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

REQUESTOR NAME	**VECC**
INFORMATION REQUEST ROUND NO:	**# 1**
TO:	**Niagara- on-the-Lake Hydro Inc. (NOTL)**
DATE:	**January 17, 2014**
CASE NO:	**EB-2013-0155**
APPLICATION NAME	**2014 Cost of Service Electricity Distribution Rate Application**

1. Foundation

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

1.1-VECC-1

Reference: Exhibit 2, Tab 3, Schedule 2, pg. 2, Table 2.3.2

a) Please provide the actual (unaudited) capital expenditures for 2013. Explain any material variance.

Response to 1.1-VECC-1

a) An updated Table 2.3.2 showing actual (unaudited) capital expenditures for 2013 is provided below.

Revised Table 2.3.2

Projects	2008	2009	2010	2011	2012	2013 Actuals (unaudited)	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Rural O/H Rebuild/Conversion							
York Rd - Shepard to Parkway	52,844						
Queenston Rd, Concession 5-7		224,429					
Stewart Rd Pole replacement			80,527				
Line 6 Conversion					168,859		
Line 5 conversion					277,419		
Expansions- Developers CCRA				51,946	55,825	31,463	55,000
Line 3 conversion						174,780	
Concession 2 Rebuild						93,428	
Concession 2 Line 7-9 Rebuild							200,000
Queenston Rd / Concession 5	254,285						
Creek Rd Feeder pole replacement			115,364				
Lakeshore Rd pole replacements					272,825		
Line 7 pole replacements					149,789		
Concession 4 rebuild						190,655	
Concession 6 rebuild Line 6-8							155,000
York Rd rebuild Concession 2-3							140,000
Line 4 rebuild Concession 2-3							110,000
Sub-Total	307,129	224,429	195,891	51,946	924,717	490,326	660,000
U/G Project Rebuild/Conversion							
Chatauqua Rebuild	347,833	755,138	315,047				
Old Town Burial/Conversion					163,450		330,000
Garrison Subd cable injection				127,380			
Simcoe St burial/conversion					409,150	441,611	
Sub-Total	347,833	755,138	315,047	127,380	572,600	441,611	330,000
Other Projects							
Transformer Station Upgrades	187,738						
Software Upgrades (CIS/FIS/File Nexus and other)	93,273	265,475				40,259	95,000
New CIS/FIS software			299,834				
Line truck #1			85,681	202,210			
Line truck #2				104,115	246,447		
System Integration (GIS,CIS,ODS)					83,993	64,636	95,000
Sub-Total	281,011	265,475	385,515	306,325	330,440	104,895	190,000
From Variance Accounts							
Smart Meters *(Approved. From USoA 1555)*					1,699,032		
CIS upgrade for TOU *(Approved. From USoA 1555)*					170,000		
Smart Grid *(Requested. From USoA 1534)*						237,952	
Sub-Total	0	0	0	0	1,869,032	237,952	0
Miscellaneous	531,027	560,021	630,795	573,240	484,860	47,431	105,000
Total	**1,467,000**	**1,805,063**	**1,527,248**	**1,058,891**	**4,181,648**	**1,322,215**	**1,285,000**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							
Total	**1,467,000**	**1,805,063**	**1,527,248**	**1,058,891**	**4,181,648**	**1,322,215**	**1,285,000**

The individual project variances between the 2013 amounts as submitted and the updated 2013 actuals (unaudited) all fall below the materiality level of $50,000. Overall, the projects listed were all completed on time and under budget due in part to favourable construction conditions and ongoing efficiency improvements. We have reviewed our project estimates in the proposed 2014 capital budget and we remain comfortable that the estimated costs presented are appropriate. The only change to 2014 is the re-allocation of $30,000 from the miscellaneous category to software upgrades, as explained in the response to Energy Probe- 22 and -23.

1.1-VECC-2

Reference: Exhibit 1, Tab 1, Schedule 2, pg. 9 / Appendix 2A - Distribution Plan, pg. 81-84

a) Please provide details on the conversion of the Old Town to underground plant, including:
   i. Total cost of the program and annual expenditures,
   ii. Year started and year expected to be completed,
   iii. Description of plant replaced and replacement plan,
   iv. Capital contribution from the Town for underground service (if no contribution has been received please explain why not and provide the Utility's policy for changes from overhead to underground service.

Response to 1.1-VECC-2

a)

i. In 2012 and 2013, NOTL Hydro completed the installation of a major 600 amp feeder 'loop' through the Old Town area at a cost of approximately $400k in each of the two years. With this loop in place, we can now branch off with 200 amp distribution networks to complete the conversion of the Town. Our 5 year plan (2014-2018) is documented in the CDSP in this application. NOTL Hydro generally completes our overhead capital projects 'in-house' and we have determined that our crews can reasonably and efficiently complete approximately $600k/year. The annual amount dedicated to the Old Town conversion project, which is predominantly contracted out, is approximately $400k.

ii. The first Old Town conversion project was completed in 1989 with a new 27.6 kV underground supply to a major hotel addition. As our CDSP indicates, we are confident that the Old Town conversion and burial will be completed by 2022.

iii. A 500 MCM (600 amp) ring has recently been constructed in the Old Town that links the F2 and F4 feeders with a series of S&C PMH unit switches. The PMH units generally include 2-200 amp fused sections to allow looped distribution supply off the main feeder. The Old Town replacement plan involves the removal of overhead poles, primary and secondary wires and transformers with 2/0 AL (200 amp) 28 kV primary cable, 3/0 AL secondary cable and pad-mounted transformers. As a majority of Old town customers are already supplied from an underground secondary cable, the conversion project is

simplified. Those customers that are not currently supplied with underground cable are offered secondary cabling to their meter base at no charge, during construction only, providing they convert their meter base to accept the underground supply. This is cost beneficial to both the customer and NOTL Hydro as it avoids the need for the installation of a new service pole at their property line.

iv. The Town of NOTL has not contributed to the Old Town underground conversion project (except on an individual customer basis). Since 1989, our predecessor, Niagara-on-the-Lake Hydro Commission and NOTL Hydro have been burying facilities in the Old Town because we believe it benefits our entire community and is the right thing to do. The historical significance of the Old Town is a key factor in attracting approximately 1 million tourists annually. Would Williamsburg Virginia continue to preserve the Colonial period and be the successful tourist draw if poles and wires donned its main streets? Niagara-on-the-Lake continues to boast the lowest tax mill rate in the Niagara Region, primarily due to tourism revenues. We are proud of our accomplishments to date as completed sections reflect the early 1800's ambiance without overhead poles and wires.

Our policy for converting existing overhead customers to an underground supply is outlined in our Conditions of Service sections 3.1.2.1 and 3.2.2.1. In summary, new customers or those upgrading their existing service in designated underground areas are required to accept an underground supply and pay for the additional costs over and above the Basic Service provided.

To encourage customers to move to an underground supply during our renewal construction projects in designated areas, we offer to install an underground supply cable to the customer’s meter base at no cost (during the construction phase only) providing that the customer convert their meter base to accept an underground supply. We justify this expense as we can avoid re-installing a service pole at the customer’s property line to maintain the existing overhead service.

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

1.2-VECC-3

Reference: Exhibit 1, Tab 2, Schedule 1, page 1

a) The evidence indicates that the customer survey was non-random (i.e. self-selection). Please confirm this correct.
b) If so, please explain how (or if) the survey corrected for self-selection bias. If nonprobability sampling was the methodology employed please explain why NOTL believes the results can be extrapolated for the general population of NOTL customers.
c) Please comment on the effect on the confidence intervals of biased sampling.
d) Were all NOTL employees, Board of directors and their immediate family, asked not to participate in the survey?

Response to 1.2-VECC-3

a) In response to the inquiry asking if the customer survey was non-random, we would like to respond based on the definition of non-random. “Non-Random Sampling” indicates that certain members of the population would be excluded from the survey process. We created the survey for maximum participation and communicated this to our entire account base.

That being said, we had to ensure that we made efforts to appeal to multiple segments of our customer base. Two input methods were created to appeal to multiple large segments of our customer base: paper-based and online.

The paper-based and online version was made available to our entire account base. A printed survey was included in all our mail-out bills starting on the first billing cycle of June 2013 and was inserted in all subsequent cycles for that month. It was assumed that the paper-based option would appeal to a tech-weary segment of our customer base. This segment is typically made up of those aged 55 and up. The printed survey also highlighted that an electronic version was available, which would appeal to those who were slightly more tech-savvy or those who did not want to send the paper-copy to NOTL Hydro.

The electronic based survey was created for online submissions and was activated the same day as the first bills containing a printed copy were mailed. Those who received a paper-based survey, but were more comfortable with an online submission were encouraged to take the survey online. All of our customers that

were subscribed to our eBilling notification method were sent a notification about the survey. It was assumed that those who completed the survey online represent a more tech savvy segment and likely one that has a lower average age than those that completed the paper-based survey.

An advertisement in the local newspaper (Niagara Advance) was issued and printed on the June 4th edition to coincide with the first billing cycle mailing. The front page of our website also highlighted the survey and offered a direct link to complete the survey online.

Printed Option
In total, 7,500 surveys were printed. They were sent in **all** mailed bills and were made available at our office counter. All billing cycles were included in the mail-outs, including all residential and business customers.

eBilling Option
In total, 1321 eBilling customers were sent an email on June 11, 2013. Our open rate was 63.3% (827 total, Industry average is 19.8%) and we had a click rate of 31.1% (406 total, Industry average is 2.7%). We regard our open and click rates as a success. We are unable to determine the source of all the 350 online responses, however it would be fair to say that many of the 350 online responses came from eBilling customers. Here are the online submission totals for the day of the email/eBlast and subsequent days:

- July 11 – 153 Online submissions
- July 12 – 79 Online submissions
- July 13 – 32 Online submissions

A response deadline of July 15, 2013 was indicated in order to have the time to analyse the responses. Any responses that were submitted after this date were declined.

b) We had an initial target of 300 surveys. As we received 550 responses, we were confident that the sample size provided us with a higher confidence level that the responses would be an accurate representation of the Niagara-on-the-Lake Customer base. With the mix of paper and online responses, we also felt that we were able to represent multiple segments of our customer base that use the online medium versus those who prefer a paper-base response.

Responses were provided from all of the main business and residential areas of the territory. We also received 66% of our responses from our most populated areas of Olde Town and Virgil. Rural responses made up 16.9% of our responses.

Due to the mix of responses from location as well as medium (paper/online), we were comfortable with the responses that we received were representative of the general population of NOTL customers.

c) We have calculated 95% and 99% Confidence intervals based on our account base and the number of responses tallied per question – see Appendix A below. Due to the response that we received compared to our account base, we are satisfied that the answers from the survey are an accurate representation of the general population of Niagara-on-the-Lake.

APPENDIX A – Survey Interval Levels

Question	Number of Responses	95% Confidence Interval	99% Confidence Interval
EXPERENCE Matrix Row 1	543	4.07	5.36
EXPERENCE Matrix Row 2	543	4.07	5.36
EXPERENCE Matrix Row 3	544	4.07	5.35
EXPERENCE Matrix Row 4	534	4.11	5.41
EXPERENCE Matrix Row 5	539	4.09	5.38
EXPERENCE Matrix Row 6	497	4.27	5.62
EXPERENCE Matrix Row 7	495	4.28	5.63
EXPERENCE Matrix Row 8	505	4.23	5.57
EXPERENCE Matrix Row 9	545	4.06	5.35
EXPERENCE Matrix Row 10	523	4.15	5.47
EXPERENCE Matrix Row 11	535	4.1	5.4
EXPERENCE Matrix Row 12	539	4.09	5.38
EXPERENCE Matrix Row 13	534	4.11	5.41
EXPERENCE Matrix Row 14	549	4.05	5.33
IMPORTANCE Matrix Row 1	542	4.07	5.36
IMPORTANCE Matrix Row 2	540	4.08	5.37
IMPORTANCE Matrix Row 3	530	4.12	5.43
IMPORTANCE Matrix Row 4	540	4.08	5.37
IMPORTANCE Matrix Row 5	535	4.1	5.4
IMPORTANCE Matrix Row 6	536	4.1	5.4
IMPORTANCE Matrix Row 7	514	4.19	5.52
IMPORTANCE Matrix Row 8	523	4.16	5.47
IMPORTANCE Matrix Row 9	543	4.07	5.36
Back Page Question 1	526	4.14	5.45
Back Page Question 2	527	4.14	5.44
Back Page Question 2B	435	4.58	6.03
Back Page Question 3	531	4.12	5.42
Back Page Question 3B*	279	5.21	6.86
Back Page Question 4	536	4.1	5.4
Back Page Question 4B	522	4.16	5.47
Back Page Question 5	538	4.09	5.38
Back Page Question 5B	529	4.13	5.43
Back Page Question 6	526	4.14	5.45

Based on 8566 Total NOTL Hydro Accounts
**based on total of 1321 eBilling Customers as of June 1, 2013*

d) Any **customer** of NOTL Hydro, regardless of their business relationship with the company, was able to participate in the survey. NOTL Hydro, at the time, had 5 employees that lived in the territory. We had another 15 employees at the time who were not customers of NOTL Hydro. The employees who were not customers were told they could not respond to the survey. NOTL Hydro also has 6 board members who reside in the service territory of NOTL Hydro (as of June 2013). All were aware of the survey. It is not known how many surveys came from staff or board members, but the incoming IP addresses were captured with all online surveys. Only 4 entries had duplicate IP addresses (2 entries from 2 IP addresses each). These were not removed from the result totals.

1.2-VECC-4

Reference: Exhibit 1, Appendix 1B

b) Does NOTL carry out transactional customer surveys (e.g. after outages, a service call or a customer complaint)? If so please describe these and present the results.

Response to 1.2-VECC-4

NOTL Hydro has not carried out any transactional customer surveys. We do provide a customer feedback section on our website which generally attracts 5-10 comments per year. As a small community, the president and senior managers occasionally receive feedback from customers. That information is documented and responded to on a timely basis and the information considered for follow-up actions. During the major lightning storm we experienced in July 2013, multiple customers responded that they agreed that our restoration efforts were more than satisfactory. However, they wished that they could be better informed during outages as to the extent of the damage and their approximate restoration times. This feedback prompted NOTL Hydro to research and include the Teleworks software system in our 2014 budgets and also reinforced the importance of completing the ongoing Outage Management system project as soon as possible.

1.2-VECC-5

Reference: Exhibit 1, Appendix 1B

a) The evidence states that 200 surveys were completed on paper and 350 were completed online. A number of questions relate to the availability and use of online services (access to account, access to consumption, requirement for service facilities for bill payment, etc.). Did the survey distinguish in responses in the type of respondents (i.e. those using internet and those using paper). If not, can this be done? If so please provide the results.

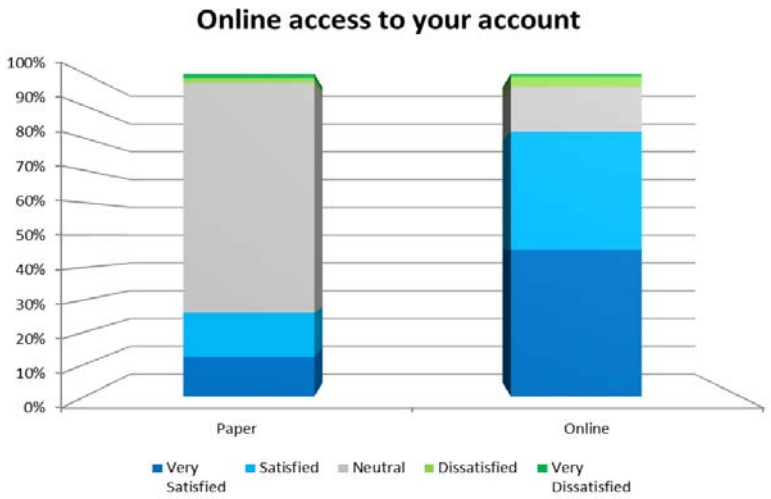
b) Please provide the question which explains to the customer what is meant by "quality of service."

Response to 1.2-VECC-5

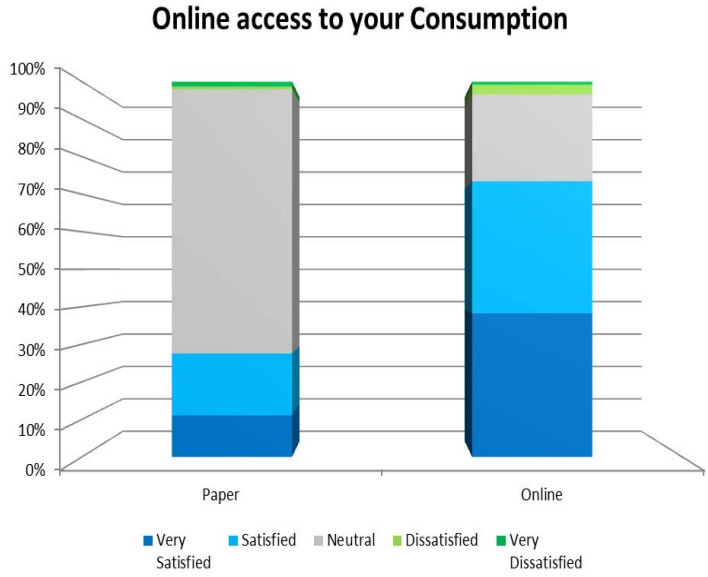
a) We analyzed the data provided and also looked at different identifiers in terms of answers by location as well as paper vs online. Most answers were consistent among the communities of Niagara-on-the-Lake (Old Town, St Davids, Queenston, Virgil, Glendale and Rural areas) but there were a few exceptions with online technology that we had anticipated. Online responses rated online/technology services higher and tended to view counter services with lower importance levels than paper-based responses. Since this was expected we did not extrapolate this information. As per your request, we have separated responses by paper/online for some of the questions that you highlighted.

Please rate **YOUR EXPERIENCE** with NOTL Hydro's performance on the following services:

Answer Options	Very Satisfied	Satisfied	Neutral	Dissatisfied	Very Dissatisfied	Rating Average	Total Responses
Online access to your account - Paper	18	20	105	2	2	3.34	147.00
Online access to your account - Online	159	128	49	11	3	4.23	350.00
Online access to your consumption - Paper	16	24	102	1	2	3.35	145.00
Online access to your consumption - Online	134	123	81	9	3	4.07	350.00



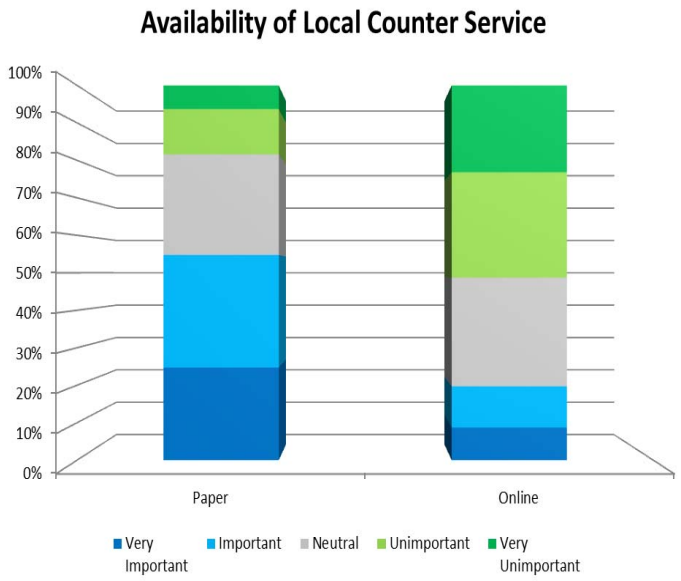
As anticipated, the satisfaction rates among the online responses were much higher than the one's provided via paper-based responses. Note that 53 paper responses did not provide an answer to this question (note that "not applicable" was not a selectable option).



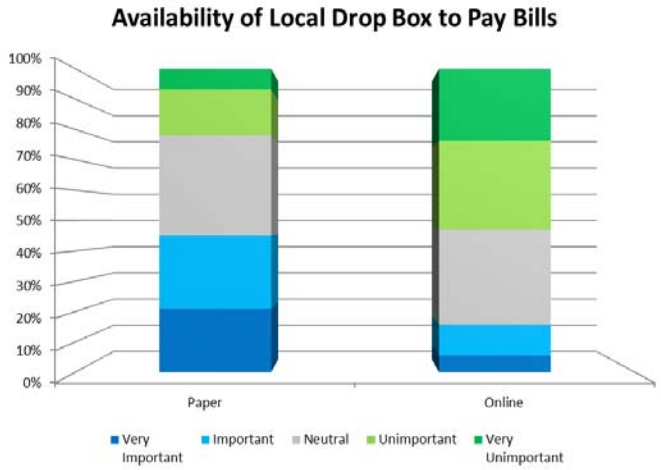
As anticipated, the satisfaction rates among the online responses were much higher than the one's provided via paper-based responses. Note that 55 paper responses did not provide an answer to this question.

Please rate the **IMPORTANCE** of the following services to you:

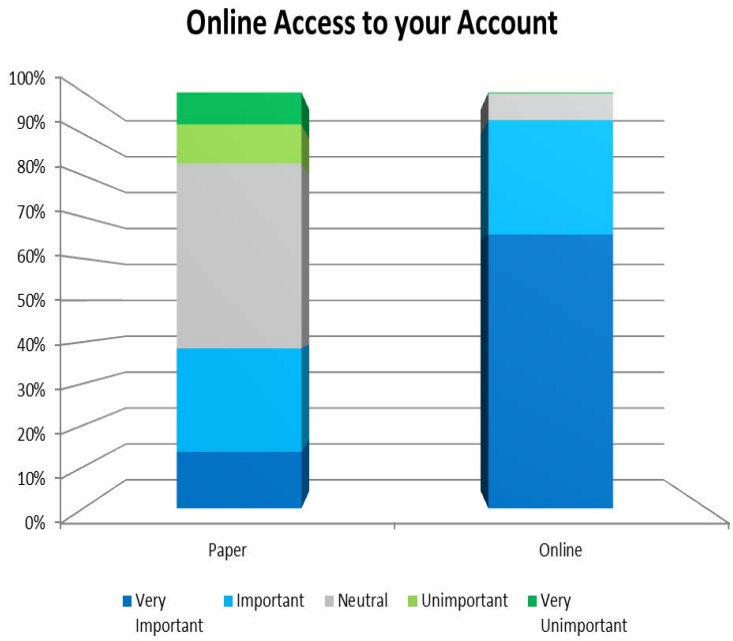
Answer Options	Very Important	Important	Neutral	Unimportant	Very Unimportant	Rating Average	Total Responses
Availability of Local Counter Service - Paper	47	57	51	23	12	3.55	190.00
Availability of Local Counter Service - Online	30	38	100	97	80	2.54	345.00
Availability of Local Drop Box to Pay Bills - Paper	40	46	63	29	13	3.37	191.00
Availability of Local Drop Box to Pay Bills - Online	19	35	108	101	82	2.44	345.00
Online Access to your account - Paper	23	42	75	16	13	3.27	169.00
Online Access to your account - Online	227	95	22	0	1	4.59	345.00
Technology to assist you with managing your electrical consumption - Paper	36	62	65	9	6	3.63	178.00
Technology to assist you with managing your electrical consumption - Online	127	126	73	13	6	4.03	345.00



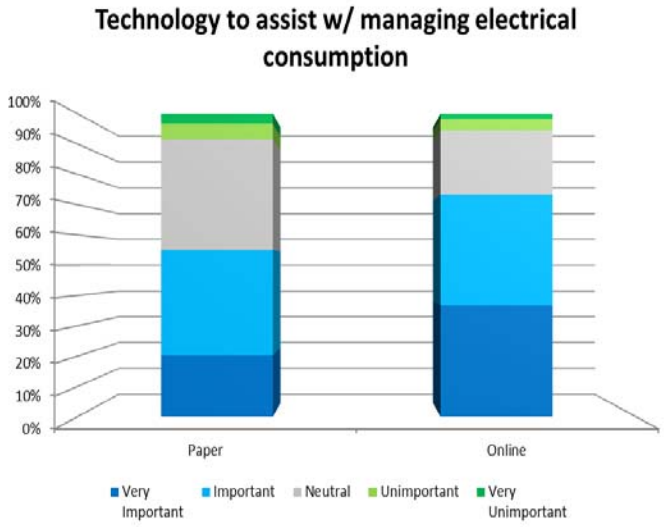
As anticipated, the importance of local counter service was drastically different from those with online and paper-based surveys. We believe that more paper surveys were submitted by those who use this service versus a more tech-savvy customer (online submissions) who likely do more interactions online and over the phone.



As anticipated, the importance of the local drop box to pay bills was drastically different from those with online and paper-based surveys. We presume that more paper surveys were submitted by those who use this service, while online submissions likely have a higher rate of customers who pay via online banking. Even if they pay online, they may still acknowledge a need for the service.



Again, we expected online submissions to have a much higher importance put on online access to accounts. Over 93% (322 responses) of online responses rated this as Important or Very Important. We assume that the majority of these 322 responses came from eBilling customers but do not have the evidence to support that assumption. Paper-based submissions had a variety of responses with almost 40% responding that online access was Important or Very Important.

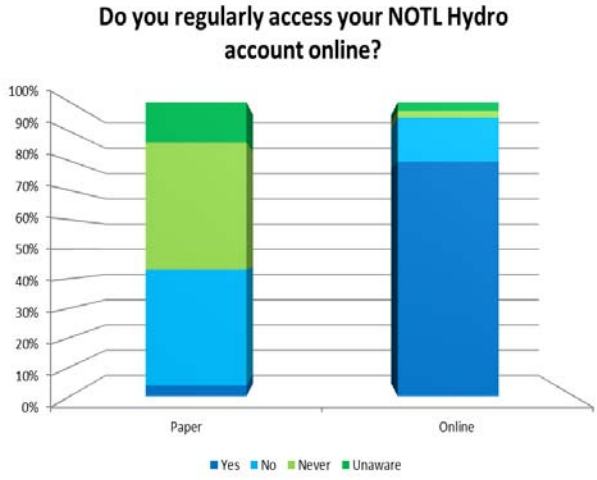


As expected, the responses from the online submissions about the importance of technology to assist with managing electrical consumption were higher than those from paper-based submissions. We were pleased to see that paper-based submissions had an importance value similar to the online submissions.

Over 50% of paper-based responses want technology to assist them in managing consumption. When we compare to the previously mentioned satisfaction level of online access to consumption (27% satisfied) we see that people want more tools, but may not necessarily like the ones we currently have.

Do you regularly access your **NOTL Hydro account online**?

Answer Options	Yes	No	Never	Unaware
Paper Responses	7	75	82	26
Online Responses	272	51	8	10



Also as anticipated, more online submissions indicated that they regularly access their NOTL Hydro account online than paper-based submissions. Almost 14% of paper-based submissions were unaware of this option. Niagara-on-the-Lake Hydro has many links to online access options on it's website, has placed advertisements in the newspaper about online access and has conducted contests encouraging people to sign-up online. We are active in promoting online access to account billing and consumption as well as eBilling access.

b) Our survey asked a general question "Please rate your experience with NOTL Hydro's performance on the following services: Quality of Service from NOTL Hydro". This was presented in an ambiguous way on purpose as many people have different definitions as to what is considered "quality". Subsequent questions on specific items such as staff helpfulness, online access, access to conservation programs, accurate billing and unplanned power outages all are potential components of "quality". Should any document be made available from the OEB that offers a specific definition of quality we would be more than happy to include in any subsequent surveys.

1.2-VECC-6

Reference: Exhibit 1, Appendix 1B / Exhibit 2, Appendix 2A/Exhibit 4, Tab 1, Schedule 2, pg.5

a) With respect to the question on notification in the case of unplanned outages the response of "*auto attendant when calling in*" is not reported (and presumably the response rate is below the lowest answer reported). However, auto attendant is a method is used by a number of utilities. Please explain what system is currently used by NOTL. If NOTL currently uses automated attendant messaging or status posting on its web site does NOTL understand why its customers responded in such low numbers to this option? Please explain.
b) Has NOTL undertaken any survey of customers immediately (or shortly) after an unplanned outage? If not, please explain why not.
c) NOTL notes in its Distribution plan that "*customers have indicated that they would be very interested in receiving status updates during an unplanned outage but very few indicated that they would make use of instantaneous load information or 'behind the meter' technologies*" (page 26). The summary of the consumer survey does not appear to discuss this issue. Please provide the basis for this conclusion or provide the consumer study reference.
d) Please explain how, after the implementation of the Teleworks program, customers who wish to find out information on outages can do so (i.e. will/does NOTL offer a "pull" as well as a "push" information solution)?

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Response to 1.2-VECC-6

a) The question that we posed in our survey was "Would you like status updates from NOTL Hydro if an unplanned power outage occurs at your home or business in NOTL?" This question was posed with the explicit intention to evaluate the potential of a new outreach technology (Teleworks) to inform customers in specific areas affected by a power outage (not for incoming calls). This service would be able to isolate areas affected and provide updates to customers who sign up to the notification service. This service is not currently an option pending Teleworks implementation in 2014.

With respect to the auto-attendant option, we have decided not to update our auto-attendant with most power outage updates. Our outages are few and rarely affect a wide area. When large areas are affected, it has historically been caused by a

weather event such as a wind storm, lightning storm or other major weather event. During previous major events, staff typically will come to the office and answer phones outside our official office hours instead of forwarding calls to our 24/7 outside-hours contracted service. This allows a higher customer interaction experience and allows our phone staff to communicate with front-line workers effectively. Future major events may involve updating our auto-attendant, but that decision will be made on a case by case scenario.

During unplanned outages that affect a wide area or customer base, we will typically update our website home page as well as our Facebook and Twitter feed with status updates.

In summary, the intention of the question was to provide a service with **outgoing** communications. Any connotations that link auto-attendant to the question was not intended which is why there was a perceived "low numbers" for this selection.

b) No. It has not been considered.

c) The comments on page 26 were not the result of the recent survey but were gathered from a Home Automation Network (HAN) pilot project we conducted in 2010-2011. NOTL Hydro provided 'behind the meter' technology that controlled non-essential residential appliances and load during the ON Peak period. Our customers clearly preferred NOTL Hydro to automatically control their non-essential load but very few expressed interest or value in viewing their instantaneous load. These comments were expressed to our team directly involved in the research. The pilot project results were published by Navigant Consulting (for the OPA) in 2011 but this customer preference was not clearly presented in the report.

d) For customers who wish to find out information on outages, their inbound phone call will allow them to access information telling them the areas of the outage and the anticipated time to reconnection (i.e. "if you are calling from the Main Street to Broadview area, we are aware of your outage and your power should be restored by 9:00am today").

In addition to this element of information customers may also use the system to pull information regarding their current balance, last payment date, and making a payment.

Teleworks also facilitates "push" communication which will help us communicate notifications of emergency outages and repair times, advise of interruptions to service due to maintenance, and assist with the collection process.

1.2-VECC-7

Reference: Exhibit 1, Appendix 1B

a) Does NOTL carry out transactional surveys (e.g. after outages, a service call or a customer complaint)? If so please describe these and present the results.
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Response to 1.2-VECC-7

a) This question appears to be the same as 1.2-VECC-4. Please refer to the response to VECC-4.

1.2-VECC-8

Reference: Exhibit 1, Tab 2, Schedule 1, page 1

a) VECC is unable to find any information on NOTL's website about the LEAP program. Is such information available on the web site? What efforts are made by NOTL to communicate the availability of LEAP?

Response to 1.2-VECC-8

a) LEAP information is not available on the website. NOTL Hydro appreciates this having been pointed out by VECC and will add this information on the website in service to the community.

NOTL Hydro informs consumers of the LEAP program in written form once per year as a bill message, and on the Disconnection Notice. NOTL Hydro informs consumers of the LEAP program in verbal form as a condition of how a security deposit may be waived, at 48 hours prior to disconnection of service due to arrears, when a consumer asks if there is help, and as a courtesy when consumers express difficulty paying invoices.

2. Performance Measures

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

2.1-VECC-9

Reference: Exhibit 1, Tab 1, Schedule 2, pg. 12 / Exhibit 4, Tab 2, Schedule 2, Table 4.2.2.

a) Please provide a table showing Statistics Canada published annual CPI for year of the years 2008 through 2014. If NOTL has wage increases greater than CPI (see Table 4.2.2) please comment on what steps are being taken to mitigate compensation exceeding inflation.

Response to 2.1-VECC-9

a) Table 4.2.2 is reproduced below:

Table 4.2.2 – Summary of Union Settlements

IBEW Agreement - Local 636	Date Signed	Effective Dates during period 2005 to 2014 (each on 1st Day of Month)																	
Period		May	Jan	May	Jun	Oct	Jan	May	Jul	Nov	Jan	May	Jul	Nov	Jan	May	Jul	Nov	Jan	May	Jan	May
From	To	2005	2009				2010				2011				2012				2013		2014	
Union Employees																						
1-May-06	30-Apr-09	5-Oct-06	2.20%																			
1-May-09	30-Apr-10	4-Aug-09		1.25%		1.25%																
1-May-10	30-Apr-13	6-Jul-10						1.40%		1.40%		1.40%		1.40%		1.40%		1.40%				
1-May-13	30-Apr-16	29-Aug-13																		2.80%		2.80%
Management Employees [1]																						
1-May-06	30-Apr-09	5-Oct-06																				
1-May-09	30-Apr-10	4-Aug-09	1.25%		1.25%		1.40%		1.40%		1.40%		1.40%		1.40%		1.40%		2.60%		2.60%	
1-May-10	30-Apr-13	6-Jul-10																				
1-May-13	30-Apr-16	29-Aug-13																				

[1] - Management % increases follow Union agreements with effective dates 4 months ahead of Union

Statistics Canada published CPI data for Ontario all items is provided in the file NOTL_CPI_VECC9.pdf provided with these responses[1]. In summary:

	2008	2009	2010	2011	2012	2013	2014
CPI	2.3%	0.4%	2.5%	3.1%	1.4%	1.0%	n/a
NOTL	3.0%	1.25% + 1.25%	1.4% + 1.4%	1.4% + 1.4%	1.4% + 1.4%	2.8%	2.8%

[1] www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ09g-eng.htm and www5.statcan.gc.ca/cansim/a26

With regard to mitigation of compensation, please also see our response to Energy Probe IR 6 e):

- The LDC industry for the most part requires a highly trained, specialized and skilled workforce to operate effectively and efficiently. In order to attract and retain such employees, we must offer competitive wages and benefits that are determined by the local and provincial market. Collective agreements and management compensations are negotiated based on these market conditions all the while keeping our customers` affordability of rates in mind.

NOTL Hydro negotiated a 2.8% annual increase in our collective agreements which was lower than all recent local LDC settlements and leaves NOTL Hydro hourly Lineperson rates slightly lower than all Niagara-based LDCs.

2.1-VECC-10

Reference: Exhibit 2, Tab 3, Schedule 5

a) For only outages excluding loss of supply, please provide a table in the following format (or using any similar categories tracked by the Utility).

.

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than pole)				
Pole Failure				
Weather				
Animals, Vehicle				
Unknown				
Total				

Response to 2.1-VECC-10

a) The following Table is provided:

DESCRIPTION	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Unknown Causes	3	2	5	6
Scheduled Outages	1	-	6	15
Tree Contact	4	-	7	6
Lightning	2	2	14	5
Equipment Failure	12	10	19	11
Adverse Weather	2	1	2	2
Human Element	2	-	1	2
Foreign Interference	4	2	2	8
Adverse Environment	-	-	-	2
Loss of Supply	1	-	-	1
TOTALS	31	17	56	58

NOTE

2011 Totals includes a single value for the April 28th Wind Storm. The combination of 100km/h winds and wet soil caused devastating damage to the area as many trees uprooted and damaged power lines. Since we were in an emergency situation, crews focused on correcting the many issues in our grid. An actual number of outages is not available.

3. Customer Focus

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

3.1-VECC-11

Reference: Exhibit 1, Appendix 1B

a) The survey asks a question as to the preferred trade-off between unplanned outages and rates. Was this the only question which was asked with respect to expenditure and rates?
b) The question provides 3 possible answers: (1) higher rates = less outages; (2) lower rates = more outages; (3) the status quo. However it does not ask whether the respondent believes the utility should be able achieve lower outages at the current rates, or at lower rates. Why was this option not asked of respondents? Was any question asked which would provide the customers impression as to the efficiency of the Utility?

Response to 3.1-VECC-11

a) Our survey (Appendix 1B) asked a number of questions that allowed us to gauge customers' feedback as to appropriate expenditure levels to rates. For example, we asked customers to rate their experience with NOTL Hydro and their view of the importance of; reliability, quality and value of Service, the frequency of Outages and restoration times. We also asked several questions relating to our potential investment in technologies that customers could indicate would be a benefit to them. The survey also asked customers to rate our current customer service levels and CDM program delivery. These particular survey results aided us in determining whether adequate funding or manpower was provided to meet customer expectations.

b) We did not ask customers this specific question because we are of the opinion that customers are not in a position to provide a useful response. The O.E.B. and intervenors have the expertise and ability to access our relative statistics and comparative figures versus other LDCs and come to a reasonable conclusion as to our ability. Our customers would, for the most part, not be in that position. Having said that, regardless of our Customers' consensus to that potential question, NOTL

Hydro is continually seeking to drive efficiencies that will improve our outage frequency and restoration times. Several components of our CDSP reflect ongoing adjustments, technologies and methodologies that continuously drive efficiencies without additional investment. To conclude, we believe that customers living in this community are in a much better position to assess our value of service relative to our current rates.

4. Operational Effectiveness

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

4.1-VECC-12

Reference: Exhibit 2, Appendix 2A, Distribution Plan, pg. 9

a) NOTL notes that it changed infra-red scan inspections from an annual to a bi-annual schedule in order to save costs. It also notes that after a planned August 2013 inspection it would analyze the cost effectiveness of this change. Please provide that analysis.

Response to 4.1-VECC-12

a) As expected, there were no hot spots reported in the August 2013 inspection. As a result, we have confirmed our decision to do this inspection bi-annually. Each inspection is $2,290. We will perform 2 inspections during this IRM period (2015 and 2017). Therefore, we have made a small adjustment to the OM&A for 2014 to reflect amortization of the cost of two inspections over the 5-year IRM period.

4.1-VECC-13

Reference: Exhibit 2, Tab 3, Schedule 5

a) NOTL states it has set reliability targets based on the SAIDI et al. metrics. However, these metrics include outages (e.g. animal or vehicle damage to plant) which are beyond the control of the Utility. Other areas which are more within the control of the Utility (e.g. equipment failure) are not separately monitored. Why has NOTL not chosen reliability targets which attempt to understand the Utility's performance for matters within its control and/or how it responds to matters beyond its control (e.g. recovery time from outages).

Response to 4.1-VECC-13

a) While our industry generally considers animal contacts and vehicle damage to plant beyond the control of the utility, we are of the opinion that a significant number of these instances can be controlled or prevented. For example, approximately 5 years ago a raccoon entered our MTS#1 station and climbed up on the HV bushings resulting in a major outage and expensive arc-related equipment damage. NOTL Hydro was not satisfied to accept such invasions to be 'beyond our control' but instead implemented measures at our stations that included extending the fences to grade and/or increased the gravel level to fill potential entry gaps. We also procured special molded high voltage insulator bushings that effectively extend the possible arc contact zone, hopefully preventing such future occurrences. We also found that some of our older 27.6 kV feeders were constructed with smaller insulators and tighter clearances and are subject to a higher frequency of bird contacts. We continue to address this situation by reinsulating and replacing these line sections in our capital program. Similarly, as NOTL Hydro continued to expand our underground network, the number of outages related to vehicles bumping in to pad mounted gear was increasing. After inspection, we implemented a program to install bollards around vulnerable equipment and instituted a design standard to install such protective equipment on specific new installations.

We agree that the SAIDI et al metrics do include elements beyond the utility's control and the frequency and impact of major damaging storms appears to be on the rise in the last decade, however, they remain an important tool by which to measure and compare our annual performance and that of our relative position within the industry. Having said that, we agree that improving outage response times is an important goal. While response times are more difficult to measure, our management and staff team is continuously evaluating and seeking means by which to improve our performance. Our current development of an Outage

Management system holds great promise of improved response times. We provide our after-hours response staff with well-equipped vehicles and communication equipment. The recent implementation of smart switches in the Old Town has on 4 occasions in the last 2 years successfully operated and reduced the outage time to over 1000 customers from perhaps 1 hour down to less than 8 seconds. We also are in the process of expanding our smart grid by adding monitoring nodes which promise to improve intelligence and response times

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-VECC-14

Reference: Exhibit 4, Tab 1, Schedule 2, pg. 1

a) Please confirm that 2013 and 2014 OM&A figures shown in Table 4.1.3 are in modified CGAAP and that they reflect any changes to NOTL's depreciation schedules and capitalization policies.
b) Using Table 4.1.3 please show separately for each major OM&A category the adjustment made for changes to NOTL's capitalization, or other IFRS related, policies.

Response to 4.2-VECC-14

a) NOTL Hydro confirms that 2013 and 2014 OM&A figures shown in Table 4.1.3 are in modified CGAAP and they reflect any changes to NOTL's depreciation schedules and capitalization policies.

b) As stated in Exhibit 2, Tab 3, Schedule 1 – Capitalization of Burdens, the only change to NOTL's capitalization or other IFRS related policies is to include truck insurance in the burden rate for truck costs. This change has the effect of increasing PP&E by approximately $4,000 in 2013 and 2014 above what it would otherwise have been and reducing OM&A by the same amount.

Using the Table 4.1.3 categories, the following Table shows the effect on OM&A separately for each category, reflected in the OM&A amounts shown in Table 4.1.3:

Adjustment Made	2013 Bridge	2014 Test
Operations	$ (1,026)	$ (1,034)
Maintenance	$ (2,753)	$ (2,746)
Subtotal	$ (3,779)	$ (3,780)
Billing and Collecting	$ (63)	$ (63)
Community Relations	$ -	$ -
Administrative and General	$ (158)	$ (157)
Subtotal	$ (221)	$ (220)
Total	$ (4,000)	$ (4,000)

4.2-VECC-15

Reference: Exhibit 4, Tab 1, Schedule 2, Table 4.1.3

a) Please update Table 4.1.3 and 4.2.1 to show 2013 actual (unaudited) amounts.

Response to 4.2-VECC-15

a) Tables 4.1.3 and 4.2.1 are updated to show 2013 actual (unaudited) amounts as follows:

Table 4.1.3 updated	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actual (Unaudited)	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Operations	$ 373,710	$ 399,162	$ 350,388	$ 424,014	$ 469,005	$ 459,770	$ 532,044
Maintenance	$ 521,359	$ 439,868	$ 394,912	$ 392,884	$ 479,908	$ 434,244	$ 416,132
SubTotal	**$ 895,069**	**$ 839,030**	**$ 745,299**	**$ 816,898**	**$ 948,913**	**$ 894,014**	**$ 948,177**
%Change (year over year)			-11.2%	9.6%	16.2%	-5.8%	6.1%
%Change (Test Year vs Last Rebasing Year - Actual)							13.0%
Billing and Collecting	$ 318,798	$ 315,290	$ 333,308	$ 402,377	$ 550,877	$ 495,697	$ 534,260
Community Relations	$ 1,020	$ 3,584	$ 3,949	$ 2,445	$ 729	$ 331	$ 12,300
Administrative and General	$ 629,254	$ 659,991	$ 686,992	$ 682,468	$ 640,886	$ 748,242	$ 720,526
SubTotal	**$ 949,071**	**$ 978,864**	**$ 1,024,249**	**$ 1,087,289**	**$ 1,192,492**	**$ 1,244,271**	**$ 1,267,085**
%Change (year over year)			4.6%	6.2%	9.7%	4.3%	1.8%
%Change (Test Year vs Last Rebasing Year - Actual)							29.4%
Total	**$ 1,844,140**	**$ 1,817,894**	**$ 1,769,548**	**$ 1,904,187**	**$ 2,141,405**	**$ 2,138,285**	**$ 2,215,262**
%Change (year over year)			-2.7%	7.6%	12.5%	-0.1%	3.6%

Table 4.2.1 Updated	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals (unaudited)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2009 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations and Maintenance Programs									
Supervision and Engineering	266,929	241,821	207,334	177,027	243,954	229,713	255,290	11,336	-11,640
Transformer & Dist. Stations	50,767	85,235	37,961	68,296	52,353	59,585	56,552	4,198	5,785
Overhead Lines	306,907	293,529	304,697	293,215	263,415	284,575	268,948	5,533	-37,960
Underground Lines	98,642	68,626	70,018	98,424	69,609	58,837	89,480	19,871	-9,161
Transformers	94,190	70,619	58,393	34,282	42,057	48,609	48,485	6,427	-45,705
Meters	29,572	21,242	11,793	38,783	185,399	96,987	115,386	-70,013	85,814
Customer Premises	48,062	57,957	55,104	106,871	92,125	115,708	114,037	21,912	65,975
Sub-Total	**895,069**	**839,030**	**745,299**	**816,898**	**948,913**	**894,014**	**948,177**	**-736**	**53,108**
Billing and Collecting Programs									
Meter Reading	49,768	50,361	49,824	24,685	140,761	89,411	87,372	-53,389	37,604
Billing	172,662	156,272	198,217	289,522	325,633	329,538	368,645	43,012	195,983
Collecting	96,368	108,657	85,267	88,169	84,483	76,748	78,243	-6,240	-18,125
Sub-Total	**318,798**	**315,290**	**333,308**	**402,377**	**550,877**	**495,697**	**534,260**	**-16,617**	**215,462**
Community Relations Program									
Community relations	1,020	3,584	3,949	2,445	729	331	12,300	11,571	11,280
Sub-Total	**1,020**	**3,584**	**3,949**	**2,445**	**729**	**331**	**12,300**	**11,571**	**11,280**
Administration and General Programs									
Administrative services	343,289	318,658	328,757	349,840	348,608	404,303	389,358	40,750	46,070
Property and liability insurance	48,300	48,355	63,983	65,241	54,842	55,255	55,831	989	7,531
Legal, audit & consulting services	58,950	32,681	43,882	35,500	51,195	69,479	40,800	-10,395	-18,150
Retiree benefits	22,000	27,233	19,833	27,803	25,249	18,345	24,494	-755	2,494
ESA and regulatory fees	30,845	72,967	28,986	52,396	41,957	66,001	58,300	16,343	27,455
Maintenance of general plant	125,870	160,096	159,249	148,688	116,034	129,339	146,242	30,208	20,372
LEAP funding	0	0	0	3,000	3,000	5,520	5,500	2,500	5,500
Special Purpose Charge	0	0	42,302	0	0	0	0		
Sub-Total	**629,254**	**659,991**	**686,992**	**682,468**	**640,886**	**748,242**	**720,526**	**79,640**	**91,272**
Miscellaneous								0	0
Total	**1,844,140**	**1,817,894**	**1,769,548**	**1,904,187**	**2,141,405**	**2,138,285**	**2,215,262**	**73,858**	**371,122**

After analyzing the actuals for 2013 (unaudited), a reduction in Operations and maintenance of $16,500 is proposed as follows.

Account 5125

- $1,500 reduction due to switching from annual to bi-annual inspections

Account 5085

- $5,000 reduction in consulting costs

Account 5010

- $2.000 reduction in engineering consultation due to internal expertise

Account 5112

- $3,000 reduction in maintenance/consultation costs as we are upgrading the station in 2015 and will require less maintenance going forward

Account 5040

- $5,039 reduction in safety training labour costs as all new employees have completed initial safety related training

These reductions are reflected in the related Operations and Maintenance programs' amounts for 2014 in the updated Tables 4.1.3 and 4.2.1 above.

In addition, there are small adjustments to truck depreciation burden expenses to OM&A resulting from the actual (unaudited) 2013 capital results and the re-allocation of $30,000 in the proposed 2014 capital expenses from trucks to software upgrades, as referenced in the response to Energy probe-22.

4.2-VECC-16

Reference: Exhibit 4, Tab 1, Schedule 2, pg. 7 / Report to Board Third Generation Incentive Regulation Stretch Factor Updates for 2013 – Nov. 27 2012

a) For the years 2009 through 2013 please provide a table showing the OM&A cost per customer and per FTE for NOTL's peer group of utilities (i.e. Small Southern Centre Wellington Hydro, Cooperative Hydro Embrun, Grimsby Power and Orangeville Hydro). Please also include Entegrus Powerlines in this comparison table.

Response to 4.2-VECC-16

a) NOTL Hydro's understanding is that the source of data in the referenced report is RRR data as summarized in the OEB Year-books. From the available year-books and data in those books, the following Table is provided:

	A	B	C	D	E	F	G	H	J
1	**Year-Book Data**	**Centre Wellington Hydro**	**Cooperative Hydro Embrun**	**Grimsby Power**	**Orangeville Hydro**	**Chatham-Kent Hydro Inc.**	**Middlesex Power Distribution Corporation**	**Entegrus Powerlines**	**NOTL Hydro Year Book**
2	**2009**								
3	Number of Customers	6,382	1,941	10,073	11,126	32,168	7,911		7,880
4	OM&A Cost per Customer	$ 262.96	$ 210.72	$ 172.75	$ 213.62	$ 172.53	$ 206.64		$ 230.70
5	Number of FTEs								
6	Customers/FTEs								
7	OM&A Cost per FTE								
8	Total Service area km^2	10	5	67	17	70	26		133
9	Total km of Line	146	27	172	173	810	125		341
10	Density (Customers/km^2)	638	388	150	654	460	304		59
11	Customers/km of Line	44	72	59	64	40	63		23
12									
13	**2010**								
14	Number of Customers	6,463	1,958	10,151	11,256	32,033	7,859		7,882
15	OM&A Cost per Customer	$ 267.74	$ 241.50	$ 175.41	$ 234.52	$ 201.96	$ 216.45		$ 224.50
16	Number of FTEs								
17	Customers/FTEs								
18	OM&A Cost per FTE								
19	Total Service area km^2	10	5	67	17	70	26		133
20	Total km of Line	147	27	241	176	883	125		342
21	Density (Customers/km^2)	646	392	152	662	458	302		59
22	Customers/km of Line	44	73	42	64	36	63		23
23									
24	**2011**								
25	Number of Customers	6,496	1,954	10,307	11,248	32,132	7,988		8,000
26	OM&A Cost per Customer	$ 298.89	$ 274.48	$ 202.10	$ 262.80	$ 208.95	$ 214.38		$ 237.65
27	Number of FTEs	14	3	18	20	43	13		19
28	Customers/FTEs	464.00	651.33	572.61	562.40	747.26	614.46		421.05
29	OM&A Cost per FTE	$ 138,685	$ 178,778	$ 115,725	$ 147,799	$ 156,139	$ 131,728		$ 100,063
30	Total Service area km^2	10	5	69	17	70	26		133
31	Total km of Line	161	27	240	176	811	135		348
32	Density (Customers/km^2)	650	391	149	662	459	307		60
33	Customers/km of Line	40	72	43	64	40	59		23
34									
35	**2012**								
36	Number of Customers	6,647	1,956	10,488	11,392			40,232	8,187
37	OM&A Cost per Customer	$ 334.69	$ 271.97	$ 285.46	$ 272.50			$ 220.81	$ 257.58
38	Number of FTEs	15	3	18	20			51	20
39	Customers/FTEs	$ 443.13	$ 652.00	$ 582.67	$ 569.60			$ 788.86	$ 409.35
40	OM&A Cost per FTE	$ 148,312	$ 177,324	$ 166,328	$ 155,216			$ 174,189	$ 105,440
41	Total Service area km^2	10	5	69	17			96	133
42	Total km of Line	149	27	238	187			959	326
43	Density (Customers/km^2)	665	391	152	670			419	62
44	Customers/km of Line	45	72	44	61			42	25
45									
46	**2013**								
47	Number of Customers								
48	OM&A Cost per Customer								
49	Number of FTEs								
50	Customers/FTEs								
51	OM&A Cost per FTE								
52									
53		Shading indicates that the Yearbook or data in it is not available.							

Please note that NOTL Hydro's OM&A in 2012 includes $184,671 in smart meter DVA disposition as shown in Table 4.1.2 in Exhibit 4 Tab 1 Schedule 1 Page 4. Of this cost of $184,671, $139,029 was incurred in 2009 to 2011, not in 2012.

Excluding this $139,029 in the 2012 calculations, with 8,187 customers and 20 FTEs per the Yearbook:

- *OM&A cost per customer in the above Table is reduced by $16.98*
- *OM&A cost per FTE is reduced by $6,951.*

Please note that Table 4.1.5 – Recoverable Cost per Customer and per FTE in Exhibit 4 Tab 1 Schedule 2 Page 7 is not adjusted for this DVA disposition.

Ontario LDCs are arguably diverse in nature and difficult to directly compare. We strongly believe that the Board's studies continue to ignore key elements that affect operating costs. In order to illustrate this issue, we have taken the liberty to add two density-related statistics to the requested table, namely customers/square km and customers/km of line. In the 1970's, Niagara was regionalized and our current service territory is 133 square km taking in the entire Municipality of Niagara-on-the-Lake. Orangeville Hydro for example with 17 square km has a customer density more than ten times that of NOTL Hydro and has almost 2.5 times more customers per km of line. The closest comparator, Grimsby Power, had 28% more customers than NOTL Hydro in 2012 and over 75% more customers per km of line. Our lower density of customers and comparatively large operating territory definitely contributes to higher labour and transportation costs and response times for example that the current O.E.B. studies continue to ignore. We would like to point out that the dispersed operating territory of Entegrus would similarly create some unique operating challenges to that utility when compared to LDCs with similar customer counts.

To our knowledge, the latest O.E.B. study also failed to recognize transformer station ownership costs in the comparator study. NOTL Hydro owns and operates two 115 kV transformer stations (approximately $50,000/year) and we do not believe that any of the listed comparators own or operate a T.S. Finally, we believe that consideration must be given to the interpretation of FTE/customer. The 2012, the NOTL Hydro count included 2 employees dedicated to the delivery of CDM programs and almost entirely funded by the OPA. We understand that some LDCs have fully contracted out this activity. NOTL Hydro also provides water/wastewater billing services to the Municipality. An equivalent of approximately one FTE is fully funded by our affiliate for the provision of that service. We are unaware as to whether our listed comparators provide a similar service. These circumstances however, provide merit to the low OM&A cost/FTE statistic and should be considered in any cohort comparison.

4.2-VECC-17

Reference: Exhibit 4, Tab 1, Schedule 2, pg. 1

a) We are unable to locate the detailed (Actual and Approved) 2009 through 2014 detailed OM&A expense which shows USoA accounts 5005 through 6205.
b) Specifically, please provide the amounts for these years for Billing and Collection accounts 5305, 5310, 5315, 5320, 5325, 5330, 5335, and 5340.
c) If Table 2-JC (NOTL-2014_Chapter2 Appendices) then please revise the table to show all the USoA accounts.

Response to 4.2-VECC-17

a) As per Page 27 of the Filing Guidelines of July 17, 2013, the Board has eliminated the requirement to provide OM&A details on an account by account basis. Hence, these details were not needed in the application.

b) Notwithstanding Response a), the following Table provides the details for the accounts requested:

Account Description	Last Rebasing Year (2009) Board Approved	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Actual	Bridge Year 2013	Test Year 2014
Billing and Collecting							
5305 Supervision	$ 13,530	$ 10,363	$ 12,009	$ 18,393	$ 15,701	$ 17,154	$ 17,692
5310 Meter Reading Expense	$ 49,768	$ 50,361	$ 49,824	$ 24,685	$ 140,761	$ 85,925	$ 87,368
5315 Customer Billing	$ 159,131	$ 145,909	$ 186,208	$ 271,130	$ 309,932	$ 339,456	$ 350,953
5320 Collecting	$ 76,368	$ 97,422	$ 73,259	$ 70,044	$ 51,999	$ 54,406	$ 55,743
5325 Collecting - Cash Over and Short	$ -	$ 1	$ 10	$ 72	-$ 10	$ -	$ -
5330 Collection Charges	$ -	-$ 111	$ -	$ -	$ -	$ -	$ -
5335 Bad Debt Expense	$ 20,000	$ 9,228	$ 9,729	$ 15,867	$ 28,523	$ 18,000	$ 18,000
5340 Miscellaneous Customer Accounts Expenses	$ -	$ 2,117	$ 2,270	$ 2,187	$ 3,971	$ 4,500	$ 4,500
Total - Billing and Collecting	$ 318,798	$ 315,290	$ 333,308	$ 402,377	$ 550,877	$ 519,441	$ 534,256

c) Notwithstanding Response a), the following Table based on Table 2-JC provides the information requested, in the first column. USoA accounts not shown have zero amounts for all the years.

USoA Accounts	Programs	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2009 Board-Approved)
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
	Operations and Maintenance									
5005 5010 5085 5105	Supervision and Engineering	266,929	241,821	207,334	177,027	243,954	251,819	263,546	19,592	-3,383
5014 5015 5016 5017 5112 5114	Transformer & Distribution Stations	50,767	85,235	37,961	68,296	52,353	66,300	59,304	6,951	8,537
5020 5025 5095 5120 5125 5130 5135	Overhead Lines	306,907	293,529	304,697	293,215	263,415	271,495	271,871	8,456	-35,036
5040 5045 5145 5150 5155	Underground Lines	98,642	68,626	70,018	98,424	69,609	89,791	91,171	21,562	-7,471
5035 5055 5160	Transformers	94,190	70,619	58,393	34,282	42,057	54,727	48,417	6,360	-45,773
5065 5175	Meters	29,572	21,242	11,793	38,783	185,399	112,721	115,373	-70,026	85,801
5070 5075	Customer Premises	48,062	57,957	55,104	106,871	92,125	112,455	113,947	21,823	65,886
	Sub-Total	**895,069**	**839,030**	**745,299**	**816,898**	**948,913**	**959,307**	**963,630**	**14,717**	**68,561**
	Billing and Collecting Programs									
5310	Meter Reading	49,768	50,361	49,824	24,685	140,761	85,925	87,368	-53,393	37,600
5305 5315	Billing	172,662	156,272	198,217	289,522	325,633	356,610	368,645	43,012	195,983
5320 5325 5330 5335 5340	Collecting	96,368	108,657	85,267	88,169	84,483	76,906	78,243	-6,240	-18,125
	Sub-Total	**318,798**	**315,290**	**333,308**	**402,377**	**550,877**	**519,441**	**534,256**	**-16,621**	**215,458**
	Community Relations Program									
5415 5420 5425	Community relations	1,020	3,584	3,949	2,445	729	500	12,300	11,571	11,280
	Sub-Total	**1,020**	**3,584**	**3,949**	**2,445**	**729**	**500**	**12,300**	**11,571**	**11,280**
	Administration and General Programs									
5605 5610 5615 5620 5660 5665	Administrative services	343,289	318,658	328,757	349,840	348,608	392,477	389,355	40,746	46,066
5635 5640	Property and liability insurance	48,300	48,355	63,983	65,241	54,842	54,952	55,831	989	7,531
5630	Legal, audit and consulting services	58,950	32,681	43,882	35,500	51,195	50,100	40,800	-10,395	-18,150
5645	Retiree benefits	22,000	27,233	19,833	27,803	25,249	29,091	24,494	-755	2,494
5655 5680	ESA and regulatory fees	30,845	72,967	28,986	52,396	41,957	42,450	58,300	16,343	27,455
5675	Maintenance of general plant	125,870	160,096	159,249	148,688	116,034	126,924	146,241	30,207	20,372
6205	LEAP funding	0	0	0	3,000	3,000	5,500	5,500	2,500	5,500
5681	Special Purpose Charge (one time)	0	0	42,302	0	0	0	0	0	0
	Sub-Total	**629,254**	**659,991**	**686,992**	**682,468**	**640,886**	**701,494**	**720,521**	**79,635**	**91,267**
	Miscellaneous								0	0
	Total	**1,844,140**	**1,817,894**	**1,769,548**	**1,904,187**	**2,141,405**	**2,180,742**	**2,230,707**	**89,302**	**386,567**

To facilitate an understanding of the mapping of USoA amounts to the programs in the above Table, the following information is also provided:

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Actual	Bridge Year 2013	Test Year 2014
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations							
5005	Operation Supervision and Engineering	$ 93,346	$ 75,340	$ 46,736	$ 66,161	$ 73,125	$ 78,393
5010	Load Dispatching	$ 10,835	$ 14,186	$ 20,300	$ 28,109	$ 34,948	$ 35,361
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -	$ -	$ -
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ 4,592	$ 4,094	$ 4,279
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 763	$ 905	$ 4,656	$ 33,352	$ 21,183	$ 18,534
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ 29	$ -	$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ 4	$ -	$ -
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 39,911	$ 32,835	$ 43,018	$ 41,996	$ 42,469	$ 43,237
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 37,724	$ 29,100	$ 30,647	$ 16,463	$ 26,957	$ 26,957
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ 3,762	$ -	$ -	$ 4,398	$ 5,016	$ 5,241
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 16,722	$ 14,768	$ 15,454	$ 15,012	$ 30,506	$ 31,250
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 4,682	$ 9,511	$ 14,630	$ 16,546	$ 14,150	$ 14,153
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operation	$ 2,643	$ -	$ -	-$ 159	$ 883	$ 909
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 18,208	$ 9,635	$ 33,829	$ 26,500	$ 44,720	$ 45,341
5070	Customer Premises - Operation Labour	$ 7,743	$ 4,580	$ 49,169	$ 28,612	$ 29,541	$ 30,992
5075	Customer Premises - Operation Materials and Expenses	$ 50,214	$ 50,524	$ 57,701	$ 63,513	$ 82,914	$ 82,955
5085	Miscellaneous Distribution Expenses	$ 94,255	$ 90,869	$ 89,627	$ 105,633	$ 103,518	$ 107,856
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 18,354	$ 18,135	$ 18,245	$ 18,245	$ 18,424	$ 18,423
5096	Other Rent	$ -	$ -	$ -	$ -	$ -	$ -
Total - Operations		$ 399,162	$ 350,388	$ 424,014	$ 469,005	$ 532,448	$ 543,882
Maintenance							
5105	Maintenance Supervision and Engineering	$ 43,385	$ 26,939	$ 20,363	$ 44,051	$ 40,228	$ 41,935
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -	$ -
5112	Maintenance of Transformer Station Equipment	$ 78,393	$ 31,403	$ 58,110	$ 9,799	$ 33,294	$ 28,571
5114	Maintenance of Distribution Station Equipment	$ 6,078	$ 5,654	$ 5,530	$ 4,578	$ 7,729	$ 7,921
5120	Maintenance of Poles, Towers and Fixtures	$ 66,004	$ 51,974	$ 68,209	$ 49,582	$ 46,762	$ 48,508
5125	Maintenance of Overhead Conductors and Devices	$ 39,380	$ 71,451	$ 64,518	$ 35,349	$ 44,839	$ 45,823
5130	Maintenance of Overhead Services	$ 33,297	$ 28,654	$ 33,633	$ 27,786	$ 22,999	$ 23,572
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 58,859	$ 72,549	$ 34,945	$ 73,994	$ 69,045	$ 65,350
5145	Maintenance of Underground Conduit	$ 1,410	$ -	$ -	$ -	$ -	$ -
5150	Maintenance of Underground Conductors and Devices	$ 5,997	$ 18,915	$ 12,844	$ 13,415	$ 18,291	$ 18,749
5155	Maintenance of Underground Services	$ 39,815	$ 26,824	$ 55,497	$ 24,635	$ 26,844	$ 27,019
5160	Maintenance of Line Transformers	$ 64,214	$ 58,393	$ 34,282	$ 37,818	$ 48,828	$ 42,268
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5175	Maintenance of Meters	$ 3,035	$ 2,158	$ 4,954	$ 158,900	$ 68,001	$ 70,032
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance		$ 439,868	$ 394,912	$ 392,884	$ 479,908	$ 426,860	$ 419,748

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Actual	Bridge Year 2013	Test Year 2014
Billing and Collecting							
5305	Supervision	$ 10,363	$ 12,009	$ 18,393	$ 15,701	$ 17,154	$ 17,692
5310	Meter Reading Expense	$ 50,361	$ 49,824	$ 24,685	$ 140,761	$ 85,925	$ 87,368
5315	Customer Billing	$ 145,909	$ 186,208	$ 271,130	$ 309,932	$ 339,456	$ 350,953
5320	Collecting	$ 97,422	$ 73,259	$ 70,044	$ 51,999	$ 54,406	$ 55,743
5325	Collecting - Cash Over and Short	$ 1	$ 10	$ 72	-$ 10	$ -	$ -
5330	Collection Charges	-$ 111	$ -	$ -	$ -	$ -	$ -
5335	Bad Debt Expense	$ 9,228	$ 9,729	$ 15,867	$ 28,523	$ 18,000	$ 18,000
5340	Miscellaneous Customer Accounts Expenses	$ 2,117	$ 2,270	$ 2,187	$ 3,971	$ 4,500	$ 4,500
Total - Billing and Collecting		$ 315,290	$ 333,308	$ 402,377	$ 550,877	$ 519,441	$ 534,256

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Actual	Bridge Year 2013	Test Year 2014
Community Relations							
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	$ -	$ -	$ -	$ -	$ -	$ -
5415	Energy Conservation	$ 145	$ 108	$ -	$ -	$ -	$ -
5420	Community Safety Program	$ 1,697	$ -	$ -	$ -	$ -	$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ 1,742	$ 3,841	$ 2,445	$ 729	$ 500	$ 12,300
5505	Supervision	$ -	$ -	$ -	$ -	$ -	$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -	$ -
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -
Total - Community Relations		$ 3,584	$ 3,949	$ 2,445	$ 729	$ 500	$ 12,300

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Actual	Bridge Year 2013	Test Year 2014
Administrative and General Expenses							
5605	Executive Salaries and Expenses	$ 69,301	$ 71,028	$ 91,436	$ 74,818	$ 92,078	$ 95,242
5610	Management Salaries and Expenses	$ 97,626	$ 91,116	$ 89,081	$ 104,053	$ 121,118	$ 123,389
5615	General Administrative Salaries and Expenses	$ 82,724	$ 109,051	$ 89,490	$ 101,497	$ 108,721	$ 98,614
5620	Office Supplies and Expenses	$ 30,252	$ 31,413	$ 41,721	$ 30,698	$ 31,560	$ 31,750
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 32,681	$ 43,882	$ 35,500	$ 51,195	$ 50,100	$ 40,800
5635	Property Insurance	$ 20,670	$ 40,843	$ 35,468	$ 27,130	$ 27,670	$ 28,113
5640	Injuries and Damages	$ 27,685	$ 23,140	$ 29,772	$ 27,713	$ 27,282	$ 27,719
5645	OMERS Pensions and Benefits	$ 27,233	$ 19,833	$ 27,803	$ 25,249	$ 29,091	$ 24,494
5646	Employee Pensions and OPEB						
5647	Employee Sick Leave						
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -	$ -
5655	Regulatory Expenses	$ 68,092	$ 23,753	$ 47,547	$ 37,105	$ 37,450	$ 53,000
5660	General Advertising Expenses	$ 1,061	$ 506	$ 299	$ 3,345	$ 2,100	$ 3,000
5665	Miscellaneous General Expenses	$ 37,694	$ 25,643	$ 37,814	$ 34,197	$ 36,900	$ 37,360
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -
5672	Lease Payment Charge						
5675	Maintenance of General Plant	$ 160,096	$ 159,249	$ 148,688	$ 116,034	$ 126,924	$ 146,241
5680	Electrical Safety Authority Fees	$ 4,875	$ 5,233	$ 4,849	$ 4,853	$ 5,000	$ 5,300
5681	Special Purpose Charge Expense	$ -	$ 42,302	$ -	$ -	$ -	$ -
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -	$ -
5695	OM&A Contra Account	$ -	$ -	$ -	$ -	$ -	$ -
6205	Donations	$ 50	$ -	$ -	$ -	$ -	$ -
6205	Donations, Sub-account LEAP Funding	$ -	$ -	$ 3,000	$ 3,000	$ 5,500	$ 5,500
Total - Administrative and General Expenses		$ 660,041	$ 686,992	$ 682,468	$ 640,886	$ 701,494	$ 720,521
Total OM&A		$ 1,817,944	$ 1,769,548	$ 1,904,187	$ 2,141,405	$ 2,180,742	$ 2,230,707
Adjustments for non-recoverable items							
5681	Special Purpose Charge Expense	$ -	$ 42,302	$ -	$ -	$ -	$ -
6205	Donations[1]	$ 50	$ -	$ -	$ -	$ -	$ -
Total Recoverable OM&A		$ 1,817,894	$ 1,727,245	$ 1,904,187	$ 2,141,405	$ 2,180,742	$ 2,230,707

4.2-VECC-18

Reference: Exhibit 4, Tab 2, Schedule 1, pg.1

a) Provide a table showing a breakdown of the cost elements of account 5315 (Customer Billing) for 2009 (actuals) vs. 2014 (forecast).
b) Please provide the same for Account 5310 (Meter Reading Expenses).
c) If not included in the requested table, please provide the manual meter reading expenses for 2009 and the forecast amounts for manual reading in 2014.

Response to 4.2-VECC-18

a) The following Table provides the requested cost elements of 5315 (customer billing) and further details for the period 2009 to 2014:

5315 Billing	Vendor	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual (unaudited)	2014 Forecast
Billing labour	Internal NOTL Hydro	$ 99,159	$ 68,093	$ 78,983	$ 132,380	$ 168,711	$ 158,964	$ 190,036
Billing expenses		$ 67,585	$ 78,482	$ 49,406	$ 79,871	$ 81,787	$ 91,121	$ 86,748
Retail Service labour and expenses		$ 26,676	$ 32,441	$ 20,274	$ 20,802	$ 17,002	$ 18,218	$ 20,960
Retail Service HUB costs	UCS/ITM/ ERTH	$ 4,885	$ 7,116	$ 5,538	$ 7,880	$ 8,770	$ 9,830	$ 9,000
RSVA/RCVA adjustments	Internal	$ (25,643)	$ (29,860)	$ (17,110)	$ (21,485)	$ (19,086)	$ (22,777)	$ (22,646)
Northstar CIS billing and hosting services	UCS*	$ -	$ -	$ 61,124	$ 75,678	$ 77,703	$ 81,408	$ 82,803
MDMR Support		$ -	$ -	$ -	$ -	$ -	$ 1,718	$ 1,745
Prior-year sales credit		$ -	$ -	$ -	$ (5,603)	$ (9,255)	$ (8,945)	$ -
Totals		$ 172,662	$ 156,272	$ 198,217	$ 289,522	$ 325,633	$ 329,538	$ 368,645

[Overall Northstar costs are shared by UCS members based on customer counts*

With regard to billing labour costs, 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*		

With regard to the prior-year sales credit from UCS, this is a credit back to all UCS members in the event that a "profit" is made by UCS, as UCS is set up on a non-profit basis. A credit is not guaranteed by UCS in any year and hence is not included in the 2014 forecast.

b) The following Table provides the requested cost elements of 5310 (meter reading) and further details for the period 2009 to 2014:

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 manual reads by Collective Utility Services (company name changed in 2012 to Niagara Field Services) were an average of 4,031 reads per month in 2009, with each billing cycle being read every other month. Estimated readings were used to bill cycles not read in the month. With the advent of smart meters, the number of reads per month has decreased to the current level of 263 reads per month.

The interval meter reads by Enerconnect and subsequently Utilismart were an average of 39 reads per month in 2009 increasing to the current level of 67 reads per month.

The Sensus smart meter reading costs beginning in 2009 were initially recorded in the smart meter OM&A variance account and subsequently approved by the Board. The total for the 2009-2011 period of $118,733 was moved from the variance account to Acct 5310 in 2012 as shown in the Table above.

The manual reads by NOTL Hydro prior to the smart meter regime included special reads relating to account moves-in and moves-out and re-reads due to incorrect initial readings. With the advent of smart meters, staff time includes coordination with our Sync Operator as well as investigating meter issues via ODS for stale meters, meters missing ON/OFF reads, estimating consumption, verifying register reads and maintaining customers' keys.

c) Included in b)

4.2-VECC-19

Reference: Exhibit 4, Tab 2

a) Please provide the fees paid to the EDA for each of the years 2009 through (forecast) 2014.
b) If NOTL purchases insurance from the MEARIE Group then please provide the annual insurance premiums, a description of the insurance coverage and whether the contract for insurance has been tendered in the last 5 years.

Response to 4.2-VECC-19

a) The following Table shows the EDA membership fees as reflected in the application. The 2014 invoice was received after the application was submitted.

Year	EDA Membership Fee
2009 Approved	$ 12,800
2009 Actual	$ 12,800
2010 Actual	$ 13,400
2011 Actual	$ 13,850
2012 Actual	$ 14,600
2013 Bridge (actual)	$ 15,300
2014 Test (forecast)	$ 15,760
2014 Actual invoice issued 5 Nov 2013	*$ 16,000*

b) NOTL Hydro does purchase insurance from the MEARIE Group, as follows:

Year	Annual Total MEARIE Premiums by Type of Insurance						
	Property[1]	Fleet/ Vehicle[2]	Comprehensive Liability[3]	Life - Employees	Life - Retirees	LTD	Totals
2009 Approved	$ 20,600	$ 7,200	$ 20,500	$ 6,155	$ 4,823	$ 26,259	$ 85,537
2009 Actual	$ 20,670	$ 7,905	$ 19,780	$ 8,441	$ 5,402	$ 24,832	$ 87,030
2010 Actual	$ 37,085	$ 7,696	$21,960 less one-time premium reduction $6,516 = $15,444	$ 8,929	$ 5,196	$ 23,465	$ 97,815
2011 Actual	$ 35,468	$ 7,923	$ 21,849	$ 7,927	$ 6,607	$ 23,806	$ 103,580
2012 Actual	$ 27,130	$ 6,845	$24,082 less one-time premium reduction $6,572 = $17,510	$ 7,058	$ 7,454	$ 21,556	$ 87,552
2013 Bridge (actual/forecast)	$ 27,670	$ 6,914	$ 27,282	$ 6,185	$ 7,827	$ 24,138	$ 100,015
2014 Test (forecast)	$ 28,113	$ 6,914	$ 27,719	$ 6,540	$ 8,218	$15,147[4] (not MEARIE)	$ 92,651
2014 annual invoice issued 15 Nov 2013	*$ 28,128*	*$ 7,156*	*$ 28,914*				

1. All risk property, boiler and machinery, crime.
2. All owned and leased vehicles
3. General liability (premises and operations, products and completed operations) and liability re: bodily injury, personal injury, property damage, tenant's legal, environmental impairment, errors and omissions/professional, non-owned automobile, legal expense reimbursment (re: conflict of interest and occupational health and safety), Directors and Officers, (privacy and network security breach 2013 and 2014 only).

4. NOTL Hydro has switched LTD to a different insurance provider for 2014 offering a reduction in premiums of approx. 37% to about $15,000, reflected in the application.

The contracts for the MEARIE insurances in the Table above have not been tendered in the last five years. However, NOTL Hydro switched from a local insurance provider to MEARIE for property insurance in the fall of 2007. This switch resulted in a 16% reduction in property insurance in 2009 and 2008 vs. 2007. Notwithstanding the savings achieved, a primary reason for the switch was the superior industry knowledge of MEARIE relative to the local company with the associated concern that the local coverage might prove unsuitable in the event that a claim was needed.

In addition to superior industry knowledge, NOTL Hydro is akin to a shareholder of MEARIE and we receive ongoing rate reductions for some policies while others have risen below that of inflation.

We have compared insurance costs for other elements of our coverage, most recently the Long Term Disability component, which was moved to a less expensive provider as indicated in the Table above.

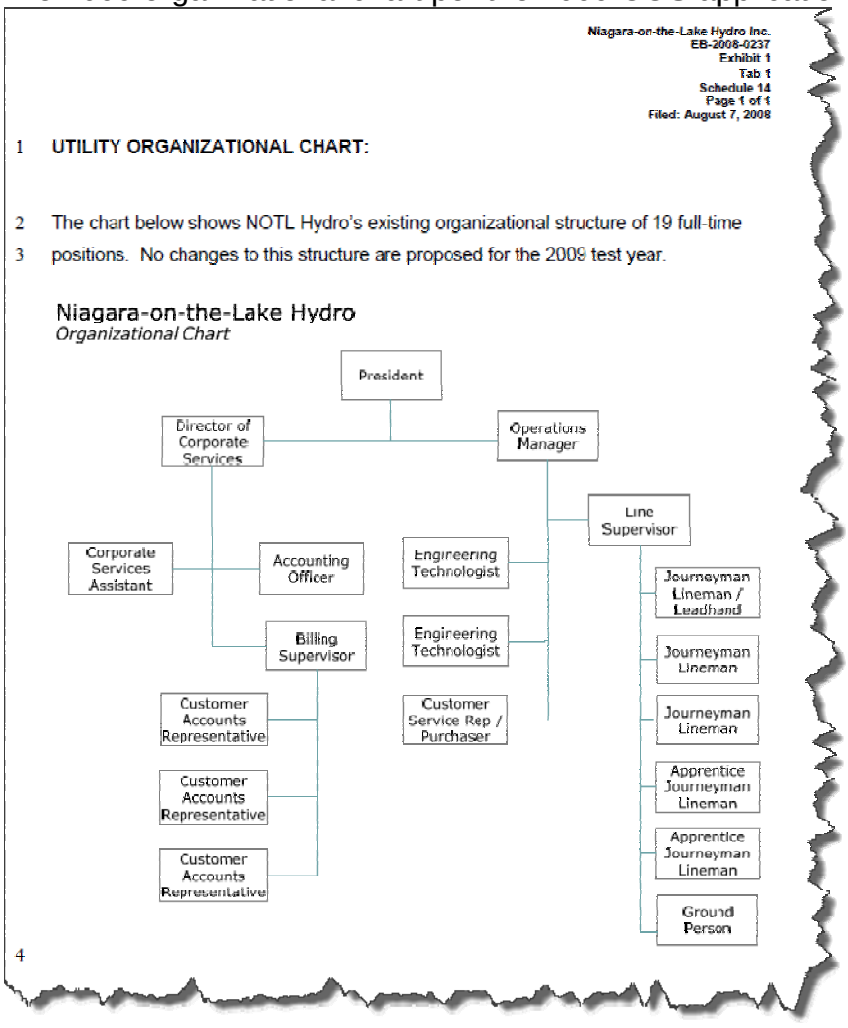
4.2-VECC-20

Reference: Exhibit 4, Tab 2, Schedule 2, pgs. 3-12

a) NOTL forecast approximately 1 less FTE than was approved by the Board in 2009. There are a number of personnel changes described in pages 3-12 of the noted reference. It appears from these descriptions that the NOTL will employ one less lineman in 2014 than it did in 2009. Please confirm this is correct. If not, please explain what position was eliminated since 2009.
b) What reductions in staff accompanied the elimination of streetlight maintenance services in 2012? If none, please explain.

Response to 4.2-VECC-20

a) The explanation is best made by comparing the 2009 and 2014 organizational charts. The 2009 organizational chart per the 2009 COS application was:



Niagara-on-the-Lake Hydro Inc.
EB-2008-0237
Exhibit 1
Tab 1
Schedule 14
Page 1 of 1
Filed: August 7, 2008

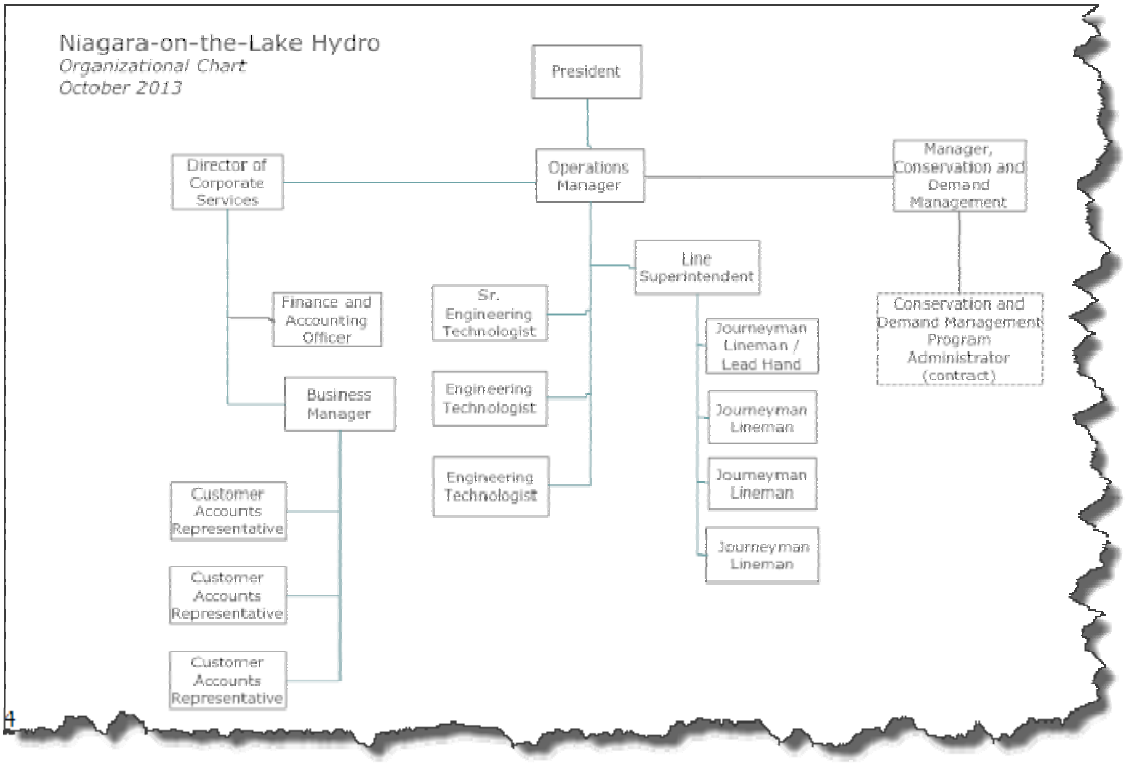
1 **UTILITY ORGANIZATIONAL CHART:**

2 The chart below shows NOTL Hydro's existing organizational structure of 19 full-time
3 positions. No changes to this structure are proposed for the 2008 test year.

Niagara-on-the-Lake Hydro
Organizational Chart

4

The 2014 organization chart per Exhibit 1, Tab 5, Schedule 14 is:



In the Line Department, one Lineman and one Ground Person were eliminated since 2009. The Table below summarizes the overall position eliminations (net of one position decrease) and changes in more detail:

Position in 2009	Position in 2014	Explanation	Net Change in Positions
Accounting Officer	Finance and Accounting Officer	Increased responsibilities	-
Line Supervisor	Line Superintendent	Increased responsibilities	-
Billing Supervisor	Business Manager	Increased responsibilities	-
Engineering Technologist	Sr. Engineering Technologist	Increased responsibilities	-
-	Engineering Technologist	New position	+1
-	Manager, CDM	New position for CDM	+1
-	CDM Program Administrator	New position for CDM	+1
Corporate Services Assistant	-	Position eliminated	-1
Customer Service Rep/ Purchaser	-	Position eliminated	-1
2 Apprentice Journeymen Linemen and 1 Ground Person	Replaced by a Journeyman Lineman	Net 2 positions eliminated	-2
		Total	-1

b) There were no reductions in staff accompanying the elimination of streetlight maintenance services in 2012. The street light maintenance contract represented 424 labour hours in 2011 and 515 labour hours in 2012, the last two years of streetlight maintenance by NOTL Hydro, or approximately 1/4 of a Lineperson. NOTL Hydro generally constructs all of our overhead capital rebuild in-house. The aforementioned labour hours were primarily reassigned to complete overhead capital projects in an efficient manner. The alternative (terminating a lineman) would have meant a reduction in line personnel to 3 (and from two crews to one crew) which would adversely affect our ability to operate effectively and efficiently, most notably during storm restoration and vacation coverage. Further, near the end of the contract period, the street light maintenance activities became more of a burden on scheduling labour rather than a gap filling measure of time management utilized in earlier years.

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?

[No interrogatory]

5. Public Policy Responsiveness

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

5.1-VECC-21

Reference: Exhibit 1, Tab 5, Schedule 15, pg. 1

a) Please confirm that the composition of the Board of Directors is in compliance with section 2.1.2 of the Affiliate Relationship Code (i.e. "A utility shall ensure that at least one-third of its Board of Directors is independent from any affiliate").

Response to 5.1-VECC-21

a) NOTL Hydro confirms that the composition of the Board of Directors is in compliance with section 2.1.2 of the Affiliate Relationship Code (i.e. "A utility shall ensure that at least one-third of its Board of Directors is independent from any affiliate"). Two of the current four Board members are independent, namely Jim Ryan (Chair) and Jim Huntingdon[2].

[2] With reference to the Corporate Entities Relationships chart on Page 2 of Exhibit 1, Tab 5, Schedule 14, Jim Huntingdon (retired) has replaced Mike Galloway on the Boards of NOTL Energy Inc. and NOTL Hydro Inc., effective January 20, 2014. Mike Galloway is President of NOTL Hydro Inc. effective January 2, 2014, as reported to the OEB Secretary by letter on December 13, 2013.

6. Financial Performance

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

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

[No interrogatory]

7. Revenue Requirement

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

7.1-VECC-22

Reference: Exhibit 2, Tab 3, Schedule 2, page 11

b) Please explain the $16,000 increase in Specific Service Charges revenue as between 2011 and 2012 and why similar annual increases are not expected for 2013 and 2014.

Response to 7.1-VECC-22

b) As there is no page 11 in Exhibit 2, Tab 3, Schedule 2, NOTL Hydro is responding to the question with reference to the following Table 3.3.11 from page 1 of Exhibit 3, Tab 3 Schedule 2.

Table 3.3.11: Summary of Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual*	2012 Actual*	Bridge Year* 2013	Test Year 2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4080 (part) and 4086	SSS Administration Revenue	$ 27,935	$ 21,383	$ 22,984	$ 23,919	$ 24,896	$ 25,483
4082	Retail Services Revenues	$ 8,531	$ 8,415	$ 7,816	$ 6,432	$ 8,017	$ 8,017
4084	Service Transaction Requests Revenues	$ 107	$ 194	$ 153	$ 67	$ 161	$ 161
4210	Rent from Electric Property	$ 70,070	$ 75,137	$ 75,070	$ 76,635	$ 79,100	$ 79,100
4225	Late Payment Charges	$ 43,050	$ 41,139	$ 48,275	$ 44,532	$ 38,000	$ 38,000
4235	Specific Service Charges	$ 47,754	$ 41,414	$ 47,203	$ 63,564	$ 57,000	$ 58,300
4305	Regulatory Debits	$ -	$ -	$ -	$ -	-$ 673,255	$ -
4324	Special Purpose Charge Recovery	$ -	$ 42,302	$ -	$ 0	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ 80,148	$ 49,533	$ 48,547	$ 52,664	$ 49,800	$ 49,800
4340	Profits & Losses from Fin. Instr. Hedges	$ 139,606	$ 8,170	-$ 65,871	$ 116,201	$ -	$ -
4355	Gain on Disposition of Property	$ 9,451	$ 6,064	$ 53,966	$ 49,000	$ -	$ -
4360	Loss on Disposition of Property	-$ 12,744	$ -	$ -	-$ 33,473	-$ 30,000	-$ 30,000
4375	Revenues from Non-Utility Operations	$ 219,129	$ 321,075	$ 361,059	$ 359,244	$ -	$ -
4380	Expenses from Non-Utility Operations	-$ 269,597	-$ 302,003	-$ 364,732	-$ 291,177	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ 21,249	$ 66,166	$ 20,267	$ 4,626	$ 7,402	$ 6,900
4405	Interest and Dividend Income	$ 26,351	$ 42,921	$ 168,707	-$ 55,981	$ 15,566	$ 7,000
Specific Service Charges		$ 47,754	$ 41,414	$ 47,203	$ 63,564	$ 57,000	$ 58,300
Late Payment Charges		$ 43,050	$ 41,139	$ 48,275	$ 44,532	$ 38,000	$ 38,000
Other Operating Revenues		$ 106,643	$ 105,729	$ 106,022	$ 107,073	$ 112,164	$ 112,751
Other Income or Deductions		$ 213,793	$ 254,251	$ 221,954	$ 203,105	-$ 630,490	$ 33,700
Total		$ 411,240	$ 442,533	$ 423,455	$ 418,273	-$ 423,325	$ 242,751

To facilitate the response, the following Table is provided, showing the individual charges included in account 4235 - Specific Service Charges. Please note that the 2013 amounts in the Table below have been updated to the 2013 actuals (unaudited). Please also note that following a review of these actuals, NOTL Hydro's best estimate of the total forecast

for account 4235 has been updated from $58,300 to $76,330. This change is reflected in the updated RRWF in response to 7.7-Staff-18.

4235 - Specific Service Charges Sub-account*	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual (unaudited)	2014 Test (Reforecast)	Type of Charge
1000	$ -	$ 147	$ 1,260	$ 3,911	$ 5,176	$ 5,300	microFIT Charge
1511	$ -	$ (30)	$ -	$ -	$ -	$ -	Misc. Revenue - Change of Occupancy
1515	$ -	$ 45	$ -	$ 45	$ -	$ 45	Misc. Revenue - Account History
1518	$ 1,043	$ 158	$ -	$ 1,936	$ 15,475	$ 2,000	Misc. Revenue - Stale Dated Cheques
1520	$ 393	$ 1,911	$ 393	$ 378	$ 1,793	$ 1,500	Misc. Revenue - Suppliers Discounts
1527	$ 3,600	$ -	$ -	$ -	$ -	$ -	Room Rental P.O.P. Site
2000	$ -	$ -	$ -	$ -	$ 414	$ 2,100	FIT Charge
2001	$ 410	$ 526	$ 465	$ 479	$ 495	$ 485	Arrears Certificate
2002	$ 120	$ 90	$ -	$ 75	$ -	$ 70	Statement of Account
2004	$ -	$ 30	$ -	$ -	$ -	$ -	Duplicate invoice for previous bill
2005	$ -	$ -	$ -	$ -	$ 15	$ -	Request for other billing information
2006	$ -	$ 45	$ 150	$ -	$ 17	$ 50	Easement Letter
2007	$ 60	$ 120	$ 195	$ 300	$ 255	$ 180	Account History
2008	$ 585	$ 840	$ 975	$ 960	$ 750	$ 825	Credit Reference / Credit Check
2009	$ 2,520	$ 1,770	$ 1,125	$ 1,125	$ 855	$ 1,000	Returned Cheque Charge & Bank Charge
2010	$ -	$ 15	$ -	$ -	$ -	$ -	Charge to certify cheque
2011	$ 17,063	$ 22,632	$ 22,530	$ 24,180	$ 25,440	$ 25,600	Account Setup Charge / Occupancy Change Charge
3001	$ 19,530	$ 12,720	$ 15,150	$ 23,070	$ 42,060	$ 32,500	Collection of Account - no disconnect
3002	$ 1,875	$ 390	$ 4,525	$ 6,170	$ 4,640	$ 4,000	Disconnection/Reconnection at Meter
3003	$ 555	$ -	$ -	$ 185	$ 555	$ 325	Disconnection/Reconnection at Meter After Hours
3004	$ -	$ -	$ 370	$ 555	$ 370	$ 350	Disconnection/Reconnection at Pole
4003	$ -	$ -	$ 65	$ 195	$ -	$ -	Install / Remove LCD - Regular Hours
Totals	$ 47,754	$ 41,409	$ 47,203	$ 63,564	$ 98,309	$ 76,330	

[* Sub-account # as used by NOTL Hydro]

Following are explanations of the larger components of the increase from 2011 to 2012 and comments on the forecast for 2014:

1000 – microFIT Charge (an increase of $2,651[3])

The increase in the microFIT charge revenue is based on the timeliness of the OPA's approval of applications. Growth is limited as an increase in demand for electricity is required before more microFITs may be connected to the system. With one transformer station at capacity for generation and the second quickly approaching capacity, after reviewing actuals from 2013, NOTL Hydro is expecting a lower growth rate for the microFIT charge in 2014, due to a reduced number of additional connections.

1518 - Miscellaneous Revenue - Stale Dated Cheques (an increase of $1,936)

The amount of stale dated cheques is largely out of the control of NOTL Hydro. NOTL Hydro attempts to contact the receiver of these funds by mail, by phone and by email where possible. Should the payee contact NOTL Hydro these funds will be immediately disbursed to them.

With regard to the actuals from 2013, we noted that more than 80% of this amount is a single cheque due to be returned to a contractor. The payment was sent to the contractor

[3] Increases/decreases in brackets refer to the change from 2011 to 2012

by mail but was returned to our offices. We then called the contractor phone number, searched online, and exhausted all of our contact options in trying to contact the contractor.

The forecast for 2014 represents a normal expected amount, excluding the unusual one-time amount seen in 2013.

2011 – Account Setup Charge/Occupancy Change Charge (an increase of $1,650)
This increase is reflected by a modest increase in of new properties built in the NOTL Hydro area and thus we expect a small increase year over year.

3001 – Collection of Account (no disconnect) (an increase of $7,920)
In 2012, NOTL Hydro increased its diligence regarding the collection procedures stated in the DSC by the OEB. This effort resulted in an increase in revenue. Reviewing the actuals from 2013 indicated a further increase in these revenues due to continued diligence. For 2014, we anticipate a reduction in revenue as we encouraged payment solutions including preauthorized payment and e-billing in an effort to reduce account delinquency. Our revenue in January 2014 is substantially less that our revenue in January 2013, as are our delinquent accounts, which is an indication of success in these efforts

3002 – Disconnection/Reconnection at Meter (an increase of $1,645)

In 2012, NOTL Hydro experienced an increase in Disconnection/Reconnection at Meter which may be contributed to the increased diligence taken on the Collection of Account (no disconnect) mentioned above. In 2013, with a similar diligence, NOTL Hydro experienced a reduction in the revenue from Disconnection/Reconnection at Meter and forecasts a slight reduction in revenue in 2014.

7.2 Are the proposed levels of depreciation/amortization expense appropriately reflective of the useful lives of the assets and the Board`s accounting policies?

7.3 Are the proposed levels of taxes appropriate?

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

7.4-VECC-23

Reference: Exhibit 1, Appendix 1C

a) The 2011 audited financial statements (pg. 8) show that balances due from the affiliate Energy Services Niagara carried an interest rate of prime plus 0.15%. In 2012 it indicates these balances do not attract any interest. Please explain the change in policy.
b) The balance for Energy Services Niagara is significantly lower than in past years. Please explain why.
c) Please provide the 2013 balances for both affiliates (i.e. including NOTL Energy Inc.
d) Why does NOTL not charge interest at the Board approved long or short term rate to these affiliates?

Response to 7.4-VECC-23

a) At the end of 2011, Energy Services Niagara Inc. ("ESNI") still had outstanding advances of funds from NOTL Hydro for water heater purchases by ESNI for ESNI's water heater rental business, at an interest rate of prime plus 0.15% and in an approximate amount of $586,000. In 2012, ESNI paid off these advances in full. Hence there was no balance of advances for water heater purchases to attract interest. There was no change in policy.

   The remaining net debit balance of $25,902 in 2012 was related to accounts payable by ESNI to NOTL Hydro for services provided by NOTL Hydro not related to ESNI's water heater business, such as water billing. Most of this amount was paid off in January 2013. NOTL Hydro does not charge interest on accounts payable that are not overdue.

b) The balance is lower because the advances referred to in a) were paid off.

c) The 2013 (unaudited) balance for accounts payable by ESNI is a debit balance of $807. The 2013 (unaudited) balance for amounts due from NOTL Energy Inc. is a debit balance of $7,823.

d) NOTL Hydro charged ESNI advances at the same interest rate (prime plus 0.15%) as its bank, CIBC, charges NOTL Hydro for loans under its demand operating credit line. NOTL Hydro believes this approach is consistent with Section 2.4.2 of the Affiliate Relationships Code.

e)

7.4-VECC-24

Reference: Exhibit 1, Tab 5 / Exhibit 4, Tab 2, Schedule 3, pg. 1-4

a) Since there is no cost to using the more accurate allocation findings of KPMG why are these not being applied?

Response to 7.4-VECC-24

Based on the experience of NOTL Hydro staff in applying the allocation methodology used in the KPMG findings, it was found that the process was much more onerous in terms of staff time than the efficient methodology currently in use. Because of the very small difference in the results, the current methodology is felt to be quite adequate and is being maintained.

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

7.5-VECC-25

Reference: Exhibit 5, Tab 1, Schedule 1

a) What are the terms/ penalty for pre-payment of the CIBC loans?

Response to 7.5-VECC-25

a) To assist in preparing the response, NOTL Hydro has obtained the following background explanation from CIBC regarding the two CIBC swap loans:

> *"NOTL Hydro's 2 loans with CIBC have the underlying interest rate fixed by way of interest rate swap.*
>
> *Assuming that you [NOTL Hydro] did not embed any prepayment optionality in the interest rate swap, loans where the underlying interest rate is fixed by way of an interest rate swap, can be prepaid with a make-whole payment, which would be either a payment made by the NOTL or a payment received by NOTL, depending on prevailing interest rates at the time.*
>
> *A swap maintains a market value throughout its life which reflects the size of the transaction, the term left to maturity, and the interest rate differential between the swap rate agreed to and the prevailing market rate for a swap with terms equal to that of the transaction currently outstanding. In the event of an early termination of the swap transaction, one of two outcomes may occur. In the event that the market rate, at the time of unwind, is lower than the swap rate, a breakage cost (effectively a make-whole premium) would be paid by NOTL to CIBC representing the present value of the interest rate differential. This methodology mirrors the impact of unwinding any other fixed-rate fixed-term loan. However, if the prevailing rate at the time of unwind is higher than the swap rate originally agreed to, the transaction is considered in-the-money, and NOTL would be entitled to a payment from CIBC representing the present value of this interest rate differential. "*

On this basis, CIBC has provided the following current estimates of the breakage costs (unwind costs):

- $105,500 on the swap to finance the construction of a new transformer station
- $137,100 on the swap to finance the purchase of a transformer station from Hydro One

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

7.6-VECC-26

Reference: Exhibit 3, Tab 3, Schedule 2, page 11

a) Please explain the $16,000 increase in Specific Service Charges revenue as between 2011 and 2012 and why similar annual increases are not expected for 2013 and 2014.

Response to 7.6-VECC-26

[There is no page 11 in the reference cited. As this question appears to be the same as 7.1-VECC-22 please refer to the response VECC-22.]

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-VECC-27

Reference: Exhibit 1, Appendix 1F, pg. 7 (IFRS Policy/ Exhibit 4, Tab 3, Schedule 1, pg. 1

a) Table 1 (page 7) of the IFRS policy shows the proposed and new useful life for various plant components. Please modify this table to show the Kinectrics Study proposed life ranges. For assets components which vary please explain why (if not already explained in the Policy document).
b) Please estimate the revenue requirement difference if NOTL had used only the Kinectrics Study proposed values (i.e. the materiality of the difference in useful life that is being proposed by NOTL vs that in the Kinectrics study. [An estimate value is sufficient as this interrogatory is to understand the materiality of any departure from the Board sponsored study].

Response to 7.7-VECC-27

a) Table 1 is modified as requested in the Table below.

The references to Kinetrics lives, Tables and line #s are taken from the application appendices, specifically "Appendix-2BB – Service Life Comparison"[4].

[4] Please note that in preparing this response, it was found that when transferring the NOTL IFRS Policy on components and depreciation into Appendix 2-BB, USoA 1845 had been inadvertently keyed into F-1 row 27 and should have been into row 29; USoA 1955 had been inadvertently keyed into F-2 row 8-Towers and should have been into F-2 row 8 Wireless.

Component	Previous Component	Proposed Useful Life	Existing Useful Life	Kinetrics			Kinetrics Report Reference	
				MIN UL	TUL	MAX UL	Table	Line #
Poles	1830 -	45	25	35	45	75	F1	1- Overall
OH Conductors and Switches	1835 -	60	25	50	60	75	F1	8
Transformers (UG and OH)	1850 -	45	25	30	40	60	F1	9,34
Transformers (Substation)	1815-1051 (York) and 1815-1052 (NOTL DS)	45	30	30	45	60	F1	12- Overall
Station Switch, Breakers, Bus-bars	1815-1051 (York) and 1815-1052 (NOTL DS)	55	40	30	50	60	F1	18
DS Station	1820 -	1 year [i.e. 2013]	25	n/a	n/a	n/a	n/a	n/a
UG Conductors and Devices	1845 -	45	25	35	40	55	F1	29,39
UG Conduit	1840 -	65	25	30	50	85	F1	40,41
UG Services	1855-1135 -	45	25	35	40	60	F1	32
OH Services	1855-1130 -	60	25	50	60	75	F1	8
SCADA	1980 -	10	15	15	20	30	F1	43
Office Equipment	1915 -	10	10	5-15			F2	1
Trucks (<3 tonnes)	1930 -7102 -	5	5	5-10			F2	2- Vans
Trucks (>3 tonnes)	1930 -7103 -	10	8	5-15			F2	2-Trucks & Buckets
Trailers	1930-7104 -	15	5	5-20			F2	2- Trailers
Administrative Buildings	1908-1030	60	50	50-75			F2	3
PCB Shed	1908-1031	30	30	50-75			F2	3
Computer Hardware	1920 -	3	5	2-5			F2	6- Hardware
Computer Software	1925 -	3	3	2-5			F2	6- Software
Communication equipment	1955 -	10	10	2-10			F2	8- Wireless
Miscellaneous Tools	1940 -	8	10	5-10			F2	7- Tools
Stores and Warehouse equipment	1935 -	10	10	5-10			F2	7- Stores
Stranded Meters	1860 -	25	25	n/a			n/a	n/a
Other Meters	1860 -	25	25	15-35			F2	9,10,11
CT/PT	1860 -	40	25	35-50			F2	12
Smart Meters	1860 -	15	N/A	5-15			F2	13
Smart Metering – Data Collectors	1860 -	15	N/A	15-20			F2	15

The Table above shows that only SCADA and the PCB shed (highlighted in yellow) are outside the Kinetrics range of useful lives.

The SCADA variance is explained in the policy document.

The PCB shed is a small concrete shed, approx.10ft by 10ft., original cost less than $9,000. While not specifically mentioned in the policy document, this asset's life was assessed in the development of the policy. It was felt that the Kinetrics report's life range of 50-75 years for "administrative buildings" would be an over-estimate of the longevity of this shed and that the existing useful life of 30 years was more realistic.

b) For the estimate of the revenue requirement difference if NOTL had used the Kinetrics Study proposed values, the NOTL useful lives were moved to the "nearest point" in the Kinetrics range as follows:

- SCADA moved from 10 to 15 years
- PCB shed moved from 30 to 50 years.

The first step in the estimation was to calculate the change in depreciation expense by using the known net book value as of December 31, 2012 of the year-by-year capital additions, applying the respective NOTL or VECC 27 lives to determine the remaining lives and calculating the depreciation accordingly. There are no capital additions for SCADA and the PCB shed in 2013 or 2014. There have been no capital additions for the PCB shed since it was acquired in 1988. The SCADA was acquired in 1996 and there were some capital additions in most years until 2011. On this basis, the depreciation values shown are for all capital additions up to 2011 but none occurred thereafter. The result is shown in the Table below.

Changes in Depreciation	PCB Shed		SCADA		Total Change in Depreciation = VECC27 - NOTL
	NOTL	VECC27	NOTL	VECC27	
Life (years)	30	50	10	15	
Depreciation 2013	$ 357	$ 66	$ 51,595	$ 15,735	$ (36,151)
Depreciation 2014	$ 357	$ 66	$ 31,797	$ 15,735	$ (16,352)

The decreases in 2013 and 2014 depreciation increase the fixed assets balances for 2013, 2014 and the average 2014 balance. This increase results in an increase in regulated return on capital of $2,779 as follows:

RATE BASE CALCULATION FOR 2014		
	Application	**Change**
Fixed Assets Opening Balance 2014	$ 22,097,123	$ 36,151
Fixed Assets Closing Balance 2014	$ 22,330,750	$ 52,503
Average Fixed Asset Balance for 2014	**$ 22,213,936**	**$ 44,327**
Working Capital Allowance	$ 2,781,742	$ -
Rate Base	**$ 24,995,678**	**$ 44,327**
Regulated Rate of Return	6.27%	6.27%
Regulated Return on Capital	**$ 1,567,217**	**$ 2,779**

The changes in 2014 depreciation and regulated return decrease the revenue requirement by approx. $14,000, below the materiality threshold of $50,000, as follows:

Service Revenue Requirement for 2014

	Application	Change
OM&A Expenses	$ 2,259,303	$ -
Amortization Expenses	$ 929,588	$ (16,352)
Total Distribution Expenses	**$ 3,188,891**	**$ (16,352)**
Regulated Return On Capital	$ 1,567,217	$ 2,779
PILs	$ 32,607	$ (93.06) *
Service Revenue Requirement	**$ 4,788,716**	**$ (13,666)**

** PILS change assumed in same ratio to expenses + return as in application*

8. Load Forecast, Cost Allocation and Rate Design

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

8.1-VECC-28

Reference: Exhibit 3, Tab 2, Schedule 1, page 8
Load Forecast Excel Model, DATA-GDP Qrtly Tab
Load Forecast Excel Model, DATA-GDP Annual Tab
2013 Ontario Budget -
http://www.fin.gov.on.ca/en/budget/fallstatement/2013/chapter2.html

a) Please explain why the annual GDP growth rates for 2012-2014 shown in cells W2 through Y2 do not match the growth rates in the 2013 Ontario Budget.

b) Please provide a version of the Load Forecast Excel Model with where all rows and columns are fully accessible and parties can view how the monthly GDP values were determined (e.g. In the GDP Annual Tab columns A and B which provide the basis for the monthly GDP values are not currently accessible).

c) Please confirm that in creating the CDM variable for purposes of the regression analysis NOTL did not apply the ½ year rule to the first year's savings attributed to CDM programs.

d) If not confirmed, please indicate where in the Load Forecast Excel Model this ½ year adjust to the first year's savings was made.

e) If confirmed, please revise the CDM variable accordingly and re-estimate the power purchase equation using this revised CDM variable. Please provide the resulting equation and the regression results similar to those shown in Table 3.2.6. Please also provide the resulting forecast for 2014.

Response to 8.1-VECC-28

a) NOTL Hydro infers that this question refers to the DATA-GDP Qrtly Sheet, cells W3 through Y3 (not cells W2 through Y2). This sheet was constructed internally, early in the development of the application, before the 2013 Budget was announced, and therefore using 2012 sources as indicated in cell B3. The objective was to derive monthly values from the quarterly values. The Load

Forecast model with rows unhidden to show how this derivation was constructed is provided. However, we were not confident that this approach was reliable and the approach was subsequently abandoned.

The monthly GDP data ultimately used in the application was later provided to us by our rate consultant, using the 2013 Budget information. The Excel model provided by the consultant is included with these responses (NOTL_Monthly GDP_VECC 28a.xlsx). The monthly GDP data used in the application is found in the DATA-GDP Annual Sheet.

b) A version of the Load Forecast Model with all rows and columns unhidden is provided (NOTL_Load Forecast - 2014_accessible.xlsx).

c) NOTL Hydro confirms that in creating the CDM variable for purposes of the regression analysis NOTL did not apply the ½ year rule to the first year's savings attributed to CDM programs.

d) N/A

e) The CDM variable was revised as per the Table below:

NOTL Hydro as submitted in application

MWh Savings by Program Year	Source	2006	2007	2008	2009	2010	2011	2012	2013	2014
2006 Programs	OPA report	598	598	598	598	104	104	95	95	89
2007 Programs	OPA report	-	410	311	298	298	298	290	290	290
2008 Programs	OPA report	-	-	764	489	489	489	461	461	432
2009 Programs	OPA report	-	-	-	670	551	551	551	538	492
2010 Programs	OPA report	-	-	-	-	669	459	458	458	429
2011 Programs	Load Forecast	-	-	-	-	-	1,023	1,023	998	829
2012 Programs	Load Forecast	-	-	-	-	-	-	879	879	870
Total		598	1,008	1,672	2,056	2,111	2,924	3,756	3,717	3,430

The above is consistent with the values from the Load Forecast in tab DATA-CDM, cells F24 to F32 of the original load forceast model

Half Year Rule for CDM Variable as requested by VECC

MWh Savings by Program Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
2006 Programs	299	598	598	598	104	104	95	95	89
2007 Programs	-	205	311	298	298	298	290	290	290
2008 Programs	-	-	382	489	489	489	461	461	432
2009 Programs	-	-	-	335	551	551	551	538	492
2010 Programs	-	-	-	-	334	459	458	458	429
2011 Programs	-	-	-	-	-	511	1,023	998	829
2012 Programs	-	-	-	-	-	-	439	879	870
Total	299	803	1,290	1,721	1,777	2,413	3,317	3,717	3,430

To prepare the load forecast assuming the half year rule on the CDM variable the above numbers were entered in tab DATA-CDM, cells F24 to F32

The resulting equation, regression results and 2014 forecast are provided below. The full load forecast Excel model with the revised CDM data is also provided (NOTL_Load Forecast - 2014_VECC 28e.xlsx).

Load Forecast Model with revised CDM data:

NOTL Hydro's Monthly Predicted Kwh Purchases
= Heating Degree Days * 3,677
+ Cooling Degree Days * 32,915
+ Ontario Real GDP Monthly % * 103,379
+ Spring Flag * (908,652)
+ Summer tourist season flag * 593,330
+ CDM Activity * (2.51)
+ Days in month * 485,836
= Intercept of (15,296,200)

Statistic	Value
R Square	97%
Adjusted R Square	97%
Mean Absolute Percent Error	2.31%
F Test	821
T-stats by Coefficient	
Heating Degree Days	19.3
Cooling Degree Days	30.9
Ontario Real GDP Monthly %	39.5
Spring Flag	(11.7)
Summer Tourist Flag	4.9
CDM Activity	(5.4)
Days in Month	12.3
Intercept	(12.4)

	Predicted Purchases (kWh)
Jan-14	16,398,305
Feb-14	14,684,531
Mar-14	15,086,642
Apr-14	13,997,808
May-14	14,226,704
Jun-14	15,798,741
Jul-14	19,273,360
Aug-14	19,134,198
Sep-14	16,206,666
Oct-14	15,285,894
Nov-14	15,304,288
Dec-14	16,492,180
Total 2014	191,889,316

8.1-VECC-29

Reference: Exhibit 3, Tab 2, Schedule 1, page 9

a) Please provide copies of the OPA's final CDM reports for NOTL for 2011 and 2012.

b) Please provide any 2013 OPA CDM reports for NOTL that are available.

Response to 8.1-VECC-29

a) and b)
The requested reports are provided in the format (Excel or pdf) as received from the OPA.

8.1-VECC-30

Reference: Exhibit 3, Tab 2, Schedule 1, page 13-15

a) Please provide a table setting out, by customer class, the 2012 and 2013 year end customer counts.

Response to 8.1-VECC-30

The Table below shows the requested counts. For actuals up to 2012, the counts were *provided in Table 3.2.8 in Exhibit 3, Tab 2, Schedule 1. The 2013 forecast was provided* in Table 3.2.10. The 2013 actuals as recently obtained are also shown below.

Table 3.2.8: Historical Customer/Connection Data							
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Total**
Number of Customers/Connections							
2002	5,507	1,234	89	1,483	110	24	8,447
2003	5,661	1,230	95	1,591	108	24	8,709
2004	5,902	1,227	98	1,611	105	24	8,967
2005	6,124	1,210	108	1,658	80	24	9,204
2006	6,276	1,209	117	1,736	77	24	9,439
2007	6,424	1,216	115	1,796	76	23	9,650
2008	6,436	1,225	115	1,904	71	22	9,773
2009	6,507	1,230	121	1,915		22	9,795
2010	6,537	1,225	121	1,920		20	9,823
2011	6,666	1,253	118	1,946		22	10,005
2012	6,818	1,252	117	1,949		22	10,158
Table 3.2.10: Customer/Connection Forecast							
2013 Forecast	6,965	1,254	120	2,003		22	10,364
Actual 2013 Customer/Connection Data							
2013 Actual	7,003	1,251	122	2,012		21	10,409

8.1-VECC-31

Reference: Exhibit 3, Tab 2, Schedule 1, pages 19-20

a) Since the current regression model already includes all of the 2012 savings from 2012 CDM programs, why is it necessary to adjust the 2013 and 2014 forecasts for ½ of the 2012 program savings?

Response to 8.1-VECC-31

a) In the year new CDM programs are initiated, it is assumed the new programs are implemented evenly over the year, which results in only one half of the full year impact of the new programs occurring in the first year of the programs. In the load forecast, 2012 is the last year in which actual data is used as a basis to develop the load forecast. Thus, for the 2012 CDM programs, only one half of the full year savings from these programs is included in the 2012 actual purchased power data. As a result, to properly adjust the 2013 and 2014 forecast of purchased power for CDM savings, that have not already occurred in the actual savings, an additional one half of the full year savings from 2012 programs needs to be included since these savings are not recognized in the 2012 actual purchased power data.

8.1-VECC-32

Reference: Exhibit 3, Tab 2, Schedule 1, pages 20-21

a) Please confirm that the LRAM adjustment will be calculated by comparing the actual reported savings in 2014 from 2011-2014 CDM programs by customer class with the values shown in Table 3.2.17.

b) Please also confirm that, unless there are future adjustments made by the OPA to the reported persistence of savings in 2014 from 2011 and 212 programs the reported savings for 2011 and 2012 will equal the savings used to establish the LRAM variance account values.

Response to 8.1-VECC-32

a) NOTL Hydro confirms that the LRAM adjustment will be calculated by comparing the actual reported savings in 2014 from 2011-2014 CDM programs by customer class with the values shown in Table 3.2.17.

b) NOTL Hydro also confirms that, unless there are future adjustments made by the OPA to the reported persistence of savings in 2014 from 2011 and 2012 programs the reported savings for 2011 and 2012 programs will equal the savings used to establish the LRAM variance account values.

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

8.2-VECC-33

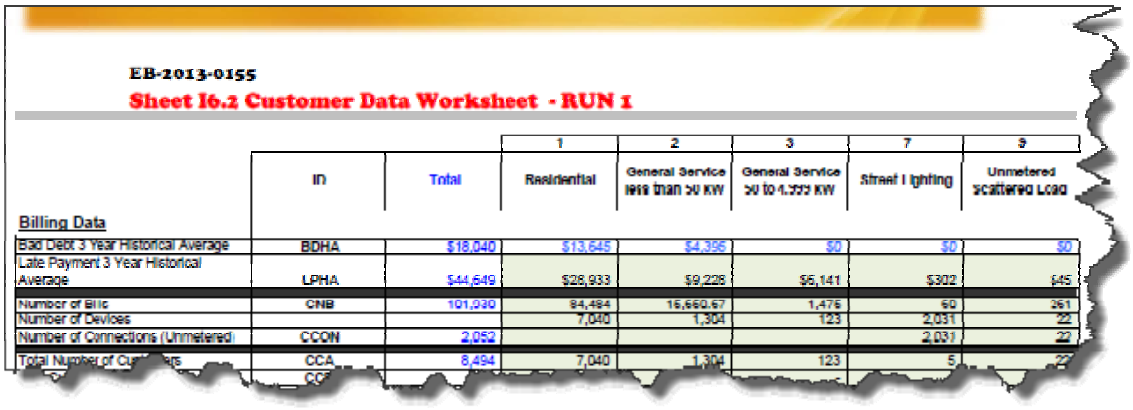
Reference: Exhibit 3, Tab 2, Schedule 1, page 23 /Cost Allocation Excel Model, Tab I6.2 (Customer Data)

a) Please explain why the customer counts reported in Table 3.2.22 don't match those used in the Cost Allocation model.

b) If required, please provide a revised/corrected version of the Cost Allocation Excel Model.

Response to 8.1-VECC-33

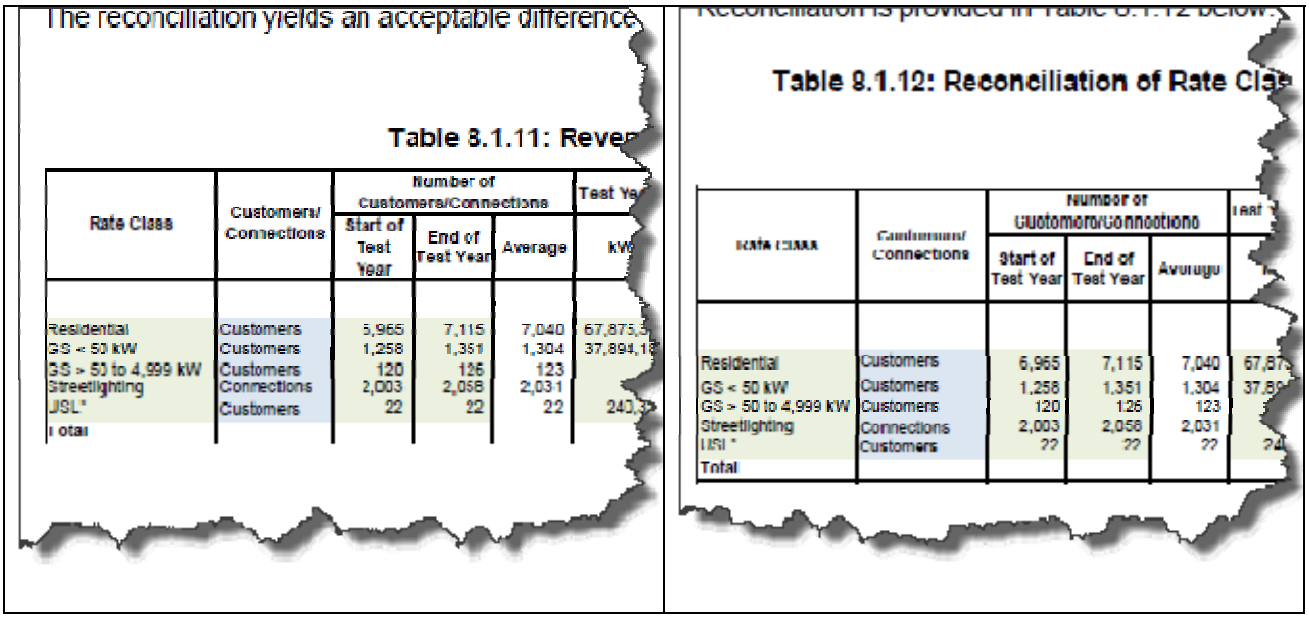
a) The customer counts in Table 3.2.22 are year-end (December 31) actuals or forecasts. Using the 2013 and 2014 year-end forecasts, the average counts for 2014 were calculated. The 2014 averages were considered to be more appropriate than the 2014 year-end values for the purposes of Cost Allocation and for the revenue calculations in Exhibit 8. Portions of the cost allocation model Sheet I6.2 and the Exhibit 8 Tables 8.1.11 and 8.1.12 are provided below to show the use of the averages:



EB-2013-0155

Sheet I6.2 Customer Data Worksheet - RUN 1

			1	2	3	7	9
Billing Data	IR	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered scattered Load
Bad Debt 3 Year Historical Average	BDHA	$18,040	$13,645	$4,395	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$44,649	$28,933	$9,228	$5,141	$302	$45
Number of Bills	CNB	101,930	84,484	15,660.67	1,476	60	361
Number of Devices			7,040	1,304	123	2,031	22
Number of Connections (Unmetered)	CCON	2,052				2,031	22
Total Number of Customers	CCA	8,494	7,040	1,304	123	5	22
	CCI						



The reconciliation yields an acceptable difference

Table 8.1.11: Reve

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Ye
		Start of Test Year	End of Test Year	Average	kW
Residential	Customers	6,965	7,115	7,040	67,875,3
GS < 50 kW	Customers	1,258	1,351	1,304	37,894,1
GS > 50 to 4,999 kW	Customers	120	126	123	
Streetlighting	Connections	2,003	2,056	2,031	
USL*	Customers	22	22	22	240,3
Total					

Table 8.1.12: Reconciliation of Rate Cla

Rate Class	Customers/ Connections	Number of Customers/Connections			Test
		Start of Test Year	End of Test Year	Average	
Residential	Customers	6,965	7,115	7,040	67,87
GS < 50 kW	Customers	1,258	1,351	1,304	37,89
GS > 50 to 4,999 kW	Customers	120	126	123	
Streetlighting	Connections	2,003	2,056	2,031	
USL*	Customers	??	??	??	24
Total					

b) No revision or correction is required.

8.2-VECC-34

Reference: Exhibit 7, Tab 1, Schedule 1, page 3

a) Please indicate for which customer classes NOTL receives a capital contribution but owns the service assets.

b) For these classes is NOTL responsible for the maintenance and repair of service assets?

c) If yes, please confirm that the use of "zero" weighting factor means that the associated customer classes will not be allocated any O&M costs associated with service assets.

Response to 8.2-VECC-34

a) Residential customers are not required to contribute to a Basic Service (overhead cable up to 200 amps, maximum 30m) as per our Conditions of Service 2.4.1. while NOTL Hydro maintains those specific service assets in perpetuity. In the event that Residential customers are required or chose to have an underground supply installed, they contribute the difference in cost from the basic service. NOTL Hydro maintains those specific service assets in perpetuity.

NOTL Hydro will install a Basic Service (overhead cable up to 200 amps) for Unmetered Scattered Load, General Service <50 kW and >50 kW customers, however the customer must contribute 100% of the actual cost to provide that service. NOTL Hydro will maintain the basic service in perpetuity. All other services (beyond a basic service) are installed and maintained by the customer.

Street Light services are exclusively installed and maintained by the owner at the owners' costs.

b) NOTL Hydro maintains all non-private Residential service assets in perpetuity. We do not maintain/repair service assets for our other rate classes.

c) NOTL Hydro confirms that that the use of "zero" weighting factor means that the associated customer classes will not be allocated any O&M costs associated with service assets.

8.2-VECC-35

Reference: Exhibit 7, Tab 1, Schedule 1, page 6

a) Please provide the derivation of the smart meter costs set out in Table 7.1.5.

Response to 8.2-VECC-35

a) Table 7.1.5 is as follows:

Table 7.1.5 Meter Capital Installation Costs	
Meter Type	Installation Cost per Meter
Smart Meter – 2S	$236
Smart Meter – 3S	$290
Smart Meter – 12S Network	$297
Other Smart Meter – GS<50kW	$635
GS>50kW (GPRS)	$1,350
Add AMRC costs per Res and GS<50kW	$27

The Table below, an expansion of Table7.1.5, provides the derivation:

Meter Capital Installation Costs			
Meter Type	Purchase Price	Installation Cost (1 hour, 2 employees and truck)	Total Installation Cost per Meter
Smart Meter – 2S	$86	$150	$236
Smart Meter – 3S	$140	$150	$290
Smart Meter – 12S Network	$147	$150	$297
Other Smart Meter – GS<50kW	$485	$150	$635
GS>50kW (GPRS)	$840 + Antenna $120	$350	$1,350
Add AMRC costs per Res and GS<50kW	$27	-	$27

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

8.3-VECC-36

Reference: Exhibit 8, Tab 1, Schedule 1, page 2/Exhibit 6, Tab 1, Schedule 1, page 2

a) Please confirm that the revenue at current rates in Table 8.1.3 was calculated using the customer counts from the Cost Allocation model and not from Exhibit 3, Table 3.2.22.

b) Please confirm that the revenues at current rates used Exhibit 6 and the Revenue Requirement Work Form were also based on the customer count forecast per the Cost Allocation model.

c) If required, please provide a revised/corrected version of the Revenue Requirement Work Form.

Response to 8.3-VECC-36

a) NOTL Hydro confirms that the revenue at current rates in Table 8.1.3 was calculated using the customer counts from the Cost Allocation model and not from Exhibit 3, Table 3.2.22. That is, the average of 2013 and 2014 year-end customer counts were used as indicated in the response to VECC-33.

b) NOTL Hydro confirms that the revenues at current rates used in Exhibit 6 and the Revenue Requirement Work Form were also based on the customer count forecast per the Cost Allocation model.

c) No revision or correction is required.

8.4 Are the proposed Total Loss Adjustment Factors appropriate for the distributor's system and a reasonable proxy for the expected losses?

8.4-VECC-37

Reference: Exhibit 8, Tab 1, Schedule 1, page 10

Preamble: At the bottom of the page NOTL notes "the continued reduction in our distribution line loss factor".

a) Given this "continued reduction" why is it appropriate to use a 5-year average loss factor as opposed to say a 3-year average?

Response to 8.4-VECC-37

a) As line losses increase exponentially with the increase in amperage, extreme weather conditions (hot and cold) can adversely drive up the factor. In other words, an extremely hot summer of 2014 could increase the factor well above the recorded 2011 and 2012 TLF values and closer to the 2010 factor. This is even evident in the slight bump up in the factor from 2011 to 2012. While we are confident that our system improvements are driving a long-term downward trend in system losses, we believe that the 5 year average removes more of the annual volatility and smooths out the curve. Our current proposal to reduce the TLF to 1.0379 represents a significant reduction since our last rate rebasing application in 2009 when the TLF was 1.0463.

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

8.5-VECC-38

Reference: Exhibit 8, Tab 1, Schedule 1, page 6

a) Please provide an updated version of the RTSR Work Form using the recently approved 2014 UTRs.

Response to 8.5-VECC-38

a) An updated version of the RTSR Work Form using the recently approved 2014 UTRs is provided[5]. The resulting revised 2014 RTS rates are:

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0072	$ 0.0013
General Service Less Than 50 kW	kWh	$ 0.0066	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 2.6853	$ 0.4602
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.9023	$ 1.1068
Unmetered Scattered Load	kWh	$ 0.0066	$ 0.0013
Street Lighting	kW	$ 2.0249	$ 0.3558

[5] January 9, 2014, EB-2012-0031

8.6 Is the proposed Tariff of Rates and Charges an accurate representation of the application, subject to the Board's findings on the application?

[No interrogatory]

9. Accounting

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

9.1-VECC-39

Reference: Exhibit 9, Tab 2, Schedule 1, pg. 19

a) Were the smart grid projects (Accounts 1534 and 1535) previously approved by the Board? If so please provide the reference decision?
b) If not, why were the projects (capital and OM&A) not included in the normal annual accounting?

Response to 9.1-VECC-39

a) The smart grid projects were not previously approved by the Board.

b) The projects were included in what NOTL Hydro would consider as normal annual accounting, but the accounts used were the variance accounts 1534 and 1535 based on the fit of the projects to the definitions in the Accounting Procedures Handbook as explained in "Frequently Asked Question" Q16 issued December 23, 2010. These accounts were approved by the Board for use by distributors where costs for smart grid initiatives were not included in rates.

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 OEB'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 to 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.

9.1-VECC-40

Reference: Exhibit 9, Tab 2, Schedule 1, pgs. 19-20

a) Please provide a table breaking down the $133,025 being claimed for account 1535 into each of the three components noted on page 20 (demonstration, studies, education) and interest expense.

Response to 9.1-VECC-40

a) The following Table provides the breakdown. All the OM&A was related to the smart grid demonstration capital project recorded in account 1534 and hence is considered to be all in the demonstration projects expense category.

	J	K
51	**Breakdown of 1535 Claim**	
52	OM&A to December 31, 2012	
53	Demonstration projects	$ 84,585
54	Studies and planning exercises	$ -
55	Education and training	$ -
56	Total OM&A	$ 84,585
57	Depreciation to December 31, 2012	$ 44,242
58	Interest to april 30, 2014	$ 4,198
59	Total	$ 133,025

9.2 **Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified, and is the treatment of each of these impacts appropriate?**

[No interrogatory]

End of document