	$ 2.69	54.02%
Distribution Volumetric Rate	per kW	$ 19.4795	0.14	$ 2.73	$ 29.9987	0.14	$ 4.20	$ 1.47	54.00%
Sub-Total A (excluding pass through)				$ 7.71			$ 11.87	**$ 4.16**	**54.01%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	$ (0.02)	-$ 1.1086	0.14	$ (0.16)	-$ 0.13	588.16%
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	$ (0.11)	-$ 0.37	-140.53%
DVA 1562 disposition	per kW	-$ 2.4982	0.14	$ (0.35)	$ -	0.14	$ -	$ 0.35	-100.00%
Tax change rider	per kW	-$ 0.9793	0.14	$ (0.14)	$ -	0.14	$ -	$ 0.14	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	$ (0.05)	-$ 0.05	
Line Losses on Cost of Power		$ 0.0876	0.01	$ 0.00	$ 0.0876	0.01	$ 0.00	-$ 0.00	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.46**			**$ 11.56**	**$ 4.10**	**54.92%**
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 2.0249	0.14	$ 0.28	$ 0.01	3.56%
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3558	0.14	$ 0.05	$ 0.00	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.78**			**$ 11.89**	**$ 4.11**	**52.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%
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	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	50	$ 4.38	$ 0.0876	50	$ 4.38	$ -	0.00%
Total Bill (before Taxes)				**$ 8.66**			**$ 12.77**	**$ 4.11**	**47.46%**
HST			13%	$ 1.13	13%		$ 1.66	$ 0.53	47.46%
Total Bill (including HST)				$ 9.79			$ 14.43	$ 4.65	47.46%
Ontario Clean Energy Benefit [1]				-$ 0.98			-$ 1.44	-$ 0.46	46.94%
Total Bill (including OCEB)				**$ 8.81**			**$ 12.99**	**$ 4.19**	**47.52%**
Total Bill (before Taxes)				**$ 13.04**			**$ 17.15**	**$ 4.11**	**31.52%**
HST			13%	$ 1.70	13%		$ 2.23	$ 0.53	31.52%
Total Bill (including HST)				$ 14.74			$ 19.38	$ 4.65	31.52%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill				**$ 14.74**			**$ 19.38**	**$ 4.65**	**31.52%**
Loss Factor (%)		4.63%			3.79%				

Customer Class:	**Unmetered Scattered Load**								
TOU / non-TOU:	TOU								
	Consumption	**900**	**kWh**	May 1 - October 31					
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 54.3100	1	$ 54.31	$ 20.6800	1	$ 20.68	-$ 33.63	-61.92%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0163	900	$ 14.67	$ 0.0062	900	$ 5.58	-$ 9.09	-61.93%
Sub-Total A (excluding pass through)				$ 68.98			$ 26.26	**-$ 42.72**	**-61.92%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0008	900	$ (0.72)	-$ 0.0006	900	$ (0.54)	$ 0.18	-25.00%
DVA 1562 disposition	per kWh	-$ 0.0037	900	$ (3.33)	$ -	900	$ -	$ 3.33	-100.00%
Tax change rider	per kWh	-$ 0.0014	900	$ (1.26)	$ -	900	$ -	$ 1.26	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	900	$ -	-$ 0.0010	900	$ (0.87)	-$ 0.87	
Low Voltage Service Charge			900	$ -		900	$ -	$ -	
Line Losses on Cost of Power		$ 0.0889	41.67	$ 3.71	$ 0.0889	34.11	$ 3.03	-$ 0.67	-18.14%
Smart Meter Entity Charge	Monthly		1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 67.38**			**$ 27.89**	**-$ 39.49**	**-58.61%**
RTSR - Network	per kWh	$ 0.0064	942	$ 6.03	$ 0.0066	934	$ 6.17	$ 0.14	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	942	$ 1.13	$ 0.0013	934	$ 1.21	$ 0.08	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 74.53**			**$ 35.27**	**-$ 39.26**	**-52.68%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	942	$ 4.14	$ 0.0044	934	$ 4.11	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	942	$ 1.13	$ 0.0012	934	$ 1.12	-$ 0.01	-0.80%
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	900	$ 6.30	$ 0.0070	900	$ 6.30	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	576	$ 41.47	$ 0.0720	576	$ 41.47	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	162	$ 17.66	$ 0.1090	162	$ 17.66	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	162	$ 20.90	$ 0.1290	162	$ 20.90	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	150	$ 14.55	$ 0.0970	150	$ 14.55	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 166.38**			**$ 127.08**	**-$ 39.31**	**-23.62%**
HST		13%		$ 21.63	13%		$ 16.52	-$ 5.11	-23.62%
Total Bill (including HST)				$ 188.01			$ 143.60	-$ 44.42	-23.62%
Ontario Clean Energy Benefit [1]				-$ 18.80			-$ 14.36	$ 4.44	-23.62%
Total Bill on TOU (including OCEB)				**$ 169.21**			**$ 129.24**	**-$ 39.98**	**-23.63%**
Total Bill on RPP (before Taxes)				**$ 163.16**			**$ 123.85**	**-$ 39.31**	**-24.09%**
HST		13%		$ 21.21	13%		$ 16.10	-$ 5.11	-24.09%
Total Bill (including HST)				$ 184.37			$ 139.95	-$ 44.42	-24.09%
Ontario Clean Energy Benefit [1]				-$ 18.44			-$ 13.99	$ 4.45	-24.13%
Total Bill on RPP (including OCEB)				**$ 165.93**			**$ 125.96**	**-$ 39.97**	**-24.09%**
Loss Factor (%)		4.63%			3.79%				