Niagara On-The-Lake HYDRO

November 20, 2018

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Attn: Ms. Kirsten Walli, Board Secretary

Re: EB-2018-0056.

Dear Sirs:

Enclosed please find two copies of Niagara-on-the-Lake Hydro Inc.'s responses to Interrogatories as part of our Cost of Service rate application for rates effective May 1, 2019. A full copy has also been uploaded electronically and distributed to all intervenors.

Yours truly,

Tim Curtis
President

c.c. Jeff Klassen, NOTL Hydro
Jay Shepherd, School Energy Coalition
Mark Rubenstein, School Energy Coalition
Wayne McNally, School Energy Coalition
John Lawford, Vulnerable Energy Consumers Coalition
Mark Garner, Vulnerable Energy Consumers Coalition
Bill Harper, Vulnerable Energy Consumers Coalition

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Rate Application Interrogatories

RESPONSES

2019 Cost of Service Rate Application

Niagara-on-the-Lake Hydro Inc. (NOTL Hydro)

EB-2018-0056

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INTERROGATORY RESPONSES

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Updated Revenue Requirement Work Form (RRWF)

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

RESPONSE

The following updated worksheets are being submitted in Microsoft Excel format with this application.

NOTL Hydro 2019 Rev Reqt Work Form 11202018
NOTL Hydro 2019 Load Forecast Wholesale 11202018
NOTL Hydro 2019 Cost Allocation Model RUN2 11202018
NOTL Hydro 2019 Filing Requirements Chapter2 Appendices 11202018
NOTL Hydro 2019 Filing Requirements Chapter2 Appendix2C 11202018
NOTL Hydro 2019 Test year Income Tax PILs 11202018

The table below provides a summary of the adjustments made in response to these interrogatories.

Reference	Description	Impacts
3-STAFF-36	Updated load forecast tab 10.1 to match CDM impact calculated in tab 10	Reduced load forecast by 477,462 kWh Reduced cost of power by $53,952
2-STAFF-13	Updated Appendix 2-BA for year to date disposals and forecast disposals for the remainder of the year	Reduced rate base by $32,090 Reduced test year depreciation expense $3,799
2-STAFF-13	Moved disposal of the old transformer from 2019 to 2018 as this disposal will be taking place this year	Reduced rate base by $108,896 Reduced test year depreciation expense $7,255
2-STAFF-23	Updated Other Revenue to reflect increase of 100 poles with Bell attachments & reduced OM&A Pole Attachment expense by 100 poles.	Increased Other Revenue $4,363 Decreased OM&A $4,363
4-STAFF-46	Updated Other Revenue for mark-up on shared services to reconcile with amount in Appendix 2-N	Increased Other Revenue $491
4-STAFF-47	Reduced estimate for intervenor costs from $75,000 to $50,000. Original amount was based on 3 intervenors.	Decreased OM&A $5,000
4-STAFF-49	Adjusted PILs model for 2018 and 2019 to move Building and Fixture additions from CCA Class 47 (8%) to CCA Class 1b (6%)	Increased PILs $434
4-STAFF-53	Updated interest rate to the most recent OEB prescribed rate of 2.17%	Increased LRAM claim $319
7-STAFF-57 7-VECC-38	Updated services weighting factors.	Adjusted tab I5.2 of Cost Allocation Model
7-STAFF-58 7-VECC-44	Updated primary and secondary customer base and demand data to reflect customers that own their own transformers	Adjusted tab I8 of Cost Allocation Model
7-STAFF-60	Corrected reversal of entries in RRWF	
n/a	Updated LEAP amount based on revised Service Revenue Requirement	Decreased OM&A $58
n/a	Updated interest rate in DVA continuity for forecasted interest to the most recent OEB prescribed interest rate of 2.17%	Increased DVA claim $181
n/a	Utilized revised DVA schedule as provided by the OEB	12 fold increase in rate riders due to calculation error in the original model used

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Updated Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Tariff Schedule and Bill Impact model for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

RESPONSE

The following updated worksheets are being submitted in Microsoft Excel format with this application.

NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 11202018
NOTL Hydro 2019 DVA Continuity Schedule CoS 11202018
NOTL Hydro 2019 LRAMVA Work Form 3.0 11202018

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Ref: Exhibit 1, Page 12

One of NOTL Hydro's requests, stated on page 12 of Exhibit 1, is for "An Order establishing a new transmission Standby Charge to be applied to customers with behind the meter generation greater than 1MW".

Staff did not find any evidence related to the new transmission Standby Charge in the application.

a) **Please confirm whether or not NOTL Hydro is requesting approval of the establishment of a new transmission Standby Charge.**
   i. **If so, please provide the reference.**

RESPONSE

NOTL Hydro confirms that it is requesting approval of the establishment of a new transmission Standby Charge. The evidence for the new transmission Standby Charge is the same as for the new distribution Standby Charge. NOTL Hydro has now filed Additional Evidence providing details about both requested Standby Charges (see Exhibit 8, Additional Evidence, filed November 2018).

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Ref: Exhibit 1, Pages 88-94

NOTL Hydro provides the 2016 scorecard and its analysis on the 2016 scorecard in pages 88 to 94 of Exhibit 1. Staff notes that 2017 scorecard is available at the end of September 2018.

a. Please provide NOTL Hydro's 2017 scorecard with the scorecard MD&A.

RESPONSE

We have attached screenshots of the OEB created scorecard to after this page. The scorecard can also be downloaded on the OEB website at: https://www.oeb.ca/documents/scorecard/2017/Scorecard%20-%20Niagara-on-the-Lake%20Hydro%20Inc..pdf

Scorecard - Niagara-on-the-Lake Hydro Inc.

9/20/2018

										Target	
Performance Outcomes	**Performance Categories**	**Measures**		**2013**	**2014**	**2015**	**2016**	**2017**	**Trend**	**Industry**	**Distributor**
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		100.00%	98.60%	96.90%	98.90%	98.94%	↓	90.00%	
		Scheduled Appointments Met On Time		99.62%	99.00%	99.70%	99.50%	100.00%	↑	90.00%	
		Telephone Calls Answered On Time		91.70%	85.30%	87.70%	86.20%	87.26%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution		1	1	7	10	15			
		Billing Accuracy			99.77%	99.83%	99.83%	99.85%	↑	98.00%	
		Customer Satisfaction Survey Results		97%	97%	87.00%	87.00	75.9			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness				81.50%	81.50%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.37	0.94	2.02	0.34	0.50	↓		3.54
		Average Number of Times that Power to a Customer is Interrupted [2]		0.15	1.07	1.20	1.03	0.88	↓		1.31
	Asset Management	Distribution System Plan Implementation Progress			99%	89.00%	112.06	110			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$699	$710	$706	$717	$698			
		Total Cost per Km of Line [3]		$18,516	$18,895	$19,106	$19,878	$19,645			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]				22.24%	54.53%	89.87%			11.68 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%				100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.68	0.62	0.92	0.88	0.83			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.57	0.46	0.72	0.69	0.54			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.01%	9.36%	9.36%	9.36%	9.36%			
			Achieved	3.84%	10.85%	8.90%	7.44%	9.81%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: ● target met ● target not met

2017 Scorecard Management Discussion and Analysis ("2017 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2017 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

Niagara-on-the-Lake Hydro manages its operations to provide the best possible service to its customers at a reasonable cost over the long term. This focus on operational excellence will generally result in good benchmarks, however there will be cases where our practices may not align with some of the benchmarks, such as our low debt to equity ratio or additional costs from keeping an office front-counter open to customers.

Customer Focus

Niagara-on-the-Lake Hydro's focus is on serving the customer. We make every effort to make it easy for our customers to engage with us should they wish to. We remain committed to providing our customers with the most reliable service at the least possible cost.

Operational Effectiveness

Safety of the public and our workers is always Niagara-on-the-Lake Hydro's over-riding priority. Niagara-on-the-Lake Hydro has had zero serious electrical incidents over the past years and is gratified to have won a prestigious safety award, the Infrastructure Health and Safety Association's "Zero Quest - Sustainability" award, the first electricity distributor in Ontario to do so.

The reliability of our system has improved substantially over the last decade and Niagara-on-the-Lake Hydro now has one of the lowest line loss ratios. Investments will continue in improving the system with additional smart grid investments being added over the next few years.

Public Policy Responsiveness

Niagara-on-the-Lake Hydro maintains strong relations and works closely with regulators and government bodies as we believe this is in the long-term best interests of our customers. However, where appropriate, we also believe it is important for us to speak against policies and decisions which we do not believe are in the long-term best interests of our customers.

Financial Performance

Niagara-on-the-Lake Hydro's financial viability is maintained through a low debt to equity ratio and a sustained profitability.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2017, Niagara-on-the-Lake Hydro connected 98.94% of the 189 requested low-voltage connections (i.e. under 750 volts) for residential and small business customers within the five-day timeline prescribed by the Ontario Energy Board. Niagara-on-the-Lake Hydro technical staff work with our customers at our office or in the field to help make the connection process as easy as possible.

- **Scheduled Appointments Met On Time**

  Niagara-on-the-Lake Hydro schedules specific appointment times with customers. It is expected that Niagara-on-the-Lake Hydro staff will keep that appointment except in the event of an emergency. No appointments were missed in 2017.

- **Telephone Calls Answered On Time**

  In 2017, Niagara-on-the-Lake Hydro answered 87.26% of the 7,606 calls it received during the year within 30 seconds. Call volumes are highest, and response times lowest, during the summer months.

Customer Satisfaction

- **First Contact Resolution**

  Niagara-on-the-Lake Hydro defines first contact resolution as the number of customer contacts that were escalated beyond customer service to the President or the Board of Directors. Through its advocacy efforts, Niagara-on-the-Lake Hydro has been encouraging more two way communication with its customers. The increased score reflects this effort.

- **Billing Accuracy**

  Billing accuracy performance remained high at 99.85% through continued focus on the billing process including an enhanced use of exception reporting.

- **Customer Satisfaction Survey Results**

In 2017, Niagara-on-the-Lake Hydro engaged a third-party organization to conduct a new customer satisfaction survey in collaboration with a number of other small electricity distributors. The posted result, 75.9%, was the combined positive and neutral response to an overall satisfaction question and was about average within this group of distributors. This survey used a different scoring methodology so the results are not comparable with previous years or with the results of many other distributors. There is a cost to surveys, which is ultimately passed on to the customer, which Niagara-on-the-Lake Hydro respects and seeks to minimize.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

A province-wide survey was undertaken in 2018 to measure public awareness to the dangers of electricity. Niagara-on-the-Lake Hydro customers scored 83.0% for safety awareness. The score was determined from 6 safety specific questions focusing on powerlines and LDC transformers. 83.0% was a slight improvement from 81.5% in 2016.

  - **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 establishes the safety requirements for the design, construction, and maintenance of electrical distribution systems, particularly in relation to the approvals and inspections required prior to putting electrical equipment into service. Over the past six years, Niagara-on-the-Lake Hydro was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and the adherence to company procedures and policies.

  - **Component C – Serious Electrical Incident Index**

Niagara-on-the-Lake Hydro has had no fatalities and no serious incidents within its territory since incorporation in 2000. To maintain this high level of safety, efforts are continually made to identify areas of concern and address these concerns by changes in procedures or by modifying access to physical areas.

Niagara-on-the-Lake Hydro's over-riding priority is safety of the public and its employees. In 2012, Niagara-on-the-Lake Hydro was the first local distribution company to receive the Infrastructure Health and Safety Association's "Zero Quest - Sustainability" award.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  The average number of hours that power to a customer is interrupted (duration of outages) is a measure of system reliability or the ability of a system to perform its required function. Niagara-on-the-Lake Hydro views reliability of electrical service as a high priority for its customers and constantly monitors its system for signs of reliability degradation. Niagara-on-the-Lake Hydro also regularly maintains its distribution system to ensure its level of reliability is kept as high as possible. However, outside factors such as severe weather, defective equipment, or even regularly scheduled maintenance can greatly impact this measure. For 2017, Niagara-on-the-Lake Hydro's customers experienced an average of 0.50 hours of interrupted power which is at the lower end of its historical performance.

- **Average Number of Times that Power to a Customer is Interrupted**

  The average number of times that power to a customer is interrupted (frequency of outages) is also a measure of system reliability and is also a high priority for Niagara-on-the-Lake Hydro. Niagara-on-the-Lake Hydro's customers experienced interrupted power an average of 0.88 times during 2017. This is within the range of its historical performance for interrupted power and consistent with other measures over the six-year period between 2011 and 2016.

Asset Management

- **Distribution System Plan Implementation Progress**

  Distribution system plan implementation progress is a new performance measure instituted by the Ontario Energy Board beginning in 2013. Niagara-on-the-Lake Hydro's Distribution System Plan was filed with the 2014 rate application and attempts to strike a balance between the need for system renewal, providing services to new and upgrading customers, adoption of new technology and automation, ongoing system maintenance and strong customer service while considering appropriate, affordable rates along with the long-term financial capabilities of our company. The plan outlines forecasted capital expenditures over the period 2014 to 2018. A prominent element of the system renewal component of the plan for 2015 was the replacement and upsizing of one of the transformer units at one of Niagara-on-the-Lake Hydro's two transformer stations. This 50 MW $2.6 million new unit will help ensure the security of supply for Niagara-on-the-Lake for years to come.

The Distribution System Plan Implementation Progress measure is intended to assess Niagara-on-the-Lake Hydro's effectiveness at planning and implementing these capital expenditures. Consistent with other new measures, utilities were given an opportunity to define this measure in the manner that best fits their organization. As a result, this measure may differ from other utilities in the Province.

Niagara-on-the-Lake Hydro currently defines this measure as the tracking of actual total capital project expenditures to planned total capital project expenditures, expressed as a percentage. For 2017, Niagara-on-the-Lake Hydro completed 110% of the capital projects planned for 2017 in terms of expenditures. The expenditure in 2017 was higher than planned due to an increase in Smart Grid investments such as new automated switches, reclosures and enhanced SCADA connectivity.

Cost Control

- **Efficiency Assessment**

The total cost performance of each electricity distributor is evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2017, for the sixth year in a row, Niagara-on-the-Lake Hydro was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, Niagara-on-the-Lake Hydro's costs are within the average cost range for electricity distributors in Ontario. In 2017, almost half of the distributors were ranked as "average efficiency" with the other distributors split approximately equally between those ranked as "more efficient" and those ranked as "less efficient.

Niagara-on-the-Lake Hydro manages its costs with a view to providing the best service to its customers. This could include additional costs such as customers having access to all staff at its office or investing to improve reliability.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of capital and operating costs divided by the total number of customers served. Operating costs are based on actual results while capital costs are determined by an econometric adjustment formula. Niagara-on-the-Lake Hydro's operating cost per customer of $280 is one of the lowest in Ontario for distributors with similar customer densities. A low capital cost per customer may be an indicator of insufficient investment rather than efficiency. Niagara-on-the-Lake Hydro maintains a consistent capital investment program to accommodate growth and continually improve the system. As a result, the total cost per customer has remained stable over the past five years.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total cost is divided by the kilometers of line that the distributor operates to serve its customers. Niagara-on-the-Lake Hydro's system currently accesses most of the Town so that most growth comes from in-fill projects using existing line or subdivision clusters served from the same line. As a result, this benchmark can be expected to increase over time with inflation and new customer growth.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  Our local presence allows Niagara-on-the-Lake Hydro to develop strong relations with our customers. This means we often become aware of energy savings opportunities during new build or refurbishment projects. Achieving 89.87% of targeted savings in the third year of a six-year timeframe is one of the stronger performances in the province.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIA's) on all renewable generation connections within 60 days of receiving authorization from the Electrical Safety Authority. In 2017, all 6 CIAs were completed within the prescribed time frame.

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2017, Niagara-on-the-Lake Hydro connected 1 new micro-embedded generation facilities (microFIT projects of less than 10 kW), which was connected within the prescribed time frame of five business days. This new connection brings the total number of micro-embedded generation facilities in Niagara-on-the-Lake at the end of 2017 to 137. Niagara-on-the-Lake Hydro works closely with its customers and their contractors to make the installation process as easy as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  Niagara-on-the-Lake Hydro's current ratio was 0.83 in 2017. Two factors lower Niagara-on-the-Lake Hydro's current ratio. First, Niagara-on-the-Lake has two demand loans that are classified as current liabilities even though the interest rate is fixed over the intended life of the loan by way of an interest rate swap. Second, Niagara-on-the-Lake Hydro maintains a practice of not carrying excess cash but using a line of credit with a Schedule A bank. This is more efficient than having excess cash in the bank. Niagara-on-the-Lake Hydro is comfortable with this practice due to its low debt levels.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The debt to equity ratio is a financial ratio indicating the relative proportion of shareholders' equity and debt used to finance a company's assets. The Ontario Energy Board uses a capital structure of 60% debt and 40% equity (a debt to equity ratio of 60/40 or 1.5) when setting rates for an electricity utility. The average debt to equity ratio in 2017 for Ontario electricity distributors was 1.26.

  In 2017, Niagara-on-the-Lake Hydro's debt to equity ratio was 0.54. Niagara-on-the-Lake Hydro's fiscal strategy regarding the debt to equity ratio has been to maintain a low risk debt/equity load. This was done to ensure that we had the borrowing capacity at favorable terms to meet the needs of the utility for planned and unexpected capital programs. Keeping the company fiscally sound serves the best interests of customers and shareholders. The debt to equity ratio decreased in 2017 as repayments of existing debt exceeded new borrowings.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  Return on equity (ROE) measures the rate of return on shareholder equity. ROE demonstrates an organization's profitability or how well a company uses its investments to generate earnings growth. Niagara-on-the-Lake Hydro's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.36% effective May 1, 2014. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. If a distributor performs outside of this range, it may trigger a regulatory review of the distributor's financial structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  Niagara-on-the-Lake Hydro achieved a ROE of 9.81% in 2017, which is well within the 9.36 +/-3% range allowed by the OEB (see above paragraph). Actual ROE will vary from year to year based on the timing of tax expenses and capital activities. The average ROE over the previous 5 years (2013 to 2017) was 8.17%, which is indicative of a financially healthy organization.

Note to Readers of 2017 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

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Ref: Appendix 1E - 2017 Customer Satisfaction Survey Detailed Final Report

Staff notes that Customer Satisfaction Index Score by Consumption Tranches in the 2017 customer survey was not calculated. The note on page 19 of Appendix 1E states that the score was not calculated because NOTL Hydro declined to present customer usage information for this calculation.

a) **Please explain why the customer consumption information was not provided to Redhead Media Solutions Inc. for the calculation of this score.**

RESPONSE

When providing information to any 3rd party, NOTL Hydro attempts to limit the amount of personal information sent to a minimum and to only provide what is necessary. It was thought that specific kWh statistics were private information and should not be provided to any 3rd party if an equivalent alternative was provided. NOTL Hydro classified customers consumption flag quartiles from 1 to 4 instead of offering kWh specifics (from less than 100 kWh to over 100,000 kWh). While we have a non-disclosure agreement in place, we wished to limit the amount of personal information leaving our premise. Account number was also not provided.

The image on the following page is a screenshot of the actual list provided to the 3rd party consultant which was intended to identify high vs low users without divulging their exact kWh usage.

	A	B	C	D	E	F
1	name	phone	customer_typ	ldc_fee	billing_entity	Consumption_Flag
2	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
3	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
4	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
5	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
6	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
7	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
8	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
9	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
10	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
11	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
12	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
13	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
14	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
15	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
16	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
17	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
18	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
19	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
20	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
21	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
22	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
23	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
24	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
25	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
26	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1
27	[illegible]	[illegible]	2	14.55	NIAGARA-ON-THE-LAKE HYDRO	1

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Ref: Appendix 1H CGC 2018 Customer Engagement Report

NOTL Hydro held four open houses in April 2018. CGC Educational Communications Inc. was hired to have confidential discussions with NOTL Hydro's customers after each open house and its observations are summarized in a final report dated May 30, 2018. Based on the customers' feedback, page 11 of the report made the following recommendations:

1. **Cost containment should not be so stringent as to limit maintenance and ongoing reliability;**
2. **Communication with customers should expand beyond the event reported here. Customers prefer to see quarterly or semi-annually reports demonstrating Niagara-on-the-Lake Hydro's progress in achieving milestones in the future plans;**
3. **Customers would prefer to see a more robust power restoration communication systems;**
4. **Residential customers would prefer to see more guidance in navigate time of use rates, especially when it comes to food preparation, such as meals at suppertime;**
5. **Customers almost unanimously prefer to see Niagara-on-the-Lake Hydro continue its effective work on conservation;**
6. **Customers saw safety as currently underrepresented in Niagara-on-the- Lake's communication platform;**
7. **Business customers would appreciate more engagement on connection assessments for renewable energy; and**
8. **Class A and aggregate account customers need support to take full advantage of the Class A program.**

a) Please provide the updates to NOTL Hydro's work with respect to each of the recommendations. If the work has been done/in progress and presented in the Application, please provide the cross-references to the respective evidence.

RESPONSE

1. Niagara-on-the-Lake Hydro agrees with the feedback provided by the customer. Cost containment is at a level where system maintenance and upgrades are performed at a level NOTL Hydro considers reasonable to both maintain reliability and manage costs. NOTL Hydro's rates and reliability are both better than average.
2. Niagara-on-the-Lake Hydro attempts to keep customers up-to-date with our dealings via several methods including:
    - An annual AGM open to the public.
    - Social Media updates on important subjects
    - Public Financial Statements made annually.

   We make the effort to keep customers informed on projects and will speak with any customer that requests updates on specific projects, but treat public updates on a case-by-case scenario. We encourage customers to contact us with any questions regarding Hydro affairs.

3. Niagara-on-the-Lake Hydro attempts to keep customers informed of any power outage. Outgoing updates are typically performed via social media via Twitter and Facebook. In order to protect the privacy and security of customers, we do not give exact locations of outages, but a general area

affected. Robust power restoration communications are being investigated with the following ideas being looked at in the short-term:

- A near real-time heat map of the general effected area that would be available on our website.
- Twitter updates for outages that affect a material number of customers could be initiated by a third party. We are investigating the use of this for non-office hour outages where the availability of staff to send updates is reduced.
- Auto-dialers and text messaging to affected customers is an option and will be reviewed. Price and net-benefit will always be considered when choosing any updates.

4. Niagara-on-the-Lake Conservation staff are available at any time to talk to customers on how to manage their consumption and have performed walk-throughs for residents to help identify opportunities for savings. NOTL Hydro was recognized by Energy Star as Utility of the Year in 2014 for developing a cookbook with recipes and tips for reducing energy use in the kitchen. It is available at - https://www.notlhydro.com/learnandsave/at-home/kitchen/. Time-of-use has been active in Niagara-on-the-Lake since 2011.
5. NOTL Hydro continues to excel in conservation targets. As of Oct 23, 2018, NOTL Hydro estimates that 99% of target has been met. The 6-year target is expected to be met before the end of 2018 (year 4) and NOTL Hydro will continue to support any customer wishing to manage their energy use.
6. NOTL Hydro has increased safety social media messaging and has also increased safety messaging in bill inserts. As a direct result of Open House feedback, an "electrical safety at home" promotional piece is being developed with the plans to be ready for an early 2019 release. It is planned to be made available electronically and in print format.
   - **Bill Inserts** – Below are examples of 2 consecutive bill inserts in late 2017. NOTL Hydro attempts to make safety messaging appropriate to time periods and will continue to do so.

i. 

-
- The following are examples of recent safety related social media posts noting that we received interrogatories on Oct 24th.

NOTL Hydro @notlhydro · Oct 23
Have you safely decorated your home both indoors and outdoors for #Halloween? Go over these tips to make sure! bit.ly/2Ox8BZa #safetytips

1 3

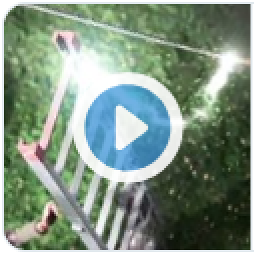
NOTL Hydro @notlhydro · Oct 23
#NOTL. Do you have any electrical safety related questions we can help you with? What do you want to know about electrical safety? At home or otherwise.

1 2

NOTL Hydro Retweeted

ESA @homeandsafety · Oct 18

Cleaning leaves from your eavestrough? Remember powerlines are lethal and unforgiving. Locate powerlines before starting any yard work and stay safe. #RespectThePower



#RespectThePower at Home

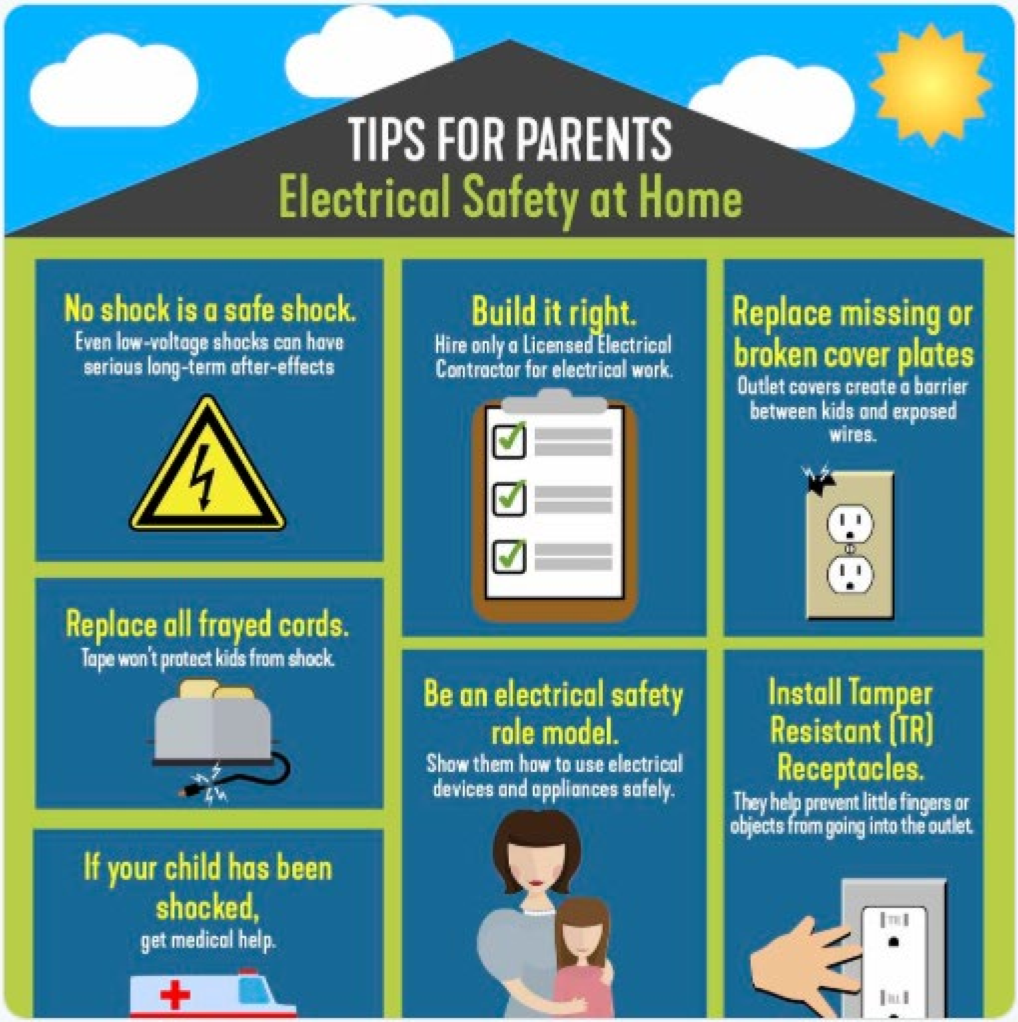
Powerlines are unforgiving and lethal. A simple chore of removing leaves from an eavestrough turns into a life-changing event. More at: http://www.esasafe.co...

youtube.com

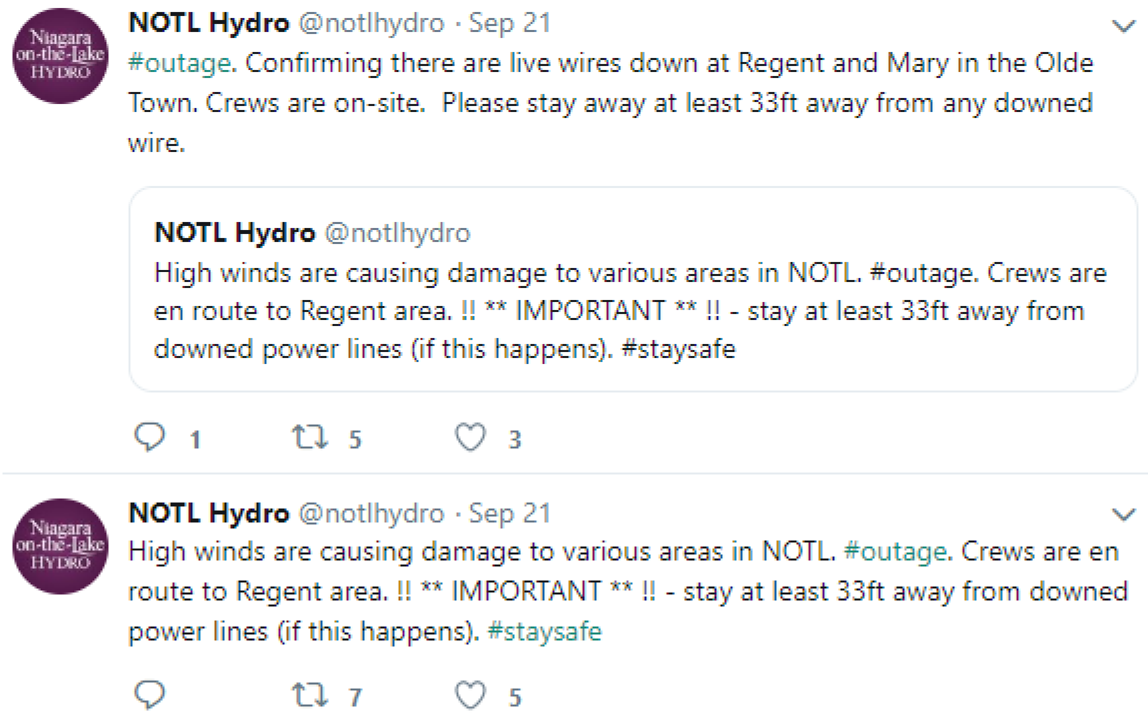
1 1 11 13

NOTL Hydro @notlhydro · Oct 15

In Ontario, more than 100 kids end up in the ER each year because of electrical injury. Learn more from @homeandsafety on how to teach your kids that there is #NoSafeShock: bit.ly/2DvUSMA



1 2


NOTL Hydro @notlhydro · Sep 21
#outage. Confirming there are live wires down at Regent and Mary in the Olde Town. Crews are on-site. Please stay away at least 33ft away from any downed wire.

NOTL Hydro @notlhydro
High winds are causing damage to various areas in NOTL. #outage. Crews are en route to Regent area. !! ** IMPORTANT ** !! - stay at least 33ft away from downed power lines (if this happens). #staysafe

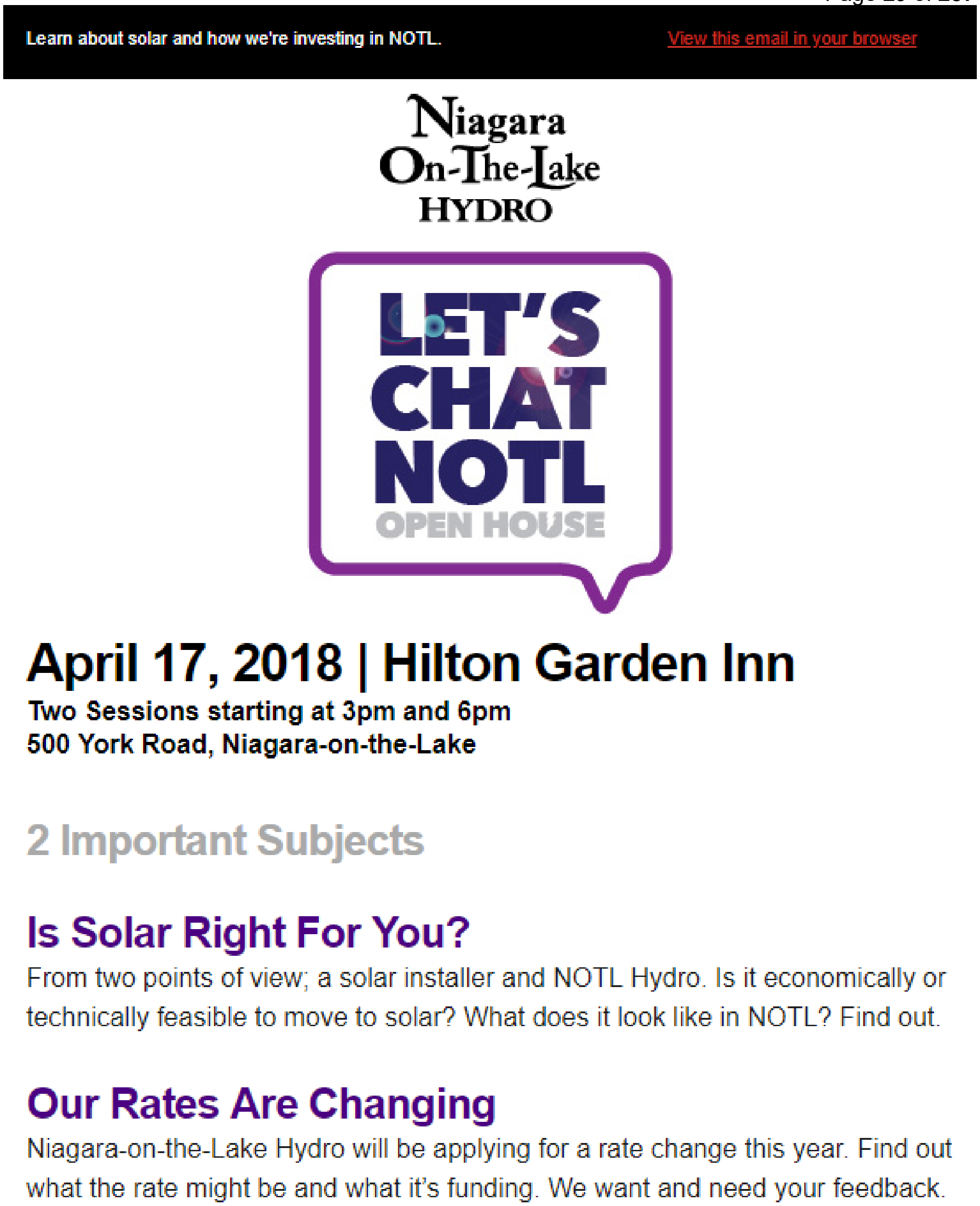
1 5 3

NOTL Hydro @notlhydro · Sep 21
High winds are causing damage to various areas in NOTL. #outage. Crews are en route to Regent area. !! ** IMPORTANT ** !! - stay at least 33ft away from downed power lines (if this happens). #staysafe

7 5

7. NOTL Hydro believes that utilities need to be enablers for distributed generation and that includes net metering. As part of our Open House presentations, the opening segments were delivered by NOTL Hydro and by vendors of solar photo-voltaic products. The intention was to give an update on the state of the industry and to dispel any myths that customers might have. NOTL Hydro has sent
   - **Bill Insert:**

   - **eBlast to eBilling Customers:**



- NOTL Hydro will continue to be enablers of renewable energy and have one of the highest ratios of customers per renewable generation project in the Province.

8. All Class A customer contacts are informed of potential events through-out the year and are sent updates from the IESO Peak Tracker located on http://www.ieso.ca/en/sector-participants/settlements/global-adjustment-for-class-a. NOTL Hydro has also met with our top customers who are not yet eligible for the program to inform them about the program should they eventually become eligible for the program. The eligible customers have also been participants in many conservation projects and have open channels of communication with NOTL Hydro.

- Sample of email sent to Class A customer contacts.

Reply Reply All Forward

Brodie Mosher 2018-08-14

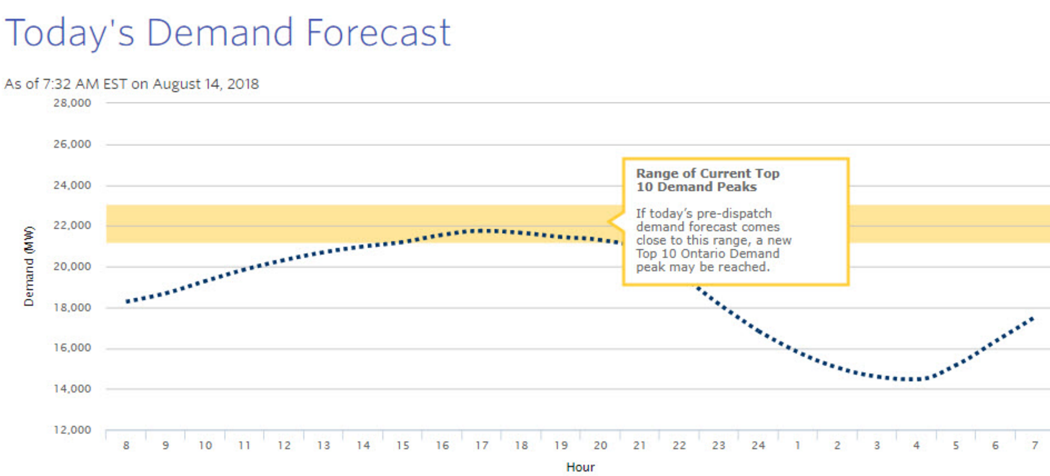
Possible Critical Peaks

Good Morning:

Please note that there are potential critical peak hours coming in the next 3 days. I will not be in the office tomorrow or Thursday and will not send out notices.

From the looks of it there is **a small chance of hitting a peak today, <u>but tomorrow (at the moment) it appears that we will likely have a critical peak hour</u>**. Please visit the following link over the next few days for more updates:
http://www.ieso.ca/en/sector-participants/settlements/global-adjustment-for-class-a

For current demand data, visit http://www.ieso.ca/en/power-data?chart=demand



1-Staff-7

Ref: Appendix 1I 2017 Open House Presentation; Appendix 1G 2018 Open House Presentation; Appendix 1Q- AGM 2018 and Appendix 1R- AGM 2017

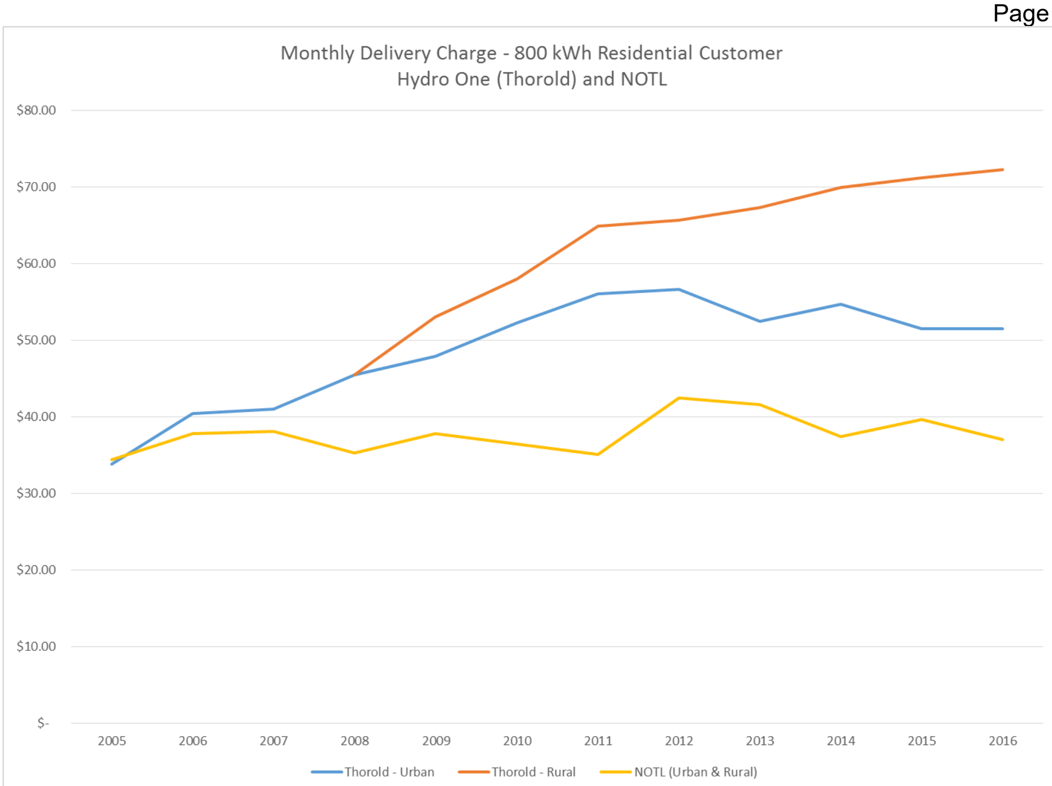
NOTL Hydro compares its rates to the rates of Hydro companies in the Niagara region at the 2017 and 2018 open houses and AGMs. These Hydro companies are Grimsby Hydro, Horizon Utilities, Welland Hydro, Hydro One-Thorold, Niagara Peninsula Energy Inc. and Canadian Niagara Power Inc.

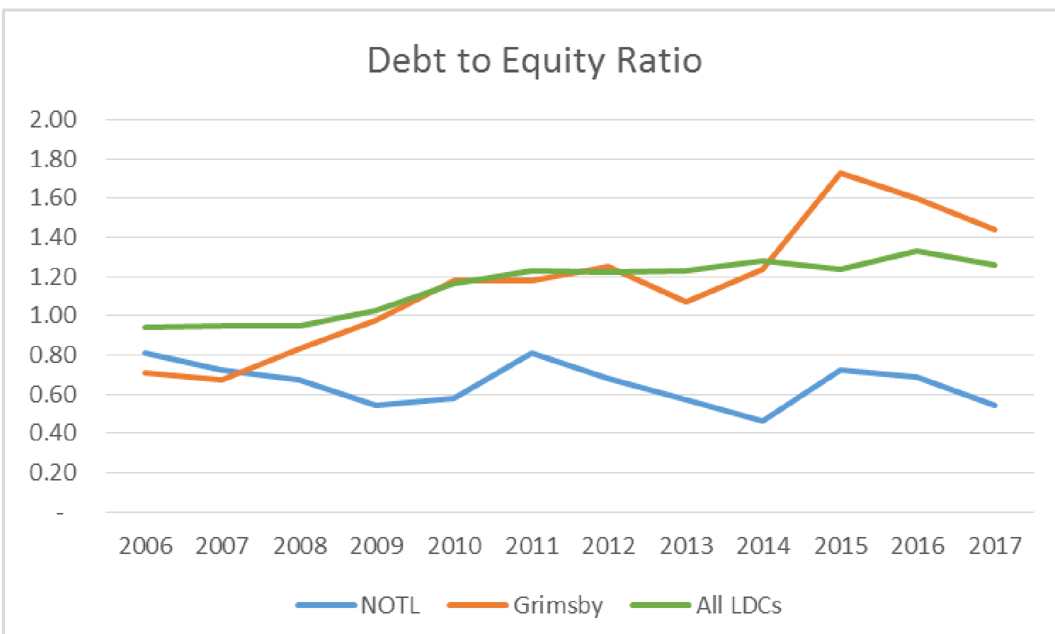
a) **Please confirm whether or not NOTL Hydro considers these companies as comparators to itself.**
b) **If so, has NOTL Hydro conducted any other benchmark analysis (such as OM&A) against these companies?**
    i. **If so, please provide the analysis.**
    ii. **If not, please explain why not.**

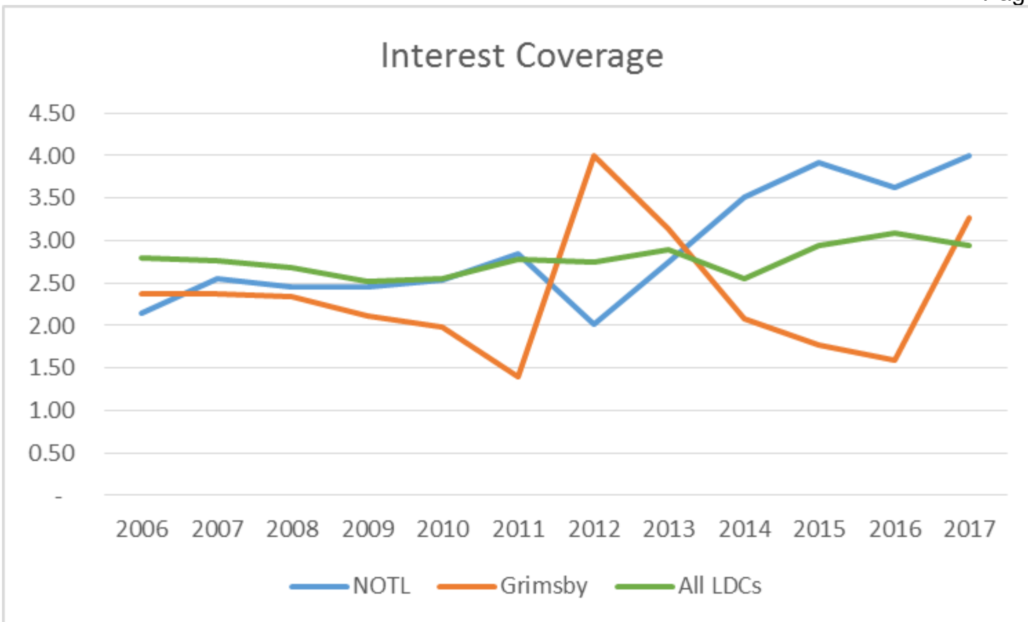
RESPONSE

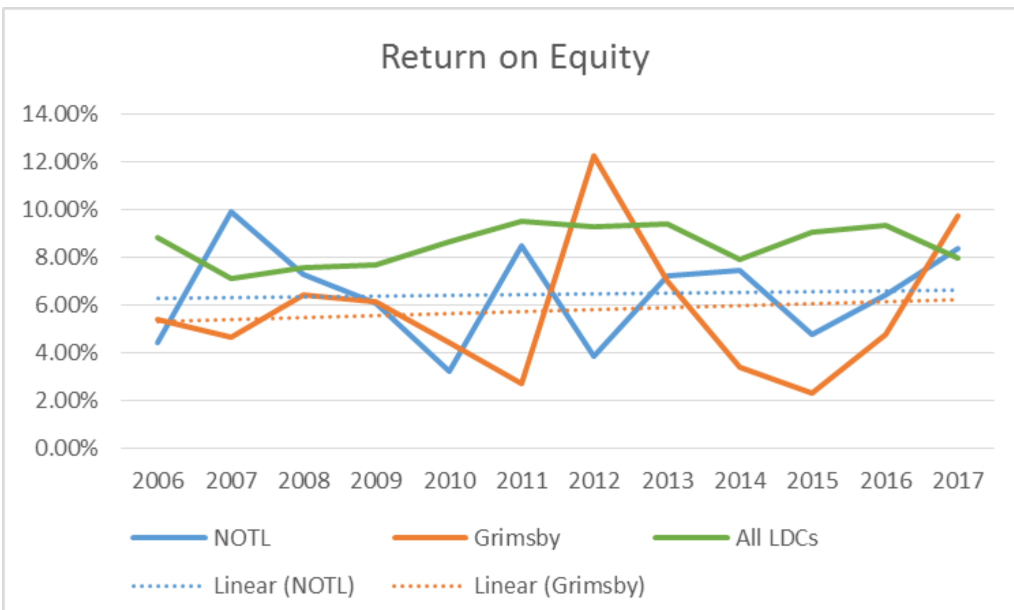
For the most part, NOTL Hydro does not consider these companies as operational comparators to itself. They are of different sizes in terms of customer count and headcount and have different operational structures. NOTL Hydro does consider that these companies are comparators for our customers. Our customers live in the Niagara Region and identify with the Niagara Region. They are most interested in how their rates compare to other municipalities in the Niagara Region. Comparisons with companies in Eastern, Northern or Southwest Ontario, even though they may be more similar to NOTL Hydro in size, would be of much less interest to our customers.

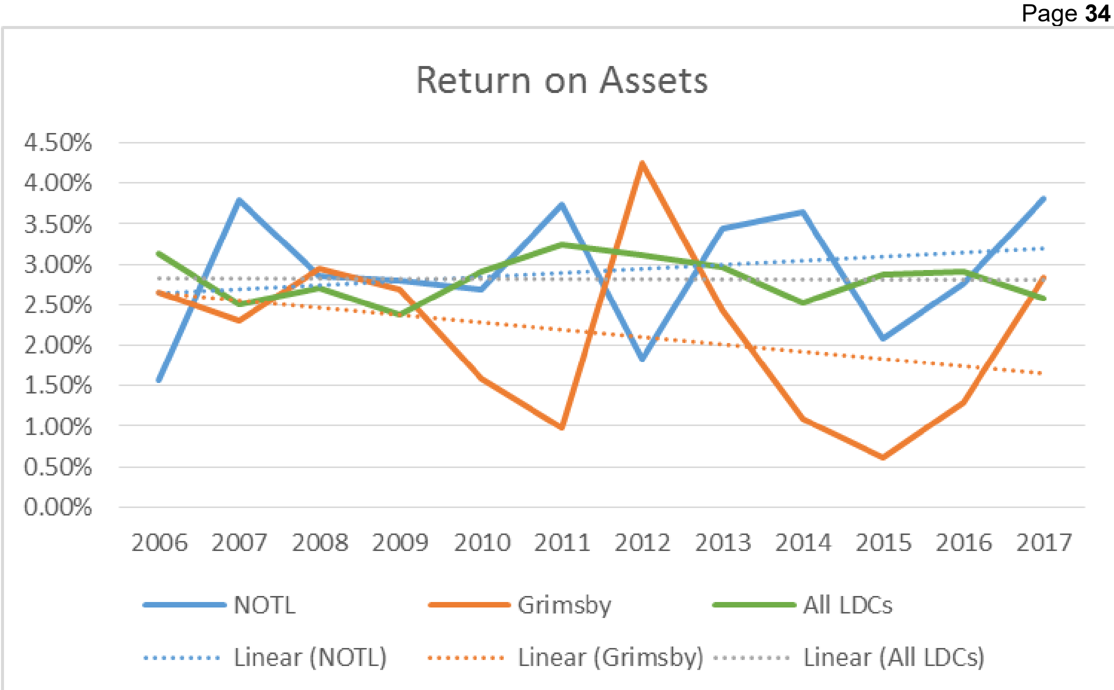
The only benchmark analysis NOTL Hydro has conducted with any of these neighbouring LDCs is one with Grimsby Power which was conducted on behalf of the NOTL Hydro Board. Grimsby Power is the closest to NOTL Hydro in terms of size.

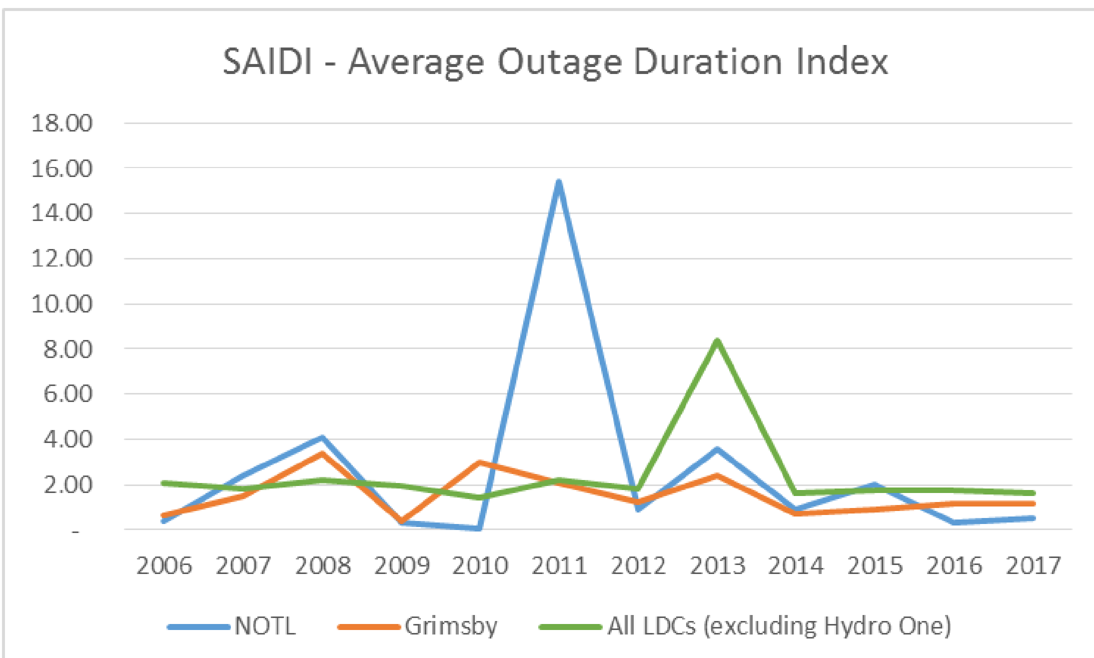

Monthly Delivery Charge - 800 kWh Residential Customer
Hydro One (Thorold) and NOTL
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Thorold - Urban
Thorold - Rural
NOTL (Urban & Rural)

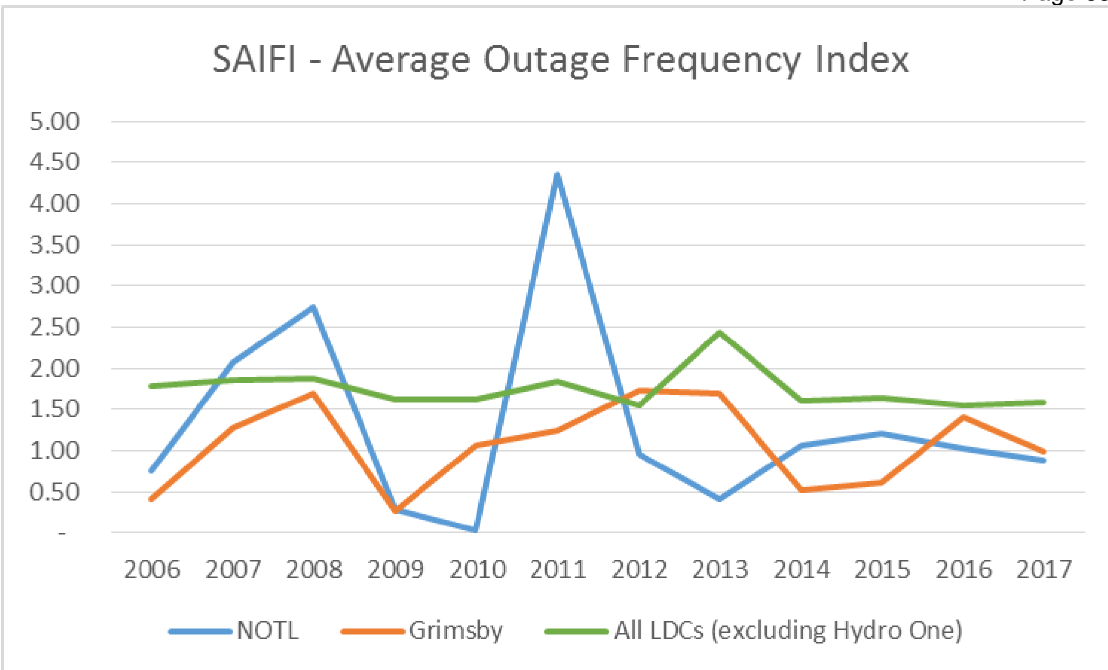

Debt to Equity Ratio
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
-
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
NOTL
Grimsby
All LDCs

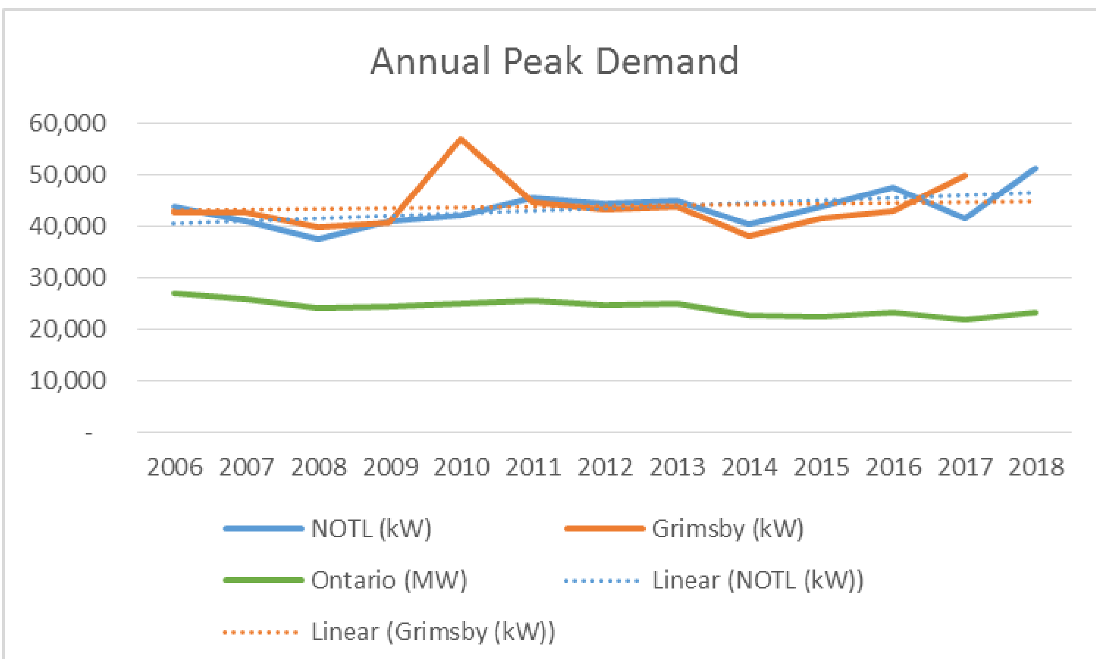
1 
Interest Coverage
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs

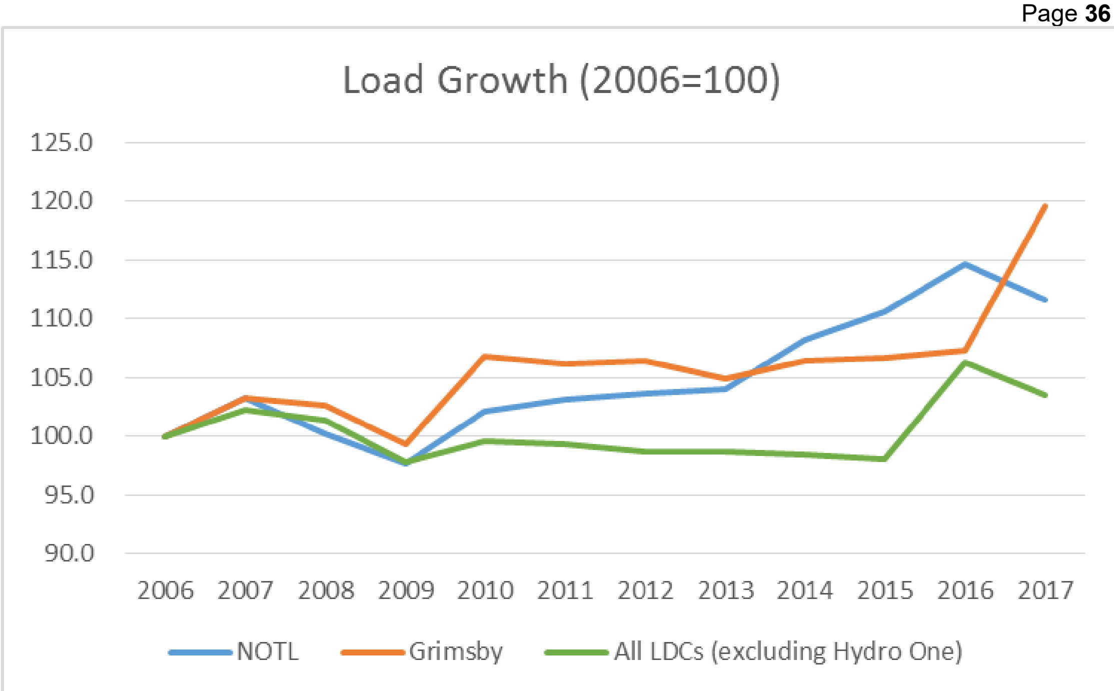
2 
Return on Equity
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs
Linear (NOTL)
Linear (Grimsby)

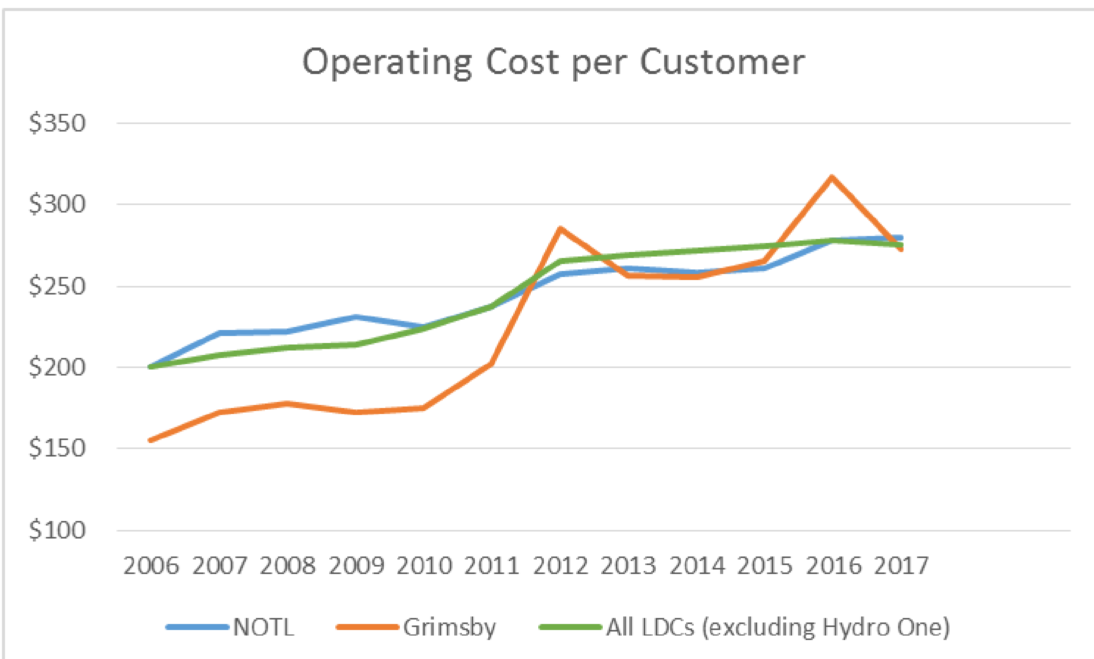
1 
Return on Assets
4.50%
4.00%
3.50%
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
NOTL
Grimsby
All LDCs
Linear (NOTL)
Linear (Grimsby)
Linear (All LDCs)

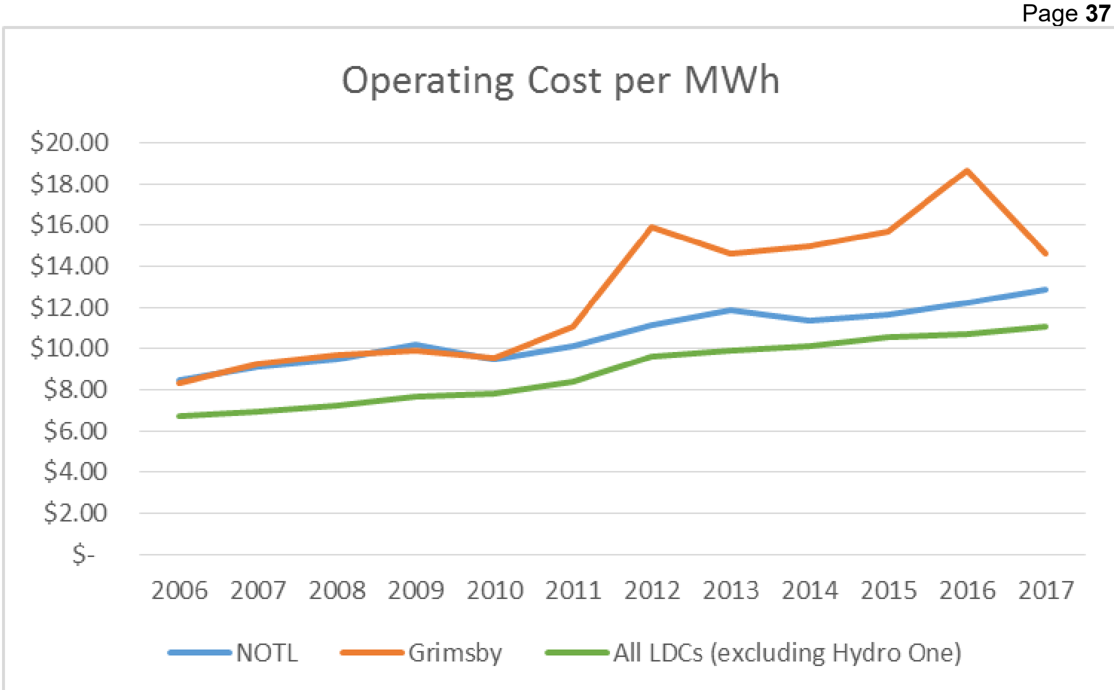
2 
SAIDI - Average Outage Duration Index
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

1 
SAIFI - Average Outage Frequency Index
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

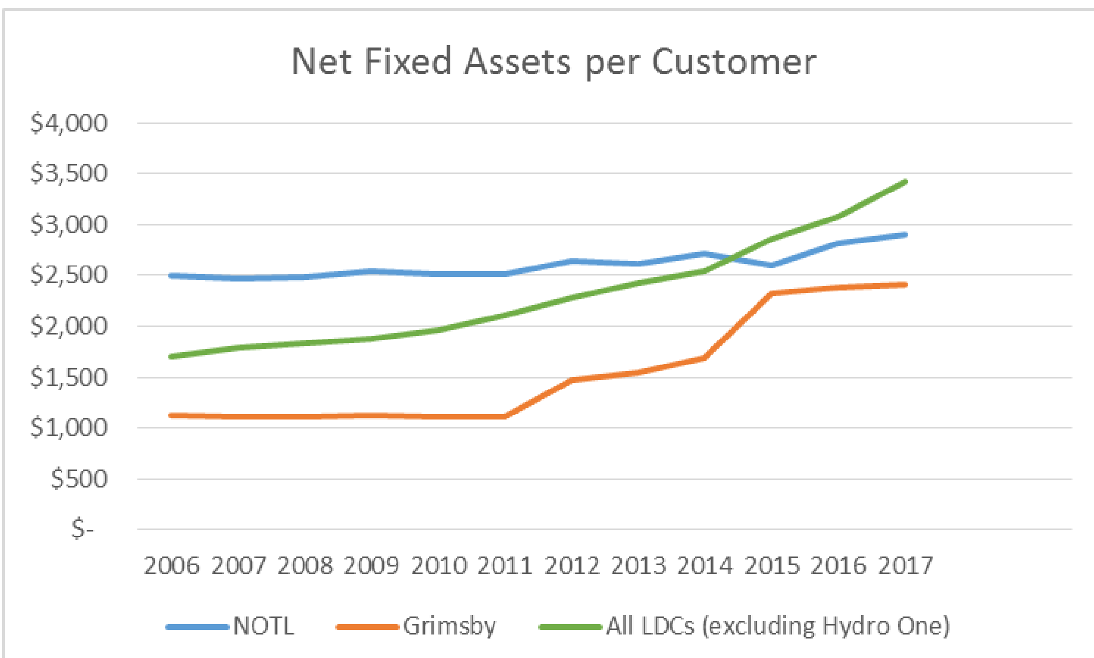
2 
Annual Peak Demand
60,000
50,000
40,000
30,000
20,000
10,000
-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
NOTL (kW)
Grimsby (kW)
Ontario (MW)
Linear (NOTL (kW))
Linear (Grimsby (kW))


Load Growth (2006=100)
125.0
120.0
115.0
110.0
105.0
100.0
95.0
90.0
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

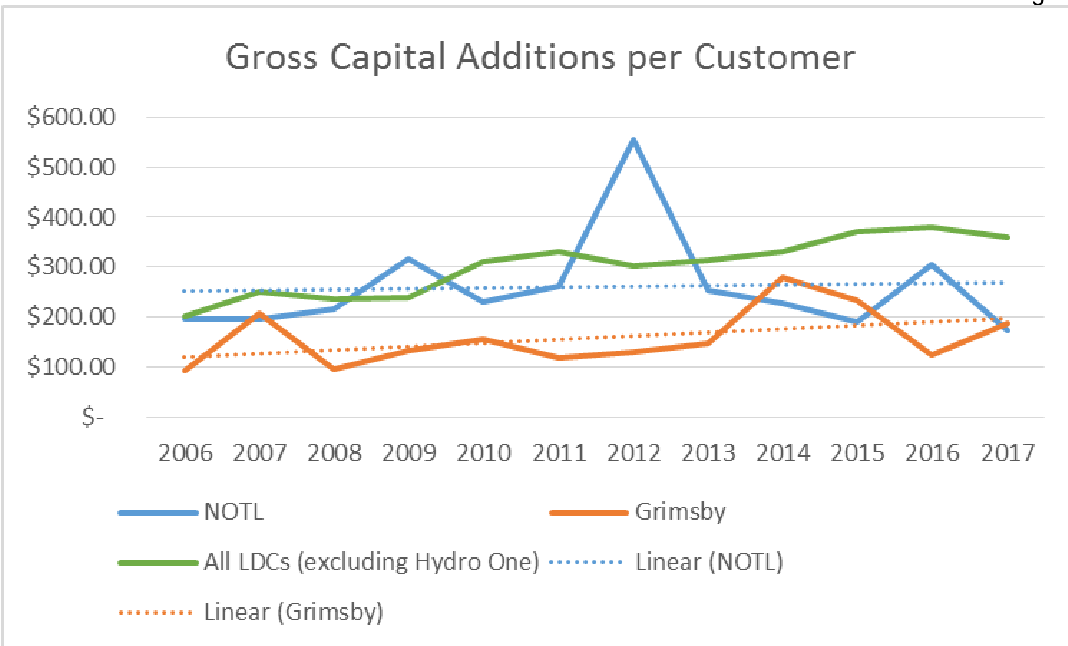

Operating Cost per Customer
$350
$300
$250
$200
$150
$100
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)


Operating Cost per MWh
$20.00
$18.00
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

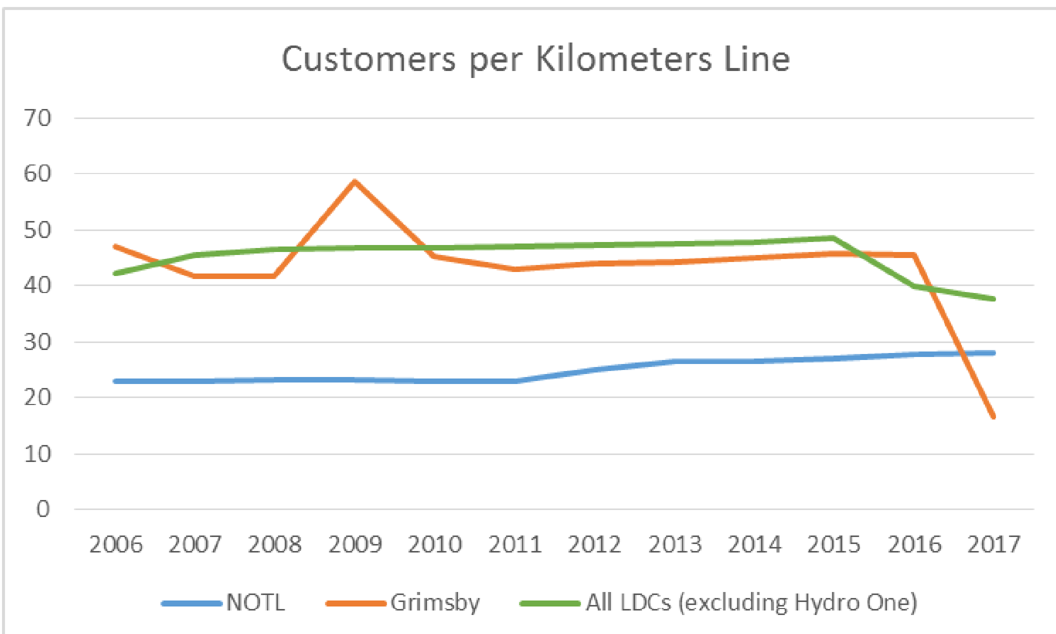
1


Net Fixed Assets per Customer
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

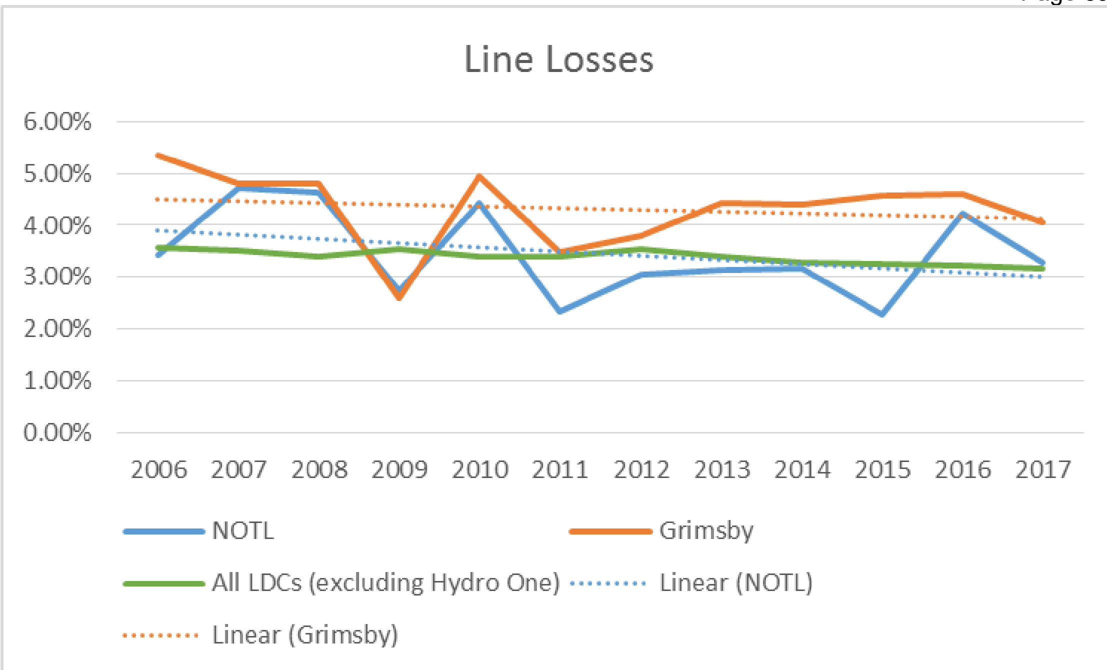
2

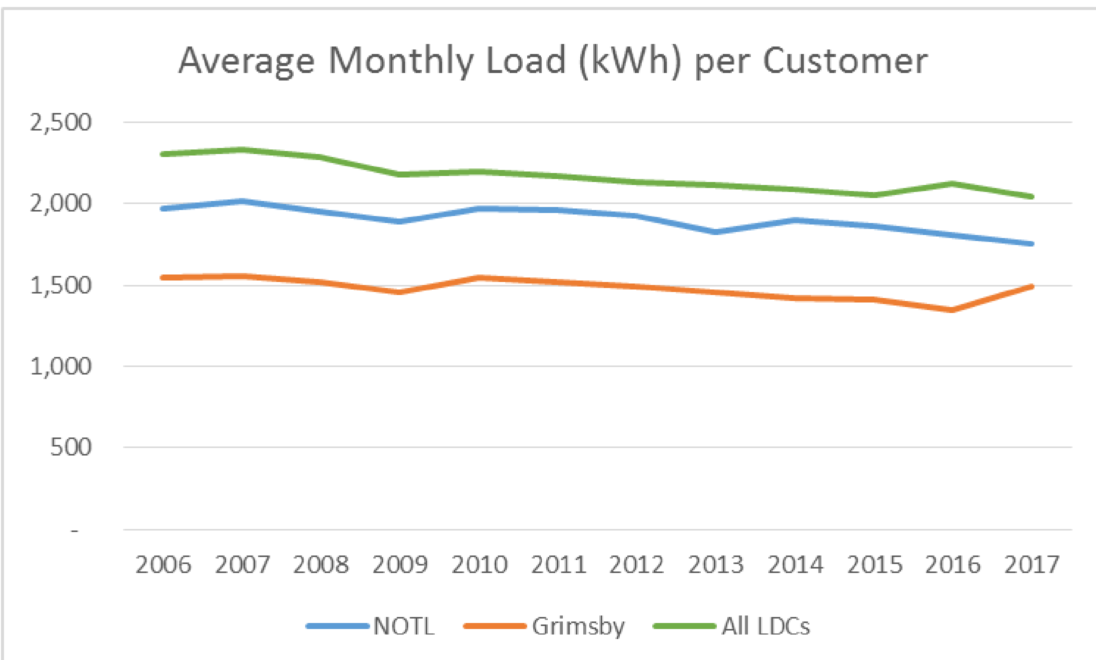

Gross Capital Additions per Customer
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)
Linear (NOTL)
Linear (Grimsby)

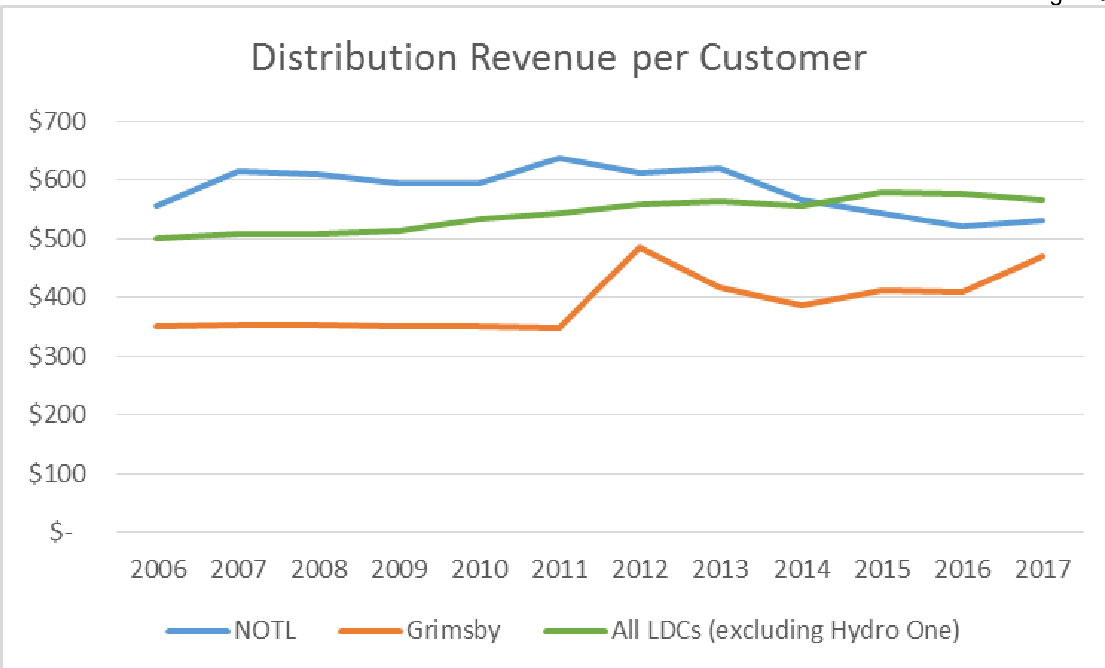
1


Customers per Kilometers Line
70
60
50
40
30
20
10
0
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

2

1 
Line Losses
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)
Linear (NOTL)
Linear (Grimsby)

2 
Average Monthly Load (kWh) per Customer
2,500
2,000
1,500
1,000
500
-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs


Distribution Revenue per Customer
$700
$600
$500
$400
$300
$200
$100
$-
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

1-Staff-8

Ref: Business Plan dated August 2018 – Appendix to Exhibit 1

NOTL Hydro explains in its 2018 Business Plan for system renewal capital expenditures that

Annual expenditures are determined based on a combination of resource availability and the need to ensure that over time annual expenditures are sufficient to replace aging stock. This is estimated by adjusting the annual depreciation of poles, conduit and transformers for inflation.

Table 17 below provides the ratios between Depreciation and System renewal capital expenditures for the years of 2014 and 2017:

Table 17: Depreciation vs. System Renewal ($000's)

	2014	2015	2016	2017
Depreciation	$564	$574	$590	$600
Inflation adjustment	143%	144%	144%	144%
Required expenditure	$806	$827	$850	$864
Actual expenditure	$1,005	$640	$1,025	$770
Variance	$199	($187)	$175	($94)

a) **Please explain if NOTL Hydro plans to replace the assets based on the asset health conditions.**
   i. **If so, please provide the plan.**
   ii. **If not, please explain why NOTL Hydro has not planned to replace the assets based on asset health conditions.**

b) **Please confirm whether or not the values in the row of Depreciation in Table**

c) **17 represent the depreciation expenses recorded in NOTL Hydro's financial records for system renewal capital assets.**
   i. **If not, please explain where the values come from.**

d) **Please provide the source of the inflation adjustment numbers used for the years of 2014 to 2017 in Table 17.**

e) **Please explain why the variances between the required expenditures and the actual expenditures on annual basis are relatively large from 2014 to 2017.**

RESPONSE

a) NOTL Hydro aims to replace the assets based on asset health conditions. Please see section 4.9 of the Asset Management Plan.

b) The values in the row of Depreciation in Table 17 represent the depreciation expenses recorded in NOTL Hydro's financial records for poles, conduit and transformers. These are all system renewal capital assets.

c) Inflation was calculated using the Bank of Canada inflation calculator which is available at: https://www.bankofcanada.ca/rates/related/inflation-calculator/

d) Actual expenditures will vary from year to year based on the budget and on adjustments made during the year while responding to the needs of our customers. Therefore, in any one year there may be variances between expected and actual expenditures. Over time the expenditures should match the requirements. Over the four years shown above the total variance was $93k or 2.78% of required expenditures.

1-Staff-9

Ref: Exhibit 1, Page 20

NOTL Hydro provides its historical PEG performance in the Table 6:

Table 6: PEG Past Performance (Stretch Factor)

	2013	2014	2015	2016
Stretch Factor Cohort - Annual Result	3	3	3	3
Associated Stretch Factor Value	0.30	0.30	0.30	0.30

NOTL Hydro states that "It is hoped that this performance improvement will continue over the next five years with the continued application of NOTL Hydro's values and that NOTL Hydro may even move into the Group 2 stretch cohort."

Staff notes from the published 2017 scorecard that NOTL Hydro's stretch cohort remains at Group 3.

a) Please provide details on any initiatives undertaken to improve NOTL Hydro's cohort assignment in future years.

RESPONSE

NOTL Hydro concurs that its stretch cohort remains at Group 3 but notes that its relative position within the cohort continued to improve. This can be seen in the table below:

Year	2013	2014	2015	2016	2017
Cost Performance	-0.7%	-2.8%	-6.6%	-6.4%	-9.2%

NOTL Hydro does not undertake any initiatives specific to improving its cohort assignment. However, NOTL Hydro believes that all its initiatives, because they are based on NOTL Hydro's values, including focus on health & safety, customer needs and financial prudence, will ultimately lead to a move to a Group 2 cohort.

1-SEC-1

[Ex.1] Please provide a copy of all documents provided to the Applicant's Board of Directors for the purposes of approving the application and the underlying budget.

RESPONSE

The following documents were provided to the Board of Directors of NOTL Hydro with regards to the rate application. Please note that the figures provided in the reports were while the preparation of the application was in progress so are different from the final application.

May 2018 – Report on the open house sessions prepared by CGC (Appendix 1H of the original submission)

June 2018 – Progress report copied below

July 2018 – Progress report copied below

August 2018 – Customer Summary (Appendix 1C of the original submission).

The Customer Summary provided a comprehensive summary of the submission so no additional report for the Board was created.

The NOTL Hydro Board of Directors does not approve the application as that is considered a Management responsibility.

Niagara-on-the-Lake Hydro Inc.
Cost of Service Application Update
June 2018

The following data is not final but we are not anticipating any major changes.

Revenue Requirement

As part of its Cost of Service Rate order, NOTL Hydro will be applying for a revenue requirement of $5,337,754. This is just revenue from rates and does not include revenue from service charges, pole rentals and other sources of income.

Based on our load forecast for 2019, and using the current 2018 distribution rates and ICM rate rider, NOTL Hydro would earn $5,530,734. The application will therefore be requesting an average reduction in distribution revenue of 3.49% or $193k. This is almost exactly the revenue the ICM rate rider would provide so our distribution rates will remain unchanged (in aggregate) and we will no longer need the ICM rate rider. The ICM rate rider was 0.07¢ per kwh for residential customers, 0.12¢per kwh for GS<50 kW customers and 34.83¢pe kW for GS>50 kW customers.

	2014	2015	2016	2017	2018	2019
Revenue requirement	$4,758	$4,674	$4,723	$5,256	$5,316	$5,338
Actual Revenue	$4,729	$4,693	$4,844	$5,019		

Our actual revenue for 2014-2017, which does not include the ICM rate rider, is shown in the table above. The table also shows what the revenue requirement would be based on the OEB model. As our distribution rates should be largely the same, this cost of service application should not have much impact on our current net income and we should be able to maintain our current profitability.

Rates

	Fixed				Variable			
	Current	Proposed	Variance	Variance %	Current	Proposed	Variance	Variance %
Residential	$26.86	$29.18	$2.32	8.6%	$0.0033	$0.0000	($0.003)	(100.0%)
GS <50	$39.41	$39.13	($0.28)	(0.7%)	$0.0118	$0.0117	($0.0001)	(0.8%)
GS>50	$281.65	$279.65	($2.00)	(0.7%)	$2.2226	$2.2068	($0.0158)	(0.7%)
USL	$21.20	$19.82	($1.38)	(6.5%)	$0.0064	$0.0060	($0.0004)	(6.3%)
Streetlights	$7.85	$7.79	($0.06)	(0.8%)	$30.6934	$30.4759	($0.2175)	(0.7%)
Large User	$281.65	$3,154.83	$2,873.18	1020.1%	$2.2226	$2.2371	$0.0145	0.7%

The above rates are being proposed based on the proposed revenue requirement. Rates were basically flat before the addition of the Large User which is allowing for a rate reduction. Residential would also show a reduction but this is hidden by the movement to 100% fixed rates. As mentioned above, the ICM rate rider will also disappear.

Financial Implications

The table below shows the changes in the calculation of the revenue requirement since 2014. The reductions the OEB has made to the allowed rates of return (lower return on equity, lower allowed working capital, lower interest on long term debt) have combined to reduce the revenue requirement by $250k. These will reduce our net income in 2019.

Offsetting this is our growth in rate base; particularly with the purchases of the transformers in 2015 and 2019. This is creating an additional $419k in allowed revenue. Some of this will be required to pay for our increased interest expense.

The other lines show a net increase of $713k in actual costs of which $126k is an increase in depreciation and $587 is driven by growth in operating costs less growth in other revenue. Our increase in operating costs is likely to be our biggest susceptibility in the rate application.

2014 Revenue Requirement	$ 4,462,246
Reduction in WACC	(204,882)
Reduction in working capital %	(51,110)
2014 Revenue Requirement using 2019 allowed returns	$ 4,206,255
Increase in fixed assets	391,001
Increase in working capital $	21,498
Other change in WACC	6,363
Increase in Regulated Return on Capital	418,863
Increase in OM&A	670,190
Increase in depreciation	126,754
Increase in Other Revenue	(96,356)
Increase in taxes	12,040
2019 Revenue Requirement	$ 5,337,745

Other Key Considerations

- We will be applying for a new Large User customer class and have assumed 5,000 kW of demand from XXXXXX each month in the forecast. This generated an additional $80k over current volumes of 2,000 kW. We will also be applying for a variance account for to which any overages or underages will be applied. In discussions with various consultants and an OEB manager we have not received any negative feedback on the variance account concept.
- The submission includes $3.5 million in new capital (less a $400k write-off) for the new transformer at York station and the transfer of the existing York transformer to NOTL station. This means no subsequent ICM. For this new capital to be allowed we will have to have the new transformer installed during 2019.
- The lithium-ion battery from the Smart Grid Fund project is included as new capital in 2019.
- The biggest factor in the increase in Other Revenue is the increase in the pole rental rates.

- Our loss factor will go from 3.79% to 3.73%

Niagara-on-the-Lake Hydro Inc.
Cost of Service Application Update
July 2018

The following data is not final but should be very close.

Revenue Requirement

As we have adjusted the model with the review and refinement of inputs the revenue requirement has crept up. Some of the larger changes included:

- Regulatory costs of $42k. We have estimated a total of $210k (worst case) which is spread over 5 years. Actual costs should be much less.
- Post-retirement benefits are $50k higher based on the actuary report.
- Wrote off one of the 25 MW transformers which reduces capital and therefore ratebase.
- Adjustments to expenses based on adjusting to actual June 2018 costs and fixing a few operational costs which appeared too low.

	2014	2015	2016	2017	2018	2019
Revenue requirement - June	$4,758	$4,674	$4,723	$5,256	$5,316	$5,338
Revenue Requirement - July	$4,758	$4,674	$4,723	$5,256	$5,375	$5,527
Actual Revenue	$4,729	$4,693	$4,844	$5,019		

Rates

	Current Rates			Proposed Rates			Variance	
	Fixed	Variable	Total	Fixed	Variable	Total	$	%
Residential	$26.86	$0.0045	$30.24	$30.61	-	$30.61	$0.38	1.2%
GS < 50 kW	$39.41	$0.0130	$65.41	$40.91	$0.0122	$65.31	($0.10)	(0.2%)
GS > 50 kW	$281.65	$2.5709	$667.29	$305.73	$2.4082	$666.96	($0.32)	-
USL	$21.20	$0.0069	$27.41	$20.97	$0.0063	$26.64	($0.77)	(2.8%)
Streetlights	$7.85	$30.6934	$3,582.74	$5.52	$21.5853	$2,519.41	($1,063.32)	(29.7%)
Large User	-	-	-	$5,574.12	$2.4082	$17,615.12		

Residential customers move to 100% fixed rates in 2019.

The current variable rates include the ICM rate rider created when we installed the 50 MW transformer in 2015. As it gets incorporated into actual rates it gets split between fixed and variable which is why the commercial fixed rates are rising and the variable rate are falling.

Streetlight rates are falling 30% due to a change in methodology required by the OEB. Streetlight revenues currently total $280k so this will be a reduction in revenue of $84k.

We tried to keep the Large User variable rate the same as the GS>50 kW rate. The fixed rates at other LDCs range from around $1,000 to over $20,000 with most being around $6,000-9,000.

1-SEC-2

Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2014, that are not already included in the application.

RESPONSE

Niagara-on-the-Lake Hydro could identify two such items that were not included in the original rate application:

1. **RRR Audit** – The OEB performed an audit of NOTL Hydro's RRR (Reporting & Record Keeping Requirements). It focused on appointments with customers as well as new services connected on time. This is a confidential document and NOTL Hydro has been advised by the OEB that the report cannot be shared publicly.
2. **Cyber Security Assessment** – This assessment was performed in late 2017 to alert NOTL Hydro of potential risks in our Networks. Due to the sensitive information pertaining to critical infrastructure contained in the report, it will not be supplied.

1-SEC-3

Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the test year. Please explain how those outcomes are incremental and commensurate with the rate increase the Applicant is seeking in this application.

RESPONSE

The table below summarizes the measurable outcomes that ratepayers can expect NOTL Hydro to achieve during the test year.

Outcome	Incremental	Commensurate with Rate Increase
Low rates	NOTL Hydro has some of the lowest rates in Ontario and the Niagara Region. This is the result of investment and operating decisions made since the company was incorporated.	If not for the OEB requirement to lower streetlighting rates, the rate increase for residential, small and medium business customers would have been zero.
New 83 MVA transformer installed at York MTS and 41,7 MVA transformer transferred to NOTL MTS.	Capacity at both stations will be increased so that both are above current peak demands and are expected to remain above for a number of years.	50% of the cost of the project has been built into the rates for 2019.
Conversion of additional sections of line from 4 kV to 27.6 kV in both rural areas and Olde Town (underground).	This project builds and continues the work voltage conversion project that has been undertaken for the past few decades.	The capital investment is equivalent to that which has been spent in prior years and the full capital spend is equivalent to depreciation adjusted for inflation.
Smart grid investments	These build on recent investments and increase the flexibility of the system.	These investments have helped reduce outage times, an important customer requirement, by allowing immediate switching during an outage.
Line losses	Line losses are best measured over multiple years but the overall trend at NOTL Hydro has been decreasing losses.	Lower line losses offset some of the impact of the rate increase.
Scorecard measures	Most scorecard measures capture the success of processes at the LDC. These are developed and improved over the years.	To some degree, the scorecard measures provide an indication of the service levels NOTL Hydro customers can expect. Not all services, such as the provision of services at the office and access to

		management are captured.
Large customer data access	GS>50 kW customers will be able to access their interval data, bills and analytical tools using the new Utilismart platform. This will be introduced, when fully installed, at no additional cost.	For large customers, this will provide a level of access to data which is beyond what is currently provided to residential and small business customers through CustomerConnect.

1-SEC-4

Please provide a step-by-step explanation of the Applicant's budgeting process.

RESPONSE

Below is a step-by-step explanation of NOTL Hydro's budgeting process.

1) Distribution Revenue
    a. NOTL Hydro completes a load forecast similar to the one submitted with this application to determine the expected load for the remainder of the reforecast year and the budget year.
    b. The consumption amounts derived from the load forecast are multiplied by the expected rates for the budget year to determine distribution revenues (rates are normally based on the initial IRM or COS as submitted by NOTL Hydro)
    c. Other revenues are forecast based on historical trends, known changes to service charges adjusted for any anomalies or known changes that will occur in the budget year.
    d. Energy sales and cost of power are calculated based on the load forecast and the most recent rates published by the OEB.
2) Operating Expenses – non-payroll
    a. Year to date operating expenses by vendor, job number and account are downloaded from Great Plains (GP) and summarized by month.
    b. Year to date operating expenses are reviewed by finance and the appropriate department heads and a forecast for the remainder of the current fiscal year is derived. This process includes several meetings, investigation of expenses to date and variance analysis compared to prior year, budget etc.
    c. Year to date actuals plus the forecast for the remaining months are combined to create the current year reforecast.
    d. Once the forecast for the current fiscal year is complete, the budget for operating expenses for the following year is created. The base for the budget is the forecast plus an inflationary factor which is normally based on the OEB Price Escalator less NOTL Hydro's assigned stretch factor.
    e. The base budget is reviewed by finance and the appropriate department head and adjusted based on non-recurring expenses, expectations for the budget year, variance analysis and discussion with senior management.
3) Payroll
    a. Year to date hours worked by employee, month, and job number and downloaded from GP and summarized by month. This includes hours for both capital and operating jobs.
    b. Year to date hours worked are reviewed by finance and the appropriate department heads and a forecast for the remainder of the current fiscal year is derived.

   c. Year to date actuals plus the forecast for the remaining months are combined to create the current year reforecast.
   d. Once the forecast for the current fiscal year is complete, the budget for hours worked for the following year is created. The base for the budget is the forecast. The budgeted amounts for each employee are adjusted based on expectations for the coming year. In particular, the hours budgeted for capital work for the Operations group is reviewed in line with the budgeted expectations for capital work versus repair and maintenance work.
   e. Wage rates for unionized employees are based on the most recent collecting agreements. Wage adjustments for non-unionized employees are budgeted in-line with the adjustments for unionized employees.

4) Benefits
   a. Benefits including CPP, EI, EHT, WSIB and OMERS are calculated based on the rate published for the budget year. If those rates are not available the most recent rates are used (adjusted for inflation). The benefits are calculated for each employee.
   b. Rates for Health and Dental, LTD, Life Insurance and EAP are based on recent claims experience and rates adjusted for inflation. These are calculated on a company basis and allocated to each employee.

5) Depreciation
   a. Depreciation expense on existing assets is estimated based on forecasts available from GP.
   b. Depreciation expense on capital work completed in the reforecast (not in GP) is then calculated using the half year rule for the reforecast and a full year for the budget year.
   c. Depreciation expense on capital work completed in the budget year is then calculated based on the half year rule

6) Interest Expense
   a. Interest expense is calculated based on debt repayment schedules for NOTL Hydro’s long-term debt and SWAP agreements
   b. Interest expenses on the line of credit and Bankers Acceptance notes are based on the most current interest rates.

7) Capital Budget
   a. For General Plant, System Renewal and System Service projects, NOTL Hydro determines a blanket budget largely based on depreciation updated for inflation. This calculation is described in Chapter 5 of the Business Plan. Projects for the budget year are funded based on criticality until the budget blanket is full. Factors which influence criticality included include labour availability, impact on reliability or costs, likelihood of potential failure and meeting long term objectives.
   b. One-time large projects which cannot be budgeted within the above framework are budgeted separately as needed. Recent examples of this include the new truck, the Lakeshore Rd. rebuild, the transformer project and the battery project.

c. Reliability and cost management are two of the factors taken into consideration in determining the annual projects. These are the top two priorities identified by our customers.

The first draft of the budget is reviewed by the management team and any necessary changes are made prior to submission to the Board of NOTL Hydro for approval. The budget for the following year is normally presented to the board at meeting held in October. At this point in the year the reforecast for the current year includes actual data up to and including August and forecast data for September through December.

1-SEC-5

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant has taken since 2014. Please quantify the savings achieved.

RESPONSE

The following are some of the productivity and efficiency measures NOTL Hydro has undertaken since 2014. It is not possible to quantify the savings in many cases.

1. Installed File Nexus in 2014. This allowed for the digitization of all customer files. This was completed for all historical files in 2015 and customer files are now digitized as they are received. This is more productive for customer service staff and more efficient for our customers.

2. Outsourced bill printing to ERTH in 2015. It was estimated that out-of-pocket costs would be the same as printing in-house due to savings in bulk purchasing and bulk postage rates. Productivity savings for customer service staff are estimated as $12,000 a year.

3. Implemented the outage management system in 2015 using Savage Inc. and smart meter data. This provides quicker notification of outages and reduces the reliance on customer calls. This is more efficient and productive as outages can be fixed on a more timely basis.

4. Joined CHEC in 2015. Significant benefits from collaboration with other small LDCs in activities such as customer surveys, cost of service rate applications, policy development and health and safety. An independent analysis valued the membership of CHEC at $255k per year.

5. Began increased outsourcing of IT services in 2015. These services have expanded over the years as IT demands and cybersecurity requirements have increased. This is efficient as without this outsourcing a new staff member would be required.

6. Reduced payroll from once a week to once every two weeks in 2015. Estimated annual productivity improvement of $4,000.

7. Purchased two electric cars in 2016. One, a Nissan Leaf, cost only $10k as was purchased as part of a Smart Grid Fund project. As the combined mileage is over 100k the estimated savings are $6-8,000.

8. Began installing various types of smart switches in 2016. These improve productivity by restoring power to certain customers quicker.

9. Brought pole testing and meter reading in-house. This saved $40k annually. This was made possible by the hiring of an additional lineman and transferring one of the existing linemen to a new role which included the two jobs above. Sound management will involve transferring services between outsourced and in-house as circumstances warrant.

10. Entered into a 3 year contract for vegetation management in 2018. Estimated annual savings of $7,000 compared to annual contracts as had previously been the practice.

11. Contracted lawn and garden maintenance at office in 2017. Estimated savings of $1,500 per year. This service has previously been performed by co-op students are apprentice linemen but as these were no longer employed (they have become linemen) the outsourcing was more cost effective.

12. All significant contracts are put out to tender. However, through this tendering process NOTL Hydro has developed strong relationships with certain suppliers (Wiens – underground work, Hiline – overhead and transmission station work, Pineridge – vegetation management) who share NOTL Hydro's values. These relationships allowed for better planning which allows for more competitive tendering. The savings is difficult to quantify but is estimated at over $100,000 per year.

13. Most of the light fixtures both inside and outside were replaced with LED lights. Estimated savings of 8,000 kwh per year.

14. The service provider for UCS (Utility Collaborative Service) switched from Util-assist to CHEC in 2018. This is estimated to save over $125,000 per year which will be shared by the participating LDCs including NOTL Hydro. UCS provides the service of hosting and maintaining the Northstar CIS system for NOTL Hydro.

15. The capability to use Cognos reporting with Northstar was introduced in 2016. This allows for more efficient and more accurate access to the underlying data.

1-SEC-6

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant plans to take in the test year. Please quantify the forecast savings.

RESPONSE

NOTL Hydro has two significant projects planned for 2019: the new 83 MVA transformer with the related changes to both transmission stations and the 250 kV battery storage unit. The first project is about improving reliability while the second is about improving customer choice for renewable generation. These two projects will take up most of the operational resources outside of the regular daily functions.

NOTL Hydro has seven non-executive staff in its "front office" functions: customer service, finance, CDM and IT. At least two of the seven will be on maternity leave during 2019. While replacement staff have been hired; the efficiency and productivity is never as high with replacement staff due to the learning curve. This limits the capacity for making substantial changes.

Nevertheless, there are some plans for actions that will improve efficiency and productivity in 2019. Savings cannot always be quantified.

- The Utilismart settlement manager will go live. This project has been in development in 2018. This software will allow NOTL Hydro's larger customers to view their usage and demand in a user-friendly fashion and allow NOTL Hydro to more efficiently prepare the 1598 reporting, monitor all generation for accounting/reporting purposes and calculate the NSLS.
- A workflow capability in the Great Plains general ledger will be brought into production in 2019. This will allow standard processes, such as account payable, to be formalized creating efficiencies.
- In cooperation with ERTH, NOTL Hydro is working on a bill print re-design to make customer bills clearer and more user friendly. This should be introduced during 2019.

- FIT and MicroFIT reporting is currently manual. During 2019, this process will be transferred to Northstar so will become a system generated process.
- Net metering reporting is currently manual. During 2019, the set-ups in Northstar will be finalized allowing these bills to be generated by the billing system.

1-SEC-7

[Exhibit 1, p.84] The Applicant says that as a result of its 2018 Open House: "These needs and preferences were used to guide NOTL Hydro as we prepared our 2019 Cost of Service application. The Investments in the transformers are a key response to the reliability preference." Please explain, using examples, of how exactly customer preferences were used to guide its 2019 Cost of Service application.

RESPONSE

Customers at NOTL Hydro's 2018 Open House were given a survey to rank their priorities for NOTL Hydro's service. This survey was also available on-line.

The top two priorities, by a significant margin, were reliability and cost. The following are some of the ways in which the 2019 Cost of Service Application was guided by this customer preference.

Reliability:

- Management's biggest concern is of losing the use of one of our transmission stations at a peak time and the second station not having the capacity to handle the full Town load. This could lead to brown outs, extended outages for customers and requests to reduce demand. This concern was heightened with the failure twice in early 2017 of the Hydro One radial line to NOTL MTS. If these failures had occurred during the summer then the above scenario might have occurred. The proposed transformer purchase addresses this issue and prepares NOTL Hydro for future growth.
- NOTL Hydro's voltage conversion program improves reliability by upgrading older lines in a consistent manner. Performance is also improved by the voltage conversion. Burying the lines underground in the Olde Town further improves reliability.
- The installation of smart grid technologies has improved reliability by helping NOTL Hydro gets sections of lines online quicker at times of an outage. The reclosure on Lakeshore Rd has been an example of this.
- NOTL Hydro's low debt:equity ratio means that NOTL Hydro can easily and quickly borrow should an emergency arise and a major investment be needed on behalf of our customers.

Cost:

- NOTL Hydro has had the lowest rates in the Niagara Region for a number of years. The Financial Post ranked our residential rates as the 7th lowest in the Province. NOTL Hydro wants to maintain this track record.

- Were it not for the OEB requirement that NOTL Hydro reduce our streetlight rates, our rate application would have had no change in rates for the residential, GS<50 kW and GS>50 kW customer classes.
- Our capital program is designed so that in most years the expenditures for non-Customer Access projects is equivalent to depreciation adjusted for inflation. As a result, the impact on rates is limited to inflation. Customer Access projects are self-financing through the increased sales so the only capital projects that drive real rate increases are the large transformer projects.
- NOTL Hydro's OM&A is increasing only 2% in the 2019 test year over the current 2018 bridge year.

1-SEC-8

[Exhibit 1, p.75, 84] Please explain why the Applicant relied on the results of the survey taken during its 2018 Open House to determine the "needs and preferences" of its application, and not the results of its 2017 Customer Survey.

RESPONSE

NOTL Hydro takes into account all its interactions with customers in determining its needs and preferences. This includes surveys, open houses, discussion with local elected representatives and, most important, its daily interaction with customers. The survey taken during the 2018 Open House, while less scientifically accurate than the 2017 or 2015 customer surveys, provided results that could be more easily correlated with the objectives of the rate application. For this reason it was referenced more than the other surveys or customer interactions.

1-SEC-9

Has the Applicant undertaken any customer surveys in 2018? If so, please provide a copy of any draft or final results.

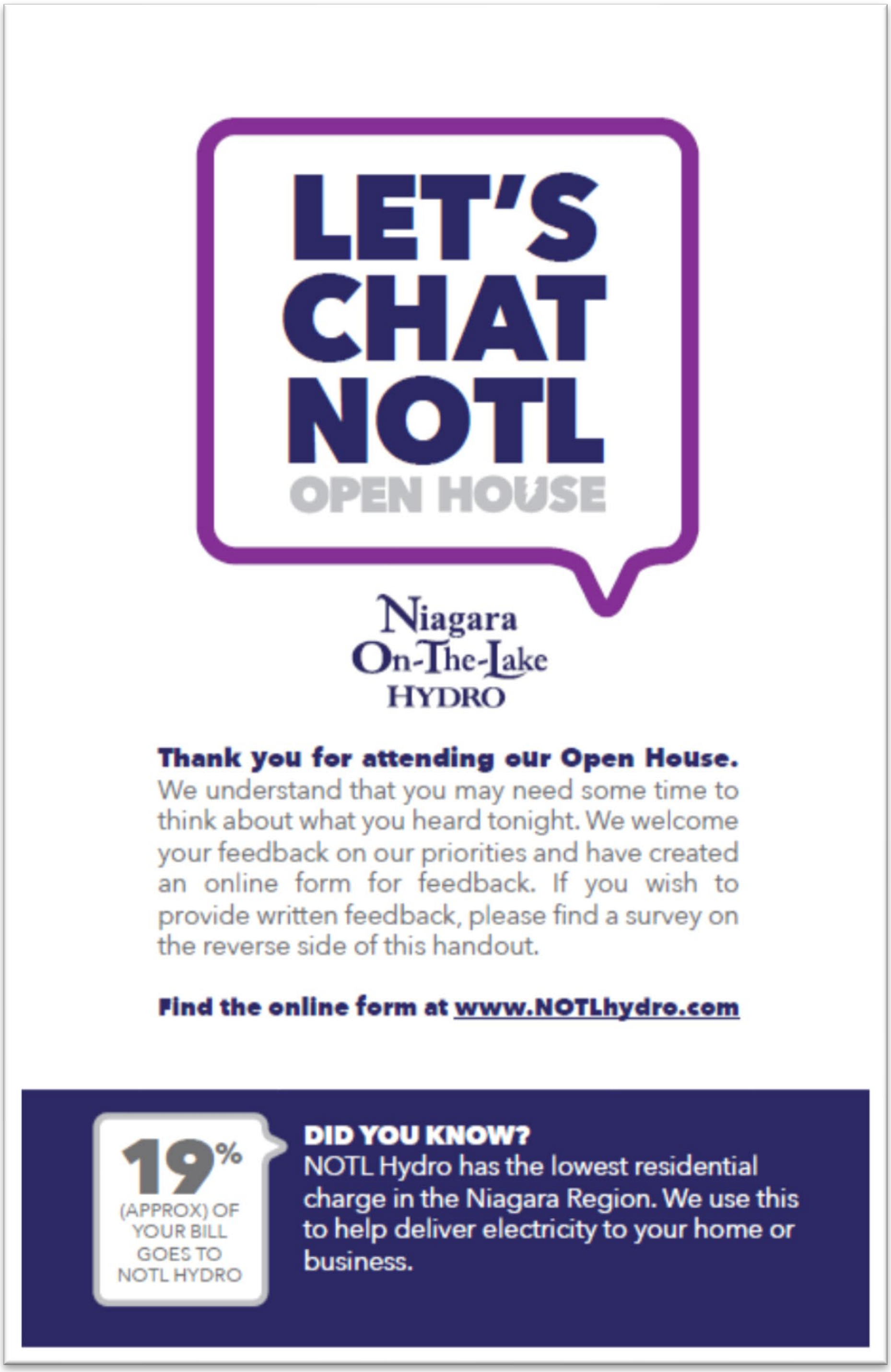
RESPONSE

NOTL Hydro performed two customer (2) surveys in 2018:

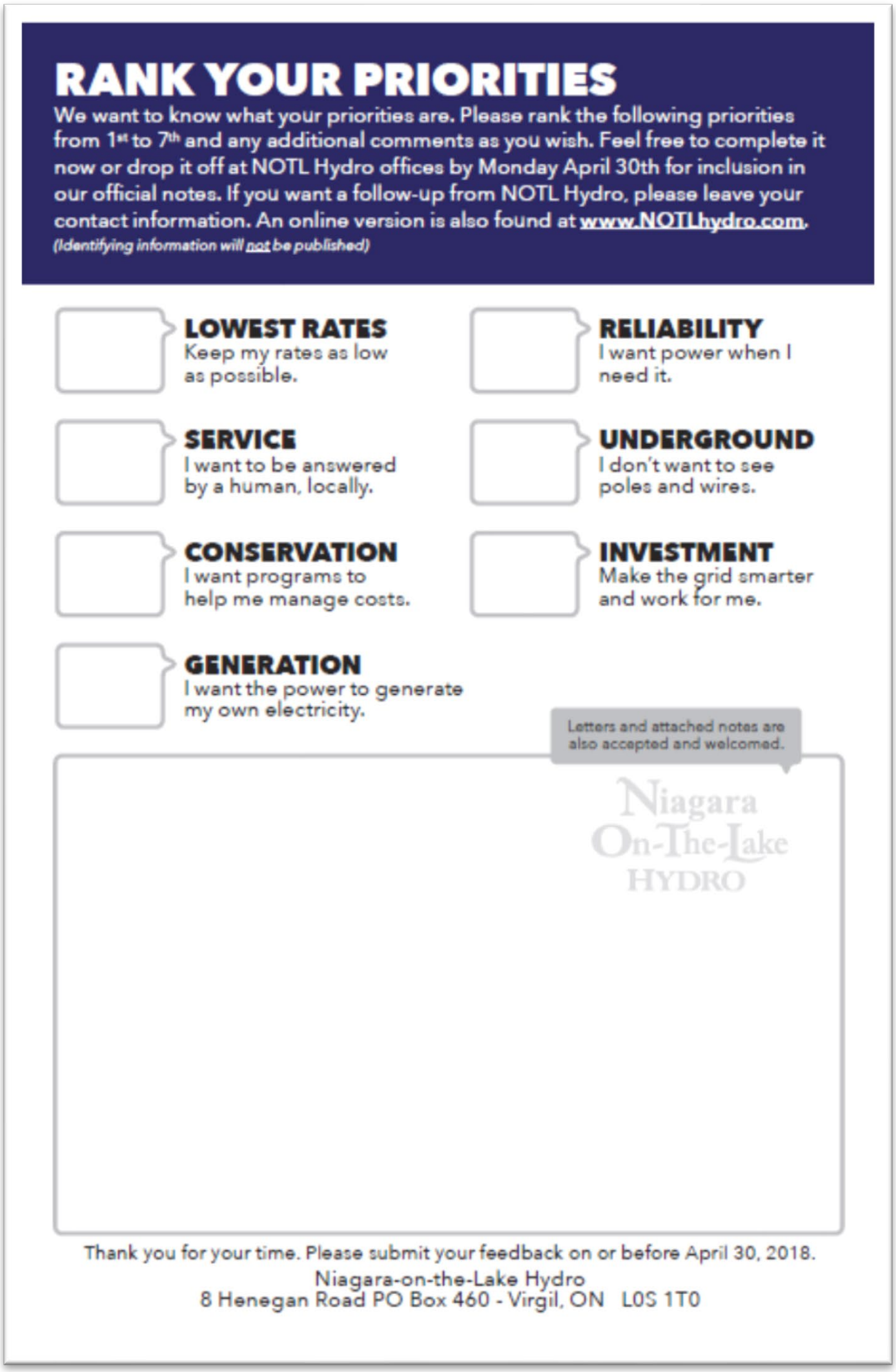
3. **ESA Safety Survey** – This was submitted in the original rate application as Appendix 1J.
4. **Open House Survey** – This survey was presented online and in paper form in support of NOTL Hydro's Open Houses in the spring of 2018. The results were incorporated into the CGC 2018 Customer Engagement Report that was submitted in the original rate application as Appendix 1H.

Survey Design and results are on the following pages.

Front of Paper Survey:



Back of Paper Survey:



RANK YOUR PRIORITIES

We want to know what your priorities are. Please rank the following priorities from 1st to 7th and any additional comments as you wish. Feel free to complete it now or drop it off at NOTL Hydro offices by Monday April 30th for inclusion in our official notes. If you want a follow-up from NOTL Hydro, please leave your contact information. An online version is also found at www.NOTLhydro.com.
(Identifying information will not be published)

LOWEST RATES
Keep my rates as low as possible.

RELIABILITY
I want power when I need it.

SERVICE
I want to be answered by a human, locally.

UNDERGROUND
I don't want to see poles and wires.

CONSERVATION
I want programs to help me manage costs.

INVESTMENT
Make the grid smarter and work for me.

GENERATION
I want the power to generate my own electricity.

Letters and attached notes are also accepted and welcomed.

Niagara On-The-Lake HYDRO

Thank you for your time. Please submit your feedback on or before April 30, 2018.
Niagara-on-the-Lake Hydro
8 Henegan Road PO Box 460 - Virgil, ON L0S 1T0

Results

37 responses were collected via paper and online submission. The responses are shown below:

		RANKING							
ID#	SOURCE	Lowest Rates	Reliability	Service	Underground	Conservation	Investment	Generation	Notes Section
1	Email	1	1	1	1	1	1	1	
2	Email	2	1	4	7	6	5	3	I really appreciate the quality of the service provided by NOTL hydro. I would like to continue to see notl hydro be owed by NOTL only. Please be very protective of out little gem.
3	Email	1	1	3	4	1	2	3	
4	Email	1	3	4	5	2	6	7	
5	Email	1	1	1	1	1	1	1	
6	Email	1	2	4	7	1	1	1	There are so many people making minimum wage that work and live in town. (Please remember that not everyone living in NOTL is wealthy, Decision makers often forget that) The cost of hydro is far too high already Even with the Ontario Electricity Support Program, which thankfully I qualify for. Keep costs as low as possible PLEASE .
7	Email	1	1	1	1	1	1	1	
8	Email	3	1	2	2	3	2	7	
9	Email	7	1	1	1	1	1	1	Ontario Hydro has been scamming its customers for decades. And we have been double paying for gross mismanagement that shows up on our bills. We've been gouged for transportation charges, etc. and are still be asked to pay for the lines leading into our homes??! I can't even think of the leadership and their cronies without the taste of spittle in my mouth. Remember, what goes around comes around in your personal lives!
10	Email	1	2	3	5	5	6	7	
11	Email	1	1	5	7	1	2	7	NOTL hydro is now peddling solar panels, that work only for NOTL hydro benefit.
12	Email	2	1	5	5	6	7	3	I would like more info about solar options
13	Email	1	3	1	3	1	2	7	
1	Printed Survey	3	1	4	7	2	6	5	NOTL Hydro takes "ownership". Toine
2	Printed Survey	2	1	4	7	3	6	5	
3	Printed Survey	1	5	2	7	6	4	3	
4	Printed Survey	2	1	3	7	6	5	4	
5	Printed Survey	2	1	5	7	6	3	4	
6	Printed Survey	1	2	3	7	6	5	4	
7	Printed Survey	4	3	7	5	6	2	1	
8	Printed Survey	3	1	6	5	4	2	7	

9	Printed Survey	1	2	3	4	6	5	7	
10	Printed Survey	1	1	1	7	7	1	7	I think that the risk of extra costs for solar panels on you house is too high. Disassemble + re-assemble for roof shingle replacement - installation causing leaks in roof - degradation + risk of damage to panels which the homeowner would pay.
11	Printed Survey	3	1	2	6	7	5	4	
12	Printed Survey	1	3	7	6	4	2	5	
13	Printed Survey	4	1	6	2	7	5	3	
14	Printed Survey	2	1	3	6	7	5	4	
15	Printed Survey	2	1	4	7	3	6	5	Reliability is extremely important but not the only issue that's important. Lowest rates should no mean "lowest possible rates", it should mean "reasonable rates" so that operations and mainteance are not compromised. Conservation is important on a global scale and to assist/support small
16	Printed Survey	3	1	2	4	6	7	5	FRONT - *NOTL Hydro is running an excellent service*. BACK - The notion of rating these components is extremely difficult. Since Hydro One generates more energy than needed why not reduce one of energy than sell excess to USA for much lower rate. Elminates premium charges.
17	Printed Survey	1	2	4	6	3	5	7	Lower rates must not be at expense of reliability
18	Printed Survey	1	2	6	7	3	4	5	
19	Printed Survey	3	1	2	7	6	4	5	Make peak vs lower cost times to reflect normal behavior. EG Lowering rates at 5 or 6 pm would be farm more beneficial to families than 7pm.
20	Printed Survey	1	4	2	7	3	6	5	
	AVERAGE	1.94	1.64	3.36	5.15	3.97	3.79	4.36	

1-SEC-10

With respect to Advocacy activities:

a) *Please provide a copy of all submissions, letters, presentations, and similar materials.*
b) *Please provide the annual cost of these activities over the last 3 years, and the forecast cost of these activities in 2018 and 2019.*

RESPONSE

The following is a list of all submissions, letters, presentations and meeting notes from 2014 to 2018 for which written material was prepared and for which a copy could be located. Some of the presentations (typically panels) had no prepared material and the meeting notes for some of the meetings have not been saved. The items below relate solely to our advocacy efforts. Items related to industry initiatives have not been included.

Copies of each of our press releases is also included though not listed below. These are also available on our website.

January 26, 2015	Notes for meeting with MPP Cindy Forster
March 3, 2015	Letter to Premier's Advisory Council on Government Assets
April 13, 2015	Notes for meeting with PC Energy critic John Yakabuski
April 14, 2015	Presentation to Ontario Power Conference
June 3, 2015	LDC of the Future presentation – Ryerson University
June 11, 2015	Letter to the Minister of Energy
June 16, 2015	Presentation at NDP Hydro One rally
August 17, 2015	Notes for meeting with Minister of Energy Bob Chiarelli
November 4, 2015	Letter to Premier's Advisory Council on Government Assets
November 27, 2015	Letter to OEB Chair
October 13, 2016	Notes for meeting with Phil Donelson – advisor to Premier Wynne
May 1, 2017	Notes for meeting with PC Energy Critic Todd Smith
May 4, 2017	Presentation to OSUM Conference
May 23, 2017	Transcript from presentation to Standing Committee on Justice Policy on the Fair Hydro Plan
May 24, 2017	Presentation at Open House (>800) on Wasaga Distribution
August 10, 2017	Letter to the Financial Accountability Office of Ontario
November 2, 2017	Letter to Minister of Finance Charles Sousa
April 9, 2018	Presentation (as part of CHEC) to the OEB Modernization Panel

The out-of-pocket costs of these activities has been minimal. These costs have been paid by the non-regulated company, Energy Services Niagara Inc.

Year	Cost	Purpose
2015	$449	Media distribution of press release
2016	$449	Media distribution of press release
2018	$2,260	Consulting on party platforms

We are not currently forecasting any future out-of-pocket costs for the remainder of 2018 or for 2019. This may change depending on whether the NOTL Energy Board feels that actions would be in the best interests of our customers.

1-SEC-11

Does the Applicant have a corporate scorecard? If so, please provide copies of each of the 2014 to 2018 versions. If not, please explain what metrics the management and Board of Directors use to measure and monitor the Applicant's activities.

RESPONSE

NOTL Hydro does not have a specific corporate scorecard. The Board of Directors meets monthly to receive reports from NOTL Hydro management and receives a variety of reports through-out the year. In particular, the results of the OEB scorecard, the PEG report and a summary of key ratios from the OEB Yearbook are provided annually which allow the Board of Directors to benchmark the performance of NOTL Hydro.

The Board of Directors does set annual priorities for management. These priorities encompass the non-regulated activities of NOTL Energy. These are provided below for 2015 to 2018:

Niagara-on-the-Lake Hydro Inc.
2015 Goals

Goal	Measure
Lobbying on behalf of small LDC's	Description of efforts and engagements over 2015 • Joined CHEC with network of 15 small LDC's all with complimentary goals • Meeting with Jim Bradley January 22 • Meeting with Cindy Forster, NDP – January 26 • Meeting with John Yakabuski, PC Energy Critic April 13 • Presented on "LDC Consolidation Myths" at Ontario Power conference on April 14 • Lunch with Peter Tabuns, NDP Energy critic May 21 • "LDC of the Future" presentation, Ryerson event, discussion on consolidation in question period June 3 • Participation in NDP event on Hydro One sale June 16 • 15 minutes with Minister of Energy August 17 • OEA Conference Panel on Consolidation September 16 • Minister debate challenge news release December 9
New transformer	On time and under budget Time: Early estimate May 2015, transformer went live June 11, 2015 Budget: Approved budget $2,645,000 Actual cost: $2,485,484 One additional project of $110,000 planned Summary: Almost on time and under budget
Succession planning	Plan Plan presented to Board at October Board meeting
Safety	Description of efforts over 2015 to ensure continued safety culture • New part time safety co-ordinator position created and filled on one year contract starting February 2015 • Dundas Power Line (contractors) no longer used for line work due to safety concerns • Safety issues factor in decision to end employment of Matt Marino • 5 JHSC meetings held during 2015 • 6 safety meetings held during 2016

Niagara-on-the-Lake Hydro Inc.
2016 Goals

1. Safety Objectives

- Ensure compliance with new working at heights and noise regulations
- Target zero lost time incidents through leadership and focus
- Direct new part time safety consultant to improve procedures and conduct inspections

Safety Accomplishments

- Full compliance with working at heights and noise regulations
- Zero lost-time incidents
- Randy Kent (formerly of Waterloo North Hydro) started in January as new safety consultant
  - Developed respect of line staff due to strong knowledge of both safety requirements and line work
  - Improved safety meetings
  - Numerous site inspections (staff and contractors)
  - Policies updated/completed in 2016 included Mayday, Noise, Backing vehicles and Bill 132/Harassment

2. Advocacy Objectives

- Take actions promoting smaller LDC's and combatting consolidation bias
- Take actions promoting steps to lower the cost of electricity on behalf of NOTL Hydro customers and all Ontario consumers
- Educate and keep NOTL Hydro customers informed of changes

Advocacy Accomplishments

- Board meeting with Tim Clutterbuck – April 2016
- Meeting with PC Energy Critic John Yakabuski – July 2016
- Board meeting with NDP Energy Critic Peter Tabuns – August 2016
- Open letter to Premier Wynne – September 2016
- Meeting with blog critic Tom Adams – October 2016
- National Post article – October 2016
- Produced pamphlet explaining electricity bill "Your Bill" – November 2016
- Meeting with Greater Niagara Chamber of Commerce – December 2016
- CHEC meeting with Ministry of Energy – December 2016

3. Financial Management Objectives

- Find suitable candidate for VP Finance position

Financial Management Accomplishment

- Jeff Klassen hired in November 2016

4. System Design

- Complete the updating of the GIS system
- Install and implement first round of new automated switches
- Facilitate new distributed generation installations in NOTL
-

System Design Accomplishments

- GIS system updated for all capital jobs
- Plan developed (lower cost alternative) for updating all outstanding spot sheets
- One third of system asset condition inventory completed and uploaded into GIS
- Remaining system asset condition inventory to be competed in 2017 with a less expensive option being reviewed
- All planned switches for five years purchased and in inventory
- First new automated switch installed (finalized in early 2017)
- Analysis of feeder capability for new generation presented to Board
- Six new FIT generation facilities expected in 2017 as a result of FIT 4 in 2016

Niagara-on-the-Lake Hydro Inc.
2017 Goals

1. **Safety Objectives**
   - Ensure readiness for potential Ministry of Labour inspection
   - Target zero lost time incidents through leadership and focus
   - Direct part time safety consultant to improve procedures and conduct inspections

Safety Accomplishments
- Zero lost time incidents
- Inspection readiness maintained though Ministry of Labour has only just started LDC inspections
- Improved safety procedures include:
  - New site inspection procedure with up to 6 site inspections a month now being performed by operations management
  - Updated contractor training procedure
  - Updated 16 Health and Safety Policies and Procedures

2. **Advocacy Objectives**
   - Take actions promoting smaller LDC's and combatting consolidation bias
   - Take actions promoting steps to lower the cost of electricity on behalf of NOTL Hydro customers and all Ontario consumers
   - Educate and keep NOTL Hydro customers informed of changes

Advocacy Accomplishments
- Actions combatting consolidation bias included:
  - Helped prevent Wasaga Beach sale/merger through direct intervention
  - Arranged Board meeting with PC Energy Critic Todd Smith
  - Analysis on Hydro One acquisitions
- Actions promoting steps to lower the cost of electricity include:
  - Monthly press releases on various opportunities to save
  - Presented to Parliament Committee on Fair Hydro Plan
  - Intervened in IESO SME rate application
- Actions on keeping NOTL Hydro Customers informed include:
  - Two Open House sessions in April 2017
  - Monthly press releases

3. **Financial Management Objectives**
   - Develop plan for 2019 Cost of Service Rate application
   - Begin Customer Engagement Process, Asset Management Process, Business Strategy and Distribution System Plan associated with the 2019 COS application
   - Provide recommendations and develop a plan for the CIS system

Financial Management Accomplishment

- Plan for 2019 Cost of Service application developed and now being implemented
- Customer Engagement Process (Open Houses in April), Asset Management Process (70% done), Business Strategy and Distribution System Plan well under way
- CIS system being rolled under CHEC which will reduce costs and help ensure greater stability in membership

4. Strategic Objectives

- Take results of customer survey and make recommendations for improvements
- Take on a leadership role at the NRBN Board
- Protect NRBN investment and help drive corporate growth
- Through planned quarterly meetings discuss with all staff the direction and goals of NOTL Hydro

Strategic Objectives Accomplishments

- A number of improvements implemented partially as a result of the customer survey including:
  - Updated website
  - Timing of bills being moved closer to time of meter reads for a number of customers
  - More staff have access to social media to make updates during outages
  - We are accepting more credit card payments
- Pro-active role on NRBN Board to protect investment and ensure:
  - NRBN is run as a business and not a department of Niagara Falls
  - SWIFT decisions are made based on business factors
  - Management develops as business leaders
- Regular discussions held with staff on direction and goals of NOTL Hydro:
  - Strategy session held in August followed by special staff strategy session
  - Five team meetings held through-out year
  - Weekly meetings with direct reports who, in turn, have periodic meetings with staff

Niagara-on-the-Lake Hydro Inc.
2018 Goals

1. **Safety Objectives**
    - Ensure readiness for potential Ministry of Labour inspection
    - Target zero lost time incidents through leadership and focus
    - Conduct safety audit and implement recommendations

Safety Accomplishments

•

2. **Advocacy Objectives**
    - Take actions promoting smaller LDC's and combatting consolidation bias
    - Take actions promoting steps to lower the cost of electricity on behalf of NOTL Hydro customers and all Ontario consumers
    - Educate and keep NOTL Hydro customers informed of changes

Advocacy Accomplishments

•

3. **Financial Management Objectives**
    - Complete 2019 Cost of Service Rate application
    - Develop plan for dealing with XXXXXX in Cost of Service Rate application
    - Implement recommendations from cyber security audit reviews

Financial Management Accomplishment

•

4. **Strategic Objectives**
    - Help guide NRBN through development of a long term strategic plan
    - Look for opportunities to grow ESNI
    - Update succession plan
    - Assess readiness and prepare NOTL Hydro for the emerging future utility transition to a role as a network integrator
    - Present the proposed detailed Asset Management Plan to the Board as developed for submission with the COS application

Strategic Objectives Accomplishments

•

1-SEC-12

[https://www.oeb.ca/sites/default/files/2019-Benchmarking-Spreadsheet-Forecast-Model-20180919.xlsx] Please complete the Board's Benchmarking Forecast Model.

RESPONSE

Attached as appendix 1-SEC-12.1

1.0-VECC-1

Reference: E1/pg. 89

a) **Please update Table 1.47 (Scorecard) so as to include 2017 actual results.**

RESPONSE

Please see response to question 1-Staff-4.

1.0-VECC-2

Reference: E1/Appendix 1F

The following extract is provided in the Redhead Media Solutions Inc. February 15, 2016 Customer Survey:

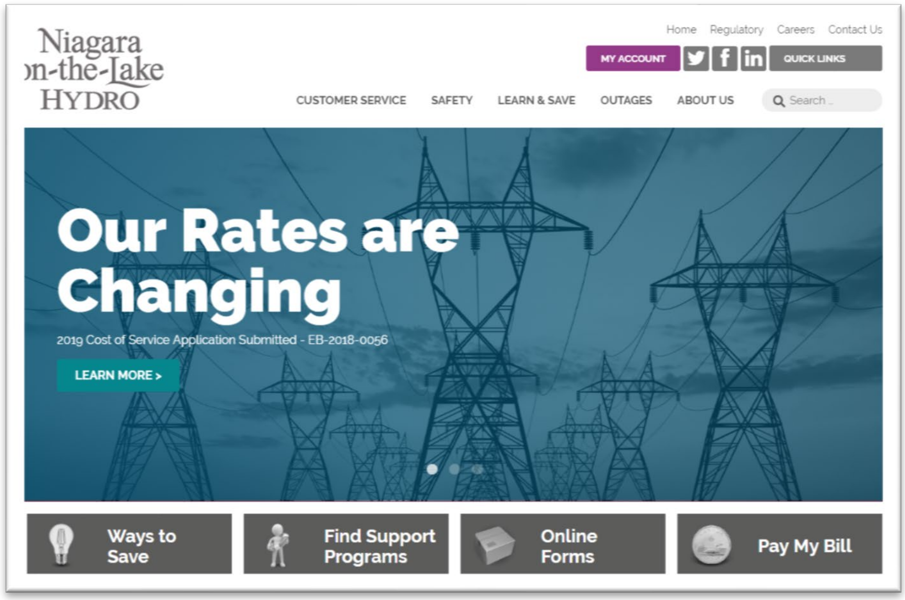
Niagara-on-the-Lake Hydro is doing well in this area, but there is room for improvement. There is a positive perception that the utility provides a reliable power supply; however, the number of outage complaints was higher than we've seen in other areas and scores for communications around either scheduled or unscheduled outages indicate that customers are not getting the information they want about outages. We make that comment, recognizing that there were two significant outages during the survey period. It is important to consider that receiving information is, for the most part, up to the customer more than it is up to the LDC. If the customer is actively seeking it, are they finding it? If they are not actively seeking it, we know that they definitely will not find it. The latter group may still find fault in the LDC for somehow not getting information into their hands.

a) Please explain what actions are being taken by NOTL to address customer complaints with respect to communications by the Utility of outages.

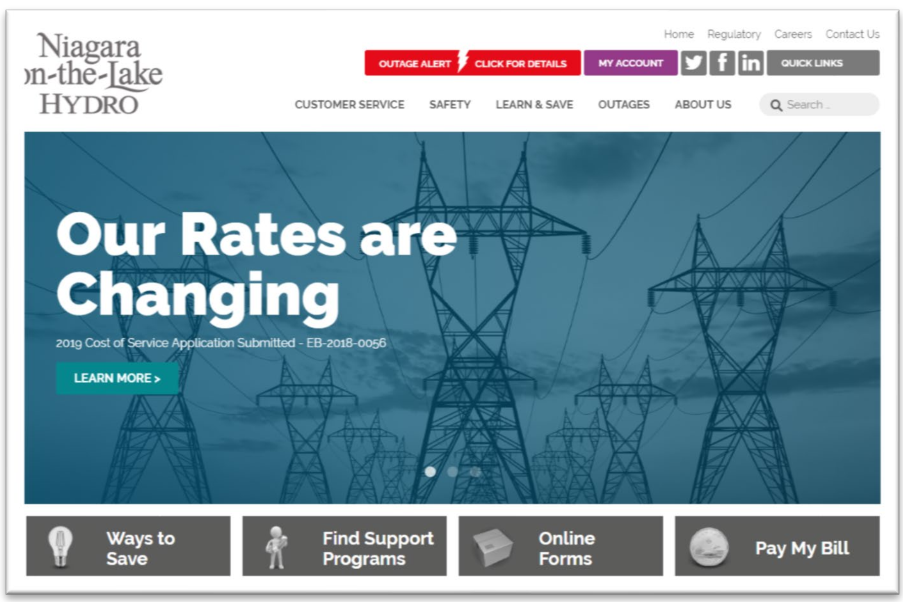
RESPONSE

Since 2016, NOTL Hydro has further developed our social media abilities and updated our website for improved communications with customers during outages.

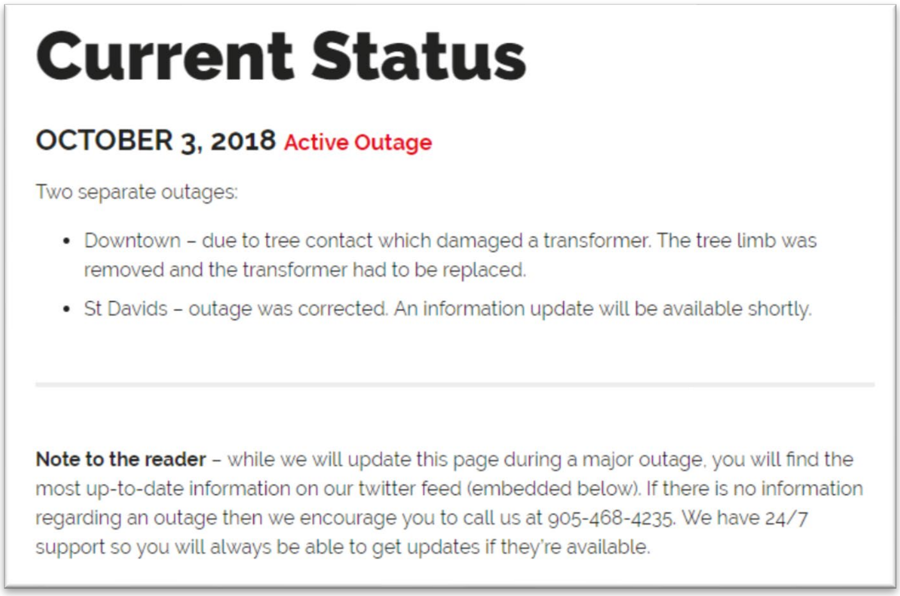
- **NOTLhydro.com Website Update**
  - The NOTL website was updated in 2017 to allow for more control, ability to update and to be accessible and available on a variety of devices that the old version could not support. NOTL Hydro built-in some outage specific options that assist visitors during an outage.
    - The appearance of the website is uniform as seen in the screenshot below:



- When an outage occurs, three members of the NOTL Hydro staff have the ability to update the website with outage details. The screenshot below shows the home page when an outage is in effect:



- When clicking on the link, the visitor is sent to another page that provides more detail on the outage as seen in the image below:



Current Status

OCTOBER 3, 2018 Active Outage

Two separate outages:

- Downtown – due to tree contact which damaged a transformer. The tree limb was removed and the transformer had to be replaced.
- St Davids – outage was corrected. An information update will be available shortly.

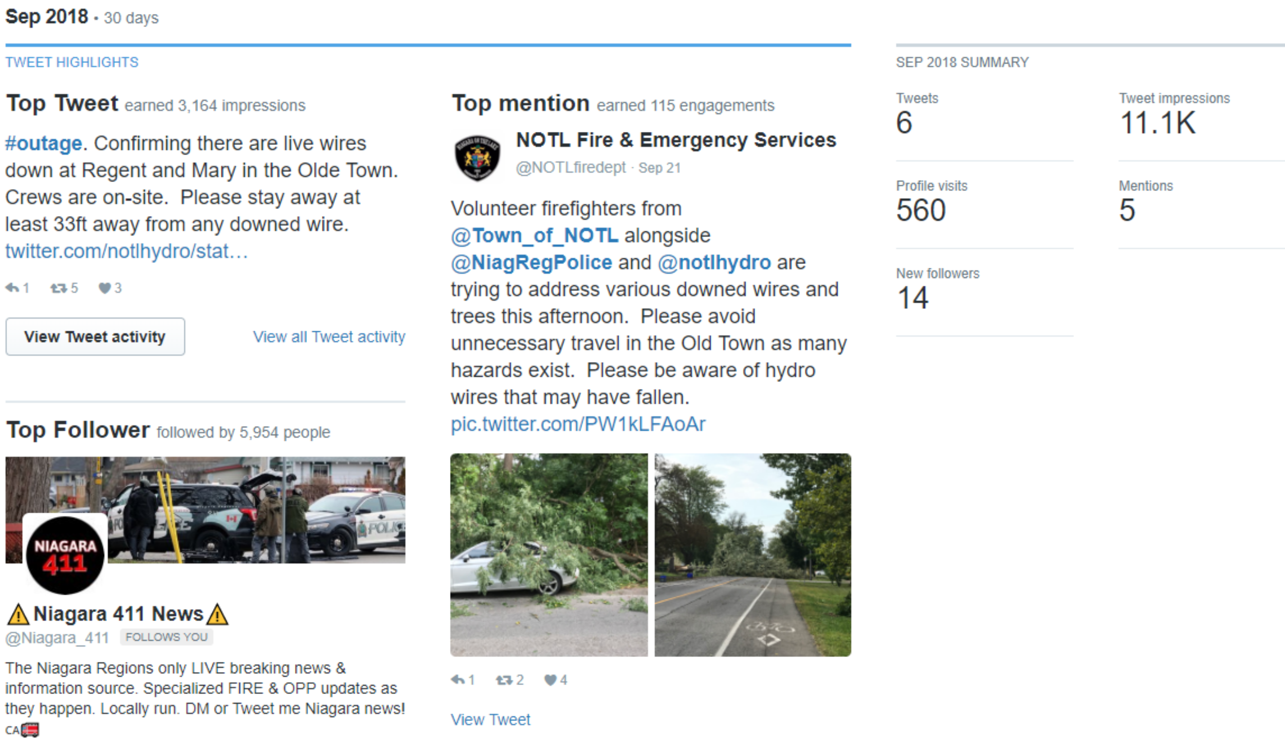
Note to the reader – while we will update this page during a major outage, you will find the most up-to-date information on our twitter feed (embedded below). If there is no information regarding an outage then we encourage you to call us at 905-468-4235. We have 24/7 support so you will always be able to get updates if they're available.

- Further website updates are being developed including potentially an interactive map that will show the general area affected. Note that in order to respect the privacy and security of our customers, we will never have public information identifying specific locations of outages.

Social Media Updates

- **Twitter** – Twitter is the resource that is recommended primary tool for customers to get updates on outages. Four NOTL Hydro staff members have access to the Twitter account in case of out-of-office hour outages. The NOTL Hydro follower account sees increases any time an outage occurs, indicating that outage updates are a key driver in obtaining followers in the area. In January 2016 **@notlhydro** had 975 followers and as of November 2, 2018, **@notlhydro** has 1,671 followers.

  - NOTL Hydro attempts to limit the number of tweets to only important subjects such as outages, safety messaging, conservation opportunities and other messaging as deemed important to the NOTL customer base. The screenshot below shows September 2018 highlights.



- **Facebook** – NOTL Hydro's facebook account is a mirror of the Twitter account as both are administered using the Hootsuite application. The NOTL Hydro account currently has 246 followers.

- **By Phone**
  - NOTL Hydro continues to offer 24/7 customer support using our local phone number 905-468-4235. In times of outages, customers are encouraged to call our number for updates or to report them. Should call volume increase to an unsustainable level staff are able to switch the line over to our call centre (located within the Niagara Region) to take on the call volumes.

NOTL Hydro will continue to look at best practices when dealing with outage notifications and will always evaluate the net benefit of the implementing any new solution considering costs, privacy, security and complexity of implementation.

2 | Rate Base

INTERROGATORY RESPONSES

2-Staff-10

Ref: NOTL Hydro's Industry Relations Enquiry IRE-2018-0638 and IRE-2018-0630

Staff understands that NOTL Hydro sent two enquiries to the OEB in September 2018, indicating that NOTL Hydro is considering constructing a section of line between two transformer stations and installing necessary switching and metering equipment. Staff did not note any evidence regarding the section of line in this application.

a) Please explain if NOTL Hydro plans to complete this work in the next five years.

i. If so, please provide updated evidence on this project and NOTL Hydro's plan is to address the impacts to rates.

RESPONSE

NOTL Hydro is currently assessing the feasibility of the project referred to above. No decision has been made. There are a number of obstacles and decision points to be overcome before NOTL Hydro can be in a position to determine if it plans to complete the work. NOTL Hydro therefore did not consider it appropriate to include cost recovery for this potential project in its Application.

NOTL Hydro notes that this project will have to be submitted to the OEB for approval before it can proceed. If a rate impact is required, it will be dealt with at that point.

2-Staff-11

Ref: Exhibit 2, Page 11; Appendix 2B NOTL Hydro Capitalization Policy; International Accounting Standard (IAS) 16 Property, Plant and Equipment

NOTL Hydro states on page 11 of Exhibit 2 with respect to its policy for the timing of capitalizing a capital project:

> **For accounting simplicity, projects are kept as capital work in progress until all the paperwork, invoicing and payments have been completed. This can become substantial period of time after the actual assets are in service. To be conservative, previous years' capital work in progress has not been included in rate base. While this policy continues to be applied, for the purpose of this forecast we have assumed that all 2018 projects are completed in 2018 and that the assets are in service. [Emphasis added by staff]**

Staffs notes that the above policy is not stated in the Appendix 2B NOTL Hydro Capitalization Policy.

Staff notes that the IAS 16 states that the timing for recognizing a PP&E item and for starting the depreciation is when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management:

> **Paragraph 20: Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management.**
>
> **Paragraph 55: Depreciation of an asset begins when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management**

a) Please confirm that the statement of "projects are kept as capital work in progress until all the paperwork, invoicing and payments have been completed" is a capitalization policy.
  i. If so, please explain why it was not included in the Appendix 2B NOTL Hydro Capitalization Policy.

b) Given NOTL Hydro's statement of "This can become substantial period of time after the actual assets are in service", please explain if and how NOTL Hydro's policy conforms to the requirements by the IAS 16.

c) Please explain why NOTL Hydro does not consider the timing of "the actual assets are in service" as the timing when a PP&E item is in the location and condition necessary for it to be capable of operating in the manner intended by management.

d) Please provide the time period that this policy has been used.

e) Please confirm whether or not this policy impacts the Construction Work in

Progress (CWIP) balances as at year end.

a. If so, please estimate the impacts for 2014 to 2017. b. If not, please explain why not.

RESPONSE

a) The statement "projects are kept as capital work in progress until all the paperwork, invoicing and payments have been completed" is not a capital policy. This process is used internally through-out the fiscal year to ensure that all costs are accurately captured. All completed jobs are left open throughout the year and closed at year-end. If an asset is ready for use at the end of the fiscal year and final costs can be reasonably estimated but invoices etc. are still outstanding, the amount is accrued and the item is capitalized in that year. Since NOTL Hydro utilizes the half year rule this process has no impact on depreciation expense or work in progress reported at year-end.

b) This process is used internally through-out the fiscal year to ensure that all costs are accurately captured. If an asset is ready for use at the end of the fiscal year and invoices etc. are still outstanding the amount is accrued and the item is capitalized. Since NOTL Hydro utilized the half year rule this process has no impact on depreciation expense or work in progress reported at year-end.

c) NOTL Hydro does capitalize assets when the item is in the location and condition necessary for it to be capable of operating the manner intended by management.

d) The current policy has been in use since NOTL Hydro transitioned to IFRS in Fiscal 2015.

e) This policy does not impact CWIP balances at year end because if an asset is ready for use at the end of the fiscal year and invoices etc. are still outstanding the amount is accrued and the item is capitalized. Since NOTL Hydro utilizes the half year rule this process has no impact on depreciation expense or work in progress reported at year-end.

2-Staff-12

Ref: Exhibit 2, Pages 14-19

Table 2.10 to Table 2.15 provide the Fixed Assets Continuity Schedules including the CWIP information. Staff summarizes the CWIP information in the Tables 2.10-2.15 for 2014 to 2019 as below:

Exhibit 2, Table 2.10 - 2.15	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecas	2019 Forecast
CWIP- Internal	599,452	259,586	574,975	1,117,946	0	0
CWIP - Customer Projects	753,380	973,622	200,223	376,553	0	0
Total CWIP	1,352,832	1,233,208	775,198	1,494,499	-	-

NOTL Hydro has not included any CWIP in 2018 and 2019 forecast.

a) Please explain the reasons of the fluctuation of the CWIP-Internal and CWIP-Customer Projects annually from 2014 to 2017.
b) Please provide an update for the status of NOTL Hydro's ongoing capital projects in 2018 and the likelihood of the capital projects being in service as at end of 2018.
c) Given the fluctuation of the actual CWIP from 2014 to 2017, please explain if and how it is reasonable for NOTL Hydro to not forecast any CWIP for 2018 bridge year and 2019 test year.
d) Please provide updated CWIP balances and updated Fixed Asset continuity schedule as applicable.

RESPONSE

a) Fluctuations in CWIP
    a. Internal
        i. 2014 - $458k related to the installation of the new transformer at York Station
        ii. 2015 – Timing of overhead and underground conversions
        iii. 2016 – Timing of overhead and underground conversions
        iv. 2017 – Work to relocate pole line along Lakeshore Rd. due to a municipal road widening, down payment on a new line truck, and timing of overhead and underground conversions

The table below shows amounts by category.

Internal CWIP (at December 31)	2014	2015	2016	2017
New Transformer	458,740	-	-	-
Overhead Conversion	129,306	163,435	268,331	283,425
Pole Relocation (Municipal Road Widening)	-	-	19,671	386,981
Underground Conversion	11,407	96,152	286,974	341,240
Line Truck	-	-	-	106,300
Total Internal	599,452	259,586	574,975	1,117,946

b. Customer
   i. 2014 and 2015 were significantly higher due to the ongoing construction of the new outlet mall (2014 included $385k and 2015 included $391k)

b) NOTL Hydro does not foresee any significant changes from 2018 capital spend as submitted. NOTL Hydro has reviewed each project and believes that all Internal projects will be completed by year end, all underground work for 2018 was complete as of September. To the best of our knowledge there will not be any significant customer projects outstanding at year end.

The only amounts that will appear in CWIP at the end of 2018 will relate to down payments and some engineering costs incurred for the 83 MVA transformer to be installed in 2019 as well as some initial engineering work for the battery project also scheduled to be completed in 2019. Both these projects are still expected to be completed and capitalized in 2019 in line with our submission and therefore neither of these items would impact the forecast rate base amounts

c) NOTL Hydro has reviewed our capital forecast for 2018 and with the exception of the battery project and costs related to the new transformed referenced in part b above, it is expected that all internal capital projects to be complete by year-end. The plan is that all 2019 internal projects will also be completed by year-end 2019. In terms of customer projects, to the best of our knowledge there will not be any significant projects outstanding at year-end. Customer projects do not impact rate base as they are included on the Asset Continuity as both assets and contributions which net to zero.

d) Not applicable

2-Staff-13

Ref: Exhibit 2, Page 33; Appendix 2-BA Fixed Asset Continuity Schedule

On page 33 of Exhibit 2, NOTL Hydro states that

> **In 2019, it is planned to dispose of one of the old 25 MVA transformer at the time the new transformer is purchased. The disposal of this asset reduced NOTL Hydro's net book value for 2019 by approximately $225k and has been incorporated into the rate base.**

In the table below, staff summarizes the gross cost and accumulated depreciation and calculates the net book value for disposals in 2014 to 2019 as per Appendix 2-BA Fixed Asset Continuity Schedule:

	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Forecast	Forecast
Cost - Disposals	- $	-$ 320,555	-$ 223,348	-$ 587,057	$ -	-$335,048
Accumulated Depreciation - Disposals	- $	-$ 276,486	-$ 181,818	-$ 485,585	$ -	-$110,001
Net Book Value - Disposals (Calculated by Staff)	- $	-$ 44,069	-$ 41,529	-$ 101,472	$ -	-$225,047

a) Please confirm whether or not NOTL has forecasted the gain/loss from the disposal in 2019.

i. If so, please confirm that the forecasted gain/loss is included in the other revenues of the test year and provide the reference to the other revenue account.

ii. If not, please explain why not.

b) Please provide the actual disposals (including gross cost and accumulated depreciation) for 2018 as of now.

c) Please update the Appendix 2-BA for 2018 disposals using the actual disposals incurred to date and forecasted disposals for the remaining period in 2018, as applicable.

RESPONSE

a) NOTL Hydro included the disposal of the transformer in the fixed asset continuity and therefore in the Net Fixed Assets (average) for the calculation of rate base.

NOTL Hydro did not forecast a gain or loss on disposal in Other Revenue since the loss on the transformer is a one-time event. Therefore, NOTL Hydro does not believe the gain/loss should be included as a revenue offset to the proposed revenue requirement. Subsequent to our application it was determined that the transformer was no longer available for use due to the removal of the tap changer and will require disposal in 2018. An updated Revenue Requirement Work Form has been filed along with OEB Staff Interrogatory #1, and the updated Bill Impacts have been filed along with OEB Staff Interrogatory #2.

b) Actual disposals as of September 30th, 2018 are summarized in the table below.

	Asset Value	Accumulated Depreciation	Proceeds	Gain / (Loss) on Disposal	Change in Net Assets
Line Truck	250,400.16	250,400.16	30,973.45	30,973.45	-
Transformers	38,400.93	19,938.96	-	(18,461.97)	18,461.97

c) Forecasted disposals for the remainder of the year are summarized in the table below.

	Asset Value	Accumulated Depreciation	Proceeds	Gain / (Loss) on Disposal	Change in Net Assets
Poles	292,156.38	287,695.50	-	(4,460.88)	4,460.88
Conductor	212,886.27	201,819.56	-	(11,066.71)	11,066.71
Transformer Station	335,048.00	110,001.00	-	(225,047.00)	225,047.00

2-Staff-14

Ref: Exhibit 2, Page 13

NOTL Hydro states that:

> **Beginning in 2014 under IFRS, all new capital contributions were recorded in Account 2440 Deferred Revenue and allocated to revenue over the service life of the related assets, For the purpose of cost allocation, and continuity within this application, NOTL Hydro has included Account 2440 in the Continuity Schedules. This is consistent with the Board required treatment.**

Staff notes from Appendix 2-BA that the amortization of Account 2440 Deferred Revenue was removed from the FA continuity schedule each year and included into Account 4245 as part of the other revenues from 2016 to 2019. For 2019 test year, a total of $123,822 for the amortization of the deferred revenues was removed from the FA continuity schedule and included in the other revenues.

a) Please confirm whether or not NOTL Hydro agrees that the amortization of the customer contributions should remain in the FA continuity schedule (i.e. net against the depreciation expense) to align with the treatment of Account 2440.
   - **i. If so, please update the Appendix 2-BA FA continuity schedule and the Appendix 2-H Other Operating Revenues.**
   - **ii. If not, please explain why not.**

b) Please update the RRWF and provide the impact on the service and base revenue requirements.

RESPONSE

a) NOTL Hydro agrees that the amortization of customer contributions should be included in the FA continuity schedule of the purpose of calculating the average net fixed assets for rate base. However, consistent with IFRS and how NOTL Hydro will calculate depreciation expense and other revenues going forward, NOTL Hydro believes that the amortization of customer contributions should be included in other revenue for calculation of the revenue requirement. Treating customer contributions as deferred revenue decreases the Service Revenue Requirement by $123,822 but has no impact on Base Revenue Requirement.

b) n/a

2-Staff-15

Ref: Appendix 2Z Cost of Power

Staff compares the GS>50 consumption for non-RPP customers that are eligible for GA modifier in Appendix 2Z to the aggregate consumption of retailer customer filed by NOTL Hydro in RRR 2.1.5.4 and notes the following discrepancy:

	Consumption kWh
GS 50 to 2,999 KW rate class GA mod consumption kWh (cell J20 in Appendix 2Z)	14,691,294
Aggregate consumption kWh of retailer customers (RRR 2.1.5.4)	19,552,534.62
Difference	(4,861,240.81)

a) Please explain the discrepancy.
b) Please update the relevant appendices/schedules as applicable.

RESPONSE

a) The difference is due to customers that are with a retailer but are not eligible for the GA Modifier. These include interval metered customers and GS>50 customers that are not eligible for RPP or ORECA. In addition, there are GS>50 customers that are not with a retailer that qualify for the GA modifier since they qualify for ORECA.

b) n/a

2-Staff-16

Ref: Exhibit 2, Page 56

NOTL Hydro provides the 2017 interruptions (total customers affected and total customer hours) by cause codes on page 56 of Exhibit 2. Staff notes that the cause code 8 Human Element is the 2nd cause for the 2017 interruptions.

2017			
Causes of Interruptions			
Code	Description	Total Customer Affected	Total Customer Hours
1	Scheduled	54.0	219.5
2	Loss of Supply	-	-
3	Tree Contact	308.0	432.2
4	Lightning	1,073.0	664.3
5	Defective Equipment	45.0	60.2
6	Adverse Weather	4,362.0	2,186.1
7	Adverse Environment	-	-
8	Human Element	2,255.0	1,052.3
9	Foreign Interference	30.0	25.6
10	Unknown/Other	39.0	48.0
	Total	**8,166.0**	**4,688.2**
	Total (Excluding Loss of Supply)	**8,166.0**	**4,688.2**
	Total (Excluding Major Events)	**8,166.0**	**4,688.2**

a) **Please explain the nature of these interruptions that are caused by Human Element. Please provide examples as necessary.**
b) **Has NOTL Hydro analyzed these interruptions for future improvements?**
   i. **If so, please provide a brief description of the work performed.**
c) **Has NOTL Hydro developed any process/procedures to address the issues from the analysis work performed in b)?**
   i. **If so, please provide a brief description of the process/procedures developed.**

RESPONSE

a) A single outage that affected 2,255 customers was caused by a car accident that resulted in a broken pole that supported a main feeder serviced from NOTL MTS.

b) All outages are tracked for number of customers affected, duration and cause. Individual outages are analyzed if opportunities for improvement are identified during the outage. That is not always the case. Sometimes repairs will incorporate a re-design if that will improve operations.

c) No specific analysis was documented on this outage.

2-Staff-17

Ref: Exhibit 2, Page 50; Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Page 10

NOTL Hydro notes the following regarding the proposed capital expenditure on a battery in 2019:

NOTL Hydro is proposing to include in its 2019 capital expenditure the purchase and installation of a 250 kVA lithium-ion battery, which will be used to enhance the capacity of the M1 feeder to allow for more distributed energy. This battery is being purchased as part of a Ministry of Energy Smart Grid Fund project.
The project will be analyzing the use of the battery to enhance the capacity of a feeder for installation of increased renewable generation, to improve voltage regulation and to engage in peak use shifting. The project will run from 2018 to 2021 when the final report is due.

NOTL Hydro states on page 10 of the consolidated DSP that "continued investment in voltage conversion program and the planned battery investment will help try to further reduce the line loss rate over the forecast period". In addition, NOTL Hydro states that "Continued investment in transformer stations and in smart grid technologies will save customers by trying to keep the outage down."

a) Please explain in detail how the planned battery investment would help further reduce the line loss rate.
b) Please explain in detail how the battery investment would help to keep the outage rate down.
c) Please explain if the project would stop running after 2021 when the final report is due.
i. If so, please explain the benefits of the project after 2021 if any.

RESPONSE

a) Distribution circuits are optimized to operate as balanced as possible. Good distribution design strives to operate feeders as balances as possible and between 3% and 5% of each other. This is a challenge when faced with long single-phase feeders that are more prevalent in rural supply designs. Unbalances circuits have higher line loss rates due to higher inductive losses. Feeder balance behaves dynamically depending on the time of day, the season and the customer loading behaviours. Balanced phases also eliminate the flow of current in the system neutral and this benefits the performance of feeder efficiency.

NOTL Hydro's plan is that battery stored energy would be injected on the feeder at times when the feeder imbalance exceeds a pre-set limit. This is expected to improve balances, and reduce line losses. This benefit and use of the battery is additional to the items discussed in the business case for the battery which has been produced sin response to SEC interrogatory #16.

b) NOTL Hydro does not make the statement that the battery investment will help keep the outage rate down. The statement about keeping the outage rate down referred to smart grid investments in general such as switches and reclosures.

c) The battery will continue to be used past 2021. Depending on use, the battery is expected to have a life of around 10 years. The actual use of the battery will depend on the results of the project and will be based on optimizing the value of the battery. This is anticipated to continue to be a mix of voltage management and peak shaving. In this sense, the benefits of the project after 2021 will be the continuation of the benefits demonstrated by the project.

2-Staff-18

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Page 9

NOTL Hydro states, under point (e), that a key element of the DSP is as follows: The DSP has still been planned so that, in line with OM&A, the net effect on rates is minimal. This is a key goal of NOTL Hydro.

a) Please provide the analysis to show that the current planned capital expenditure with the current proposed OM&A have a minimal net effect on rates.
b) If there is no such analysis referred in a), please explain how NOTL Hydro ensures the minimal net effect on rates with current capital expenditures and the OM&A proposed.

RESPONSE

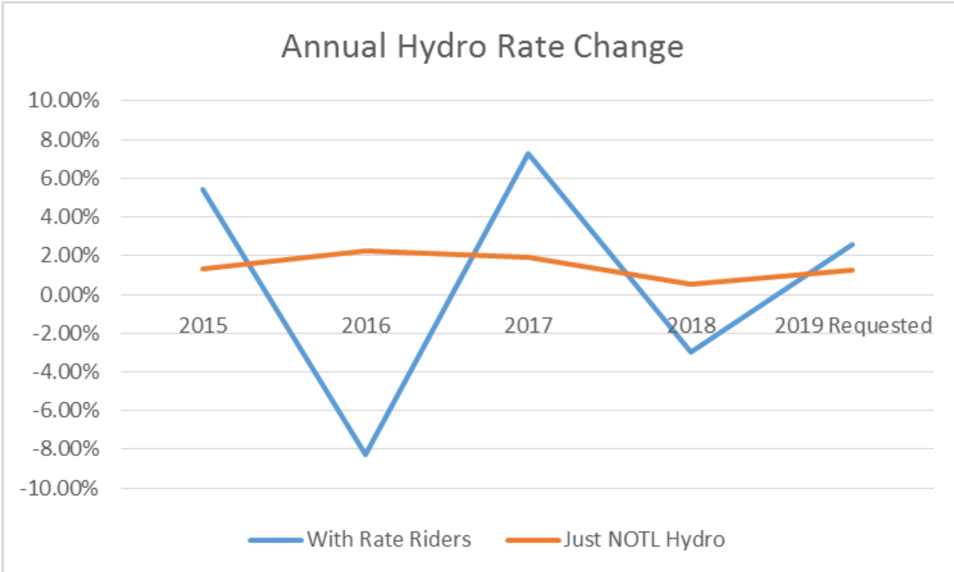
NOTL Hydro ensures the minimal effect on rates through its underlying strategy with regards to capital investments. For the purpose of this analysis, capital investments can be grouped in three categories: System Access, recurring capital and one-time projects.

System Access capital investments are considered to generate the cash flow to cover the costs of the investment so the only impact on rates should be negative. New subdivisions are managed through the CCRA process so that they generate the required return on investment. New customers located on existing lines require minimal investments. New customers requiring capital investments beyond what is standard pay for the excess cost of these investments.

Recurring capital investments are structured each year so that, on average, they are equivalent to the depreciation on the existing assets adjusted for inflation. This process was described in Chapter 5 of the Business Plan. The effect on rates of these investments will only be the inflationary impact.

This leaves the one time projects such as the transformer project in this application. These will have an impact on rates but are not every year and are considered necessary for the ongoing reliability of the service.

Evidence of this approach can be seen in NOTL Hydro's rates over the past four years and including this rate application. The average rate increase for distribution rates, excluding the rate riders, is 1.46% or less than the rate of inflation.


Annual Hydro Rate Change
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
-2.00%
-4.00%
-6.00%
-8.00%
-10.00%
2015
2016
2017
2018
2019 Requested
With Rate Riders
Just NOTL Hydro

2-Staff-19

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Pages 9 and 19

With respect to the proposed new 83 MVA transformer, NOTL Hydro notes that this $3.3 million investment will provide Niagara-on-the-Lake with full redundancy at both supply points at any time of the year. The new capacity at both stations will be sufficient for many years. The investment will also replace an aged 25MVA transformer that recently required emergency repairs.

On page 19 of the Consolidated DSP, NOTL Hydro indicates that on August 28, 2015, there was a loss of supply from Hydro One on one line that resulted in a loss of supply to customers because the other Hydro One line was out of service for maintenance. NOTL Hydro was able to receive power for over half of its customers as the supply lines are bidirectional, but four hours elapsed before full power was restored.

a) Has NOTL done any analysis of the expected increase in system reliability as a result of being able to meet maximum peak demands through either of its transformer stations?

i. If so, please provide this analysis.

ii. If not, please explain why no analysis has been done.

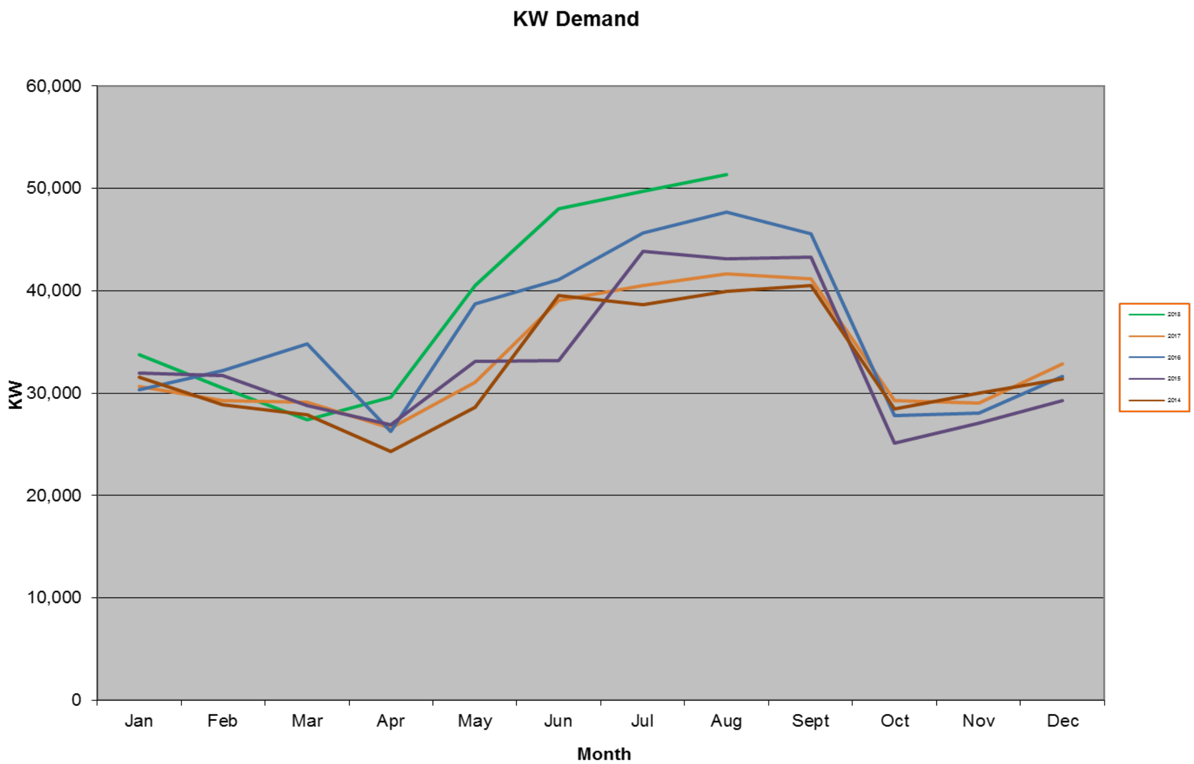
b) Would the investment in a new 83 MVA transformer mitigate against severe weather events such as severe lightning storms and ice storms that took place in 2015?

c) Would the proposed increase in transformer capacity to 83 MVA at York MTS have had any impact on the results of the outage in 2015 due to the loss of supply from Hydro One?

i. If so, please identify the expected decrease in customer outages that would have resulted.

RESPONSE

a) The graph below indicates a history of monthly system load with the peak set during summer months when air conditioning and tourism increase demand.



NOTL MTS has installed transformation of 30/40/50MVA and 15/20/25MVA. York MTS has transformation of 25/33/41.7MVA. Whereas all of the Town's electrical demand could be supplied from NOTL MTS during the peak month, the transformer at York MTS could not sustain the Town's load from about May to October before it exceeds its OLTC rating. In addition, the large customer connected in 2018 only contributed 3MW to 4MW to the current annual peak and this site has a load request of between 15 MW and 20 MW. When this load materializes, the low transformation capability at York MTS will be a bigger issue.

b) On two separate occasions in 2018, once in April and the second in early May, transmission poles owned by Hydro One servicing NOTL MTS were broken due to high winds experienced in the region. In each case, the Town's load was switched to York MTS for approximately a week to complete repairs. The 41.7 MVA power transformer was operating at its second stage of cooling which meant the total daytime load exceeded 33 MVA. If this was during a typical summer month, the Town's customers would be in rotational load curtailment. Customer hours affected with the first incident totalled approximately 12,000 which was the time to complete switching at the distribution feeders from NOTL MTS to York MTS. At the second incident, the supply was not interrupted to NOTL MTS but kept operating with a broken and leaning pole until the load was safely switched to York MTS.

Severe weather events increase the potential that the wooden transmission poles on the Hydro One radial line might come down. The larger transformer at York

MTS would therefore increase reliability in this scenario. The increase in the transformer would have no impact on outages due to any failures within NOTL Hydro's distribution system due to the severe weather.

c) The loss of supply in 2015 was due to a system failure on one transmission circuit that was supplying the load of the Town while the second transmission circuit was not in service for work due to pre-planned maintenance. A larger power transformer at York would not necessarily reduce or eliminate such an outage from occurring on the transmission system in the future as there only two options for supply to NOTL at 115kV.

2-Staff-20

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Pages 10 and 31

NOTL Hydro states in Section 5.2.1.3 Cost Savings that "the primary source of savings from an effective asset management process is reduced unplanned maintenance and repairs". However, Table 16: Capital Expenditure Summary on page 31 of the Consolidated DSP shows that actual expenditures on System O&M have increased from $904,000 in 2014 to $1,152,000 in 2018, thus increasing by $248,000 (27%) over 4 years.

a) **Please provide evidence that unplanned maintenance expenditure is decreasing.**
b) **Given that unplanned maintenance cost is decreasing, please explain why overall System O&M costs are increasing.**

RESPONSE

a) NOTL Hydro does not track maintenance expenditures between planned and unplanned so is not able to provide this measure. However, in section 5.2.1.3, NOTL Hydro does note how it believes it has managed unplanned maintenance. Namely, that it has been able to keep unplanned overtime to a minimum, that its line losses have continued to decline and that its outage record has remained stable.

b) Overall System O&M costs change and increase because of a variety of factors including inflation, system growth, additional services and accounting practices. NOTL Hydro's view is that its overall O&M cost would be higher without its success in reducing unplanned O&M costs. A more detailed analysis of the impact of these factors, in this case for all O&M and not just System O&M, can be found in Section 2.4.1.1.

2-Staff-21

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Page 11

NOTL Hydro states in Section 5.2.1.6 Future Contingencies that

> **None of NOTL Hydro's plans are contingent on future events. The exceptions are the System Access activities which are contingent on customer demand but there is a strong track record of this demand.**
>
> **A potential future event (though within this planning horizon) that could have a significant impact would be the lifting of the generation constraint within the Niagara region. This could lead to more investment in generation in Niagara-on-the-Lake to which NOTL Hydro would need to respond."**

a) Please confirm whether or not it is NOTL Hydro's practice to budget for contingencies in the Capital Expenditures Plan.
   - **i. If contingencies have not been budgeted, please explain how NOTL Hydro would respond to ad-hoc investment needs resulting from any future risks or unforeseen events.**
   - **ii. If contingencies have been budgeted, please provide the reference to the Capital Expenditure Plan and clarify the amount budgeted as contingency.**

b) Has NOTL Hydro assessed the timing and the quantum of expenditures that would result from the lifting of the generation constraint within the Niagara region?
   - **i. If so, please provide the analysis.**
   - **ii. If not, please explain why not, and how NOTL Hydro would respond to additional investment needs?**

RESPONSE

a) It is not NOTL Hydro's practice to budget for contingencies. Annually, a budget is created for the General Plant, System Renewal and System Service projects. Any contingencies are dealt with by adjusting the annual budgets. These updates are reported to the NOTL Hydro Board monthly. If a contingency is so large that it cannot be dealt with in this manner then a separate budgetary approval is sought from the NOTL Hydro Board. An example of this is the Lakeshore Rd project that had its own, multi-year budget, as it was too big a project to be contained in the regular budgets.

b) The Niagara region is currently constrained as there is insufficient transmission to transmit any additional generation out of the region. A number of generation projects in the Niagara Region, including in Niagara-on-the-Lake, have not proceeded due to this constraint.

There are a significant number of uncertainties that prevent NOTL Hydro from analyzing the time and quantum of investment that might be needed. These include:

- The number of generation projects that might result is unknown; especially as there are no more FIT contracts and the impact of net metering is still unknown.
- Hydro One's transmission requirements in terms of managing potential backfeeds and management voltages is unknown.
- The best technical solutions are still unknown. Options include installing a DEMS (Distributed Energy Management System), requiring generators to have LDC controllable inverters, installing additional protection and control systems at the transmission stations, using battery storage to mitigate the impact or various combinations of the above. The primary objective of our battery storage project is to research this issue further.

NOTL Hydro has had numerous discussions with the OEB, the Ministry of Energy, Hydro One and various US industry participants on this issue.

2-Staff-22

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Pages 31-34

Section 5.4.2, "Capital Expenditure Summary", provides details on year-over- year variances in capital expenditures from 2014-2018.

The variances by categories for the historical period of 2014-2018 are summarized in the table below:

	2014-2018 Planned Expenditure	2014-2018 Actual Expenditure	Variance $ (Actual-Planned)	Variance %	Reasons provided
System Access	$500k	$1,746k	$1,246k	249%	Underestimated the expenditures that it would be required to absorb under the Connection and Cost Recovery Agreements
System Renewal (excluding the transformer)	$4,995k	$4,292k	($703k)	(14%)	Resources were focused on the transformer project and not as much voltage conversion work was done as
System Service	$315k	$597k	$282k	90%	Increased service to meet the requirements of the IESO and the maintenance of the old 25 MVA transformer
General Plant	$475k	$940k	$465k	98%	The purchase of a new line truck in 2018

a) **Please explain why NOTL Hydro underestimated the expenditures for system access in 2014-2018.**
b) **Please explain why the purchase of a new line truck was not included in the planned expenditures of 2014-2018.**
c) **Given the variances experienced as described above by NOTL Hydro, please explain if any controls and additional steps have been introduced in NOTL Hydro's budgeting process to reduce the variances between actual and planned expenditures and to increase the accuracy of estimates.**

RESPONSE

None of the members of the senior management team who prepared the 2013 cost of service rate application are now with NOTL Hydro. Therefore, any explanations as to "why" the Distribution System Plan was prepared as it was represents our best estimates given the current management's knowledge of processes at NOTL Hydro.

a) In its Distribution System Plan for 2014-2018, NOTL Hydro noted that "System Access spending can be quite unpredictable as it is driven primarily by new customer expansion plans". It also noted that "Advance notice for municipally requested plant relocations is generally one year or less. CCRA-related refunds to land developers have been averaging $55,000 per year and we generally have been connecting 200 residential customers annually requiring a smart meter investment of $10,000. Our proposed budget has been set at $100k annually."

   Actual CCRA refunds to developers averaged $147,136 from 2014-2017 (2014 - $174,143, 2015 - $195,837, 2016 - $143,654, 2017 - $74,908). These were an average of $90k per year higher due to more subdivision developments than expected. This accounts for $450k of the increase when extrapolated to 2014-2018.

   The 2014-2018 DSP also did not include the municipally requested Lakeshore Rd. project which is budgeted at $575k.

b) In its Distribution System Plan for 2014-2018, NOTL Hydro noted that "Our general plant expenditures were ramped up between 2009 and 2012 as we replaced all 3 large line vehicles." As noted in the interrogatory, no new vehicles were included in the DSP for 2014-2018.

   The actual purchase years of the 3 new line vehicles were 2007, 2011 and 2013. In 2017, it was determined that the oldest of the vehicles, which was now 10 years old, was showing substantial wear and tear and should be replaced. A new vehicle was ordered for 2018. This investment both improved morale amongst the line staff and reduced down time as the older vehicle needed repairs.

c) With regards to System Access spending, no new budgeting processes have been introduced. System Access spending is self-financing in the sense that all the expenditures create their own revenue stream in new customers. The focus of the budgeting is therefore directed at the General Plant, System Renewal and System Service categories as these are either replacements of existing stock or additions to the system. The expenditures in these areas are carefully controlled, in aggregate, in the manner described in the current DSP. The total spend in these three categories is $44k or 0.76% over that planned in the 2014-2018 DSP.

With regards to the replacements of the remaining vehicles, these have been estimated in the 10-year capital forecast but will be subject to the annual evaluations of the conditions of the vehicles.

2-Staff-23

Ref: Exhibit 2, Appendix 2A, Consolidated Distribution System Plan, Page 46

NOTL Hydro explains one of its system access projects as follows:

The Region of Niagara undertook a rebuilding and road widening project on Lakeshore Road between Nine Mile Creek Rd and Townline Rd. This involved the rebuilding of an existing pole line of approximately 100 poles that was Bell Canada owned and part of the final arrangements included NOTL Hydro undertaking the construction responsibility and retaining the ownership of this line. This was negotiated by the Region and agreed by Bell Canada. The total cost of the rebuilding program is estimated to settle at $600,000, of which about $220,000 is expected to be recovered from the Region as a capital contribution.

a) **Did the existing line of 100 poles owned by Bell Canada carry electricity distribution lines or were they only used to support Bell Canada services?**
   i. **In the event that the 100 poles noted carried electricity distribution lines, does NOTL Hydro benefit from any reduction in pole rents paid to Bell Canada as the result of assuming ownership of the replacement line?**
   ii. **If the answer to (i) is yes, please indicate the annual reduction in pole rents paid.**

b) **Does NOTL Hydro expect to receive revenues in the future from Bell Canada as a result of its assumption of ownership of the new line? If so, how much revenue is expected annually? And how this is reflected in the other revenues?**

c) **What was the rationale for the adoption of final arrangements involving ownership by NOTL rather than Bell Canada?**

d) **What is the basis of the expected capital contribution of $220,000 to be provided by the Region?**
   i. **Please provide any policies or models that are used by the Region to support its $220,000 contribution.**

RESPONSE

a) The original 100 poles were Bell Canada owned poles and they had distribution lines and services supported from them in a joint use purpose.
   i. Annual joint use fees paid by NOTL Hydro will be reduced for the affected poles to Bell Canada once the pole line is re-built in early 2018.
   ii. NOTL Hydro will not pay Bell Canada any ongoing joint attachment fees eliminating an annual payment of $4,363.

   The financial models will be updated to reflect this. Please see response to OEB Staff interrogatories #1 and 2.

b) NOTL Hydro will charge Bell Canada the new OEB approved rate of $43.63 per pole starting in 2019 which equates to $4,363 annually for the subject poles. These payments were not reflected in the submitted forecast of Other Revenue. The financial models will be updated to reflect this. Please se response to OEB Staff interrogatories #1 and 2.

c) The Region of Niagara had a narrow timeline in order to proceed with their road widening project and the utility poles had to be relocated first. Recognizing the original pole line was owned by Bell Canada but the bulk of the work involved distribution lines and hardware, they approached both Bell Canada and NOTL Hydro on the question of ownership. Underpinning the Region's question was recognizing the relocation would proceed more swiftly if it were managed and finally owned by NOTL Hydro. There was agreement by all parties to proceed.

d) The basis of the capital contribution by the Region was the Provincial Public Service Works on Highways Act that most LDCs and roadway agencies follow. It lists an equal cost share of labour and labour saving devices (trucking and equipment used for stringing, etc) and 100% of costs related to specific requests made by customers affected by the power interruption and inconveniences.

2-Staff-24

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Pages 49 - 52; Appendix F of the DSP

NOTL Hydro has proposed to replace the remaining 25 MVA unit at NOTL MTS with the 41.7 MVA transformer that is currently operating at York MTS, with the intention of outfitting York MTS with a new 83 MVA power transformer in its place. The noted justification is to ensure the capacity at both the NOTL and York MTS is independently sufficient to handle the full NOTLH load in the future and to ensure redundancy should there be a failure at one station. As per Table 29 Transformer Project Budget, the purchasing cost of the new transformer is $1.35 million out of the total project cost of $3.3 million. The proposed transformer upgrades for the proposed 83 MVA transformer plotted on Table 26 illustrate a significant capacity buffer over the projected MVA peak beyond 2045.

Staff notes that Appendix F of the DSP provides six options to increase station capacity. One of the options is to replace the existing 15/20/25 MVA NOTL T1 with a new 25/33/41.7 MVA transformer similar to York T1. This option would bring the NOTL DS capability up to 66.7 MVA, which would allow it to supply the utility peak load.

a) Please provide the detailed analysis of pros and cons including cost considerations for each of the alternative options in Appendix F of the DSP and the rationale for the selection of this proposed option.
b) Please provide the rationale for building a significant future capacity buffer by investing in the proposed 83 MVA transformer.
c) The ultimate plan outlined in Appendix F envisaged two 25/33/41.7 MVA transformers at York rather than the single 83 MVA transformer that has been proposed. Would the proposed reliance on a single transformer, rather than two smaller transformers as outlined in Appendix F, carry greater reliability risk from the potential for transformer failure?
   i. If so, please quantify the reliability risk.

RESPONSE

a) **Option 1 – Upgrade to DESN** – Establishing a DESN design at one or both stations would allow for a second supply of transmission voltage at the station. This helps with redundancy but does not offer additional capacity to serve the growing load. A DESN at just NOTL MTS is also not practical as would require an additional high voltage radial line from the Q11S. This is estimated to cost over $2 million and the second line would not be positively received by the community due to the esthetics. The reliability concern should York MTS become the sole source of transformation would also remain an issue.

   In conclusion, while this option improves reliability, it is expensive and did not add capacity. The DESN option is one NOTL Hydro will continue to analyse but did not address the relevant issues at this time.

Option 2 – Replace Transformers – The Raven report was written in 2012 so the older transformers at NOTL MTS are now 35 years old. The T1 has already been replaced for a 30/40/50MVA unit. The second transformer T2 of the same vintage is still in service but it developed an electrical fault within the tap changer compartment in 2018. The tap changer had to be replaced. Fortunately, the tap changer from the older T1 was available and was moved to the T2 unit. This replaced tap changer will have to be closely monitored. While the EPTCON analysis may show the T2 transformer as healthy, NOTL Hydro no longer feels confident in relying upon the T2 transformer for meeting the power needs of its customers without back-up.

The Raven report did not recommend replacing the transformer at York MTS due to its low age. However, by replacing the transformer at York MTS with the larger 83 MVA unit and using the 41.7 MVA unit from York MTS to replace the old T2 transformer, NOTL Hydro is exercising this recommendation while also dealing with its concerns with under-capacity at the York MTS.

This option is supported with a $3.305 million project estimate.

Option 3 – Construct a New Supply Station - The stated reason for why this was not considered still remains valid. A new station would cost between $10 million and $20 million. Option 2 would give all the same benefits and at much less capital cost.

Option 4 – Add Static Capacitors to each Station – The stated reason for why this was not considered still remains valid. The capacity improvement would be quite small against the capital cost of installing capacitors at both stations. Static capacitors may be reviewed as an option in the future when the goal becomes correcting power factor imbalances from distributed generation but that is not the objective at this time.

Option 5 – Add a Fourth Substation Transformer – The basis of information for this option is now outdated. The present plan is to increase the capacity at NOTL MTS to 91.7 MVA and York MTS to 83.3 MVA. In the process of obtain pricing for the new transformer, suppliers were asked to bid on a 40/53/67 MVA transformer and 50/67/83 MVA transformer as they would both be suited for physical connections without major modifications. The cost of the 83 MVA unit was $100,000 more than the 67 MVA and it offers 24% more capacity and closer to the combined capacity of the York transformers. The longer term benefits was well worth the marginal extra cost.

To add a second power transformer at York Station would involve a substantial addition to the station footprint with all the connecting details on both transmission and distribution voltages. The cost would substantially exceed the cost of the present project and not add as much overall capacity for growth and supply contingencies.

Option 6 – Do Nothing – This would not be acceptable by NOTL Hydro's stakeholders and it would be contrary to the Company's Mission and Values. At all stakeholder meetings including the OEB meeting in the community, a common feedback message is to continue the forward thinking by NOTL Hydro to meet current and future growth challenges of the community and high system reliability while still managing costs.

b) The primary rationale for investing in the 83 MVA transformer at York MTS is the concern of reliability. Should the NOTL MTS service be lost, as has happened twice in 2018 when the Hydro One radial line went down, then the full Town load has to be supplied by York MTS. The 41.7 MVA transformer at York MTS is no longer sufficient to meet the full Town load at all times. The use of the 83 MVA transformer as a buffer for future growth was a secondary consideration.

c) There is a higher risk in having a single larger transformer at York MTS instead of two smaller units. However, as the NOTL MTS will be able to carry the full Town load this risk is mitigated. NOTL Hydro did consider this alternative but felt the incremental cost of reconfiguring the station and installing all the additional breakers and control equipment made it too expensive an option at this point. This will be a potential option in the future depending on the growth in demand in Niagara-on-the-Lake.

2-Staff-25

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Page 61

Table 34 below details NOTL Hydro's pole replacement analysis, including the quantity of poles scheduled to be replaced between 2019 and 2023 and the associated cost.

Pole Ranking	Quantity	Replacement Plan	cost
Critical	36	Replace in 2019	$ 150,000
Poor - replace in < 5 years (146)	30	Replace in 2020	$ 150,000
	35	Replace in 2021	$ 200,000
	35	Replace in 2022	$ 200,000
	45	Replace in 2023	$ 225,000
Good - replace in 5 to 10 years (1577)	70 to 75 each year	2024 +	
Excellent - Replace 10 years + (3740)			

Staff calculates the unit cost of the pole replacement based on the values provided in Table 34 as follows:

Critical	36	Replace in 2019	$150,000	$4,167
Poor - replace in <5 Years	30	Replace in 2020	$150,000	$5,000
	35	Replace in 2021	$200,000	$5,714
	35	Replace in 2022	$200,000	$5,714
	45	Replace in 2023	$250,000	$5,556

a) **Please explain the annual variation in estimated unit cost for pole replacement.**

RESPONSE

A number of factors cause variations in the cost to replace poor condition poles. These include:

- their locations as relative to each other;
- one off replacements versus replacing a string of poles;
- single versus three phase service on the pole;
- the nature of the framing;
- other services on the pole
- adjacent to a roadway to off road; and
- on a busy or a quiet road.

For 2020 to 2023, a generic estimate of around $5,000 per pole was used; adjusted for inflation and rounded to even numbers. For 2019, the specific poles to be replaced that year have been identified in a more in-depth fashion so the estimate for 2019 is based on the estimated costs for the specific poles to be replaced.

2-Staff-26

Ref: Appendix A, Asset Management Plan (AMP), Page 8

Table 4 below lists the Major Distribution Assets as of February 2018:

Asset	Count
Poles	6,809
Pole mounted transformers	1,003
Pad mounted transformers	799
Transmission voltage transformers	4
PMH units	20
Junction boxes	144
Primary wire - Overhead	236 km
Primary wire - Underground	132 km
Secondary wire - Overhead	171 km
Secondary wire - Underground	332 km

A robust Asset Management Plan would contain age distributions and asset health condition data for each asset class. This data would be used to determine asset failure rates, which would in turn be the basis for investment prioritization.

a) **Please confirm whether or not NOTL Hydro has age distribution data for each asset class.**
   i. **If so, please provide.**
   ii. **If not, please explain why not.**
b) **Please confirm whether or not NOTL Hydro has asset health condition distribution data for each asset class.**
   i. **If so, please provide.**
   ii. **If not, please explain why not.**

RESPONSE

a) Section 4.9 of the Asset Management Plan describes age distribution of significant asset classes; namely transformers and conduit. The aging of poles was not provided as the condition assessment provides a better tool for determining which poles to replace. The actual aging of the poles is provided below:

Age	Number of Poles
0 – 9 years	491
10 – 19 years	716
20 – 29 years	1,042

30 – 39 years	1,053
40 – 49 years	667
50 + years	1,129
unknown	1,711

b) The table above has been expanded with the health information for each asset class:

Asset	Count	condition			method of assessment
		poor	fair	good	
Poles	6,809	2.60%	23%	74%	pole tested and age
Pole mounted transformers	1,003	5%	23%	72%	mainly based on age and IR scan
Pad mounted transformers	799	0.50%	12.5%	87%	mainly based on age
Transmission Voltage Transformers	4	1	1	2	annual testing data and age
PMH units	20	1	3	16	annual inspectionsand assessments
Junction Boxes	144	2%	15%	83%	annual inspectionsand assessments
Primary wire - Overhead	236 km	<1%	10%	89%	mainly based on age of installation and adjusted for older 4 kV distribution areas
Primary wire - Underground	132 km	<1%	21%	78%	
Secondary wire - Overhead	171 km	<5%	27%	69%	
Secondary wire - Underground	332 km	<5%	21%	76%	

Annual IR (infra-red) scan is done of the distribution system which reveal hot spots on components that are signs of imminent failures. The subject components are replaced on a planned basis. The data is matched against age of other related devices, wire and loading so a determination is made if additional replacements or repair are needed.

2-Staff-27

Ref: Appendix A, Asset Management Plan, Page 13

Section 2.6 Prioritization explains that "NOTL Hydro assesses each investment on a case-by-case basis. The over-riding consideration in all assessments is what, in the opinion of NOTL Hydro, is in the long-term best interests of customers." Section 2.1 of the AMP explains that NOTL Hydro had polled and ranked the customer priorities in 2018. Staff notes that reliability ranked number one.

a. **Please explain how NOTL Hydro determines what gets funded every year?**
b. **Please explain how this ad-hoc prioritization on a project-by-project basis has aligned with the ranked customer priorities?**

RESPONSE:

All Customer Access projects are funded.

For General Plant, System Renewal and System Service projects, NOTL Hydro determines a blanket budget largely based on depreciation updated for inflation. This calculation is described in Chapter 5 of the Business Plan. Projects for the budget year are funded based on criticality until the budget blanket is full. Factors which influence criticality included include labour availability, impact on reliability or costs, likelihood of potential failure and meeting long term objectives.

One-time large projects which cannot be budgeted within the above framework are budgeted separately as needed. Recent examples of this include the new truck, the Lakeshore Rd. rebuild, the transformer project and the batter project.

Reliability and cost management are two of the factors taken into consideration in determining the annual projects. These are the top two priorities identified by our customers.

2-Staff-28

Ref: Appendix A, Asset Management Plan, Page 14

Page 14 of the AMP contains the following statement:

Part of any DSP is a replacement program for the assets of the LDC. Ongoing investments in capital renewal are an important part of maintaining a strong distribution system. The AMP helps identify which assets to replace in any given year and which assets may benefit from alternative measures such as enhanced maintenance, rebuilds or technological changes. The database part of the AMP will allow the LDC to take in all factors such as age, condition, location and customer needs when determining what assets to replace.

a) Please provide additional information on the database that is part of the AMP. What system application is used to capture age, condition, location and customer needs?
b) How many of the different asset classes have their age, condition, location and customer needs captured?
c) Please explain how asset replacement needs are prioritized from a customer perspective.

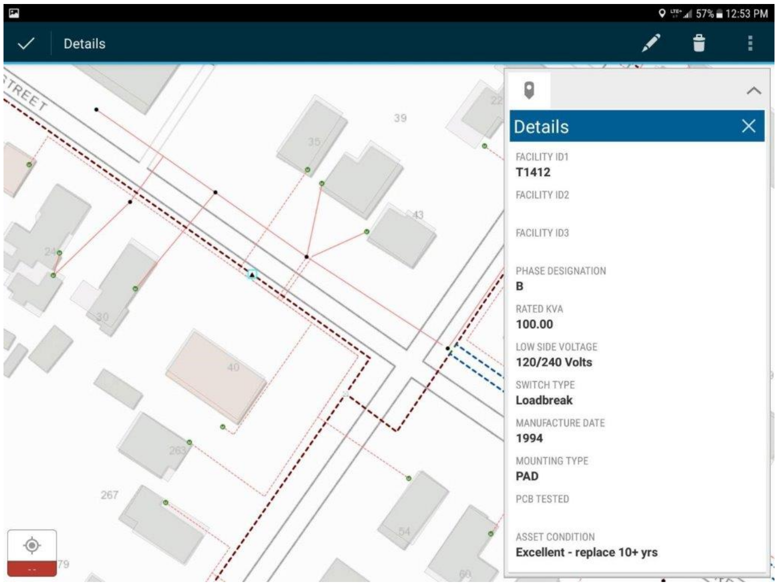
RESPONSE

a) NOTL Hydro subscribes to a full license of ESRI's GIS software. This software is used to store all the data as it provides a customer-centric means of accessing the data in a relational manner. As more and different data is gathered the use of the GIS software is expanded.

A number of tools are used to gather the required information. These include:

- Manual and infra-red inspections by NOTL Hydro staff;
- A tool known as PICUS that determines the remaining life of wood poles;
- Spot sheets as developed for ongoing services;
- Other NOTL Hydro systems that aggregate data.

A number of screen shots are provided below to illustrate the data.


12:53 PM
Details
STREET
Details
FACILITY ID1
T1412
FACILITY ID2
FACILITY ID3
PHASE DESIGNATION
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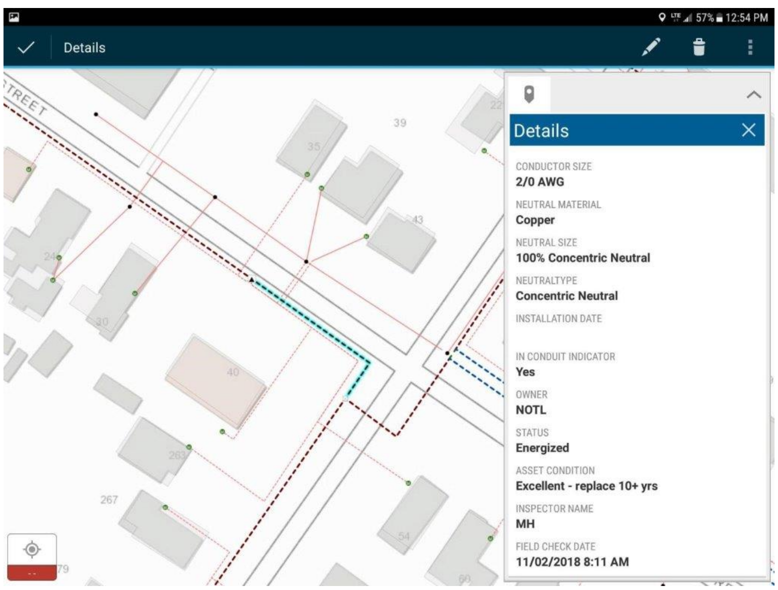
RATED KVA
100.00
LOW SIDE VOLTAGE
120/240 Volts
SWITCH TYPE
Loadbreak
MANUFACTURE DATE
1994
MOUNTING TYPE
PAD
PCB TESTED
ASSET CONDITION
Excellent - replace 10+ yrs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CONDUCTOR SIZE
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NEUTRALTYPE
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INSTALLATION DATE
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ASSET CONDITION
Excellent - replace 10+ yrs
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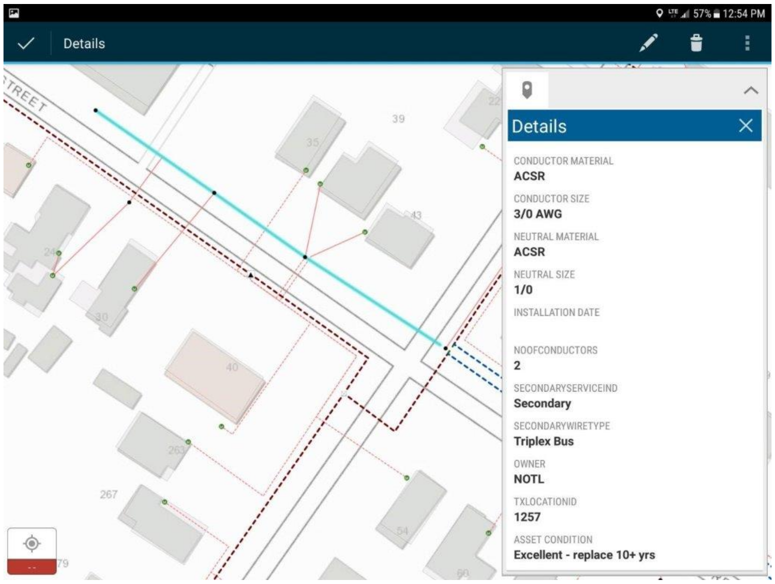
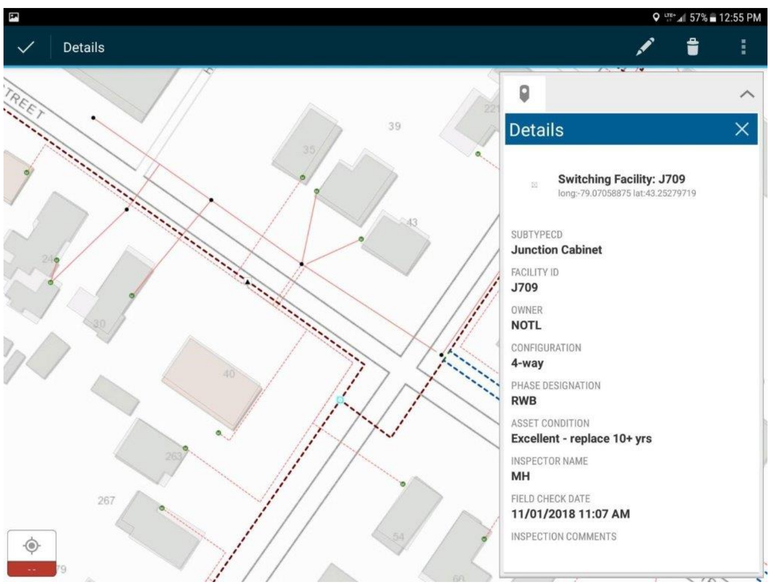
FIELD CHECK DATE
11/02/2018 8:11 AM





b) As applicable, assets such as poles, transformers, wire and conductors that can be attributed to specific customer supply are captured. System side components such as switchgear, station components and feeder specific details are not attributed to specific customers except for system maps that show circuit details. These are then used by Operations staff to plan switching and work protection details.

The table below provides a summary of these assets.

Asset	Count	condition			method of assessment
		poor	fair	good	
Poles	6,809	2.60%	23%	74%	pole tested and age
Pole mounted transformers	1,003	5%	23%	72%	mainly based on age and IR scan
Pad mounted transformers	799	0.50%	12.5%	87%	mainly based on age
Transmission Voltage Transformers	4	1	1	2	annual testing data and age
PMH units	20	1	3	16	annual inspectionsand assessments
Junction Boxes	144	2%	15%	83%	annual inspectionsand assessments
Primary wire - Overhead	236 km	<1%	10%	89%	mainly based on age of installation
Primary wire - Underground	132 km	<1%	21%	78%	and adjusted for older 4 kV distribution
Secondary wire - Overhead	171 km	<5%	27%	69%	areas
Secondary wire - Underground	332 km	<5%	21%	76%	

c) Our customers have indicated that the two most important considerations are reliability and cost. Asset replacements are prioritized based on these considerations. First, as explained in more detail in OEB staff question 27, the annual spend on asset replacement is determined based on the depreciation of the existing asset based adjusted for inflation. This is an effective means of managing the impact of asset replacements on rates. Second, within that budget the assets for replacement are determined based on a combination of factors including condition and age. As explained is response to OEB Staff interrogatory #29, the voltage conversion program has served as an effective proxy for this analysis and as that ends the detailed information by asset will be used. Any special projects or needs identified by customers, NOTL Hydro's Board or shareholder are considered as part of this determination.

2-Staff-29

Ref: Appendix 2A, Cost of Service Rate Application – Consolidated DSP, Page 9; Appendix A, Asset Management Plan, Pages 21 and 24

Section 4.9 Asset Replacement explains that NOTL Hydro's focus has been on the voltage conversion program to date, but that "as the rural voltage conversion becomes close to being finished, NOTL Hydro will switch to a more strategic asset replacements based on asset conditions, line performance and correlation with other future strategic plans."

Section 5.2.1.1 of the DSP states that "within four years all the major pockets of the rural areas will have been converted."

The Capital Expenditure Plan proposes to budget for a relatively consistent system renewal budget from 2022 to 2028.

a) Please confirm whether or not NOTL Hydro has any current guidelines or asset management processes that will guide the future shift to more strategic asset replacements based on asset conditions, line performance and correlation with future strategic plans?

b) How has the completion of the voltage conversion program been reflected in the long term capital expenditure plan from 2022 to 2028?

i. If it has been reflected in the budget, please explain how it has been reflected.

ii. If it has not been reflected in the budget, please update the budget.

RESPONSE

The NOTL Hydro asset management system is being developed for the purpose of guiding NOTL Hydro in its annual capital budgeting once the overhead voltage conversion program is complete. The voltage conversion program was always an easy means of determining which assets should be replaced in the annual budget. If a section of line was still 4 kV then NOTL Hydro knew that it was old and that there would be substantial performance benefits to switching to 27.6 kV. Once the voltage conversion is complete, the asset management system will be used to identify which assets should be replaced based on the factors identified in Section 4.9.

Table 19 of the Distribution System Plan provides the forecast capital plans out to 2028. Every year there are planned expenditures for System Renewal – Overhead. Until 2022 these are largely, but not entirely, the voltage conversion programs. After 2022, NOTL Hydro will move to expenditures based more on asset condition. NOTL Hydro believes it is important to maintain a constant asset replacement program so as to ensure the long-term health of the assets.

2-Staff-30

Ref: Consolidated DSP, Page 49; Appendix E Condition Report, Pages 2-4; Appendix F Long Term Supply Plan, Pages 7-9; Appendix G NOTL T2 OLTC Failure, Section 6 – Conclusion

Regarding the proposed 83MVA Transformer at York TS and the move of the existing 41.7MVA transformer to replace the T2 transformer at NOTL TS, the Consolidated DSP notes at page 49 that NOTL Hydro needs to replace the T2 transformer as soon as possible.

Section 7 of the Long Term Supply Plan prepared in 2012 by Raven Engineering Inc. (Appendix F) outlined six options to increase the station capacity at York TS and NOTL TS to permit each station to supply peak utility load. Its summary of Option 2 for replacing transformers at NOTL TS states that:

The existing transformers are 29 years old and could be either refurbished and sold, or sold as is to help offset the cost of two new larger transformers. However, the transformers have significant life left in them and the utility should utilize these assets if possible. This option is better suited to a very large utility that can use the transformers at another substation location. [Emphasis added by Staff]

Section 8 outlines Raven Engineering Inc.'s recommendation that "the most economical option to provide station capacity to meet utility peak load under contingency conditions is Option 4 – Add a Fourth Substation Transformer." Option 4 involved "replacing the 25 MVA NOTL T1 with a new 41.7 MVA transformer similar to York T1. This would bring the NOTL DS capability up to 66.7 MVA which would allow it to supply the utility load peak."

The T1 and T2 Asset Condition Assessment by Ascent in 2012 (Appendix E) notes with respect of the 25 MVA transformers: Both units appear to be fit for continued service, although it is evident from the test data that the replacement of both transformers should be considered and budgeted for within the next five years, as both transformers are approaching end of life, regardless of their current condition. [Emphasis added by Staff]

Later on page 4, Ascent notes: Both NOTL DS-T1 and NOTL DS-T2 are fit for continued service – although there are indications of overloading. Since the transformers will continue to be overloaded and are approaching the end of their design life, the following measures should be taken to ensure continued trouble-free service.

A number of measures for ensuring trouble-free service were then suggested, including a detailed load study and quarterly oil sampling.

EPTCON's report dated 2018 on the T2 Tap Changer Failure (Appendix G) notes: T2 itself, based on the test data obtained during this investigation, appears to be healthy.

a. **Given the evidence by Ascent, EPTCON and Raven Engineering Inc. that indicates the health condition of T2, please provide an explanation as to why 25 MVA transformer (T2) at NOTL station needs to be replaced as soon as possible.**

b. **Please provide any updated engineering or third party report(s) used by NOTL Hydro to examine its investment options and to support its recommendation to install a new 83 MVA transformer at York MTS and move the existing York MTS 41.7 MVA transformer to NOTL MTS, while putting the remaining 25 MVA transformer (T2) in standby mode.**
   i. **If not, please explain why no analysis has been done.**

c. **Please provide an explanation of how information on asset condition has informed the decision on the recommended transformer upgrade program.**

RESPONSE

a) The Raven report was written in 2012 so the older transformers at NOTL MTS are now 35 years old. The T1 has already been replaced for a 30/40/50MVA unit. The second transformer T2 of the same vintage is still in service but it developed an electrical fault within the tap changer compartment in 2018. The tap changer had to be replaced. Fortunately, the tap changer from the older T1 was available and was moved to the T2 unit. This replaced tap changer will have to be closely monitored. While the EPTCON analysis may show the T2 transformer as healthy, NOTL Hydro no longer feels confident in relying upon the T2 transformer for meeting the power needs of its customers without back-up. The T2 transformer will still be in service with the existing plan. However, as the third unit at the station it will not be needed to meet the peak demands.

   As noted above, the Ascent report recommended replacement of both units within 5 years. The T1 transformer was replaced within 3 years and, with this action, the T2 transformer will have been replaced within 7 years.

b) The original Raven report was relied upon to make the decision based on the best of and updated versions of Option 2 and Option 5. While the Raven report was written in 2012, the analysis of options is still the most relevant. Raven engineering has participated in all steps in the preparation and review of the current steps and in dealing with the issues with the T2 tap changer. However, no updated report was requested.

   The option of adding a second power transformer at York Station was analysed and eliminated at it would involve a substantial addition to the station footprint with all the connecting details on both transmission and distribution voltages. The cost would substantially exceed the cost of the present project and not add as much overall capacity for growth and supply contingencies.

c) Asset condition was one of three major deciding factors towards the station upgrading program. The others were servicing new load growth over the next planning cycle and adequacy of supply capacity in the event one station is removed from service.

2-SEC-13

[Ex.2, p.45] Please provide a revised version of Appendix 2-AB where the historical 'plan' amount is the annual budgeted amount as opposed to the amount provided in the Applicant's previous DSP.

RESPONSE

The updated table is provided below. NOTL Hydro's annual budgeted capital and O&M have been substituted for the 2014 DSP. Please note that NOTL Hydro does not specifically budget for System Access expenditures as part of its annual budgeting process. A placeholder amount is included in the budget but for purposes of managing capital expenditures it is the balance net of the System Access costs that is monitored and reviewed.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

Forecast Period: *2019*

CATEGORY	Historical Period (annual budget & actual)															2019
	2014			2015			2016			2017			2018			
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	
System Access	595	955	60.6%	515	983	91.0%	515	1,830	255.3%	515	550	6.8%	535	2,604	386.7%	83
System Renewal	1,028	874	-15.0%	1,000	542	-45.8%	1,058	710	-32.9%	950	692	-27.2%	1,402	1,474	5.1%	1,09
System Service	-	40	--	2,597	2,658	2.3%	150	229	52.8%	70	207	195.3%	85	125	47.1%	3,83
General Plant	162	113	-30.5%	115	66	-42.3%	167	107	-35.9%	165	155	-6.3%	413	499	20.8%	8
TOTAL EXPENDITURE	1,785	1,982	11.0%	4,227	4,250	0.5%	1,890	2,876	52.2%	1,700	1,603	-5.7%	2,435	4,701	93.1%	5,84
Capital Contributions	-	- 708	--	-	- 601	--	-	- 1,603	--	-	- 320	--	-	- 1,984	--	- 78
Net Capital Expenditures	1,785	1,274	-28.7%	4,227	3,649	-13.7%	1,890	1,273	-32.7%	1,700	1,283	-24.5%	2,435	2,717	11.6%	5,06
System O&M	$ 925	$ 904	-2.3%	$ 1,039	$ 1,000	-3.7%	$ 1,144	$ 1,131	-1.2%	$ 1,201	$ 1,089	-9.4%	$ 1,148	$ 1,152	0.4%	$ 1,1

2-SEC-14

[Ex.2, p.50] Please explain the basis for the 'mark-up' on labour, materials, and truck time charged by the Applicant for work done on behalf of a customer.

RESPONSE

The purpose of the 'mark-up' is to bring the hourly rate from a marginal cost to a full cost basis. The rates prior to the mark-up have no allocation of overhead so the purpose of the mark-up is to cover overhead costs (building costs, management, support services such as accounting, HR, health and safety).

2-SEC-15

For each material 2018 capital project, please provide the forecast in-service date. Have any of the forecast in-service dates changed since the filing of the application?

RESPONSE

Please see the table below for the in-service dates of the major projects in 2018. These dates are in line with those anticipated at the time of the filing of the application.

Reference Number	Description	Status of Completion
5.4.3.3.1	Olde Town Rebuild, Underground Conversion	May 2018
5.4.3.3.2	Rural Overhead Conversion Project #1 Project #2	 June 2018 Dec 2018
5.4.3.3.3	Specific to Large Customer Connection Specific to Region road widening, pole relocation	Oct 2018 May 2018
5.4.3.3.4	SCADA Software Upgrade	June 2018
5.4.3.3.5	Fleet Replacement of a Line Truck	Feb 2018

2-SEC-16

[DSP, p.52] With respect to the Storage Battery Project:

a. **Please provide the business case for the Storage Battery Project.**
b. **Please provide a copy of the application/submission that was provided to the smart grid fund.**
c. **The Applicant states: "It is expected that approximately 25% of the capital expenditure will be recovered from the smart grid fund." Please provide specifics regarding the funding arrangement with the Smart Grid Fund. Please provide a copy of any agreements that the Applicant has with the Smart Grid Fund.**

RESPONSE

a) The business case for the project is provided below. Note that other benefits of the battery project are described in response to OEB Staff interrogatory #17.

b) A copy of the application/submission has been attached as an appendix.

c) A copy of the agreement has been attached as an appendix. The total cost of the project is $522,340 or which $442,340 is capital and $80,000 is operating. The Government of Ontario Smart Grid Fund will be providing a subsidy of $118,151. Panasonic will be supplying the battery at cost plus services which is a subsidy of $64,735.

Niagara-on-the-Lake Hydro
Smart Grid Fund Application
March 2018

On March 6, 2018 the Ministry of Energy issued a call for new applications for Smart Grid Fund projects. The applications were due by March 23, 2018. A short window.

NOTL Hydro submitted an application on March 22, 2018.

Title: Distributed Generation Capacity Project

Description: NOTL Hydro has three feeder lines that are at capacity in terms of how much distributed generation they can handle. A 250 kW lithium ion battery, provided by Panasonic, will be installed on one of these feeders (M1) at the transmission station (York). Using both SCADA and meter data, the loading and generation data will be analyzed both before and after the installation of the battery. The goal of the analysis is to determine the optimal use of the battery and amount of additional distributed generation that the use of the battery will allow. The impact of this on Ravine Vineyard, who are installing a 71.4 kW net metering rooftop solar plant, will be analyzed in detail as part of this. In addition, the battery will also be used for time of use shifting if not needed for the above use.

Collaborators: Panasonic Eco Solutions Canada Inc.
Ravine Vineyard Estate Winery

Cost:

	$ 129,335	Smart Grid Fund (25%)
	$ 64,735	Panasonic – discount on battery and services
	<u>$ 328,270</u>	NOTL Hydro
	$ 522,340	Total

NOTL Hydro Cost Breakdown:

$ 244,520	Capital – third party
$ 22,500	Capital – NOTL Hydro labour
$ 27,500	Operating – third party
<u>$ 33,750</u>	Operating – NOTL Hydro labour
$ 328,270	Total NOTL Hydro

Timing: April 2018 – April 2020

2-SEC-17

[DSP, p.48] With respect to the Transformer Station Power Transformer Replacement and Rearrangements capital work:

a. **Has the Applicant developed a formal business case(s) for this program? If so, please provide a copy.**
b. **[p.50] Please provide the forecast date of competition for each listed milestone.**
c. **Please provide the basis of the 10% contingency.**
d. **Please provide the most detailed project spreadsheet and budget that is available.**

RESPONSE

a) Please see below. Please note that confidential information such as the vendors and their quotes have been removed.

17 July 2018

To: **Board of Directors**

Subject: **Transformer Station Changes**

At the May Board meeting management presented a plan to make changes at both transformer stations mainly derived from problems that developed at a transformer in NOTL MTS but also consider future load growth and single contingency supply capabilities between both stations. A motion was approved to proceed with a plan to acquire a new power transformer and make all necessary modifications at both station to maximum budget of $4.0 million.

The plan in summary would be:

- To retire the existing 25MVA transformer (old T1) at NOTL MTS and re-position existing T2 which has now been repaired to the location vacated by old T1.
- Move 41 MVA unit from York MTS to the T2 location and complete all line and load side connections including controls and SCADA points.
- Acquire a new larger transformer for York MTS and complete all line and load side connections including controls and SCADA points.

A more detailed request for quotes was issued to transformer manufacturers for a 40/53/67 MVA unit and 50/67/83 MVA unit and. Based on the pricing provided, the larger transformer could be purchased for a premium cost of about $200,000. This transformer would have sufficiently larger capacity that it would provide room for growth and back-up for many years to come. Reference checks were done of the selected supplier including Whitby Hydro, Alectra Utilities and Orillia Power and the feedback was all positive. A factory visit has been arranged for Friday July 27th. Assuming all checks out with no surprises, management will issue a purchase order towards the purchase of a 50/67/83 MVA transformer.

In addition to the above a further revision to the original scope is planned where it is now proposed to connect the re-positioned T2 inside NOTL MTS at 115kV with a separate tap and provisioning two low-voltage breakers/reclosures. The total project estimate including the revised scope is estimated to be $3.305 million and this includes obtaining system and connection impact studies by IESO and Hydro One. This amount will be part of the capital addition to assets for 2019 and included with our rate application. Progress payments of up to 50% will likely be required by the end of 2018 for the transformer and this will be treated in CWIP (construction while in progress) with an expected in service date by the end of 2019.

b) Scope of Project, NOTL Hydro – Transformer stations 2018 / 2019

Milestones	**By & @**	**Date of Completion**
• Obtain SIA and CIA	IESO and Hydro One	Q1 2019
• Remove old T1 (spare) by a licensed handler	NOTL MTS2	Nov 2018
• Disconnect the line and load sides of T2	NOTL MTS2	Sept 2019
• Place T2 on the pad of the T1 (spare)	NOTL MTS2	Sept 2019
• Install two low voltage breakers and tie to existing low voltage bus	NOTL MTS2	Q2 2019
• Connect line and load sides of T3 (old T2) at **NOTL MTS2**	NOTL MTS2	July 2019
• Disconnect the line and load sides of 41.7 MVA transformer at **York MTS1**.		Oct 2019
• Move 41.7 MVA transformer from **York MTS1** to **NOTL MTS2**.		Oct 2019
• Place 41.7 MVA on the T2 (new T2) pad and re-connect line and loads sides	NOTL MTS2	Oct 2019

• Reconnect all controls and SCADA points to RTU from T2 and T3	NOTL MTS2	Oct/Nov 2019
• Perform all commissioning tests on T2 and T3	NOTL MTS2	Nov 2019
• Place on potential and add load.	NOTL MTS2	EO Nov 2019
• New power transformer 50/66.6/83.3 MVA will be supplied and installed by NOTLH supplier.	York MTS1	Oct 2019
• Connect line and load sides to new transformer and reconnect all controls and SCADA points to RTU.	York MTS1	Oct 2019
• Perform all commissioning tests on new transformer.	York MTS1	Nov 2019
• Place on potential and add load.	York MTS1	EO Nov 2019
• Reinstate all grounds and hard surfaces including fence fabric at both stations if these have been disturbed, removed or damaged in the course of the project.	York MTS1 & NOTL MTS2	Spring 2020

c) NOTL Hydro (The Applicant) feels the 10% contingency is needed as this project relies integrates multiple activities including heavy haulers, electrical contractors, control wiring including SCADA integration, two existing station sites that should have in ground conduits which hopefully won't need rehabilitation, a commissioning agent, a factory acceptance agent for the 83 MVA transformer, the coordination with Hydro One and wholesale metering MSP and internal labour and management time.

NOTL Hydro debated whether a larger contingency would be needed but determined that the 10% should be sufficient.

d) The most detailed project spreadsheet and budget still remains table 28 in the Consolidated Distribution System Plan.

2-SEC-18

[DSP, p.55] With respect to the Underground Voltage projects, for each year between 2014 and 2019, please provide the km of work completed or planned to be completed, and the program cost.

RESPONSE

Year of Conversion	Km of work completed / planned	Program cost
2014	0.61	$322,973
2015	0.2	$191,856
2016	0.53	$321,649
2017	0.47	$256,602
2018	0.29	$193,657
2019	0.50	$345,000

2-SEC-19

[DSP, p.58] With respect to the Overhead Voltage projects, for each year between 2014 and 2019, please provide the km of work completed or planned to be completed, and the program cost.

RESPONSE

Year of Conversion	Km of work completed / planned	Program cost
2014	0.91	$174,152
2015	4.21	$502,428
2016	3.79	$306,239
2017	4.59	$680,479
2018	2.83	$325,000
2019	3.60	$477,000

2-SEC-20

[DSP, p.61] For each year between 2014 and 2019, please provide the number of poles replaced or planned to be replaced and the program cost.

RESPONSE

For 2014 to 2017, pole replacements were specifically done as part of the voltage conversion segments. For 2018, 2019 and beyond the cost of pole changes due from AMP are noted second after the poles that are affected by the planned voltage conversion program

Year of Pole Replacement	Quantity of poles affected	Program cost
2014	41	$174,152
2015	90	$502,428
2016	67	$306,239
2017	107	$680,479
2018	60 + 21	$325,000 + $100,000
2019	37 + 35	$290,000 + $175,000

2-SEC-21

Please provide a revised version of Appendix 2-AA by adding a column showing year-to-date actuals.

RESPONSE

The table below provided actual capital spend as of September 30, 2018 (most recent available data) and a revised 2018 forecast.

Appendix 2-AA
Capital Projects Table

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year	2018 YTD Sept	2018 Forecast
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access								
Subdivisions	539,093	503,221	486,601	131,216	125,000	125,000	0	125,000
Customer Projects	88,393	85,943	1,026,673	142,348	1,526,445	360,500	780,681	1,150,000
New Connections	290,017	350,282	294,760	203,853	270,000	290,000	102,127	195,000
Meters	37,966	43,952	21,599	72,522	60,000	60,000	29,325	60,000
Municipal Relocations	0	0	0	0	622,283	0	675,633	675,633
Sub-Total	955,469	983,399	1,829,632	549,939	2,603,728	835,500	1,587,766	2,205,633
System Renewal								
Overhead	557,162	465,034	393,511	499,940	945,417	637,000	468,163	883,417
Underground	316,729	77,093	316,751	192,059	528,355	335,000	193,657	566,034
Underground - Additional Virgil	0	0	0	0	0	125,000	0	0
Sub-Total	873,891	542,127	710,262	692,000	1,473,773	1,097,000	661,819	1,449,452
System Service								
Tranformer Stations	11,056	2,536,747	76,778	44,135	5,000	3,310,000	21,207	129,000
Battery	0	0	0	0	0	442,340	0	0
Integration	29,053	52,384	88,111	33,998	0	0	0	0
SCADA / Switches	0	68,898	64,290	128,546	120,000	80,000	10,171	20,171
Sub-Total	40,109	2,658,029	229,179	206,679	125,000	3,832,340	31,378	149,171
General Plant								
Buildings & Fixtures	5,717	7,008	81,142	49,690	52,260	23,150	45,760	51,510
Computer Hardware & Software	100,322	6,290	11,084	44,934	29,250	20,600	15,886	26,878
Rolling Stock - Line Trucks	0	0	0	0	364,295	0	364,295	364,295
Sub-Total	106,039	13,298	92,227	94,624	445,805	43,750	425,941	442,682
Miscellaneous	6,545	53,107	14,828	60,003	52,975	40,000	21,110	57,110
Total	**1,982,054**	**4,249,959**	**2,876,128**	**1,603,244**	**4,701,280**	**5,848,590**	**2,728,014**	**4,304,047**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*	0	0	0	0	0	0	0	0
Total	**1,982,054**	**4,249,959**	**2,876,128**	**1,603,244**	**4,701,280**	**5,848,590**	**2,728,014**	**4,304,047**

2-SEC-22

[DSP, Appendix A, p.13] Please explain, using specific examples, how the Applicant prioritizes individual capital projects.

RESPONSE

All Customer Access projects are funded and given a priority.

For General Plant, System Renewal and System Service projects, NOTL Hydro determines an annual blanket budget largely based on depreciation updated for inflation. This calculation is described in Chapter 5 of the Business Plan. Projects for the budget year are funded based on criticality until the budget blanket is full. Factors which influence criticality included include labour availability, impact on reliability or costs, likelihood of potential failure and meeting long term objectives. To meet all these factors we typically end up with a mix of underground conversions, overhead conversions, smart grid investments and general plant investments.

One-time large projects which cannot be budgeted within the above framework and budgeted separately as needed. Recent examples of this include the new truck, the Lakeshore Rd. rebuild, the transformer project and the batter project.

Reliability and cost management are two of the factors taken into consideration in determining the annual projects. These are the top two priorities identified by our customers.

2-SEC-23

[DSP, Appendix A, p.16] With respect to the Asset Condition Assessment:

a. **Please provide a table showing for each major asset category, the number of assets in each asset condition assessment category.**
b. **For each asset, please provide details regarding how the Applicant has categorized the assets into their asset condition assessment category.**
c. **If not included in your response to part (b), please provide information on the inputs and how they are used, in the determination of the asset condition.**

RESPONSE

All parts of this interrogatory are answered with the following table:

Asset	Count	condition			method of assessment
		poor	fair	good	
Poles	6,809	2.60%	23%	74%	pole tested and by age
Pole mounted transformers	1,003	5%	23%	72%	mainly based on age and IR scan
Pad mounted transformers	799	0.50%	12.5%	87%	mainly based on age
Transmission Voltage Transformers	4	1	1	2	annual testing data
PMH units	20	1	3	16	annual inspections and assessments
Junction Boxes	144	2%	15%	83%	annual inspections and assessments
Primary wire - Overhead	236 km	<1%	10%	89%	mainly based on age of installation and adjusted for older 4 kV distribution areas
Primary wire - Underground	132 km	<1%	21%	78%	
Secondary wire - Overhead	171 km	<5%	27%	69%	
Secondary wire - Underground	332 km	<5%	21%	76%	

2-SEC-24

[EB-2014-0155, DSP, p.34-35] Please complete the following table related to for all material capital projects between 2014 and 2018 contained in the Applicant's DSP:

2014 NOTL DSP Forecast					**Actual**		**Variance**	
Budget Item/Description	Classification (System Renewal etc)	Forecast Year to be undertaken	Budget Amount	Priority	Year Completed	Actual Costs	Explanation of Cost Variance (if >5%)	Explanation if project not completed

RESPONSE

The completed table is below. The priority field was removed as the projects were not ranked. Overhead and underground conversion projects are re-assessed each year based on conditions and the long-term plan so there are changes from what was originally planned. This is particularly the case for the underground conversion projects where the focus switched from the originally planned Simcoe area to the Lansdowne area.

2014 NOTL DSP Forecast				**Actual**		**Variance**	
Budget Item/Description	Classification (System Renewal etc)	Forecast Year to be undertaken	Budget Amount	Year Completed	Actual Costs	Explanation of Cost Variance (if >5%)	Explanation if project not completed
Old Town voltage conversion (Johnson – Simcoe to Dorchester)	System Renewal	2014	$330,000	2014	$332,973	-	Simcoe St converted instead as deemed more critical
Overhead voltage conversion (Concession 2 – Line 7-9)	System Renewal	2014	$200,000	2015	$195,769	-	-
Overhead voltage conversion (Concession 6 – Line 6-8)	System Renewal	2014	$155,000	2015	$137,486	Actual cost is lower than budget	-
Overhead voltage conversion (York Rd – Concession 2-3)	System Renewal	2014	$140,000	2014	$174,152	Additional costs due to traffic management	-

Overhead voltage conversion (Line 4 – Concession 2-3)	System Renewal	2016	$110,000	2016	$86,621	Actual cost is lower than budget	-
System Integration – Outage Management System	System Service	2014	$90,000	2015	$26,201	Less expensive alternative found with Savage	-
Software upgrades	General Plant	2014	$65,000	2014	$103,174	File Nexus upgrade more complicated than expected	-
Old Town voltage conversion (Johnson – Dorchester to Palatine)	System Renewal	2015	$385,000	2015	$191,856	Lower spend due to focus on transformer project	Simcoe and Anne Street converted instead.
New 50 MVa transformer	System Renewal	2015	$3,000,000	2015	$2,565,528	$3 million was an early estimate.	-
Overhead voltage conversion (Concession 6 – Warner Rd area)	System Renewal	2015	$270,000				Conversion of this area now scheduled for 2019
Overhead voltage conversion (Concession 2 – Line 1-3)	System Renewal	2015	$150,000	2016	$130,733	Actual cost is lower than budget	-
Overhead voltage conversion (Concession 2 – Line 6-7)	System Renewal	2015	$105,000	2015	$97,070	Actual cost is lower than budget	-
Overhead voltage conversion (Concession 6 – Line5-6)	System Renewal	2015	$90,000	2015	$72,103	Actual cost is lower than budget	-
Scada upgrades	System Service	2015	$50,000	2015	$68,898	Scope of project expanded	-
Old Town voltage conversion (Johnson – Orchard - Lansdowne)	System Renewal	2016	$400,000	2016	$321,649	Actual cost is lower than budget	-
Overhead voltage conversion (Line 2 - Concession 2-4)	System Renewal	2016	$190,000	2017	$346,642	Project combined with Line 2 - Concession 1-2	Project combined with Line 2 - Concession 1-2
Overhead voltage conversion (Carlton – Townline to McNab)	System Renewal	2017	$180,000	2017	$185,760	-	-
Overhead voltage conversion (Lakeshore – Stewart to Read)	System Renewal	2016	$120,000				Conversion of this area now scheduled for 2019
Overhead voltage conversion (McNab – Carlton to Scott)	System Renewal	2016	$105,000	2016	$88,885	Actual cost is lower than budget	-
Scada upgrades	System Service	2016	$50,000	2016	$18,088	$45,000 spend on auto switches instead	-
Old Town voltage	System	2017	$400,000	2017	$256,602	Change in streets	More of Johnson St in Lansdowne

conversion (Gage – Simcoe to Dorchester)	Renewal					converted	area converted instead
Overhead voltage conversion (Line 1 - Concession 1-4)	System Renewal	2017	$265,000	2018	$260,000	In progress estimate	-
Overhead voltage conversion (Concession 7 – Line 3)	System Renewal	2017	$120,000	2018	$62,265	Actual cost is lower than budget	-
Overhead voltage conversion (Line 2 – Concession 1-2)	System Renewal	2017	$105,000	2017	-	-	Project combined with Line 2 - Concession 2-4
Scada upgrades	System Service	2017	$50,000	2017	$60,974	Ongoing project	-
Old Town voltage conversion (Centre – Simcoe to Dorchester)	System Renewal	2018	$400,000	2018	$193,657	Change in streets converted	More of Johnson St in Lansdowne area converted instead
Overhead voltage conversion (Line 2 - Concession 7)	System Renewal	2018	$205,000				Conversion of this area now scheduled for 2021
Overhead voltage conversion (Line 1 – Townline to Concession 6)	System Renewal	2018	$195,000				Conversion of this area now scheduled for 2020
Overhead voltage conversion (Line 3– Concession 6)	System Renewal	2018	$165,000	2017	$148,077	Actual cost is lower than budget	-
Scada upgrades	System Service	2018	$50,000	2018	$10,000	-	Delayed as budget needed for repairs to T2 transformer at NOTL MTS

2.0-VECC-3

Reference: E2/pg. 12

a) **Why is NOTL replacing the current above ground plant with underground as part of the Highway 55/Vigil road widening? Is this project part of the Old Town underground conversion program?**

b) **What is the incremental cost of the underground replacement as compared to like-for like above ground plant for this area?**

RESPONSE

a) The Region of Niagara has planned a road widening and deep utility rehabilitation program on Highway 55 between Creek Road and East West line in Virgil. Virgil is in a different part of Niagara-on-the-Lake than the Olde Town but is a heavily trafficked area as most people heading to the Olde Town drive through Virgil.

The segment between Creek Road and Line 1, where the underground conversion is planned, is dominated by commercial businesses and is quite condensed for that short span. It is about one third of the planned road rehabilitation. The commercial businesses are becoming more and more geared to the tourist trade rather than just servicing local residents. As a result, safety, reliability and esthetics are becoming more important. In this sense it is not part of the Olde Town underground conversion program but is being performed for similar reasons.

Most of the electrical services on this segment are primary supplied to pad mount transformers. The voltage is 27.6 kV so no conversion is necessary but the segment has some of the older 27.6 kV assets in the Town. It is planned that the road contractor hired by the Region will install necessary ductwork and civil structures to support underground electrical connections. NOTL Hydro will budget and install high voltage cable, switchgear, junction boxes, transformers and service cable where necessary.

Parts of 2019 and 2020 capital budgets will include NOTL Hydro's design and scope for the project. The on-going underground conversion expansion in Olde Town and Heritage districts will be delayed for 2020 with the budget allocated to this project. As the underground plan will only cover a third of the road widening segment, the remainder will still remain with overhead distribution.

b) The budget for this project is $725,000 which includes the underground conversion and a new smart switch for $150,000. A like-for-like project with overhead distribution is estimated to cost $400,000 comprising of $250,000 for the new lines and $150,000 for the smart switch. The incremental cost is therefore $325,000.

Please note that an overhead system does not have the same reliability and safety performance as an underground system so is not truly like-for-like. This is a particular concern with the road widening as the poles will become much closer to the road than is currently the case; increasing the risk of accidents. There would not be room to move the poles further from the road as the commercial businesses are very close to the road in this section.

2.0-VECC-4

Reference: Ex2/pg. 46

a) **Please update Table 2.34 to show the actual and forecast capital contributions for each year.**

RESPONSE

Niagara-on-the-Lake Hydro Inc.
Capital Expenditure Plan - Contributions
2014 - 2028

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
System Access															
Subdivisions	(475,796)	383	(347,773)	(59,081)	(62,500)	(62,500)	(65,000)	(65,000)	(65,000)	(68,500)	(68,500)	(68,500)	(68,500)	(70,000)	(70,000)
Customer Projects	(11,698)	(330,534)	(1,075,010)	(140,010)	(1,526,445)	(360,500)	(371,315)	(382,454)	(393,928)	(405,746)	(417,918)	(430,456)	(443,370)	(456,671)	(470,371)
New connections - overhead	(13,526)	(8,490)	(4,549)	(5,774)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)
New Connections - underground	(207,443)	(262,080)	(175,945)	(115,089)	(190,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)	(215,000)
Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal Relocations	-	-	-	-	(200,000)	-	-	-	-	-	-	-	-	-	-
System Access Total	(708,464)	(600,722)	(1,603,277)	(319,954)	(1,983,945)	(643,000)	(656,315)	(667,454)	(678,928)	(694,246)	(706,418)	(718,956)	(731,870)	(746,671)	(760,371)
System Renewal															
Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Underground	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Underground - Additional Virgil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
System Renewal Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
System Service															
Transformer stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery	-	-	-	-	-	(144,136)	-	-	-	-	-	-	-	-	-
Integration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SCADA / switches	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
System Service Total	-	-	-	-	-	(144,136)	-	-	-	-	-	-	-	-	-
General Plant															
Buildings and fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hardware	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling stock	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling stock - Line Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Tools	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Recurring total	(708,464)	(600,722)	(1,603,277)	(319,954)	(1,983,945)	(787,136)	(656,315)	(667,454)	(678,928)	(694,246)	(706,418)	(718,956)	(731,870)	(746,671)	(760,371)
Transformer (ICM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total expenditure	(708,464)	(600,722)	(1,603,277)	(319,954)	(1,983,945)	(787,136)	(656,315)	(667,454)	(678,928)	(694,246)	(706,418)	(718,956)	(731,870)	(746,671)	(760,371)

2.0-VECC-5

Reference: E2/S2.2.2.5/pg. 50

a) With respect to the 250 kVA lithium-ion battery (Smart Grid Fund) project at the M1 feeder please provide:
- **i. the total cost of the project broken down by capital and OM&A costs;**
- **ii. the amount of any grants or subsidies being provided and by whom: and,**
- **iii. the business case showing the net benefit to NOTL ratepayers of this project.**

b) As part of this project is NOTL planning to make publicly available the study results of this pilot project?

c) Given the large investment required for a new 83 MVA transformer in 2019 why would it not be preferable to defer the battery project to 2020 or beyond?

RESPONSE

a) Provided:
- i. The total cost of the project is $522,340 of which $442,340 is capital and $80,000 is operating.
- ii. The Government of Ontario Smart Grid Fund will be providing a subsidy of $118,151. Panasonic will be supplying the battery at cost plus services which is a subsidy of $64,735.
- iii. The business case is provided below. Note that other benefits of the battery project are described in response to OEB Staff interrogatory #17.

b) NOTL Hydro has no objections to making the results of the project public and certainly hopes to present them at future conferences. As this is a Smart Grid Fund project we will be guided by the Ministry of Energy in this regard.

c) The timing of the battery project was driven by the timing of the availability of funding through the Smart Grid Fund. Deferring to 2020 was not an option.

Niagara-on-the-Lake Hydro
Smart Grid Fund Application
March 2018

On March 6, 2018 the Ministry of Energy issued a call for new applications for Smart Grid Fund projects. The applications were due by March 23, 2018. A short window.

NOTL Hydro submitted an application on March 22, 2018.

Title: Distributed Generation Capacity Project

Description: NOTL Hydro has three feeder lines that are at capacity in terms of how much distributed generation they can handle. A 250 kW lithium ion battery, provided by Panasonic, will be installed on one of these feeders (M1) at the transmission station (York). Using both SCADA and meter data, the loading and generation data will be analyzed both before and after the installation of the battery. The goal of the analysis is to determine the optimal use of the battery and amount of additional distributed generation that the use of the battery will allow. The impact of this on Ravine Vineyard, who are installing a 71.4 kW net metering rooftop solar plant, will be analyzed in detail as part of this. In addition, the battery will also be used for time of use shifting if not needed for the above use.

Collaborators: Panasonic Eco Solutions Canada Inc.
Ravine Vineyard Estate Winery

Cost:

\$ 129,335	Smart Grid Fund (25%)
\$ 64,735	Panasonic – discount on battery and services
<u>\$ 328,270</u>	NOTL Hydro
\$ 522,340	Total

NOTL Hydro Cost Breakdown:

\$ 244,520	Capital – third party
\$ 22,500	Capital – NOTL Hydro labour
\$ 27,500	Operating – third party
<u>\$ 33,750</u>	Operating – NOTL Hydro labour
\$ 328,270	Total NOTL Hydro

Timing: April 2018 – April 2020

2.0-VECC-6

Reference: E2/Appendix 2A/DSP/pg.32

Pre-amble: At the above reference NOTL states: "The large variance in 2018 is due to the Lakeshore Rd job as the Niagara Region has their own formula which drives how much of the costs of the project they will compensate NOTL Hydro."

a) **Please confirm that NOTL is subject to road construction cost-sharing arrangements based on the Government of Ontario Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49 ("the Act"), which stipulates that the Utility is required to pay 100 percent of materials for relocation work, but that the associated labour and vehicle cost are to be shared equally with the appropriate Road Authority.**

RESPONSE

a) Confirmed that NOTL Hydro is subject to 'the Act'. In addition, it includes equal sharing of the cost of design and project management.

2.0-VECC-7

Reference: E2/Appendix 2A/DSP/pgs. 38,

a) **In its last cost of service application EB-2013-0155 NOTL described a plan to convert all of the Niagara-on-the-Lake Olde Town to underground service by 2022. If this is still the case please explain why no detailed plan for this project is included in the current Distribution System Plan.**

b) **Are the underground voltage projects shown at Table 22 and Table 30, the entire underground plant conversion capital costs for the Olde Town project? If yes will the project be completed by 2023?**

c) **Please provide a map showing an outline of the entire area subject to the Olde Town underground conversion. Please confirm the boundaries are those required by the Town bylaw as part of its heritage policy.**

d) **Please provide a copy of the Town by-law related to this requirement.**

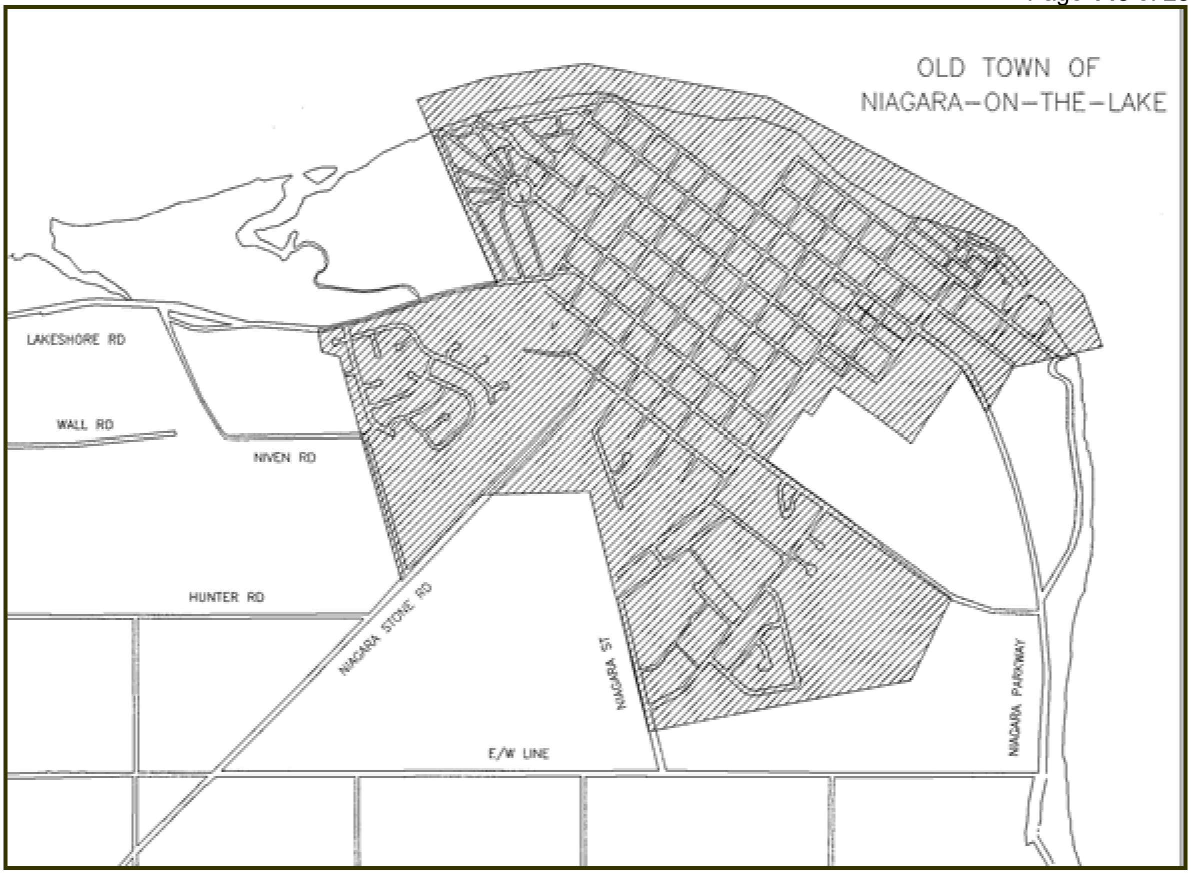
RESPONSES

a) NOTL Hydro is unaware of this plan. Page 84 of the DSP filed with EB-2013-0155 reads "We estimate that the entire historic Old Town will be converted to 27.6 kV and buried within 15 years." This would imply completion by 2029. Our current estimate is completion by 2034 (see page 56 of the current DSP).

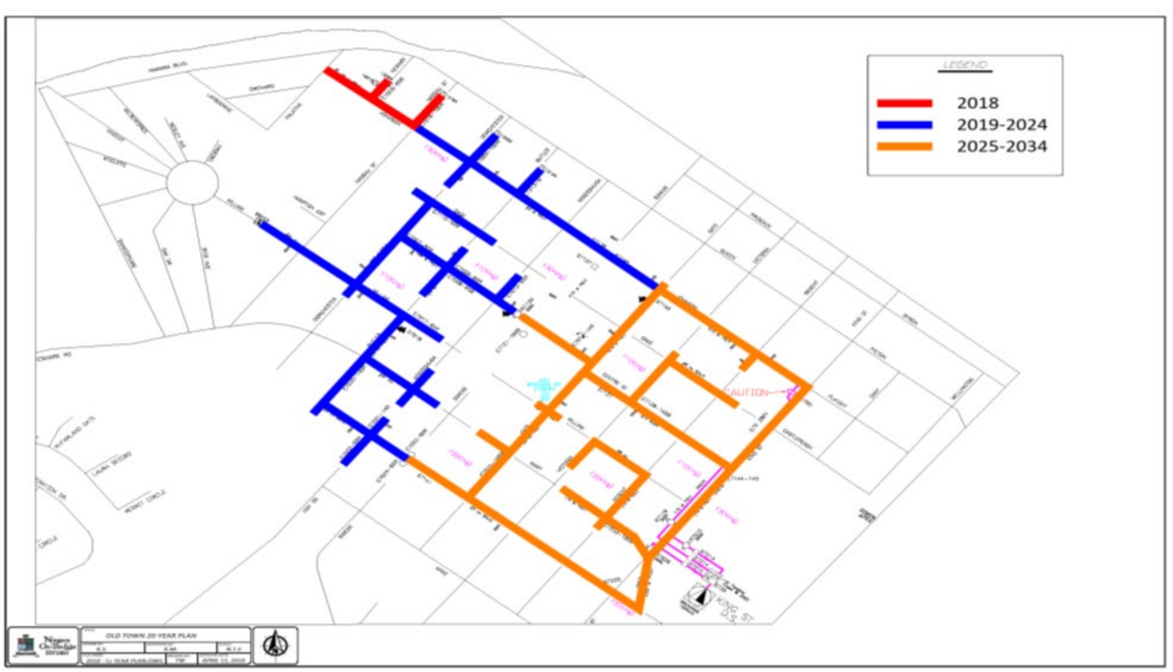
NOTL Hydro notes that the conversion of the rural 4 kV system is expected to be fully converted to 27.6 kV by 2022 (with the exception of the firelanes for which there is currently no plans to convert) and wonders if this is the plan being referenced.

b) No. Table 22 are the conversions for the past 5 years and Table 30 are the conversions planned for the next 5 years. Full conversion of the Olde Town is now expected to take until 2034.

c) The reference to the Town by-law in the DSP refers to new services rather than the requirement to convert existing services to underground. Below please find the boundaries of the Olde Town area in which new services are required to be underground.



This map is a reasonable proxy for the area in which underground conversions have either been completed or are planned to be completed. The map of the planned underground conversions is provided below.



Please see the section below for a discussion of the Town by-law.

d) The reference to a Town by-law dates back to the 2009 and 2013 Cost of Service applications. However, upon inquiry NOTL Hydro has not been able to ascertain the existence of the actual by-law. NOTL Hydro suspects this may be the local equivalent of an urban myth.

NOTL Hydro does have very strong building codes and by-laws with respect to developments within the Olde Town; all designed to protect the heritage features currently in existence. These protections date back many decades including a detailed report in the mid 1980's. It is suspected that the practice of requiring underground services for new connections developed in line with the other heritage requirements and that, with time, it came to be assumed that there was a by-law.

NOTL Hydro's requirements with respect to new connection in the urban areas is provided as part of the Conditions of Service. There is no mention in the Conditions of Service of a by-law.

The decision to convert the overhead 4 kV service to underground 27.6 kV is one made by NOTL Hydro. The voltage conversion and replacement of the existing structures is required due to their age and condition. The conversion to underground at the same time provides the additional benefits of added safety and reliability due to the congested and busy conditions in the Olde Town. As the Olde Town is also a popular tourist destination with over 1 million tourists a year, the underground conversion also meets local needs.

2.0-VECC-8

Reference: E2/Appendix 2A/ DSP

a) **Please explain the lower than average underground plant investment in 2015 as compared to 2014 and 2016-2017.**

RESPONSE

Management's and staff resources were significantly diverted in 2015 to the installation of the new 50 MVA transformer at NOTL MTS. As a result, some of the underground projects were deferred to 2016.

2.0-VECC-9

Reference: E2/ Table 2.34 (Appendix 2-AA)

a) **Please explain the large increase in customer projects in 2018 as compared to prior and subsequent years.**

b) **Please explain why there is no balance forecast under Continuity Account 2056 CWIP-Customer Projects in 2019, whereas all prior years have a positive balance of 200k or more.**

RESPONSE

a) The large increase in customer projects in 2018 is driven by the project to establish a feed with a capacity of 20 MW for the proposed Large Use class customer. It had a budget of $800k which was fully paid by the future Large Use customer so the capital spend will have no impact on rates of other customers.

b) The existence of a balance in CWIP is a matter of timing. Was a project completed and closed as at the end of the year? The purpose of the 2019 capital forecast was to provide our best estimate of the investments required by NOTL Hydro in Customer Access projects. Whether or not a particular project is complete at the end of 2019 does not really impact the size of the investment required. Please also see response to OEB Staff Interrogatory #12.

2.0-VECC-10

Reference: E2/ Table 2.34 (Appendix 2-AA)

a) **Please provide an update of Table 2.34 (Appendix 2-AA) showing both forecast and actual amounts expended in 2018 (ending October 30).**

RESPONSE

a) The table below provided actual capital spend as of September 30, 2018 (most recent available data) and a revised 2018 forecast:

Appendix 2-AA
Capital Projects Table

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year	2018 YTD Sept	2018 Forecast
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access								
Subdivisions	539,093	503,221	486,601	131,216	125,000	125,000	0	125,000
Customer Projects	88,393	85,943	1,026,673	142,348	1,526,445	360,500	780,681	1,150,000
New Connections	290,017	350,282	294,760	203,853	270,000	290,000	102,127	195,000
Meters	37,966	43,952	21,599	72,522	60,000	60,000	29,325	60,000
Municipal Relocations	0	0	0	0	622,283	0	675,633	675,633
Sub-Total	955,469	983,399	1,829,632	549,939	2,603,728	835,500	1,587,766	2,205,633
System Renewal								
Overhead	557,162	465,034	393,511	499,940	945,417	637,000	468,163	883,417
Underground	316,729	77,093	316,751	192,059	528,355	335,000	193,657	566,034
Underground - Additional Virgil	0	0	0	0	0	125,000	0	0
Sub-Total	873,891	542,127	710,262	692,000	1,473,773	1,097,000	661,819	1,449,452
System Service								
Tranformer Stations	11,056	2,536,747	76,778	44,135	5,000	3,310,000	21,207	129,000
Battery	0	0	0	0	0	442,340	0	0
Integration	29,053	52,384	88,111	33,998	0	0	0	0
SCADA / Switches	0	68,898	64,290	128,546	120,000	80,000	10,171	20,171
Sub-Total	40,109	2,658,029	229,179	206,679	125,000	3,832,340	31,378	149,171
General Plant								
Buildings & Fixtures	5,717	7,008	81,142	49,690	52,260	23,150	45,760	51,510
Computer Hardware & Software	100,322	6,290	11,084	44,934	29,250	20,600	15,886	26,878
Rolling Stock - Line Trucks	0	0	0	0	364,295	0	364,295	364,295
Sub-Total	106,039	13,298	92,227	94,624	445,805	43,750	425,941	442,682
Miscellaneous	6,545	53,107	14,828	60,003	52,975	40,000	21,110	57,110
Total	**1,982,054**	**4,249,959**	**2,876,128**	**1,603,244**	**4,701,280**	**5,848,590**	**2,728,014**	**4,304,047**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*	0	0	0	0	0	0	0	0
Total	**1,982,054**	**4,249,959**	**2,876,128**	**1,603,244**	**4,701,280**	**5,848,590**	**2,728,014**	**4,304,047**

2.0-VECC-11

Reference: E2/ pg.34

a) **Please explain the large increase in customer projects in 2018 as compared to prior and subsequent years.**

RESPONSE

Please see the response to VECC Interrogatory #9a.

2.0-VECC-12

Reference E2/pg.33, 43

a) **Please provide the detailed budget (transformer and other capital costs, capitalized labour and non-capitalized labour) and the construction schedule for the York station transformer replacement.**

RESPONSE

a) Please refer to Table 28 of The Consolidated Distribution System Plan for a budget breakdown.

All costs related to acquiring the new power transformer at York MTS, moving the existing transformer to NOTL MTS, connecting the new transformer at York MTS and commissioning, added to this making connection arrangements of the transferred transformer at NOTL MTS and its commissioning with all their associated impact assessments by IESO and Hydro One are included within the total budget estimate of $3.305 million.

The majority of the labour is contracted to the transformer supplier, electrical contractor and commissioning agents hired by NOTL Hydro together with internal labour and management time directly attributed to the project will be capitalized and included in the project estimate. It is not expected to have additional non-capitalized labour involved with this project.

The following is a schedule for the delivery of the transformer destined to York MTS. During the month of October, it is expected that both transformers will be positioned on their respective pads, connections made and commissioned just prior to the end of October. Sufficient early work will be carried out to prepare for the delivery of the new transformer at York MTS and for the move of the relocated transformer at NOTL MTS.

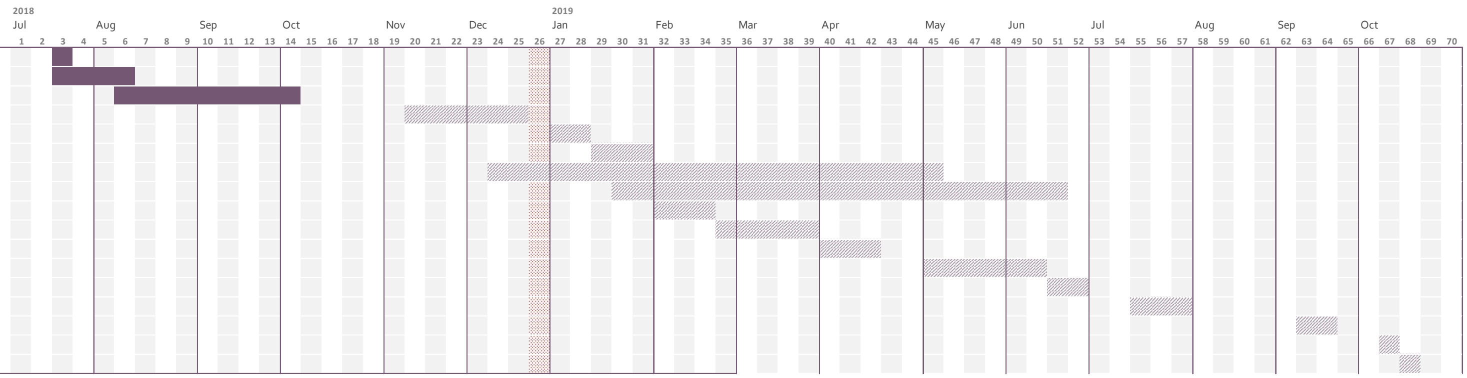
NOTL Hydro

50/67/83 MVA, 115.5 KV Delta - 28 KV Wye - PO # 001002

Period Highlight: 80 | Plan | Actual | % Complete | Actual (beyond plan) | % Complete (beyond plan)

NTC Order # 2933-18001

ACTIVITY	PLAN START	PLAN DURATION	ACTUAL START	ACTUAL DURATION	PERCENT COMPLETE
PO Received	3	1	3	1	100%
Design	3	4	3	4	100%
KOM and Re-Design	6	9	6	9	100%
Drawing / Drafting	20	6	0	0	0%
Client Drawing Review	27	2	0	0	0%
Estimate for Drawing Revisions	29	3	0	0	0%
Placement of Major PO's	24	22	0	0	0%
Receipt of Major PO's	30	22	0	0	0%
Core Stacking	32	3	0	0	0%
Coil Winding	35	5	0	0	0%
Coil Sizing & Nesting	40	3	0	0	0%
Assembly & Dry out	45	6	0	0	0%
Tank & Vac. Oil Fill	51	2	0	0	0%
Controls & FAT Testing	55	3	0	0	0%
Paint & Final Assembly	63	2	0	0	0%
Shipment Ready	67	1	0	0	0%
Delivery to Site	68	1	0	0	0%



2.0-VECC-13

Reference: E2/Appendix A/Asset Management Plan/pg.8

Table 4: Major Distribution Assets as of February 2018

Asset	Count
Poles	6,809
Pole mounted transformers	1,003
Pad mounted transformers	799
Transmission voltage	4
PMH units	20
Junction boxes	144
Primary wire - Overhead	236 km
Primary wire - Underground	132 km
Secondary wire - Overhead	171 km
Secondary wire - Underground	332 km

a) **For each category of capital assets shown in Table 4, please indicate the percentage of assets found to be in good, fair or poor condition and the method by which that assessment was made.**

RESPONSE

The table above has been expanded with information as requested:

Asset	Count	condition			method of assessment
		poor	fair	good	
Poles	6,809	2.60%	23%	74%	pole tested and age
Pole mounted transformers	1,003	5%	23%	72%	mainly based on age and IR scan
Pad mounted transformers	799	0.50%	12.5%	87%	mainly based on age
Transmission Voltage Transformers	4	1	1	2	annual testing data and age
PMH units	20	1	3	16	annual inspectionsand assessments
Junction Boxes	144	2%	15%	83%	annual inspectionsand assessments
Primary wire - Overhead	236 km	<1%	10%	89%	mainly based on age of installation and adjusted for older 4 kV distribution areas
Primary wire - Underground	132 km	<1%	21%	78%	
Secondary wire - Overhead	171 km	<5%	27%	69%	
Secondary wire - Underground	332 km	<5%	21%	76%	

Annual IR (infra-red) scan is done of the distribution system which reveal hot spots on components that are signs of imminent failures. The subject components are replaced on a planned basis. The data is matched against age of other related devices, wire and loading so a determination is made if additional replacements or repair are needed.

2.0-VECC-14

Reference: E2/ Continuity Schedule 2018/pg.18

a) **Why are there no disposals shown for 2018 (and unlike each of the prior years which have between 200 and 500k in disposals)?**

RESPONSE

d) Please see response to OEB Staff interrogatory #12. At the time of the application NOTL Hydro was not aware of any significant disposals that would impact net assets and the calculation of rate base. Subsequent to our application it was determined that one of the transformers and NOTL station would require disposal in 2018 as it is no longer available for use as the tap changer from this unit was used to repair another transformer. Currently, NOTL Hydro estimates that the change in net assets for 2018 due to disposals to be $259,037 which includes $225,047 included in 2019 in our application.

Actual disposals as of September 30th, 2018 are summarized in the table below.

	Asset Value	Accumulated Depreciation	Proceeds	Gain / (Loss) on Disposal	Change in Net Assets
Line Truck	250,400.16	250,400.16	30,973.45	30,973.45	-
Transformers	38,400.93	19,938.96	-	(18,461.97)	18,461.97

Forecasted disposals for the remainder of the year are summarized in the table below.

	Asset Value	Accumulated Depreciation	Proceeds	Gain / (Loss) on Disposal	Change in Net Assets
Poles	292,156.38	287,695.50	-	(4,460.88)	4,460.88
Conductor	212,886.27	201,819.56	-	(11,066.71)	11,066.71
Transformer Station	335,048.00	110,001.00	-	(225,047.00)	225,047.00
Total 2018	**1,128,891.74**	**869,855.18**	**30,973.45**	**(228,063.11)**	**259,036.56**

3 | Load & Other Revenue Forecast

INTERROGATORY RESPONSES

3-Staff-31

Ref: Exhibit 3, Page 10; NOTL Hydro Load Forecast Wholesale Model, Sheet 6. WS Regression Analysis

NOTL Hydro indicates that variables used include heating and cooling degree days as well as "total customer count, daylight hours, days per month, a spring/fall flag, and cost of power."

a) Please confirm that the Blended Rate coefficient is indicating that as the price of electricity increases, the wholesale energy usage increases as well. Please explain how higher energy prices would lead to increased consumption.

b) Please explain why the variables Blended Rate and Daylight Hours were included in the regression model despite t-Stats of 0.31 and -1.12 respectively which indicate a lack of statistical significance.

c) Has NOTL Hydro attempted regression(s) including a trend variable and an indicator of economic output such as GDP or full-time employment?

i. If so, please explain why they were dismissed.

ii. If not, please produce a load forecast including a trend variable and an economic variable as an alternative scenario. Please also summarize the impact to the load forecasts under this scenario as compared to the current methodology.

RESPONSE

a) NOTL Hydro confirms that the Blended Rate coefficient gives a counterintuitive result. The low t-stat for this variable indicates that this result is not statistically reliable. NOTL Hydro is open to removing the Blended Rate variable in the revised Load Forecast submitted with these responses.

b) The two variables were originally left in as their impact was immaterial.

c) NOTL Hydro attempted regression analysis including monthly Canadian GDP and Ontario CPI. Key economic data for Niagara-on-the-Lake is not readily available and NOTL Hydro does not believe that province wide or even regional economic data is representative of NOTL Hydro's customer base. The results of adding these variables as well as removing the Blended Rate and Daylight hours variables are summarized in the table below.

	Submission	**Canada CDP**	**Ontario CPI**	**Remove Blended Rate and Daylight Hours**
Adjusted R-Square	0.9456	0.9513	0.9461	0.9460
t-stat (additional variable)	n/a	3.15	1.34	n/a
Weather Normalized Load Forecast	214,325,152	210,148,975	214,154,508	213,198,991

3-Staff-32

Ref: Exhibit 3, Pages 11-14; NOTL Hydro Load Forecast Wholesale Model, Sheet 4. Customer Growth

NOTL Hydro has calculated a geometric growth rate for the residential rate class of 1.0292, which would result in a customer connection forecast in 2019 of 8,303. It concluded that a forecast of 8,152 was more appropriate, and provided the following rationale:

> In 2015/2016, the Cannery Park residential development was completed. A total of 187 residential customers were added in these two years just from this development. There are no developments of this scale planned for 2018-2019 or even for the next five years.

NOTL Hydro also states:

> In late 2017, NOTL Hydro completed the transfers of loads with its neighbouring utilities, Alectra and Niagara Peninsula Energy Inc. As a result of these load transfers, a net of 38 residential customers were transferred to these other LDCs.

Staff calculates that removing 187 customers from 2015/2016 would result in a geometric mean growth rate of 1.0251 for the residential class as below:

$$\text{Geometric Mean Growth Rate} = D\left(\frac{DDDD\ DDDDDDDD\ DDDDD}{DDDD\ DDDDDDDD\ DDDDD}\right)^{\frac{0}{D}}$$

$$= D\left(\frac{DDDDDDDD}{DODD}\right)^{\frac{0}{D}}$$

$$= 1.1887^{\frac{0}{D}}$$

$$= 1.0251$$

Staff calculates that applying a geometric mean growth rate of 1.0251 to the residential class customer count, and reducing the 2018 customer count by 38 would result in a residential customer count of 7,997 in 2018, and 8,198 in 2019.

2018 Customer Count = 7,838 * 1.0251 – 38
= 8,035 – 38
= 7,997

2019 Customer Count= 7,997 * 1.0251= 8,198

a) Please confirm the staff calculated rate of 1.0251.
b) Please confirm the staff calculated residential customer counts of 7,997 in 2018 and 8,198 in 2019 respectively.
c) Please explain why NOTL views 8,152 customers as appropriate in 2019 given the calculations in parts a) and b).

RESPONSE

a) NOTL Hydro confirms that removing 187 customers from 2016 and 2017 results in a geometric mean growth rate of 1.0251.

b) NOTL Hydro confirms the staff calculation of 7,997 and 8,198 in part b above

c) As of September 30, 2018 NOTL, Hydro had 7,923 residential customers and approximately 70 additional new residential connections for the remainder of the year resulting in an average number of customers for 2018 of 7,932. Applying the staff calculated geometric mean growth rate of 1.0251 would result in a 2019 average number of customers of 8,131. Based on the current number of residential customers and the number of new developments scheduled in 2019, NOTL Hydro still views 8,152 as the appropriate number of customers for 2019.

3-Staff-33

Ref: Exhibit 3, Page 20; Filing Requirements for Electricity Distribution Rate Applications – Chapter 2, July 12, 2018, page 23

NOTL Hydro indicates that it adopted a "7-year average from 2011 to 2017 as the definition of weather normal in order to remain consistent with the other variables used in this analysis."

NOTL Hydro explained the reasons for the seven historical years selected for its weather normalization for the load forecast:

> **The proposed normal weather methodology was chosen as the last seven years captures the impact of increasing temperatures from climate change and NOTL Hydro has no grounds for making any non-normal assumptions.**

The filing requirements state that "In addition to the proposed test year load forecast, the load forecasts based on 10-year average and 20-year trends in HDD and CDD" must be provided and "If the applicant proposes an alternative approach, it must be supported".

a) Please provide load forecast runs where HDD and CDD are defined as 10-year average and a trend based on 20-years.
b) Please provide the source and/or the supporting evidence of the statement "the last seven years captures the impact of increasing temperatures from climate change".

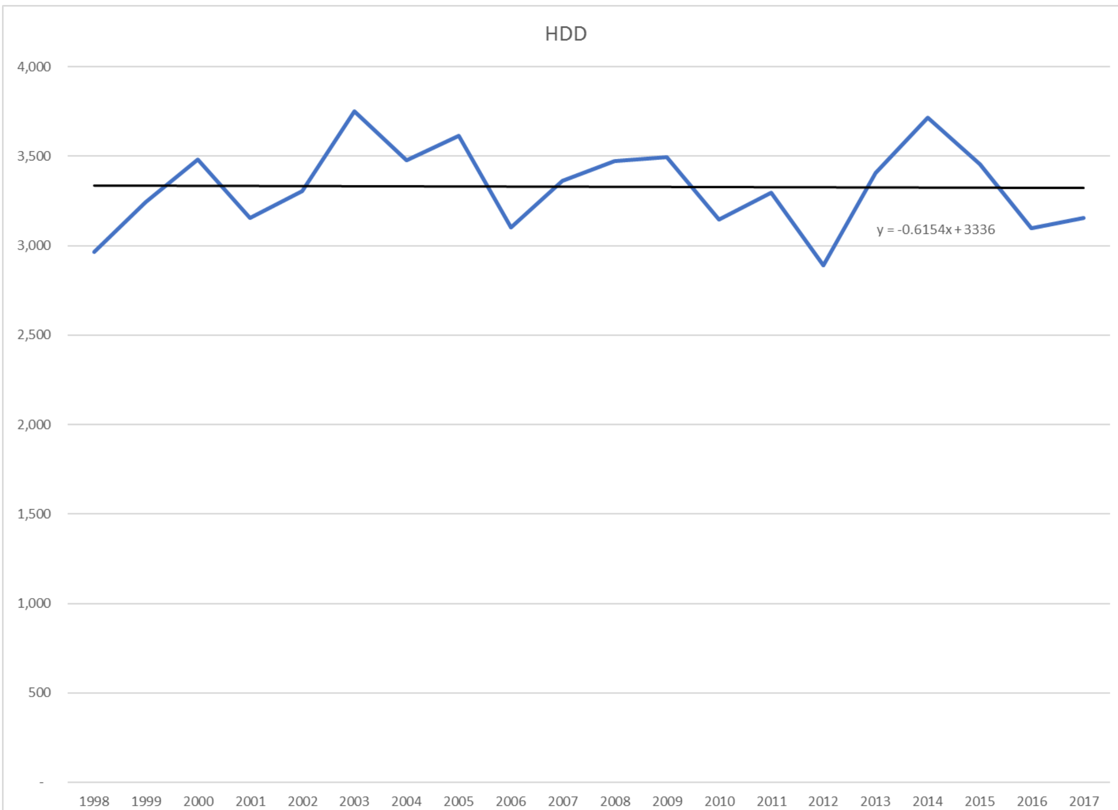
RESPONSE

a) The chart below contains a comparison of the Load Forecast using the 7, 10, and 20-year averages. NOTL Hydro maintains that regression analysis based on data from the last 7 years consistent with other variables is appropriate as the differences in result between the 7-year average and the 10- and 20-year average results are less than 0.32% and 0.22% respectively.

Month	7 Year Average HDD	7 Year Average CDD	10 Year Average HDD	10 Year Average CDD	20 Year Average HDD	20 Year Average CDD
January	624	-	631	-	631	-
February	580	-	575	-	566	-
March	516	-	510	-	509	-
April	330	-	318	-	326	0
May	155	12	158	11	163	10
June	31	55	33	54	33	57
July	1	145	1	138	1	136
August	0	128	1	126	1	128
September	31	57	34	51	31	53
October	162	7	169	5	182	5
November	348	-	351	-	350	-
December	511	-	532	-	536	-
Total	3,289	404	3,314	384	3,330	389

	7 Year	10 Year	20 Year
Weather Normalized Regression Results	214,325,152	213,640,888	213,851,261
Variance from 7 year results		(684,264)	(473,891)
% Variance from 7 year results		(0.32%)	(0.22%)

1



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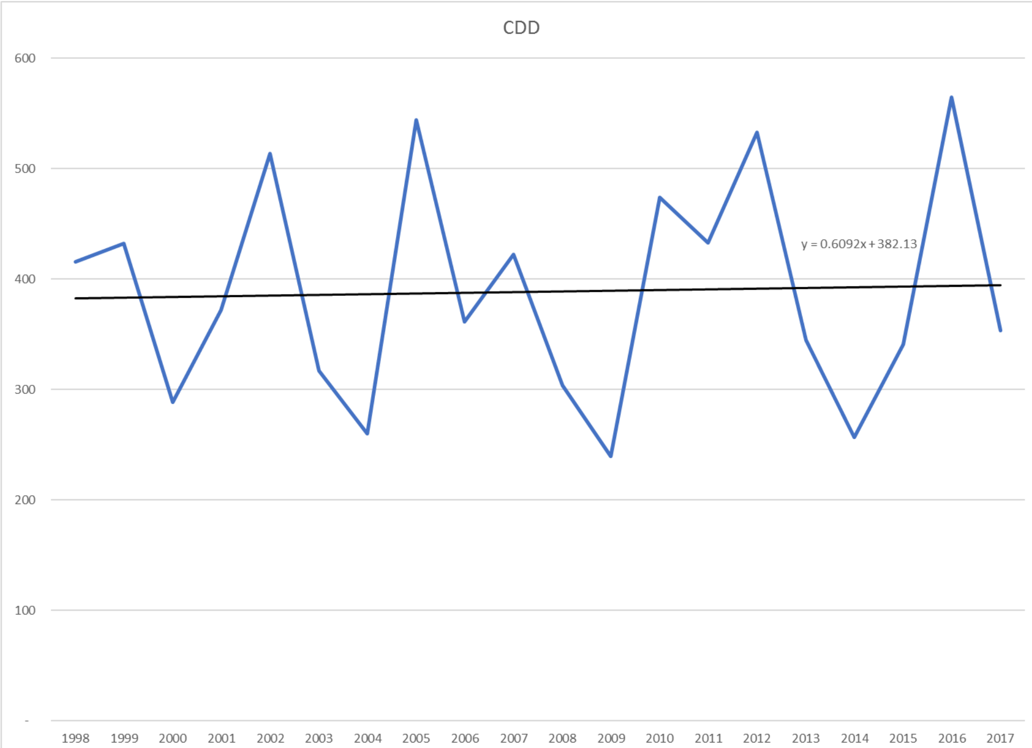


b) According to the National Oceanic and Atmospheric Administration the last seven years would capture six of the ten warmest years including the top four years.

(1880–2017)

Top 10 warmest years (NOAA)

Rank	**Year**	**Anomaly °C**	**Anomaly °F**
1	2016	0.94	1.69
2	2015	0.90	1.62
3	2017	0.84	1.51
4	2014	0.74	1.33
5	2010	0.70	1.26
6	2013	0.66	1.19
7	2005	0.65	1.17
8	2009	0.64	1.15
9	1998	0.63	1.13
10	2012	0.62	1.12

3-Staff-34

Ref: Exhibit 2, Appendix 2A, Page 46; Exhibit 3, Page 30; Exhibit 7, Pages 14-15

NOTL Hydro is proposing the use of a variance account to true-up the load of a customer assigned to a new large use rate class. The forecasted load is an assumed 5,000 kW based on customer estimates which range from 4 MW to 20 MW. NOTL is also proposing a standby rate for the Large Use rate class for a 2.5MW of Combined Heat and Power Generator.

The DSP states that "One customer is expanding significantly and has estimated their ultimate demand will be between 15 MW and 20 MW."

a) Please provide examples where variance accounts have been approved for variances from the load forecast under similar circumstances.
b) Please provide details available to NOTL Hydro regarding the estimates of load from 4 MW to 20 MW for the large use customer.
c) Given that the range in the DSP spans 15 MW to 20 MW, please explain the reasons that NOTL Hydro assumes 5 MW for the large use customer's load forecast when this amount is significantly below the range of values used in the DSP.
d) Is the 2.5 MW of standby generation in addition to the 5 MW of forecasted demand, or a part of it? I.e. 5 MW at the load account plus 2.5 MW supplied by the generator? Or is it a 2.5 MW at the load account plus 2.5 MW supplied by the generator?
e) Does the load profile for the Large User rate class reflect only the anticipated deliveries to the load account, or does it reflect the anticipated deliveries to the load account plus load displacement generation?
f) Would the proposed variance account true-up the load account, or the combination of the load account and standby charges account?

RESPONSE

a) NOTL Hydro is not aware of examples of variance accounts for variances from the load forecast under similar circumstances. This question was asked of a number of sector participants at the time the rate application was being prepared and none were aware of any examples.

b) The Large Use customer has provided NOTL Hydro with an estimate of their monthly demand when operations are developed to their full capacity. No firm estimate has been provided as to when this will be complete. This supports NOTL Hydro's request for a variance account. It should be noted that the Large Use customer has made a capital contribution to NOTL Hydro to support the construction of facilities to serve the increased load forecast, indicating the customer's firm plans to expand (see response to VECC Interrogatory #47).

c) The range of 15 MW to 20 MW refers to the potential maximum demand at this site over the next five years. The maximum demand in any given month will usually be lower; especially as the demand is expected to be seasonal. The range of 4 MW to 20 MW refers to the likely range in demand for any month. The 5 MW was used in the forecast was the most conservative estimate for the forecast and maximized the future rate rebate that would flow to NOTL Hydro customers in the future from the rebate.

d) NOTL Hydro considers the standby charge to be part of the monthly demand charge so it would be included in the calculation of the variance. To illustrate: if the demand was 10 MW and the standby charge was 2 MW (for a total of 12 MW) then the revenues from 7 MW (12 MW total less the 5 MW) would be applied to the variance account.

e) The load profile includes the load displacement generation.

f) As per question d), the proposed variance account would true-up to the combination of the load account and the standby charges.

3-Staff-35

Ref: Exhibit 3, Pages 33-34

NOTL Hydro states that "While the forecast as presented in the previous section assumes some level of embedded 'natural conservation', it does not take into account the impacts on energy purchases arising from CDM programs undertaken by NOTL Hydro's customers."

a) What steps has NOTL Hydro taken to ensure that un-adjusted forecast as presented in Table 3.29 captures natural conservation, but not the impacts of historic CDM?

RESPONSE

a) To clarify, the non-CDM adjusted forecast presented in exhibit 3 pg. 33 does not include the full CDM impact for 2017 – 2019. The impacts of historical CDM programs are embedded in the actual data used to arrive at the regression results. NOTL Hydro assumed that 50% of the 2017 programs are reflected in the regression while an additional 50% are accounted for as an adjustment to the forecast as presented in exhibit 3 pg. 35.

3-Staff-36

Ref: Exhibit 3, Pages 35-36; NOTL Hydro Load Forecast Wholesale Model, Tab 10 CDM Adjustment and Tab 10.1 CDM Allocation

Table 3.32 indicates the CDM adjustment to the load forecast should be 3,770,854 kWh. However, Table 3.33 indicates that the total CDM adjustment to the load forecast is 3,293,292 kWh. The same inconsistency is noted on Tab 10 and Tab 10.1 of the load forecast model.

a) Please reconcile the apparent inconsistency.
b) Please update the load forecast model and evidence as applicable.

RESPONSE

a) The amount on tab 10.1 of the NOTL Hydro Load Forecast Wholesale Model should be 3,770,854 consistent with the amount on tab 10.

b) Load Forecast model has been updated and is being filed in response to OEB Staff interrogatory #1.

3-Staff-37

Ref: Appendix 2-H Other Operating Revenues

Staff notes that the sum of the revenues listed in the Appendix 2-H does not add up to the total other revenues in row 51 of Appendix 2-H because the SSS Admin revenues are not included in the table.

a) Please update the Appendix 2-H by including SSS Admin Revenues (USoA 4086) for all years.

RESPONSE

a) Appendix 2-H has been updated to included SSS Admin Revenue (USoA 4086). The updated schedule is being filed in response to OEB Staff interrogatory #1.

3-Staff-38

Ref: Exhibit 3, Page 46

NOTL Hydro provides a breakdown of the other income and expense in the Table 3.44:

Table 3.44: Other Income and Expenses

	Actual	Actual	Actual	2017	Forecast	Forecast	Forecast
	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	2014	2015	2016	2017	2018	2019	2019 (new rates)
	Total	Total	Total	Total	Total	Total	Total
Other Income and Expenses							
Regulatory Debit	($223,973.78)	-$18,904.87	$0.00	$0.00	$0.00	$0.00	$0.00
4305 CGAAP Accounting Changes	($96,075.39)	-$145,981.35	-$200,949.82	-$239,781.83	-$277,138.39	-$92,379.46	$0.00
REVENUE FROM JOBS	$28,107.64	$30,384.92	$139,972.87	$37,213.35	$37,213.35	$37,213.35	$37,213.35
PROFIT/LOSS ON INVESTMENT	$45,452.00	$36,133.00	$62,352.00	$46,137.00	$0.00	$0.00	$0.00
GAIN ON DISP OF PROPERTY	($3,380.74)	$0.00	$0.00	$9,413.44	$0.00	$0.00	$0.00
Loss on Disposal of Property	$0.00	$0.00	$0.00	-$19,023.31	$0.00	$0.00	$0.00
REVENUES NON-UTILITY OPERATIO	$644,642.68	$3,723.32	$0.00	$0.00	$0.00	$0.00	$0.00
EXPENSES NON-UTILITY OPERATIO	($674,289.75)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CDM REV	$0.00	$956,195.28	$371,343.55	$597,786.59	$500,000.00	$300,000.00	$300,000.00
CDM EXP	$0.00	-$875,823.97	-$381,147.39	-$512,228.80	-$500,000.00	-$300,000.00	-$300,000.00
MISC INCOME SALE OF SCRAP	$4,754.10	$0.00	$6,254.50	$3,019.50	$3,507.03	$3,507.03	$3,507.03
MISC INCOME ADMIN EXP RECOVER	$5,572.56	$6,783.72	$6,962.58	$4,377.96	$5,924.21	$5,924.21	$5,924.21
INT & DIV INCOME MISCELLANEOUS	$0.00	$3,679.73	$9,779.83	$0.00	$0.00	$0.00	$0.00
INT & DIV INCOME CIBC T-BILLS	$0.00	$0.00	$0.00	$1,170.23	$1,170.23	$1,170.23	$1,170.23
INT & DIV INCOME CIBC 69-0211	$6,208.41	$9,503.40	$2,362.55	$3,119.19	$3,119.19	$3,119.19	$3,119.19
					$0.00		
Total Other Income and Expenses	**($262,982.27)**	**$5,693.18**	**$16,930.67**	**-$68,796.68**	**-$226,204.39**	**-$41,445.46**	**$50,934.00**
Total Other Revenue	**-$44,439.78**	**$248,915.16**	**$318,872.28**	**$237,274.92**	**$111,968.52**	**$331,717.68**	**$502,939.00**

Staff notes that Regulatory debit of ($223,973.78) is the main cause for the net cost for 2014 actual other revenues.

a) **Please explain the nature of Regulatory debt line in Table 3.44.**

RESPONSE

a) The regulatory debit of $223,973.78 in 2014 related to changes in depreciation as a result of a change to useful lives that occurred in 2013. This amount related to the difference in depreciation expense as a result of changing the lives of assets for the period from January 2014 to April 2014. This stub period was prior to the rates in NOTL Hydro’s 2014 Cost of Service taking effect was not included in the initial calculation for account 1576.

3-SEC-25

Please provide a revised version of Appendix 2-H by adding a column showing year-to-date actuals.

RESPONSE

Below are the year-to-date actuals for Appendix 2-H

USoA #	USoA Description	Year to date at Sept 2018
4235	**Specific Service Charges**	($46,160)
4225	**Late Payment Charges**	($35,791)
4082	**Retail Services Revenues**	($4,133)
4084	Service Transaction Requests (STR) Revenues	($18)
4086	SSS Administration Revenue	($20,771)
4205	Interdepartmental Rents	$0
4210	Rent from Electric Property	($35,432)
4215	Other Utility Operating Income	$0
4220	Other Electric Revenues	$0
4240	Provision for Rate Refunds	$0
4245	Government Assistance Directly Credited to Income	$0
4305	Regulatory Debits	$188,166
4310	Regulatory Credits	$0
4315	Revenues from Electric Plant Leased to Others	$0
4320	Expenses of Electric Plant Leased to Others	$0
4325	Revenues from Merchandise Jobbing, Etc.	($18,946)
4330	Costs and Expenses of Merchandising Jobbing, Etc.	$0
4335	Profits and Losses from Financial Instrument Hedges	$0
4340	Profits and Losses from Financial Instrument Investments	$0
4345	Gains from Disposition of Future Use Utility Plant	$0
4350	Losses from Disposition of Future Use Utility Plant	$0
4355	Gain on Disposition of Utility and Other Property	($30,973)
4360	Loss on Disposition of Utility and Other Property	$0
4365	Gains from Disposition of Allowances for Emission	$0
4370	Losses from Disposition of Allowances for Emission	$0
4375	Revenues from Non-Utility Operations	($210,668)
4375	Sub-account Generation Facility Revenues	$0
4380	Expenses of Non-Utility Operations	$230,686
4380	Sub-account Generation Facility Expenses	$0
4385	Non-Utility Rental Income	$0
4390	Miscellaneous Non-Operating Income	($12,006)
4395	Rate-Payer Benefit Including Interest	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0
4405	Interest and Dividend Income	($5,792)
4415	Equity in Earnings of Subsidiary Companies	$0
Total		($1,839)
Specific Service Charges		($46,160)
Late Payment Charges		($35,791)
Other Operating Revenues		($60,354)
Other Income or Deductions		$140,467
Total		($1,839)

Account 4210 - Rent from Electric Property	
Specific Charge for Access to the Power Poles – per pole/year	($32,632)
ROOM RENTAL P.O.P. SITE	$0
ROOF RENTAL FIT	($2,800)
Account 4305 - Regulatory Debits	
Regulatory Debit	$0
4305 CGAAP Accounting Changes	$188,166
Account 4390 - Miscellaneous Non-Operating Income	
MISC INCOME SALE OF SCRAP	($6,593)
MISC INCOME ADMIN EXP RECOVER	($5,413)
Account 4405 - Interest and Dividend Income (excluding variance account interest)	
INT & DIV INCOME CIBC T-BILLS	$0
INT & DIV INCOME CIBC 69-0211	($5,792)

3-SEC-26

[Ex.3, p.30, Ex.9, Appendix 9C] The Applicant proposes a Large User Variance Account.

a) Please provide the Applicant's proposed disposition methodology of any balance that accumulates in the account.
b) When would the Applicant propose to clear any balances?
c) For each of the following two scenarios, please provide a) the forecast debits/credits, b) the expected disposition amounts and how they would be allocated to rate classes, c) proposed rate riders based on the proposed disposition methodology, d) forecast bill impacts of the disposition.
   i. Large User actual demand of 2500 kw in 2019
   ii. Large User actual demand of 7500 kw in 2019
d) Has the Applicant consulted with any customers in the Large User class or other rate class about this proposal? If so, please provide details.

RESPONSE

a) NOTL Hydro proposes to dispose of the variance balances by allocating them across customer classes based on distribution revenue. The customer class balances would then be allocated based on consumption.

b) NOTL Hydro proposes to clear any balances annually in the same manner that many other variance accounts are cleared.

c) The requested information is provided in the table below.

Variance (kW)	(2,500)	2,500					
Months	12	12					
Proposed Large Use Variable Distribution Rate	$2.61320	$2.61320					
$ Variance	($78,396)	$78,396					
Variance - Large User Demand 2,500 kW/month	**Estimated Distribution Revenue - 2019**	**Proportion**	**Variance Account**	**kWh**	**Rate Rider / kWh**	**Monthly Consumption (kWh)**	**Monthly Bill Impact**
Residential	$2,958,418	55.1%	(43,216)	73,998,981	($0.00058)	750	($0.44)
GS<50	$1,187,793	22.1%	(17,351)	41,877,513	($0.00041)	2,000	($0.83)
GS>50	$988,010	18.4%	(14,433)	82,705,771	($0.00017)	52,500	($9.16)
Streetlights	$224,121	4.2%	(3,274)	886,616	($0.00369)	10,150	($37.48)
Unmetered	$8,426	0.2%	(123)	251,508	($0.00049)	800	($0.39)
Total excluding Large User	$5,366,768	100.0%	(78,396)	199,720,389			
Large User	$177,656			23,308,825			
Total Distribution Revenue	$5,544,424	100.0%	(78,396)	223,029,214			
Variance - Large User Demand 7,500 kW/month	**Estimated Distribution Revenue - 2019**	**Proportion**	**Variance Account**	**kWh**	**Rate Rider / kWh**	**Monthly Consumption**	**Monthly Bill Impact**
Residential	$2,958,418	55.1%	43,216	73,998,981	$0.00058	750	$0.44
GS<50	$1,187,793	22.1%	17,351	41,877,513	$0.00041	2,000	$0.83
GS>50	$988,010	18.4%	14,433	82,705,771	$0.00017	52,500	$9.16
Streetlights	$224,121	4.2%	3,274	886,616	$0.00369	10,150	$37.48
Unmetered	$8,426	0.2%	123	251,508	$0.00049	800	$0.39
Total excluding Large User	$5,366,768	100.0%	78,396	199,720,389			
Large User	$177,656			23,308,825			
Total Distribution Revenue	$5,544,424	100.0%	78,396	223,029,214			

d) NOTL Hydro has discussed this briefly with the proposed Large Use customer though the variance account has limited impact on the cost of services for this customer. They will be billed the same with or without the variance account. The only other customers this has been discussed with were those at the Open House.

3.0-VECC-15

Reference: Exhibit 3, page 7

a) **Please re-do Table 3.4 and include, for the years 2016-2018, the revenues from the ICM rate rider.**

RESPONSE

a) Below is an update to table 3.4 that includes ICM rate rider revenues (000's).

	2014	2015	2016	2017	2018	2019
Service Revenue	$4,729	$4,693	$4,844	$5,017	$5,153	$5,546
ICM		$104	$176	$173	$179	$0
Service Revenue + ICM	$4,729	$4,797	$5,020	$5,190	$5,332	$5,546
Annual Growth		1.43%	4.65%	3.40%	2.74%	4.00%

3.0-VECC-16

Reference: Exhibit 3, page 10

a) **Why were only seven years of data used for purposes of developing the multi-variate regression model (as opposed to including more historical years)?**

RESPONSE

a) Due to a change of billing systems in 2010, NOTL Hydro was not able to verify actual consumption data by rate class by month prior to 2011. For consistency, the 7-year period from 2011 – 2017 that was used to allocate consumption for the bridge and test year was also used for the regression analysis.

3.0-VECC-17

Reference: Exhibit 3, pages 11-14 and page 26

a) At page 26, the Application states that the "the expected growth rate (for Residential customers) has been adjusted by reducing it to 2.21%; the historical growth rate without Cannery Park". Please provide the calculation supporting the claim that the 2.21% represents the historical growth rate without Cannery Park.

b) At page 14, the Application states that "forecasted growth in GS<50 kW customers has been reduced to 3 new customers each year to remove the impact of the Outlet Mall from the forecast". Please provide the calculations that demonstrate that, without the Outlet Mall, the historical growth rate (for GS<50) would have been three customers per year.

c) Please provide i) the customers count by class as of June 30, 2018 and ii) the most recent customer count by class available.

d) With respect to page 26 (lines 1-2), please: i) confirm that the historical data (i.e., 2011-2017) on customer counts presented in Table 3.21 is based on the average of the twelve monthly values for each year and ii) clarify what Tables in the Application (if any) are based on year-end customer counts.

RESPONSE

a) NOTL Hydro calculated an average increase of 176 new customers per year from 2011 to 2017 excluding the impact of Cannery Park. The tables below outline the calculations.

	2011	2012	2013	2014	2015	2016	2017	Average
Average # of Residential Customers	6,594	6,716	6,912	7,110	7,389	7,661	7,838	
Growth		122	196	198	279	272	178	
Cannery Park Adjustment		-	-	-	(94)	(94)	-	
Adjusted Growth		122	196	198	186	178	178	**176**

2017 Average # Residential Customers	7,838
Add: Average # new customers	176
Less: Loss of Load Transfer Customers	(38)
2018 Forecast	**7,976**
Add: Average # new customers	176
2019 Forecast	**8,152**
% change to 2018 Forecast	**2.21%**

b) Excluding the 90 new customers that resulted from the opening of the outlet mall in 2014, NOTL Hydro calculated the average increase in GS<50 customers to be 1. Growth in GS<50 customers is somewhat sporadic. NOTL Hydro believes that recent growth was a better indicator for this category. The average increase from 2015 (after completion of the outlet mall) – 2017 was used.

	2015	2016	2017	Average
Average # of GS<50 Customers	1,322	1,333	1,332	
Growth	-	11	(1)	
Outlet Mall	-	-	-	
Adjusted Growth	-	11	(1)	**3**

c) The table below contains customer counts as of June 30, 2018 and October 31, 2018.

	30-Jun-18	31-Oct-18
Residential	7,917	7,962
GS <50kW	1,338	1,350
GS >50 - 4,999kW	128	127
Streetlights	5	5
Unmetered	29	29
Large User	-	-
	9,417	9,473

d) NOTL Hydro confirms that the historical customer counts presented in Table 3.21 are based on the average of the twelve-monthly values for each year. Average number of customers is used throughout the application.

3.0-VECC-18

Reference: Exhibit 3, pages 19-24

a) **What customer classes are included in determining the value for the Customer Count variable?**

b) **It is noted (see Table 3.18) that neither the Daylight Hours variable nor the Blended Rate variable are statistically significant. Please provide a regression model and results (similar to Table 3.18) that excludes these two variables along with an alternative forecast (similar to the excel load forecast filed) based on this revised model.**

RESPONSE

a) Residential, GA<50kW and GS >50kW – 4,999kW

b) Please see below:

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.974318517							
R Square	0.949296573							
Adjusted R Square	0.946046354							
Standard Error	494542.4365							
Observations	84							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	5	3.57163E+14	7.14326E+13	292.0715131	5.58366E-49			
Residual	78	1.90766E+13	2.44572E+11					
Total	83	3.7624E+14						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-11248612.85	2313451.175	-4.862265074	5.89798E-06	-15854340.34	-6642885.359	-15854340.34	-6642885.359
HDD	3186.920665	368.9010634	8.638957652	5.41894E-13	2452.495064	3921.346265	2452.495064	3921.346265
CDD	38556.45006	1780.637554	21.65317135	1.00356E-34	35011.473	42101.42711	35011.473	42101.42711
# Customers	1307.58547	112.0753525	11.66702081	8.82912E-19	1084.460583	1530.710357	1084.460583	1530.710357
Day per Month	455493.4099	69668.48137	6.538012613	5.87881E-09	316794.118	594192.7018	316794.118	594192.7018
Spring/Fall Flag	797298.212	138317.2112	5.764273331	1.56471E-07	521929.7974	1072666.626	521929.7974	1072666.626

3.0-VECC-19

Reference: Exhibit 3, page 33 and Exhibit 8, page 26

a) Please provide a revised version of Table 3.29 that includes rows which set out: i) purchases (including IESO, SOP, FIT and MicroFIT) – both actual and forecast and ii) calculated losses for each year – both historical and forecast.

RESPONSE

a) Please see table below

	2011	2012	2013	2014	2015	2016	2017	2018F	2019F
IESO	172,952,898	175,015,278	174,453,179	182,267,235	186,601,102	194,519,543	190,337,392	196,969,599	220,626,357
SOP	15,095,889	12,668,908	13,566,559	12,179,335	12,739,289	12,038,127	10,971,592	10,971,592	10,971,592
FIT	3,911	598,435	650,444	851,260	866,605	895,000	867,723	1,229,080	1,492,970
MicroFit	245,823	886,451	1,152,871	1,453,817	1,566,819	1,736,631	1,608,060	1,683,789	1,683,789
	188,298,521	189,169,073	189,823,053	196,751,647	201,773,815	209,189,302	203,784,767	210,854,060	234,774,708
Consumption	181,309,571	181,845,359	182,708,524	189,355,729	193,845,050	202,468,101	196,959,263	203,154,504	226,322,506
Loss Factor	1.0385	1.0403	1.0389	1.0391	1.0409	1.0332	1.0347	1.0379	1.0373

3.0-VECC-20

Reference: Exhibit 3, page 29

a) **Please confirm that the "weather normalized" values for Residential and GS<50 are calculated by applying the ratio of Actual Residential Sales over Actual Wholesale Purchases to the calculated value for Weather Normalized Wholesale Purchases.**

b) **Please confirm that in those years where the Actual Wholesale Purchases exceed the Weather Normalized Wholesale Purchases one would expect the percentage of Wholesale Purchases accounted for by the Residential and GS<50 classes to be higher – since these classes are also weather sensitive.**
   i. **If not confirmed, please explain why not.**
   ii. **If confirmed, please explain why the calculation, as described in part (a), results in weather normalized values for the Residential and GS<50 classes.**

RESPONSE

a) Confirmed. The "weather normalized" or "predicted" values for Residential customers are calculated by applying the rate of Actual Residential Sales over Actual Wholesale Purchases multiplied by the Weather Normalized Wholesale Purchases and the values for GS<50 customers are calculated by applying the rate of Actual GS<50 Sales over Actual Wholesale Purchases multiplied by the Weather Normalized Wholesale Purchases.

b) Confirmed. NOTL Hydro agrees that one would expect that is those years where the Actual Wholesale Purchases exceed the Weather Normalized Wholesale Purchases the percentage of Wholesale Purchases accounted for by the Residential and GS<50 classes would be higher provided all other variables are unchanged. For example, number of customers and rate classifications.

   Actual results for Residential and GS<50 customers do not fully support this assumption as the ratios in the years where the actual wholesale purchases exceed the weather normalized wholesale purchases (2014 & 2015) are relatively consistent with the years where the opposite is true. The ratio is also impacted by other factors such as the opening of the outlet mall in 2014, which increased the number of GS<50 customers by approximately 100 and GS>50 by approximately 5. There were also a higher than normal number of customers that were reclassified from GS>50 to GS<50 during 2015 as part of NOTL Hydro's annual rate classification changes.

3.0-VECC-21

Reference: Exhibit 3, page 31

a) **Please provide the derivation of the 2018 and 2019 value for the average use per connection for USL (9,573.38 kWh).**

RESPONSE

a) The average use for USL connections was based on actual usage and number of customer billed since March 1, 2018. There are 26 USL connections that are billed monthly.

Accounts Billed	Usage Month	Total Usage	Monthly Usage Per Customer	Annual Usage per Customer
26	Mar-18	20,959	806.12	9673.38
26	Apr-18	20,959	806.12	9673.38
26	May-18	20,959	806.12	9673.38
26	Jun-18	20,959	806.12	9673.38

3.0-VECC-22

Reference: Exhibit 3, page 34

a) Please provide a copy of the most recently approved 2015-2020 CDM Plan for NOTL.

b) Please confirm that the IESO report in Appendix 3A is equivalent to the excel based report found on the IESO web-site at: http://www.ieso.ca/sector-participants/conservation-delivery-and-tools/conservation-targets-and-results. If not confirmed, please provide Appendix3A in excel format.

RESPONSES

Please note the following:

a) Ontario CDM Plans can be found at http://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/CDM-Plans.
   - NOTL's Approved CDM Plan is located here: http://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/-/media/files/ieso/document-library/conservation/CDM-plans/CDM-Plan-Niagara-on-the-Lake-Hydro-Inc.pdf
   - NOTL Conditional Approval Letter is located here: http://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/-/media/files/ieso/document-library/conservation/CDM-plans/CDM-Plan-Conditional-Approval-Letter-Niagara-on-the-Lake-Hydro-Inc.pdf

b) Confirmed that the report in Appendix 3A is equivalent to the report cited in **http://www.ieso.ca/sector-participants/conservation-delivery-and-tools/conservation-targets-and-results**.

3.0-VECC-23

Reference: Exhibit 3, pages 45-49

a) **Please explain more fully how the 2018 and 2019 forecast Late Payment revenues were determined.**

b) **Please explain the significant fluctuation in Revenue from Merchandising (Account 4325) in 2016.**

RESPONSE

a) Late payment revenue forecasts for 2018 and 2019 are based on the average of the prior 4 years (2014 – 2017)

b) The fluctuation in account 4325 in 2016 was due to increased revenue related to the completion of customer driven work and final billing of the cost to the Outlet Mall.

4 | Operations, Maintenance & Administration

INTERROGATORY RESPONSES

4-Staff-39

Ref: Appendix 2-JB Recoverable OM&A Cost Drivers; Exhibit 4, Page 11, Table 4.10

The recoverable OM&A cost drivers table in Appendix 2-JB does not match to Table 4.10 in the Exhibit 4. Staff notes that the table in excel may not have the correct closing balances for the OM&A expenses.

a) Please update the Appendix 2-JB to match with the Table 4.10 in Exhibit 4.

RESPONSE

a) Appendix 2-JB has been updated to match with Table 4.10. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-40

Ref: Appendix 2-JC OM&A Programs Table; Exhibit 4, Page 22

Staff notes that the following cell values on the Appendix 2-JC OM&A Programs Table does not agree to the Board approved column on Table 4.20 of Exhibit 4:

- **Cell B35, sub-total for Operation for last rebasing year**
- **Cell B55, sub-total for Administrative and General for last rebasing year**
- **Cell B56, total for last rebasing year**

Staff notes that the values for last rebasing year on Table 4.20 of Exhibit 4 agree to the values approved by the OEB in NOTL Hydro's 2014 CoS application.

a) Please update the Appendix 2-JC to ensure that the values on the Appendix agree to the OEB-approved values.

RESPONSE

a) Appendix 2-JC has been updated to agree with OEB approved values. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-41

Ref: Exhibit 4, Page 11 and Page 12; Appendix 2-K Employee Costs

NOTL Hydro explains that one of the OM&A cost driver is the cost for new staff: "In 2016 and 2017 NOTL Hydro hired a new Customer Service Representative and a new Lineman due to the overall growth in the company business."

Table 4.10 on page 10 of Exhibit 4 list the new staff's cost which is separate from the wage increase for a total of $141,321 ($31,780+$67,541+$42,000).

Staff notes from Appendix 2-K Employee Costs that NOTL Hydro's headcount in 2019 has not been increased from 2014 OEB-approved headcount (2014 approved headcount of 19.1 and 2019 forecasted headcount of 18).

a) Please confirm whether or not the new staff (headcounts) hired in 2016 and 2107 were included in the 2014 headcounts and the OM&A expense approved by the OEB?
   i. If so, please explain why the cost of new staff is considered as a cost driver for the OM&A expense increase.
   ii. If not, please reconcile the cost drivers of total wage increase and total new staff costs to the increase of employee costs from 2014 approved to 2019 forecast in Appendix 2-K.

b) Please update the Appendix 2-JB OM&A Cost Drivers and Appendix 2-K Employee Costs as applicable.

RESPONSE

The headcount of 19.1 approved for the 2014 test year included 6 management staff and 13.1 union staff. After the new staff were hired the NOTL staffing consisted of 6 management staff and 12 union staff so the headcount was within that approved for 2014.

Table 4.10 analyzes the changes in operating costs from year to year. Therefore, as the new staff were hired they created an increase in costs compared to the previous year.

The reconciliation requested in a) ii is below:

	Employee Compensation	Source
2014 Board Approved	$1,813,931	Per Appendix 2-K
2014 Headcount reduction	(174,519)	Per Appendix 2-K
2014 Actual	1,639,412	Per Appendix 2-K
New hires (2015-2017)	141,321	Per Appendix 2-JB
Wage increases	269,962	Per Appendix 2-JB
Other	(8,284)	
2019 Test Year	$2,042,411	Per Appendix 2-K

The updated Appendix 2-JB is below. The negative new staff cost of $100,000 is lower than the $174,519 in the reconciliation above as one of the staff reductions was a leave related to a CDM staff. CDM costs are not included in OM&A. The settlement is shown as offsetting as the reduction in staff costs could be considered a result of the lower settlement costs.

Recoverable OM&A Cost Driver Table

Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
OM&A	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Opening Balance	$2,155,262.00	$2,208,203.00	$2,323,118.84	$2,532,190.98	$2,595,121.03	$2,904,865.12
Continuous Cost Increases						
Wage increase		$42,767	$69,517	$71,121	$42,850	$43,707
Inflation		$11,287	$17,696	$17,315	$9,046	$20,721
New staff	-$100,000		$31,780	$67,541	$42,000	
Locate costs		$26,000				
Cyber security				$25,000	$5,000	
Utilismart contract				$25,000		
CHEC		$22,300	$4,700			
Settlement	$75,445					
Variable Costs						
Capitalized labour		-$82,845	$56,124	$19,736	$73,129	$1,316
Transformer St. Mtce		$15,000	$13,000	-$36,000	$46,000	-$25,000
Tree trimming		$23,500	$0	-$40,000	$45,000	
Underground services		$30,000	-$17,000			
One-time Costs						
Regulatory costs	$52,941	-$42,353				$46,198
Severance		$42,000	-$42,000			
Micro-grid study			$100,000	-$100,000		
Temporary staff		$30,490	-$11,942	-$18,548	$25,000	
Other	$24,555	-$3,230	-$12,803	$31,765	$21,719	-$17,621
Decrease in OM&A offseting increase						
Closing Balance	$2,208,203	$2,323,119	$2,532,191	$2,595,121	$2,904,865	$2,974,186
Summay Integrity Check	**$2,208,203**	**$2,323,119**	**$2,532,191**	**$2,595,121**	**$2,904,865**	**$2,974,186**
Difference	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

4-Staff-42

Ref: Exhibit 4, Page 17

In explaining the 2017 to 2018 year-over-year variance for OM&A, NOTL Hydro states that

> **Operation costs are forecast to be flat. The transfer of the cost of VP Operations to administration is being offset by an increase in labour as less allocation to capital work is expected. This is not a change in accounting policy but change in work practice.**

a) Please elaborate on why and how NOTL Hydro considers less allocation to capital work is a change in work practice, not a change in accounting policy.
b) Please provide the quantum of the change of this work practice and the impact of the OM&A expense and capital.

RESPONSE

a) IFRS requires that senior management only capitalize hours directly to projects to which their hours are directly attributable. For 2018, NOTL Hydro reviewed the tasks undertaken by and time spent by the President and VP Operations. This resulted in fewer hours of these two management staff being capitalized and more being expensed as part of OM&A.

b) The quantum of change is summarized in the table below:

	Hours	$
Forecast 2018	158	$13,128
2017	1,294	$108,577
Variance	(1,136)	($95,449)

4-Staff-43

Ref: Exhibit 4, Page 18 and Page 19

NOTL Hydro compares its 2016 OM&A per customer to the provincial average excluding Hydro One and states that:

> According to the OEB's published 2016 Yearbook, the total cost per customer provincial average was $431. However, if Hydro One is removed from this calculation the provincial average becomes $278. NOTL Hydro's total cost per customer average was $278.

a) Please compare NOTL Hydro's OM&A per customer in 2017 to the provincial average excluding Hydro One that is published from 2017 Electricity Distributors Yearbook.

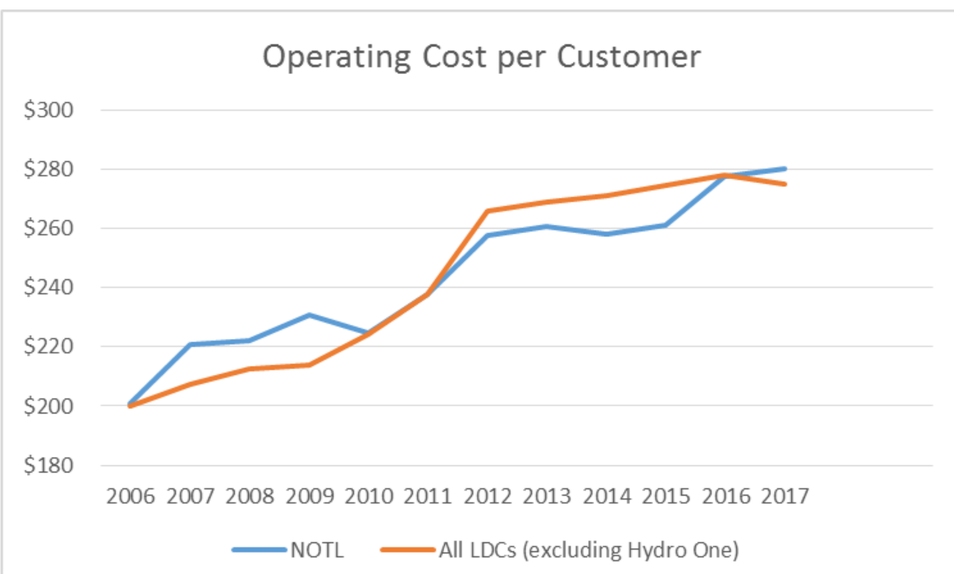
b) Has NOTL Hydro benchmarked itself with the neighbouring distributors with respect to the OM&A expense, similar to the revenue benchmark NOTL has performed and presented in the open houses and AGMs?

   i. If so, please provide the benchmark analysis.

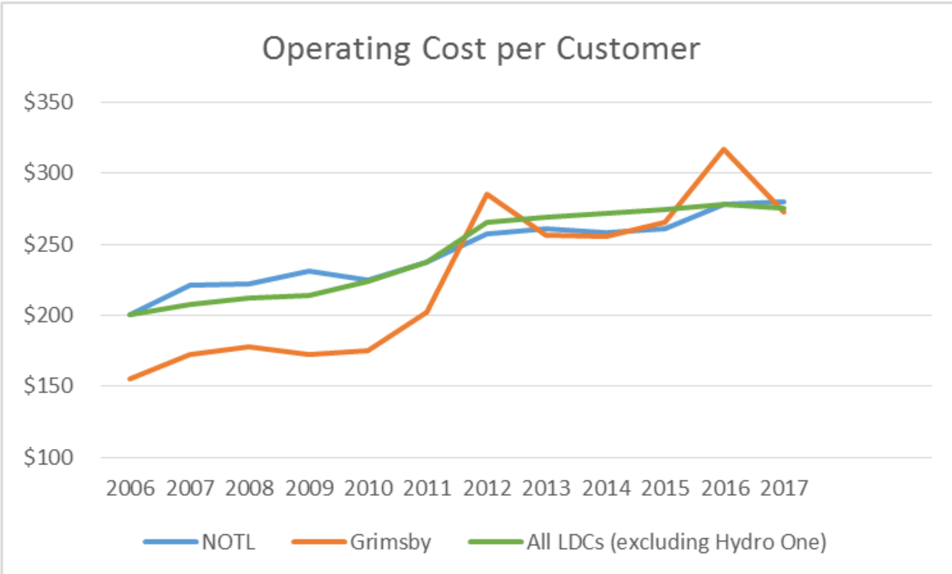
   ii. If not, please explain why not.

RESPONSE

a) Please see the chart below



b) As per question 7, NOTL Hydro benchmarks its rates against neighbouring distributors as we believe that is what is important to our customers. NOTL Hydro does not benchmark OM&A against neighbouring distributors as we recognize they can be very different structurally. However, NOTL Hydro did recently compare its OM&A to Grimsby Power as they have a similar number of customers. This analysis is provided below.


Operating Cost per Customer
$350
$300
$250
$200
$150
$100
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
NOTL
Grimsby
All LDCs (excluding Hydro One)

4-Staff-44

Ref: Exhibit 4, Page 23

NOTL Hydro provides the variance analysis for operation costs by program in the table below:

Table 4.21: Operations Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Distribution sub-stations	$53,690	$18,984	Increased maintenance at the 2 transmission stations due to age, increased activity and service requirements. Most of this work is contracted to third parties due to need for transmission voltage expertise.
Overhead	$192,432	$69,673	All non-capital service work on overhead lines increasing due to wage increases, increased traffic in Town and shift in focus on customer service from capital work.
Engineering	-$45,671	-$62,067	Transfer of most of non-dedicated VP Operations time to Administration.

a) With respect to the increase of $192,432 in Overhead costs, please provide a further breakdown of the total increase to the increase due to wage increases, the increase due to increased traffic in Town and the increase due to the shift in focus on customer service from capital work.

b) Please confirm whether or not the shift in focus on customer service from capital work means the shift in focus on maintenance service from capital work?

c) Please provide the linkage between “the shift in focus on customer service from capital work” and the overhead capital projects in Exhibit 2.

RESPONSE

a) The breakdown of the overhead by G/L accounts is as follows:

	2014	2019	Change
5020-Overhead Distribution Lines and Feeders - Operation Labour	41,385	138,805	97,420
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	26,958	97,357	70,400
5125-Maintenance of Overhead Conductors and Devices	44,391	60,033	15,642
5130-Maintenance of Overhead Services	23,664	32,693	9,029
	136,397	328,888	192,491

The breakdown by type of costs can be shown as:

Cost type	Cost
Safety consulting	$40,000
Inflation (8%)	10,900
Increased hours (5020,2025)	105,300
Increased Maintenance (5125,5130)	19,200

Subcontracted	17,000
Total	$192,400

- NOTL Hydro did not have a safety consultant in 2014. One was first hired in 2015 and the current consultant provides services 2-3 days a month.
- NOTL Hydro is not able to put a cost to the increased traffic in town. This was an anecdotal observation by staff as to the increase in hours to this type of service.
- The increased hours are for both service work and for safety sessions.

The increased time spent on service work (and safety) is a reflection on the growth of the system in size and complexity and an increase in focus on responding to customer needs.

b & c) Although NOTL Hydro staff are spending more time on service work, the level of capital spending is being maintained. More of the capital work is now either outsourced or focused on investments that do not require the same level of internal labour input such as smart grid devices, underground work and transmission station work.

4-Staff-45

Ref: Exhibit 4, Page 24 and Page 28

NOTL Hydro provides the variance analysis for administration costs by program in the table below:

Table 4.23: Administration Program Costs Drivers

Cost	Variance since Board Approved 2014	Variance since 2017	Explanation
Executive salaries and professional services	$296,103	$161,609	Increased due to addition of VP Operations to Administration, new staff in all three executive roles and less time charged to capital due to focus on other responsibilities.
IT, software, communications	$67,273	$10,986	Increased due to increased cyber-security demands that required new contract with IT provider and more time dedicated by internal staff.

Staff notes that the executive headcount has not been increased over the period of 2014 to 2019 as per Table 4.29 in Exhibit 4 page 28.

a) Please provide a further breakdown of the variance of $296,103 for executive salaries and professional services to the increases due to three reasons provided in Table 4.23.

b) Please explain and reconcile the statement of "the new staff in all three executive roles" with the fact that the executive headcount has not been increased from 2014 to 2019.

RESPONSE

a) Please see the table below for a further breakdown:

	2014	2019	Change
5605-Executive Salaries and Expenses	95,246	431,171	335,925
5610-Management Salaries and Expenses	123,389	15,574	(107,816)
5615-General Administrative Salaries and Expenses	98,614	164,354	65,741
5630-Outside Services Employed	40,800	48,576	7,776
5635-Property Insurance	28,113	21,493	(6,620)
5640-Injuries and Damages	27,719	28,817	1,099
Total			296,105

b) Further to the table above:

- In 2016, the titles of the Manager, Operations and the Director of Corporate Services were changed to Vice President, Operations and Vice President, Finance. At that time, the allocation of their costs switched from management accounts to the Executive account. In the case of the VP Finance this can be seen in the switching of the costs from 5610 to 5615. In the case of the VP Operations the switch was across functional reporting groupings from Operations to Administration.

- The roles of President, VP Finance and VP Operations are all being provided by different employees in 2019 compared to 2014. It is estimated that the combination of inflation, new hires at higher salaries and the transfer of the non-capitalized cost of the VP Operations have increased costs by around $120k.
- In 2014, a significant amount of the time of the President and the Manager, Operations was booked to capital under CGAAP. Under IFRS, this is no longer allowed and only senior management time working directly on a project can be capitalized. The cost of administration has increased correspondingly and it is estimated that this is over $100k.
- In 2014, General Administrative Salaries and Expenses (Account 5615) were one accounting staff and part of the Business Manager whose time was split between administration and billing and collecting. The Business Manager was replaced by a Business Analyst whose time is 100% administration as deals with regulatory reporting.

4-Staff-46

Ref: Exhibit 4, Page 32

NOTL Hydro provides a breakdown of the 2019 shared services to its sister company ESNI in the table below:

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service-Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$85,676.13	$71,666.78
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$2,103.03	$1,752.53
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$44,117.04	$40,106.40
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00

a) **Please reconcile the mark up on the share services for 2019 to the other revenues in Appendix 2-H for the 2019 test year.**

RESPONSE

a) The table below shows where the mark-up in shared services are reflected in Appendix 2-H. NOTL Hydro acknowledges that the amount of mark-up that should be included in account 4235 in Appendix 2-H should be $4,603.06 ($4,010.64 + $592.42) and that the actual amount reflected for mark-up in Appendix 2-H is $4,112.36, a difference of $490.70. The updated schedule is being filed in response to OEB Staff interrogatory #1.

Year: 2019

Shared Services

Name of Company: From	Name of Company: To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Other Revenue	Account
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Billing- Customer Service- Billing/collecting/Account Inquiries/Reports/Water reads	Cost-Base	$85,676.13	$71,666.78	$14,009.36	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Gas Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll	Cost-Base	$0.00	$0.00	$0.00	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Electric Water Heaters- Finance-Accounts Payable/Receivable,Account Reconcilations, Payroll/Solar Panel- Engineering Consulting	Cost-Base	$2,103.03	$1,752.53	$350.51	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Bills- Printed/Cancelled bills	Cost-Base	$44,117.04	$40,106.40	$4,010.64	4235
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Water Meter Installs- Contractor charges for #Meter Installed	Cost-Base	$12,078.00	$10,980.00	$1,098.00	4325
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Adminstrative Expenses- Mtce General Plant, Property Taxes, Property Insurance, Audit Fees, Office Supplies	Cost-Base	$6,516.63	$5,924.21	$592.42	4235
Niagara-on-the-Lake Hydro Inc	Energy Services Inc	Board Of Directors-Payroll	Cost-Base	$8,400.00	$8,400.00	$0.00	n/a

4-Staff-47

Ref: Exhibit 4, Page 32

NOTL Hydro forecasts $30,000 for oral hearings and $75,000 for intervenor costs as part of the total cost of $190,000 for preparing the 2019 cost of service application. NOTL Hydro explains that "Interrogatory, settlement and hearing costs have been estimated based on other rate applications".

a) Please provide the rate applications that NOTL Hydro has used for its estimate of the oral hearing and intervenor costs and how the estimates were derived.

b) Given the two intervenors in this case, please confirm whether or not any of the estimated cost for preparing the 2019 cost of service application is to be updated.

i. If so, please provide the updated estimate and the updated appendix.

ii. If not, please explain why not.

RESPONSE

a) NOTL reviewed cost awards for several 2017 and 2018 Cost of Service applications including (CNP, Centre Wellington, and Hawkesbury). Individual intervenor costs in those applications ranged from $8,878 to over $39,000. NOTL Hydro estimated $25,000 per intervenor with an assumption of 3 intervenors to arrive at $75,000. Oral Hearing costs were estimated based on consultations with Tandem Energy Services and their historical experience in these matters.

b) Given that there are 2 intervenors opposed to the 3 that were estimated by NOTL Hydro in the application, NOTL Hydro believes intervenor costs can be reduced to $50,000. The updated schedule is being filed in response to OEB Staff interrogatory #1.

4-Staff-48

Ref: Exhibit 4, Page 51

NOTL Hydro states that "NOTL Hydro had a loss for income tax purposes in the years 2014-2016 so no income tax expense was calculated."

a) **Please provide the tax losses for the years 2014-2016 respectively.**
b) **Please explain if NOTL Hydro has carried back the tax losses from 2014-2016.**
c) **If the answer to b) is no, please provide NOTL Hydro's plan to carry forward the tax losses from 2014-2016.**
d) **Please provide the impact of NOTL Hydro's plan in c) to the forecast PILs in 2019 if any.**

RESPONSE

a) The losses for the tax years 2014, 2015 and 2016 are $51,083, $383,781 and $18,286 respectively.

b) NOTL Hydro has carried back the losses from 2014 of $51,083 to 2012, the losses from 2015 of $383,781 to 2012 and the losses from 2016 of $18,286 to 2013.

c) Not applicable, losses were fully utilized.

d) Not applicable.

4-Staff-49

Ref: NOTL Hydro 2019 Test Year Income Tax PILs Model; Appendix 2-BA Fixed Asset Continuity Schedule

Staff notes that the total addition on Schedule 8 CCA for the test year in NOTL Hydro's PILs model agrees to the total addition for the test year fixed asset continuity schedule in Appendix 2-BA. However, the addition for Building and Fixture of $52,260 is included as part of the CCA class 47 addition of $4,702,650 on schedule 8 for the test year in the PILs model.

Staff notes that the building and fixture was mapped to the CCA class 1b with the CCA rate of 6% on NOTL Hydro's 2017 tax return.

a) Please explain why the CCA class of building and fixture for the test year is mapped to Class 47 with the CCA rate of 8% instead of Class 1 with the CCA rate of 6%.
b) Please update the PILs model as applicable.

RESPONSE

a) The amount of $52,260 should be included in Class 1b for the bridge year and $23,150 should be included in Class 1b for the test year

b) An updated PILs model is being filed in response to Staff Interrogatory #1.

4-Staff-50

Ref: NOTL Hydro 2019 Test Year Income Tax PILs Model

Staff notes that the capital addition of the battery for the smart grid project is mapped to CCA Class 43.1 with the rate of 30% on the test year schedule 8.

The Government of Canada website[1] describes the CCA Class 43.1 as follows:

Class 43.1 (30%)

> **Include in Class 43.1 with a CCA rate of 30% electrical vehicle charging stations (EVCSs) set up to supply more than 10 kilowatts but less than 90 kilowatts of continuous power. This is for property acquired for use after March 21, 2016, that has not been used or acquired for use before March 22, 2016.**

a) Please explain the rationale to map the battery to the CCA Class 43.1.
b) Please explain if NOTL Hydro has consulted with any external professionals for its assessment of the CCA class of the battery. i. If so, please provide the correspondence.
c) Please update the PILs model if in any case the assessment for the CCA Class is changed.

RESPONSE

a) On July 26, 2016, the Government proposed amendments to CCA Classes 43.1 and 43.2 to include clean energy capital costs which encompass certain electrical storage property under subparagraph (d)(xviii) of Class 43.1 in Schedule II.

(xviii) fixed location energy storage property that

(A) is used by the taxpayer, or by a lessee of the taxpayer, primarily for the purpose of storing electrical energy

(I) including batteries, compressed air energy storage, flywheels, ancillary equipment (including control and conditioning equipment) and related structures, and (II) not including buildings, pumped hydroelectric storage, hydro electric dams and reservoirs, property used solely for backup electrical energy, batteries used in motor vehicles, fuel cell systems where the hydrogen is produced via steam reformation of methane and property otherwise included in Class 10 or 17, and

(B) either

(I) if the electrical energy to be stored is used in connection with property of the taxpayer or a lessee of the taxpayer, as the case may be, is described in paragraph (c) or would be described in this paragraph if it were read without reference to this subparagraph, or
(II) meets the condition that the efficiency of the electrical energy storage system that includes the property—computed by reference to the quantity of electrical energy supplied to and discharged from the electrical energy storage system—is greater than 50%.

Based on the above, qualifying electrical energy storage property includes batteries, compressed air energy storage, flywheels, ancillary equipment (including control and conditioning equipment) and related structures. In order to be eligible for inclusion in Class 43.1, the electrical energy storage property must meet one of the two additional conditions. First, the electrical energy to be stored by the electrical storage equipment must be used in connection with Class 43.1 property of the taxpayer or a lessee of the taxpayer, as the case may be. Second, where the property is not to be used in connection with Class 43.1 property of the taxpayer or a lessee of the taxpayer, the round trip efficiency of the electrical energy storage system must be greater than 50%.

NOTL Hydro has included the capital addition of the battery for the smart grid project in Class 43.1 as it would qualify under the new subparagraph (d)(xviii). The battery will be a stand-alone unit tied to the NOTL Hydro distribution system. The primary purpose of the battery will be to allow more renewable energy to be stored on the NOTL Hydro distribution system. As the battery will be tied to the distribution system, it is likely not used in connection with other Class 43.1 property. However, the battery meets the second condition as the battery has a round trip efficiency of greater than 50%.

On February 27, 2018, the Government confirmed its intention to proceed with the above tax measure in Budget 2018. As the capital addition relates to 2019, it has been assumed that the proposed legislation will be implemented and the battery will qualify as a Class 43.1 asset.

b) NOTL Hydro has consulted with KPMG LLP for its assessment of the CCA class of the battery.

c) Not applicable

4-Staff-51

Ref: NOTL Hydro LRAMVA Workform, Sheet 5 2015-2020 LRAM, Table 5-b and Table 5-c; 2014 Cost of Service Application (EB-2013-0155) Settlement Agreement, Page 54

NOTL Hydro provides a rate class breakdown of its LRAMVA threshold established in Table 3.2.17 from the 2014 Settlement Agreement.

a) **Please confirm the years in which actual savings were included in the 2014 load forecast.**
b) **Please discuss the appropriateness of including 2011 persistence savings in 2016 and 2017.**

RESPONSE

a) The table below shows the excerpt of the LRAM threshold calculations that were filed as part of the Draft Rate Order supporting NOTL's 2014 Decision and Order (EB-2013-0155). As indicated below, savings from 2011 to 2014 were included in the 2014 load forecast.

Table 3.2.16: Schedule to Achieve 4 Year kWh CDM Target					
4 Year 2011 to 2014 kWh target					
8,270,000					
	2011	2012	2013	2014	Total
2011 Programs	12.4%	12.4%	12.1%	10.0%	46.8%
2012 Programs		10.6%	10.6%	10.5%	31.8%
2013 Programs			7.1%	7.1%	14.3%
2014 Programs				7.1%	7.1%
	12.4%	23.0%	29.8%	34.8%	100.0%
kWh					
2011 Programs	1,022,875	1,022,875	997,755	828,587	3,872,092
2012 Programs		878,526	878,526	870,079	2,627,131
2013 Programs			590,259	590,259	1,180,518
2014 Programs				590,259	590,259
	1,022,875	1,901,401	2,466,540	2,879,184	8,270,000

	Table 3.2.17: 2014 Expected Savings for LRAM Variance Account							
		Residential	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**	**Total**

	kWh	**461,087**	**1,231,015**	**1,187,082**	**0**		**0**	**2,879,184**
	kW where applicable			**1,104**	**0**			**1,104**

b) The rationale for including 2011 persistence savings in 2016 and 2017 is that the conservation programs implemented in 2011-2014 continue to generate savings in 2016 and 2017. The methodology used in NOTL's calculations is consistent with the methodology used and approved in the following 2018 rate cases.
   a. EB-2017-0013
   b. EB-2017-0032
   c. EB-2017-0048

4-Staff-52

Ref: NOTL Hydro LRAMVA Workform, Sheet 3-a Rate Class Allocations and Sheet 5 2015-2020 LRAM

The LRAMVA is the difference between actual savings allocated across customer classes compared to forecast savings by customer class. NOTL Hydro did not provide a summary table as requested in Table 3-a to outline the calculation of the rate class allocations.

a) Please explain how the savings for the commercial and industrial classes were allocated to NOTL Hydro's customer classes.
b) Please show the calculation of 30% of the savings for Save on Energy retrofit program to the streetlighting class in 2015.

RESPONSE

a) In order to calculate the totals from the Retrofit Program, NOTL Hydro totaled the gross savings per project and allocated them according to the rate class of the service address of the project. Net numbers per project were not available due to adjustments from the IESO that we could not identify by project or rate class. The allocation of the gross savings was then applied to the final verified net savings for the Retrofit Program. The remainder of the savings was split up by program by actual participation among rate classes. Projections for future years were based on the average savings by rate classes from historical performance.

b) Below is the calculation of the 30% savings for Save on Energy for streetlights in 2015.

CDM Results | 2015

		kWh	% by Rate Category			NET	Gross	Gross %
Residential		325,210	10.91%					
	Coupons	108,046			Retrofit Actual	1,703,597	2,349,283	
	BiAnnual Retailer	145,228			Street Light	509,083	702,032	29.88%
	Appliance Retirement	3,267			GS Under 50	330,772	456,139	19.42%
	Home Assistance	2,326			GS Over 50	863,742	1,191,112	50.70%
	HVAC	66,343						
GS<50		402,299	13.50%					
	Retrofit	330,772						
	Small Business Lighting	71,527						
	HPNC	0						
GS>50		1,743,150	58.50%					
	Audit	71,357						
	HPNC	425,850						
	Energy Manager	283,809						
	Retrofit	863,742						
	Ebx	57,642						
	Enabled Savings	40,750						
Street Lighting		509,083	17.08%					
TOTAL		2,979,742	100.00%					

4-Staff-53

Ref: NOTL Hydro LRAMVA Workform, Sheet 6 Carrying Charges

In Table 6 of the LRAMVA workform, NOTL Hydro includes 1.89% interest rate for Q4 2018 to calculate the carrying charge for the LRAMVA.

a) **Please update the Q4 2018 interest rate in Table 6 to reflect the OEB's most recently approved prescribed interest rate for deferral and variance accounts.**

RESPONSE

a) NOTL Hydro has updated the interest rate in Table 6 for Q4 2018, and Q1 & Q2 2019 to the approved prescribed Q4 interest rate for deferral and variance accounts of 2.17%. The updated LRAMVA model is being filed in response to OEB Staff interrogatory #2.

4-Staff-54

a) Please file a excel copy of the 2017 Final Results Report.
b) Please file a copy of the 2014 Persistence Savings Report.
c) If NOTL Hydro made any changes to the LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form. Please confirm any changes to the LRAMVA workform in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

RESPONSE

a) Attached as appendix 4.STAFF.54.1 2017 Final results Reports

b) Attached as appendix 4.STAFF.54.2 2011-2015 LDC CDM Program Persistence Results Report_Niagara-on-the-Lake

c) Revised LRAMVA workform will be submitted.

4-SEC-27

Please provide revised versions of Appendix 2-JB and 2-JC with an added column showing year-to-date actuals.

RESPONSE

NOTL Hydro does not foresee any material changes to our 2018 forecast as presented in our applications or to Appendix 2-JB.

Below are the year-to-date values for Appendix 2-JC as of September 30, 2018.

Appendix 2-JC
OM&A Programs Table

Programs	2018 YTD at September
Reporting Basis	
Customer Service	
Customer Service, Mailing Costs, Billing and Collections	392,118
Bad Debts	13,500
Monthly Billing (net of savings)	0
Sub-Total	405,618
Operations	
Service Locates	65,780
Municipal Transformer Station -operating and maintenance costs	13,385
Meters maintenance	68,966
Distribution sub-stations and protection and control	111,457
Asset management & maintenance department	0
Overhead lines	237,879
Underground Lines	51,628
24/7 Control room operations and load dispatch activities	39,173
Operations & engineering ,Inspection drafting & design construction services	42,004
Distribution Transformers	26,239
Tree trimming	70,673
Underground conduit	0
Poles Towers & Fixtures	41,944
Fleet costs	0
Sub-Total	769,127
Administrative and General	
Operational Effectiveness & Communication	10,215
Health & Safety Costs	0
Executive, Financial , Legal, Professional and Insurance Services	545,905
Post employment costs	16,740
Procurement and Materials Management	0
Office building & security costs	13,993
IT, software, telecommunications	165,737
Internal Labour & Benefit Costs - attributed to capital work	0
Administrative services recovered from affiliates	0
Collection charges recovered from customers	0
Regulatory & Compliance	57,388
Metering Compliance	0
Smart Meter data management program	0
Capitalization Policy Change (Effective Jan 1 , 2013)	0
ESA Fees	5,202
LEAP	0
Donations	0
Other	43,170
Sub-Total	858,350
Total	**2,033,095**

4-SEC-28

[Ex.4, p.7] In describing the drivers of OM&A, the Applicant states: "No winter disconnections. This lead to more write-offs." Please reconcile this statement with the Applicants actual bad debt expense which appears to have increased by only $2000 in the test year compared to the 2014 Board approved amount.

RESPONSE

Actual bad debt expenses will vary from year to year for a variety of reasons including any large customer debts (2016 was high due to a grow-op bad debt), timing of the booking of the expense and the general economy. The cost of a program like banning winter disconnections extends to more than bad debts as more resources are also spent chasing payments from customers during the winter season.

NOTL Hydro has determined that the no winter disconnection policy for 2017-2018 led to an additional $5,300 in bad debts. These were booked in 2018. Additional costs for 2018-2019 are unknown but could escalate as customers develop a better understanding of the disconnection ban.

4-SEC-29

[Ex.4, p.7, Table 4.6] Please provide the full derivation of Table 4.6.

RESPONSE

Please see pages 5-7 which provides a full explanation of how all items in Table 4.6 were derived. It has been copied below.

The one exception to the above is the line item "Increase in requirements" for which a narrative description has been provided but no quantification of the estimated impact. Changes in the requirements of electricity distributors have been substantial over the past 5 years and more change is expected in the future with the increase in distributed generation and demands for improved reliability. It is not possible to quantify the impact of each and all these changes on operating costs.

As shown in Table 4.2 below, NOTL Hydro's increase in OM&A spending from its 2014 Cost of Service to the 2019 Test Year is $818,923 or 38% over the 5 years.

Table 4.2: 2014 Board Approved vs. 2019 Test Year OM&A

	Board Approved	2019	Change
Operations	$532,044	$715,973	$183,929
Maintenance	$416,132	$449,790	$33,658
Billing and Collecting	$534,260	$632,867	$98,608
Community Relations	$17,800	$11,485	-$6,315
Administrative and General	$655,026	$1,164,070	$509,044
Total	**$2,155,262**	**$2,974,186**	**$818,923**
%Change (year over year)			38.0%

The 38% increase in OM&A is the result of a combination of inflation, growth and increasing complexity of operations.

Inflation is estimated to be 7% from 2014-2019 using the inflation factors provided each year by the OEB and less the productivity factor of 0.30%. NOTL Hydro has had a PEG rating of 3 in each of these years. For 2019 we have used the average inflation over the past four years as the best estimate.

Table 4.3: Inflation less productivity 2015-2019

Year	2015	2016	2017	2018	2019	Total
Inflation	1.30%	1.80%	1.60%	0.90%	1.40%	7.00%

Growth can be measured in a number of ways. An increase in customers increases operating costs as there are more customers to have service installed, to be billed monthly and to be responded to. During the 2014-2019 period NOTL Hydro increased its customer service staff by one new full-time customer service representative. The increase in customers also leads to an increase in load, increasing demand on NOTL Hydro assets which requires maintenance be increased accordingly. During the 2014-2019 period NOTL Hydro will have installed two new transformers at its transmission station to manage the increasing load and to ensure redundancy of supply. Finally, an increase in assets (net book value) requires increased maintenance. During the 2014-2019 period NOTL Hydro added one new lineman.

Table 4.4: NOTL Hydro Growth Indicators

Measure	2014	2019	% Increase
# Customers	8,574	9,649	12.5%

Load (MWh)	189,356	223,061	17.8%
Assets ($000's)	23,501	30,657	30.5%
Average			20.3%

NOTL Hydro is attributing 20.3% of its increase in OM&A to growth factors note above.

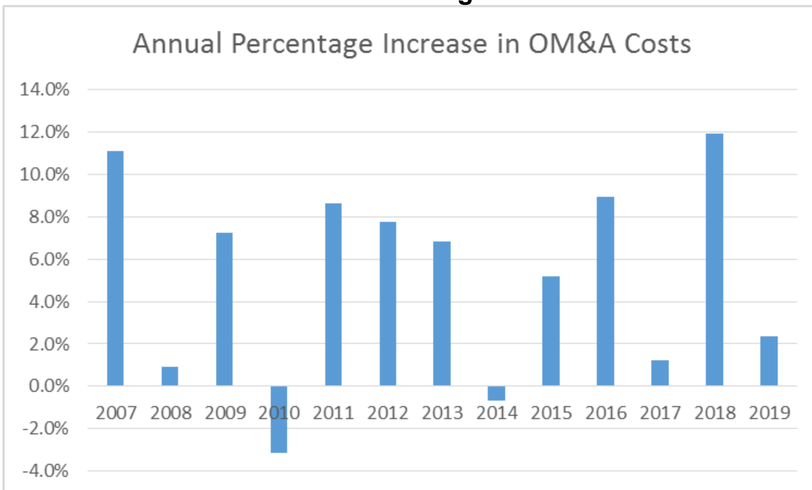
Some of the increase in OM&A is the result of changes in operations or the regulatory environment that increase both revenues and expenses. Just looking at expenses in isolation does not give the full story. Some examples in the case of NOTL Hydro include:

- Pole rental costs are forecast to increase $13.3 thousand from 2017 to 2019 due to the increase in the province-wide pole rental rate. NOTL Hydro has forecast an increase in pole rental revenue of $70 thousand which serves to reduce rates.
- The net increase in the Utilismart service is $29.4 thousand. Some of this will be recovered by the requested increase in the monthly MicroFIT charge which will generate around $8 thousand per year. The rest is increased services to our large customers who will be able to access the data.

Together, these two items represent a $42.7 or 2% increase in OM&A costs.

One of the challenges with OM&A in a smaller LDC is the "lumpiness" of the change. Some years, like 2018, may have several drivers of expense increases while other years, such as 2017 and the 2019 forecast, the changes are quite small. This can be seen in the table below. A longer time horizon yields a different analysis. For instance, from 2006-2019 the average annual increase in OM&A expenses is 5.3%. From 2014-2019 the average annual increase is 5.9%. This would indicate that the higher increases in 2014-2019 is a matter of "timing" and that 3% of the increase from 2014-2019 (5.9% - 5.3% * 5 years = 3%) is a matter of looking at the costs over a short time horizon.

Table 4.5: Annual Percentage Growth in OM&A



The remaining driver of increases in OM&A costs is the increasing complexity of providing electricity distribution services in Ontario. Some of these complexities include:

- Increased expectations by customers. NOTL Hydro introduced its Outage Management System in 2015 so that it can respond to outages without relying solely on customer calls. Like many LDCs, we now have stories of restoring power before a customer is even aware the power is out.
- Net metering. These are much more time consuming to service than a regular customer or a standalone generator due to the complexity of the calculations. NOTL Hydro now has seven net metering customers across all major customer classes (residential, GS<50 kW and GS>50 kW).
- Increased renewable generation. Excluding net metering, these have grown from 117 in 2014 to 153 in 2018; a 31% increase. Renewable generation is increasing costs in another way as NOTL Hydro adapts its asset base and operations in expectation of much more renewable generation in the future.
- Increased regulatory reporting. The volume and complexity of the RRR and other ad hoc reporting to the OEB has grown substantially from 2014 to 2018.
- Increased labour costs. While the inflation estimate above was 7% the cost of labour at NOTL Hydro has gone up a minimum of 11.8% due to the agreements with unionized staff.
- No winter disconnections. This lead to more write-offs. This is somewhat heightened in Niagara-on-the-Lake as there are Niagara College student tenants whose terms end

before the end of the disconnect ban. This also leads to increased costs as more phone calls and other efforts to obtain payments must be undertaken.

- Increased Ministry of Energy programs. New programs such as the OESP and the Affordability Fund all require resources to implement and manage from the context of integrating them within the LDC.

A breakdown of the 2014-2019 increase in OM&A costs would therefore be:

Table 4.6: Breakdown of Increase in OM&A (2014-2019)

Cause	**Percentage**
Inflation	7%
Growth	20%
Expenses with offsetting revenue	2%
“Timing”	3%
Increase in requirements	6%
Total	**38%**

4-SEC-30

[Ex.4, p.25] Please provide revised versions of Appendix 2-K with an added row showing the amount for each year allocation to capital and OM&A.

RESPONSE

Below is a revised version of Appendix 2-K.

Appendix 2-K
Employee Costs

	Last Rebasing Year (2014 Board Approved)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	6	5	5	5	6	6	6
Non-Management (union and non-union)	13	10	11	12	12	12	12
Total	19	15	16	17	18	18	18
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 611,906	$ 538,997	$ 530,811	$ 574,605	$ 564,591	$ 652,445	$ 665,494
Non-Management (union and non-union)	$ 874,309	$ 794,717	$ 849,769	$ 841,184	$ 964,936	$ 976,380	$ 995,910
Total	$ 1,486,214	$ 1,333,714	$ 1,380,580	$ 1,415,789	$ 1,529,527	$ 1,628,826	$ 1,661,404
Total Benefits (Current + Accrued)							
Management (including executive)	$ 130,289	$ 123,542	$ 99,963	$ 135,696	$ 131,592	$ 148,231	$ 150,442
Non-Management (union and non-union)	$ 197,428	$ 182,156	$ 160,029	$ 198,649	$ 224,903	$ 227,360	$ 230,565
Total	$ 327,717	$ 305,698	$ 259,992	$ 334,345	$ 356,495	$ 375,592	$ 381,007
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 742,195	$ 662,540	$ 630,774	$ 710,301	$ 696,183	$ 800,676	$ 815,936
Non-Management (union and non-union)	$ 1,071,737	$ 976,873	$ 1,009,798	$ 1,039,833	$ 1,189,839	$ 1,203,741	$ 1,226,475
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
OM&A	$ 1,017,499	$ 996,664	$ 1,020,261	$ 1,105,954	$ 1,293,811	$ 1,434,069	$ 1,474,177
Capital & Billable	$ 796,432	$ 642,748	$ 620,311	$ 644,180	$ 592,211	$ 570,348	$ 568,235
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411

4.0-VECC-24

Reference: E4/pg. 7

a) **Given NOTL's bad debt expense in 2017 was less than in 2014 (17,789 as comparted to 51,789) what evidence does NOTL have that the prohibition on winter disconnection has resulted in more write-offs (bad debt expense).**

RESPONSE

Actual bad debt expenses will vary from year to year for a variety of reasons including any large customer debts (2016 was high due to a grow-op bad debt), timing of the booking of the expense and the general economy. The cost of a program like no winter disconnections extends to more than bad debts as more resources are also spent chasing payments from customers during the winter season.

NOTL Hydro has determined that the no winter disconnection policy for 2017-2018 lead to an additional $5,300 in bad debts. These were booked in 2018.

4.0-VECC-25

Reference: E4/Table 4.6/pg.7

a) **Please explain how the calculation of a 20% increase in OM&A attributable to "growth" was derived.**

RESPONSE

Please see response to SEC interrogatory #29 in addition to page 5 of Exhibit 4 as copied below.

Growth can be measured in a number of ways. An increase in customers increases operating costs as there are more customers to have service installed, to be billed monthly and to be responded to. During the 2014-2019 period NOTL Hydro increased its customer service staff by one new full-time customer service representative. The increase in customers also leads to an increase in load, increasing demand on NOTL Hydro assets which requires maintenance be increased accordingly. During the 2014-2019 period NOTL Hydro will have installed two new transformers at its transmission station to manage the increasing load and to ensure redundancy of supply. Finally, an increase in assets (net book value) requires increased maintenance. During the 2014-2019 period NOTL Hydro added one new lineman.

Table 4.4: NOTL Hydro Growth Indicators

Measure	2014	2019	% Increase
# Customers	8,574	9,649	12.5%
Load (MWh)	189,356	223,061	17.8%
Assets ($000's)	23,501	30,657	30.5%
Average			20.3%

NOTL Hydro is attributing 20.3% of its increase in OM&A to growth factors note above.

4.0-VECC-26

Reference: E 4/Table 4.7/pg. 8

a) **In discussing the 19% increase in OM&A per customer NOTL makes the following statement: "** ***OM&A per customer is expected to rise 19% between 2014 and 2019. This is consistent with the calculation above as the increase in OM&A per customer is the non-growth increase (inflation, offsetting revenues, requirements, etc.)*** **above."**

It is unclear what this statement is trying to convey. Since 2014 the OM&A increase to 2019 (forecast) has risen by 19.4%. Inflation between that same period would account for approximately 6.6% of that increase (Bank of Canada inflation calculator https://www.bankofcanada.ca/rates/related/inflation-calculator/)

In the result there is 12.8% (13%) increase above inflation during the last rate period. Please explain the factors causing this 13% increase (or 15% if measured from last Board approved) and using the categories shown in Table 4.6

RESPONSE

The statement is trying to convey the following (obviously somewhat unsuccessfully):

The increase in OM&A was 38%. NOTL Hydro had argued that 20% of this increase was due to growth. When you look at the increase in OM&A per customer you are basically eliminating the growth factor. The increase in OM&A per customer of 19% implies that around 19% of the increase in OM&A was due to growth (close enough to 20%) and around 19% was due to other factors.

Based on Table 4.6, the increase in the OM&A per customer would be broken down to:

Cause	Percentage
Inflation	7%
Expenses with offsetting revenue	2%
"Timing"	3%
Increase in requirements	7%
Total	**19%**

Details to the derivation of the "Expenses with offsetting revenue" and "Timing" can be found on page 6 of Exhibit 4. The cost of the "Increase in requirements" is harder to demonstrate but some of the factors have been provided on page 7 of Exhibit 4.

4.0-VECC-27

Reference: E4/pg. 9

a) **Please explain why Community Relations should be increase to $11,485 given that in the period 2014 to 2017 the average spending in this category was just $3,800?**

RESPONSE

a) NOTL Hydro hosted 4 customer sessions in 2018. 2 for residential, 1 for class A customers, and 1 for small business owners at an overall cost of $13,450. NOTL Hydro also held 2 customer sessions in 2017. NOTL Hydro plans to hold similar events going forward to continue to engage our customers.

4.0-VECC-28

Reference: E4/pg. 16

a) **At the above reference NOTL states: "*Billing and Collecting was down $54k or 9.0% as 2015 had the $42k severance payment*." Are severance costs recorded under the ambit of "Billing and Collecting" rather than under accounts related to Administrative and General? If so what other compensation costs are recorded under the accounts for Billing and Collecting?**

RESPONSE

Labour costs are allocated to the functional areas including Billing and Collecting. Labour costs are burdened so include all labour related costs such as benefits, vacation, EI, CPP, etc. Where a severance relates to a particular functional area, the associated cost is allocated to that area.

4.0-VECC-29

Reference: E4/Table 4.24 (Appendix 2-K)/pg. 25

a) Please amend Table 4.24 (Appendix 2-k) to show the amount and percentage of employee compensation capitalized in each year.

RESPONSE

a) Below is an amended version of Appendix 2-K

Employee Costs

	Last Rebasing Year (2014 Board Approved)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	6	5	5	5	6	6	6
Non-Management (union and non-union)	13	10	11	12	12	12	12
Total	19	15	16	17	18	18	18
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 611,906	$ 538,997	$ 530,811	$ 574,605	$ 564,591	$ 652,445	$ 665,494
Non-Management (union and non-union)	$ 874,309	$ 794,717	$ 849,769	$ 841,184	$ 964,936	$ 976,380	$ 995,910
Total	$ 1,486,214	$ 1,333,714	$ 1,380,580	$ 1,415,789	$ 1,529,527	$ 1,628,826	$ 1,661,404
Total Benefits (Current + Accrued)							
Management (including executive)	$ 130,289	$ 123,542	$ 99,963	$ 135,696	$ 131,592	$ 148,231	$ 150,442
Non-Management (union and non-union)	$ 197,428	$ 182,156	$ 160,029	$ 198,649	$ 224,903	$ 227,360	$ 230,565
Total	$ 327,717	$ 305,698	$ 259,992	$ 334,345	$ 356,495	$ 375,592	$ 381,007
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 742,195	$ 662,540	$ 630,774	$ 710,301	$ 696,183	$ 800,676	$ 815,936
Non-Management (union and non-union)	$ 1,071,737	$ 976,873	$ 1,009,798	$ 1,039,833	$ 1,189,839	$ 1,203,741	$ 1,226,475
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
OM&A	$ 1,017,499	$ 996,664	$ 1,020,261	$ 1,105,954	$ 1,293,811	$ 1,434,069	$ 1,474,177
Capital & Billable	$ 796,432	$ 642,748	$ 620,311	$ 644,180	$ 592,211	$ 570,348	$ 568,235
Total	$ 1,813,931	$ 1,639,412	$ 1,640,572	$ 1,750,134	$ 1,886,022	$ 2,004,417	$ 2,042,411
% OM&A	56.1%	60.8%	62.2%	63.2%	68.6%	71.5%	72.2%
% Capital	43.9%	39.2%	37.8%	36.8%	31.4%	28.5%	27.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

4.0-VECC-30

Reference: E4/pg. 25

a) **The average total compensation per employee approved by the Board was $95,470 in 2014. The forecast 2019 average will be $113,467. This increase is significantly above the inflationary increase - 18.4% vs approximately 6.4% inflation. What productivity increases have been achieved which support compensation increases above inflation?**

RESPONSE

A common measure of productivity in the industry is customers per employee. From 2014 to 2019 this ratio will increase from 455 to 536. NOTL Hydro is serving 12% more customers with one fewer employee.

Year	Customers	Employees	Customers / Employee
2014 approved	8,647	19	455
2014	8,574	15	572
2015	8,860	16	554
2016	9,134	17	537
2017	9,321	18	518
2018 Bridge	9,469	18	526
2019 Test	9,649	18	536

Please also see SEC Interrogatory #5 for various productivity initiatives.

4.0-VECC-31

Reference: E4/pg. 33

Table 4.32: Services to ESNI Comparisons

Service	2014 OEB Approved	2017 Actual	2019 Proposed
Water heaters rental support	$4,200	$7,505	$2,103
Water and waste water billing	$110,500	$141,808	$141,871
Administration	$5,800	$4,816	$6,517
Board of Directors	-	$8,400	$8,400
Total	$120,500	$162,530	$158,891

a) In 2014 NOTL stated the cost of serving Energy services for water billing was $74,791. In 2019 that cost was 71,666 or 4% decrease in costs. During that same period NOTL's billing and collection costs rose from $559,556 to $597,617 and are projected to increase to $632,867. As Table 4.32 shows shared service costs are in real terms also declining. Water billing costs are in real terms decreasing while those of electricity customers are rising. Please explain why.

RESPONSE

In 2015, the Town of Niagara-on-the-Lake began installing smart meters on all its water accounts. ESNI split its charges that year between water billing and water installs. In 2014 these were combined in the water billing account. The comparison of the water billing costs from 2014 to 2019 should therefore be as follows which shows an increase in costs.

Year	Water Billing Cost	Water Installs Cost	Total
2014	$74,792	-	$74,792
2015	$65,755	$24,190	$89,945
2016	$69,251	$12,574	$81,825
2017	$68,030	$15,850	$81,880
2018	$69,201	$10,980	$80,181
2019	$71,667	$10,980	$82,647

The higher charge in 2015 was for the support provided by ESNI during the installation of most of the water smart meters. Subsequent to that, costs were lower than they otherwise would have been due to savings from the use of smart meters. The full cost of purchasing and installing the water smart meters was the responsibility of the Town of Niagara-on-the-Lake.

It is also noted that a big driver of the increase in the cost of Billing and Collecting in 2019 is the introduction of the Utilismart service for our larger customers. This will provide a level of service and access not available to water customers.

4.0-VECC-32

Reference: E4/pg. 18 Table 4.18 & pg.36

a) **Have any one-time regulatory costs been included in Table 4.18 (Appendix 2-JA) in 2018 and 2019? If so please identify the amounts for each year.**

b) **Please update Table 4.18 to show both 2018 actuals to-date and 2018 forecast to year-end.**

RESPONSE

a) The only one-time costs regulatory costs included in table 4.18 relate to the completion of this application ($190,000 / 5) of $38,000 in 2019.

b) Please see below for updated table 4.18

	YTD at Sept 30, 2018	2018 Forecast
OM&A Costs		
O&M Costs	$ 1,170,487	$ 1,762,870
Admin Expenses	$ 848,530	$ 1,141,995
Total Recoverable OM&A	$ 2,019,017	$ 2,904,865
Number of Customers	9,406	9,469
Number of FTEs	17.7	18.1
Customers/FTE	532.42	523.61
OM&A Cost per customer		
O&M Cost per customer	$ 124	$ 186
Admin per customer	$ 90	$ 121
Total OM&A per customer	$ 215	$ 307
OM&A cost per FTE		
O&M per FTE	$ 66,254	$ 97,486
Admin per FTE	$ 48,030	$ 63,152
Total OM&A per FTE	$ 114,284	$ 160,638

4.0-VECC-33

Reference: E4/Table 4.35/pg. 37

a) **Please update Table 4.35 to show the amounts expended to-date.**

RESPONSE

a) Cost of service expenses invoiced as of September 30, 2018.

Cost of Service Cost Components	
invoiced as of September 30, 2018	
Application - Consulting (TESI)	$1,601.98
Application - Consulting (CGE)	$13,500.00
Application - Auditor	$0.00
Application - Legal	$7,562.50
Applictation - Other	
Interogatories - Consulting	$0.00
Interogatories - Auditor	$0.00
Interogatories - Legal	$0.00
Settlement - Consulting	$0.00
Settlement - Legal Review	$0.00
Presentation Day	
OEB Customer Session	$0.00
Public Notice	$0.00
Oral Hearings	$0.00
Intervenor Costs	$0.00
Incremental	
Rate Order	$0.00
Total Cost of Service Filing costs	$22,664.48

4.0-VECC-34

Reference: E4/pg.39

a) In each of the years 2014 through 2017 was all of NOTL allocated LEAP funding used?

b) Were any requests denied due to lack of funding?

RESPONSE

a) No

b) No

4.0-VECC-35

Reference: E4/pg.52

a) **Please provide the actual taxes (PILs) remitted in each of 2014 through 2017.**

RESPONSE

a) The actuals PILS payments in 2014, 2015, and 2016 are nil as NOTL Hydro was in a loss position in those years. The PILS payment made in 2017 was $374,643

4.0-VECC-36

Reference: E4/pg. 36

a) **Please explain the increase of $9,540 in Board Assessment costs as between 2018 and 2019.**

RESPONSE

a) Currently, NOTL Hydro accounts for OEB Assessments in 2 accounts. Account 5655 Regulatory Expenses and Account 1508 – OEB Cost Assessments. $7,575 of each quarterly invoice is expensed to account 5655 (based on the approved amount in NOTL Hydro's 2014 Cost of Service Application) for a total of $30,300 annually and the remainder is expensed to the 1508 variance account. NOTL Hydro estimates annual assessments to be approximately $39,840 in 2019 with the full amount expensed to account 5655.

	2018F	2019F
OEB Annual Assessment Invoice	$39,231	$39,840
Account 5655 - Regulatory Expenses	$30,300	$39,840
Account 1508 - OEB Costs Assessments	$8,931	$0

5 | Cost of Capital

INTERROGATORY RESPONSES

5-Staff-55

Ref: Exhibit 5, Page 12

NOTL Hydro states regarding the additional future debt that NOTL Hydro will need to borrow to fund the planned investment in a new transformer. Negotiations are currently underway with CIBC and a long term fixed rate loan (either a fixed rate loan or a long term floating rate loan with a swap) is expected. The cost of this debt will depend on interest rates in 2019 so cannot be forecast with any certainty. The current average borrowing rate of 3.71% appears to be a reasonable proxy.

Staff understands that NOTL Hydro borrowed a long-term debt for the 2015 transformer from the town of Niagara-on-the-lake with 3% interest rate.

a) For the purposes of lowering the interest rates, has NOTL Hydro considered any other options (such as town) for the borrowing for the new transformer in 2019?
   i. If not, please explain why not.

RESPONSE

NOTL Hydro borrows based on where the best overall package can be obtained. This is not just rates but includes factors such as term, repayment options and flexibility. In the past, NOTL Hydro has borrowed from Infrastructure Ontario, CIBC and the Town of Niagara-on-the-Lake. NOTL Hydro looked at both Infrastructure Ontario and the Town of Niagara-on-the-Lake for the new borrowings. However, Infrastructure Ontario has become increasingly inflexible in their terms and the Town of Niagara-on-the-Lake has limited flexibility in how much they can lend NOTL Hydro due to their own liquidity and risk management requirements.

5-Staff-56

Ref: Appendix 1L 2017 Audited Financial Statements (AFSs), Page 21, Note 12 Long-term Debt; Exhibit 5, Page 9

NOTL Hydro states, in its 2017 AFSs Note 12, for the long-term debt that "The Corporation has two demand instalment loans bearing interest at prime plus 0.75%." and "The Corporation has a third demand instalment loan which bears interest at the underlying market rate for banker's acceptance notes."

NOTL Hydro further states that "The Corporation has entered into interest rate swap agreements to fix the interest rates on two of the demand instalment loans at 6.03% and 5.38% with maturity dates of August 2018 and October 2020."

Staff notes from Table 5.11 2014 to 2019 Debt Instruments that NOTL Hydro lists two demand installment loans in the 2017 debt instrument table. These demand loans have 6.13% and 6.03% interest rates respectively.

a) Please explain why NOTL Hydro stated three installment loans in its 2017 AFSs while the evidence for 2017 debt instrument only shows two demand instrument loans.
b) Please explain the differences or provide a reconciliation between the interest rates stated in Note 12 of the 2017 AFSs and the values shown in the table of 2017 Debt instruments.

RESPONSE

a) Please see the seventh bullet point in section 2.5.2.3 of the evidence for the third demand instrument loan. As this loan has not yet been hedged by way of a swap it is included in short –term debt.

b) The note in the AFS is incorrect. The first loan has a swap rate of 5.28% which when combined with the spread of 0.75% gives an all-in rate of 6.03%. The second loan has a swap rate of 5.38% which when combined with the spread of 0.75% gives an all-in rate of 6.13%.

5-SEC-31

[Ex.5, Appendix 5-A] The terms of the Promissory Notes with the Town of Niagara-on-the-Lake state that it will mature on August 1, 2018. The terms also allow that the Promissory Note shall be renewed for an additional 10 years unless written notice is provided 90 days prior to maturity.

a) Did either party provide notice that the Promissory Note shall not be renewed? If so, please provide details.
b) If the answer to part (a) is no, please explain what, if any, due diligence the Applicant conducted to determine that renewal of the Promissory Note was in the best interest of ratepayers. Please provide documentary evidence of such due diligence.

RESPONSE

Neither party provided notice that the Promissory Note shall not be renewed.

NOTL Hydro notes that for the purpose of this application, the deemed interest rate of 4.16% was used as the cost of this Promissory Note rather than the actual rate of 7.25%. NOTL Hydro considers 4.16% a fair rate given the repayment terms of the Promissory Note are far more flexible than any of its other loans. As a result, NOTL Hydro did not conduct any due diligence into alternative borrowings.

With regards to its debt financing, NOTL Hydro's focus is on obtaining financing for its large capital projects in 2019 and on maintaining its strategic low debt/equity ratio.

5-SEC-32

[Ex.5] Please provide the Applicant's actual regulated ROE for each year between 2014 to 2017. Please provide its forecast 2018 regulated ROE.

RESPONSE

	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Forecast
Actual ROE	10.85%	8.90%	7.44%	9.81%	9.99%

5.0-VECC-37

Reference: E5/Table 5.11/pg.9 & pg. 12

a) NOTL notes that it will need to borrow (long-term debt) to finance the York Station transformer. Please provide an update as to the status of this debt issuance.

b) Table 5.11 Year 2019 does not show any loans which with a start date in 2019 (there is 0 principal loan at 6.03% with a start date of August 29, 2003). Please update Table 5.11 to show the current forecast for 2019 long-term debt, including that associated with the York Station.

RESPONSE

a) NOTL Hydro has forecast its cash flow requirements over 2019 based on the planned capital expenditures and other known or expected impacts on cash flow. It is forecast that $5 million will need to be borrowed. NOTL Hydro has an existing facility under which it can currently borrow $2 million. That will be exercised with the first tranche of $1 million planned for December 2018 and the second tranche during 2019. Negotiations have commenced for an additional $3 million facility. Due to its low debt:equity ratio NOTL Hydro is not anticipating any difficulties in raising the required debt.

b) The updated table is provided below. All the additional debt has been shown with a start date of January 1, 2019 though the reality is it will be spread across the remainder of 2018 and all of 2019. A rate of 3.71% has been shown. The current publicly available 10 year swap rate is 2.92%. With the bank spread of 0.75% our borrowing rate would become 3.67%. As rates are rising we have increased this by the additional 4 basis points.

			Year	2019						
Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	January 1 Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 140,354.69	Actual interest exp
2	NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -	Fixed rate via swap
3	York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 18,898.02	Fixed rate via swap
4	Infrastructure Ontario Loan	Infrastructure Onta	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 28,551.00	
5	Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 54,628.35	
6	Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 40,289.76	
7	New loans		Third-Party	Fixed Rate	1-Jan-19	10	$ 5,000,000	3.71%	$ 185,500.00	Fixed rate via swap
									$ -	
Total							$ 11,624,865	3.71%	$ 468,221.82	

6 | Revenue Requirement – Not Applicable

INTERROGATORY RESPONSES

There were no interrogatories for Exhibit 6.

7 | Cost Allocation

INTERROGATORY RESPONSES

7-Staff-57

Ref: Exhibit 7, Page 5

In describing its proposed services weighting factors, NOTL Hydro states that it "services all Residential accounts as well as GS < 50 kW and GS 50kW – 4,999kW accounts with a 200 amp or less service."

NOTL Hydro proposes to use a weighting factor of 0.1 for the General Service 50kW – 4,999kW rate class "on the basis of the ratio of customers in this class with a 200 amp or less service. Staff notes that a 200-amp service operating at 240 volts is capable of serving not more than 48kW of load.

a) Please confirm whether or not a 200 amp or less service refers to a 200-amp single phase service at approximately 240/120 volts.
b) Please confirm whether or not the customer is required to pay for the service connection where a greater service is required.
c) If part a) and part b) are confirmed, please explain how approximately 10% of the customers in the General Service 50kW – 4,999kW rate class can be served with 200 amp or less services.
d) If part a) or part b) are not confirmed, please provide a derivation of services weighting factors. In doing so, please provide an average cost to NOTL for service connections provided in whole or in part by NOTL Hydro in each rate class, and the proportion of customers who are served by a service connection provided by NOTL Hydro in whole or in part.

RESPONSE

a) Confirmed

b) Confirmed

c) NOTL Hydro based the type of service on meter type and inadvertently included a meter type that is 200 amp but is used for 3-phase services. Removing these customers from the calculation (355 GS<50 customers and 10 GS>50 customers) results in a revised weighting factor of 1 for Residential, 0.5 for GS<50, and 0 for GS>50. An update Cost Allocation model is being filed in response to OEB Interrogatory #1.

d) The average cost to connect a new residential or GS<50 customer with a 200 amp or less service is approximately $750. As of June 2018, there were 7,922 residential customers and 704 GS<50 customers. Based on this methodology the revised weighting factor is 1 for Residential, 0.1 for GS<50 and 0 for GS>50.

7-Staff-58

Ref: Exhibit 2, Appendix 2A, Page 46; Exhibit 7, Pages 7, 8 and 10; Cost Allocation Model, Sheet I6.1 Revenue, Sheet I6.2 Customer Data, Sheet I8 Demand Data

NOTL Hydro has indicated on Sheet I6.1 Revenue that in the General Service > 50 kW rate class, a portion of the load qualifies for transformer ownership allowance, and that in the Large Use rate class, all of the load qualifies for transformer ownership allowance.

However, on Sheet I6.2 Customer Data the large user is counted in the line transformer customer base and secondary customer base, indicating it is reliant on NOTL line transformation and secondary distribution. In the General Service > 50 kW rate class, the number of customers entered as reliant on NOTL Hydro 's line transformation is 112 as compared to 131 total customers, which is consistent with some customers providing their own transformers. However, all 131 customers are entered as being connected to NOTL Hydro's secondary distribution system.

The DSP states that "NOTL Hydro recovered as a capital contribution, all new infrastructure costs at the transformer station, feeder upgrades, smart switch, metering and all other connection costs to meet the requested obligation totaling to an estimated $800,000."

On worksheet I8, all non-coincident peak (NCP) demand for all rate classes has been recorded at all levels of the distribution system, including Primary, Line Transformation, and Secondary.

a) Please review and explain the apparent inconsistencies.
b) Please correct the entries as applicable.
c) Are any existing primary distribution assets, including feeders, poles, conduit, and associated hardware used in the provision of service to the Large Use customer?
i. If so, please explain.
ii. If not, has NOTL Hydro considered a direct allocation of the identified dedicated assets and associated operation and maintenance to the Large Use rate class?

RESPONSE

a) NOTL Hydro reviewed the number of customers and agrees that the number of customers for GS>50 Secondary Customer Base should be 112 and the number of customers for Large User Line Transformer Customer Base and Secondary Customer Base should be 0. NOTL Hydro reviewed the NCP demand data, the amounts in the table below reflect the exclusion of customers that own their transformers.

1

EB-2018-0056
Sheet I6.2 Customer Data Worksheet - Initial Submission

			1	2	3	6	7	9
	ID	Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$36,754	$13,848	$22,898	$8	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$41,605	18,943.10	9,306.19	13,294.17	$0	28.59	33.06
Number of Bills	CNB	115,837	97,829	16,052	1,572	12	60	312
Number of Devices	CDEV		8,152	1,338	131	1	2,187	26
Number of Connections (Unmetered)	CCON	11,835	8,152	1,338	131	1	2,187	26
Total Number of Customers	CCA	9,653	8,152	1,338	131	1	5	26
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	9,760	8,152	1,338	131	1	112	26
Line Transformer Customer Base	CCLT	9,740	8,152	1,338	112	-	112	26
Secondary Customer Base	CCS	9,633	8,152	1,338	112	-	5	26
Weighted - Services	CWCS	9,223	8,152	1,060	10	-	-	-
Weighted Meter -Capital	CWMC	4,986,263	3,286,777	950,151	743,226	6,108	-	-
Weighted Meter Reading	CWMR	17,495	8,152	1,338	7,674	59	272	-
Weighted Bills	CWNB	115,665	97,829	16,052	1,473	11	56	245

2

EB-2018-0056
Sheet I8 Demand Data Worksheet - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	6	7	9
Customer Classes		Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
		CP Sanity Check	Pass	Check 4CP	Pass	Check 4CP and 12CP	Check 12CP	Check 12CP
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	41,778	13,833	11,810	15,338	769	-	27
Bulk Delivery CP	BCP1	41,778	13,833	11,810	15,338	769	-	27
Total Sytem CP	DCP1	41,778	13,833	11,810	15,338	769	-	27
4 CP								
Transformation CP	TCP4	163,108	47,985	50,468	56,216	8,333	-	106
Bulk Delivery CP	BCP4	163,108	47,985	50,468	56,216	8,333	-	106
Total Sytem CP	DCP4	163,108	47,985	50,468	56,216	8,333	-	106
12 CP								
Transformation CP	TCP12	420,616	132,805	113,209	135,028	38,333	904	337
Bulk Delivery CP	BCP12	420,616	132,805	113,209	135,028	38,333	904	337
Total Sytem CP	DCP12	420,616	132,805	113,209	135,028	38,333	904	337
NON CO_INCIDENT PEAK								
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP								
Classification NCP from Load Data Provider	DNCP1	53,528	15,899	14,878	16,103	6,410	207	31
Primary NCP	PNCP1	53,528	15,899	14,878	16,103	6,410	207	31
Line Transformer NCP	LTNCP1	44,782	15,899	14,878	13,768	-	207	31
Secondary NCP	SNCP1	44,782	15,899	14,878	13,768	-	207	31
4 NCP								
Classification NCP from Load Data Provider	DNCP4	190,284	59,754	55,447	59,781	14,359	820	123
Primary NCP	PNCP4	190,284	59,754	55,447	59,781	14,359	820	123
Line Transformer NCP	LTNCP4	167,255	59,754	55,447	51,110	-	820	123
Secondary NCP	SNCP4	167,255	59,754	55,447	51,110	-	820	123
12 NCP								
Classification NCP from Load Data Provider	DNCP12	493,194	161,381	124,161	144,840	60,000	2,443	369
Primary NCP	PNCP12	493,194	161,381	124,161	144,840	60,000	2,443	369
Line Transformer NCP	LTNCP12	412,187	161,381	124,161	123,833	-	2,443	369
Secondary NCP	SNCP12	412,187	161,381	124,161	123,833	-	2,443	369

b) The update Cost Allocation model being filed in response to OEB Staff interrogatory #1 has been be updated for the change in part a.

c) Yes, the existing primary assets are used in the provision of service to the new large user

i. The Large Use customer is supplied by an express feeder that also supplies 6 other small capacity customers that happen to be in the immediate path of supply. NOTL Hydro had a feeder available to service the Large Use customer by shifting the supply to all other customers (with the exception of 6) to adjacent feeders. This eliminated the need to build an express feeder to the station and was the best use of distribution assets.
The express feeder was constructed in 2008 is approximately 2.9 kms in length. NOTL Hydro estimates that the cost to construct that feeder was approximately $350,000 (split 60% poles and 40% conductor) based on the cost and age of the line NOTL Hydro has adjusted the Cost Allocation model to directly allocate $158,667 from account 1830 Poles, Towers, and Fixtures and $114,333 from account 1835 Overhead Conductors and Devices to the large user class. The calculation of these amounts is summarized in the table below.

	Cost	Depreciation Rate (Years)	Annual Depreciation	Accumulated Depreciaton	NBV
Poles	210,000.00	45	4,666.67	51,333.33	158,666.67
Conductor	140,000.00	60	2,333.33	25,666.67	114,333.33
Total	350,000.00		7,000.00	77,000.00	273,000.00

7-Staff-59

Ref: Exhibit 7, Page 9; Cost Allocation Model, Sheet I7.1 Meter Capital, Sheet I7.2 Meter Reading

NOTL Hydro indicates that it has ten smart meters in the GS > 50 kW rate class, and is using Demand with IT meters in both the GS < 50 kW and GS > 50 kW.

The Street Light rate class has no meters assigned at all. For meter reading, NOTL indicates all GS < 50 kW reads are the less costly smart meter reads, while all GS > 50 kW, meter reads are the costlier interval meter reads. NOTL Hydro states that "The higher allocation percentage for GS>50 and Street lights reflect the incremental costs associated with reading interval meters".

a) Please confirm that the methodology to read a smart meter and a Demand with IT meter depends on the class using the meter, or revise as required.
b) Please explain or correct the apparent inconsistency of meter reading for five meters in the street light rate class, while no meters are recorded for the class.

RESPONSE

a) The methodology to read a smart meter and a Demand with IT meter is the same for all rate classes.

b) Street light accounts are not metered however NOTL Hydro utilizes Utilismart to estimate the interval data for these accounts. Utilismart bills NOTL Hydro the same rate for street light accounts and interval metered customers.

7-Staff-60

Ref: Cost Allocation Model, Sheet O1 Revenue to Cost; RRWF, Sheet

11.Cost Allocation
The Cost Allocation model indicates $186,682 of allocated revenue requirement the Large User and $185,989 for Street Light (row 40). The RRWF indicates $186,682 for streetlights, and $185,989 for the Large User.
a) Please correct the reversal of the entries

RESPONSE

a) NOTL Hydro has corrected the reversal of the entries in the RRWF. The updated schedule is being filed in response to OEB Staff interrogatory #1.

7-Staff-61

Ref: Exhibit 7, Page 16

NOTL Hydro states that:

- **The full feeder line to the customer is scheduled to be completed in July 2018. NOTL 3 Hydro therefore does not have any usage history with the customer having full access of up to 20 MW of capacity.**
- **The customer is still working on their premises so will not be in a position to determine peak demand for at least a year.**

a) **Please advise on the status of the feeder line which was to be completed July 2018, and whether the customer has access to the full 20 MW of capacity.**
b) **Please provide an updated estimate of peak demand, if one is available.**
c) **Please provide an updated estimate of when the customer premises are expected to be completed.**

RESPONSE

a) The work to make available access to the feeder by the customer has been completed.

b) No other updates were supplied by the customer and the information provided still stands in the application of a peak demand of between 15 MW and 20 MW. Please see the response to Staff Interrogatory #34.

c) NOTL Hydro has no information and does not seek information on the progress of work by the customer. Normally work on private property is the business of the property owner unless it has an impact on upstream assets. Please see the response to Staff Interrogatory #34.

7-Staff-62

Ref: Exhibit 7, Page 22; RRWF, Sheet 11. Cost Allocation

NOTL Hydro is proposing to decrease the revenue to cost ratio for the Streetlights rate class from 161.88% to 129.52%, and increase the Large Use revenue to cost ratio from 72.15% to 100.37%, which is greater than the low-end of the OEB's policy range of 85%.

NOTL Hydro states that the two-year adjustment to the Street Lights is to minimize the impact to the Residential rate class, the revenue to cost ratio for which is proposed to increase from 90.53% to 90.75%.

a) Please explain why the Large User revenue to cost ratio has been increased to 100.37% - beyond the revenue to cost ratio of the next lowest rate class, Residential, and beyond unity or 100%.

b) Please provide bill impacts for a scenario where the street light rate class revenue to cost ratio is reduced to 120% in 2019.

RESPONSE

a) Due to the reversal of entries in the RRWF as cited in 7-Staff-60 the cost ratio for Large User was incorrectly showing as 100.37%. Following the correction of those entries the Large User revenue to cost ratio is 100.00%. A revenue to cost ratio of 100% for the new rate class implies they are not subsidizing or receiving a subsidy from other rate classes.

b) Bill impacts where street light rate class revenue to cost ratio is 120% in 2019

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Total – Total Bill $	Total – Total Bill %
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 1.26	1.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 3.00	1.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 239.41	3.0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ (0.17)	-0.1%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ (935.48)	-19.6%
LARGE USER - Non-RPP (Other)	kw	$ 13,249.28	4.6%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 2.67	4.0%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 3.45	2.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 8.84	2.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 239.41	3.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (903.55)	-17.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 384.79	4.8%

7-Staff-63

Ref: Exhibit 7, Page 14 and 15

NOTL Hydro proposes a standby rate for Large User customer rate class. Staff notes that there is only one customer in this proposed rate class.

NOTL Hydro proposes that Standby Charge will be based on applicable monthly Large Use Volumetric Charges. NOTL Hydro states that in the case where the utility grade metering is installed on the generator, the customer is only charged if the customer is generating at the peak time and then only for the generation at that time.

The Large User customer has the utility grade metering installed on the generator and agrees with the metering approach proposed by NOTL Hydro.

a) Please provide the names of the utilities who NOTL is aware are using the same method for the Standby Charge and the EB# of the applicable rate applications.

b) Please provide the proposed changes to NOTL Hydro's Conditions of Service with respect to the Standby Charge proposed.

RESPONSE

NOTL Hydro has prepared additional evidence with respect to the Standby Charges that has been filed along with the responses to the interrogatories.

a) NOTL Hydro modeled its Standby Charge on that used by Kingston Utilities EB-2017-0055. This was agreed to between NOTL Hydro and the potential Large Use customer who was familiar with the method used by Kingston Utilities. There are a number of other utilities that have Standby Charges but most seem to charge based on either the nameplate capacity of the generation or a negotiated rate.

b) The requirements for different types of embedded generation (FIT, Net metering < 10 kW, Net metering > 10 kW) are detailed in Appendix 5 of the Conditions of Service. An additional section will be added to Appendix 5 for Load Displacement Generation that will include when the Standby Charge will be applicable and how it will be applied.

7.0-VECC-38

Reference: Exhibit 7, page 5

a) **The Application states: "*The weighting factor "0.8" (for GS<50) is proposed based on the ratio of customers in this class with 200 amp or less service*". Please explain how this ratio is determined and why it is appropriate to use in determining the Services weighting factor for the GS<50 class.**

b) **The Application states: "*The weighting factor "0.1" (for GS>50) is proposed based on the ratio of customers in this class with 200 amp or less service*". Please explain how this ratio is determined and why it is appropriate to use in determining the Services weighting factor for the GS>50 class.**

RESPONSE

a) This ratio was determined by dividing the number of customers with 200 amp or less service by the total number of customers in the GS<50 rate class. NOTL Hydro based the type of service on meter type and inadvertently included a meter type that is 200 amp but is used for 3-phase services. Removing these customers from the calculation (355 GS<50 customers) results in a revised weighting factor of 0.5 for GS<50. NOTL Hydro believes that this is an appropriate way to determine the weighting factor as NOTL Hydro is responsible for the costs of 200 amp or less services while customers bear the cost of services over 200 amps. Please also see response to OEB Staff interrogatories #1 and 57.

b) This ratio was determined by dividing the number of customers with 200 amp or less service by the total number of customers in the GS>50 rate class. NOTL Hydro based the type of service on meter type and inadvertently included a meter type that is 200 amp but is used for 3-phase services. Removing these customers from the calculation (10 GS>50 customers) results in a revised weighting factor of 0 for GS>50. NOTL Hydro believes that this is an appropriate way to determine the weighting factor as NOTL Hydro is responsible for the costs of 200 amp or less services while customers bear the cost of services over 200 amps.

7.0-VECC-39

REFERENCE: EXHIBIT 7, PAGE 5

a) Please provide a copy of the "detailed review" undertaken to determine the Billing and Collecting weighting factors.

RESPONSE

a) Attached as appendix 7-VECC-39.1

7.0-VECC-40

Reference: Exhibit 7, page 6 (lines 4-6)

a) **Please explain how level of the level of "activity in account changes" impacts the Billing and Collecting costs and the related weighting factors – particularly when account change activity is subject to a specific service charge.**

RESPONSE

The reference to "activity in account changes" was intended to convey activity beyond the specific changes for which a service charge can be applied. Proportionately, much more of the Customer Service staff time, and all staff time, is devoted to residential customers than to the other classes. This was one of the factors used in determining the class weighting.

7.0-VECC-41

Reference: Exhibit 7, page 9

a) **It is understood that the values for Tab I8 for the LU class were provided by the customer concerned. Please provide a schedule that compares these values from Tab I8 for the LU class with the values that would result from applying the GS>50 load profile to the new LU class.**

b) **Please indicate when the Sentinel Lighting class was eliminated.**

RESPONSE

a) The table below

	Large User	
Coincidental Peak	Customer Profile	GS>50 Load Profile
1 CP	769	4,323
4 CP	8,333	15,843
12 CP	38,333	38,055
Non-coincidental Peak	Customer Profile	GS>50 Load Profile
1 NCP	6,410	4,538
4 NCP	14,359	16,848
12 NCP	60,000	40,820

b) Sentinel Lighting class was eliminated in 2009

7.0-VECC-42

Reference: Exhibit 7, pages 14-15

a) **Please clarify whether NOTL is proposing: i) to introduce a standby rate for customers in the LU class with load displacement generation (lines 15-16) or ii) introduce a new customer class for customers with load displacement generation (lines 17-18).**

b) **Would there be minimum size for load displacement generation before the standby charge would be applicable?**

c) **Is it at the customer's discretion as to whether or not "utility grade metering" is installed on the generator? If installed, who pays the meter and its ongoing maintenance?**

RESPONSE

NOTL Hydro has prepared additional evidence with respect to the Standby Charges that has been filed along with the responses to the interrogatories. Please see Exhibit 8, Additional Evidence, filed November 2018.

a) NOTL Hydro is proposing a Standby Charge for all customers that install load displacement generation or storage with a capacity of more than 250 kW. Most rate orders appear to show Standby Charges on a separate page so it is assumed that this is a new customer class.

b) The minimum proposed size is 250 kW.

c) This reference was included by error and has been removed. What NOTL Hydro considers to be "utility grade metering" is not normally required but will depend on the specific situation.

As part of its Generator Monitoring Requirements, it is a requirement for customers to install a specific meter recording system with the generation. Guidelines specify the type of meters and communication modes requirements. The cost of the monitoring equipment and its ongoing upkeep will be paid by the customer.

7.0-VECC-43

Reference: Exhibit 7, pages 18 and 22

a) **The proposed 2019 Revenue to Cost ratios set out in Table 7.11 do not match those in Table 7.17 for the Streetlights and USL classes. Please reconcile.**

RESPONSE

a) Please see revised table 7.11 below

2019 Proposed							
Class	Service Revenue Requirement		Miscellaneous Revenue		Base Revenue		Proposed Revenue to Cost Expenses %
Residential	$3,276,521	54.2%	$318,103	63.2%	$2,958,418	53.4%	90.8%
GS < 50 kW	$1,277,871	21.1%	$90,078	17.9%	$1,187,793	21.4%	111.1%
GS > 50 kW	$1,055,293	17.5%	$67,283	13.4%	$988,010	17.8%	116.5%
Street Lights	$241,785	4.0%	$17,664	3.5%	$224,121	4.0%	129.5%
Unmetered Scattered Load	$9,211	0.2%	$785	0.2%	$8,426	0.2%	114.5%
Large User	$186,682	3.1%	$9,026	1.8%	$177,656	3.2%	100.4%
	$6,047,363	100.0%	$502,939	100.0%	$5,544,424	100.0%	

7.0-VECC-44

Reference: NOTL's 2019 Cost Allocation Model

a) **With respect to Tab I7, which of the meter types listed are suitable for customers with greater than 200 amp service?**

b) **With respect to Tab I7, please confirm that none of the customers in the Residential, GS<50, GS>50 or Large Use classes have more than one meter. If not confirmed, please revise Tabs I7 and I8.**

c) **With respect to Tab I8, please explain why, for the GS>50 and LU classes, the CP and NCP demand values for Line Transformer and Secondary are the same as for Primary.**

RESPONSE

a) Please see table below

Meters suitable for Customers with greater than 200 amp service				
	Residential	**GS<50**	**GS>50**	**Large User**
Smart Meters	0	206	0	0
Demand with IT	0	71	36	0
Bi-Directional Smart meters	0	1	0	0
Demand with IT and Interval Capability - Secondary	0	0	1	0
9S -wWIC	0	0	28	0
Other	0	1	56	1
Total	0	279	121	1

b) Confirmed

c) Please see response to OEB Staff interrogatory #58. NOTL Hydro reviewed the NCP demand data, the amounts in the table below reflect the exclusion of customers that own their transformers. The Cost Allocation model submitted with the responses will be updated to reflect this change.

EB-2018-0056

Sheet I8 Demand Data Worksheet - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	6	7	9
Customer Classes		Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
		CP Sanity Check	Pass	Check 4CP	Pass	Check 4CP and 12CP	Check 12CP	Check 12CP
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	41,778	13,833	11,810	15,338	769	-	27
Bulk Delivery CP	BCP1	41,778	13,833	11,810	15,338	769	-	27
Total Sytem CP	DCP1	41,778	13,833	11,810	15,338	769	-	27
4 CP								
Transformation CP	TCP4	163,108	47,985	50,468	56,216	8,333	-	106
Bulk Delivery CP	BCP4	163,108	47,985	50,468	56,216	8,333	-	106
Total Sytem CP	DCP4	163,108	47,985	50,468	56,216	8,333	-	106
12 CP								
Transformation CP	TCP12	420,616	132,805	113,209	135,028	38,333	904	337
Bulk Delivery CP	BCP12	420,616	132,805	113,209	135,028	38,333	904	337
Total Sytem CP	DCP12	420,616	132,805	113,209	135,028	38,333	904	337
NON CO_INCIDENT PEAK								
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP								
Classification NCP from Load Data Provider	DNCP1	53,528	15,899	14,878	16,103	6,410	207	31
Primary NCP	PNCP1	53,528	15,899	14,878	16,103	6,410	207	31
Line Transformer NCP	LTNCP1	44,782	15,899	14,878	13,768	-	207	31
Secondary NCP	SNCP1	44,782	15,899	14,878	13,768	-	207	31
4 NCP								
Classification NCP from Load Data Provider	DNCP4	190,284	59,754	55,447	59,781	14,359	820	123
Primary NCP	PNCP4	190,284	59,754	55,447	59,781	14,359	820	123
Line Transformer NCP	LTNCP4	167,255	59,754	55,447	51,110	-	820	123
Secondary NCP	SNCP4	167,255	59,754	55,447	51,110	-	820	123
12 NCP								
Classification NCP from Load Data Provider	DNCP12	493,194	161,381	124,161	144,840	60,000	2,443	369
Primary NCP	PNCP12	493,194	161,381	124,161	144,840	60,000	2,443	369
Line Transformer NCP	LTNCP12	412,187	161,381	124,161	123,833	-	2,443	369
Secondary NCP	SNCP12	412,187	161,381	124,161	123,833	-	2,443	369

8 | Load & Other Revenue Forecast

INTERROGATORY RESPONSES

8-Staff-64

Ref: Exhibit 8, Pages 7-8; Filing Requirements for Electricity Distribution Rate Applications – Chapter 2, July 12, 2018, Page 50

Filing Requirements for Electricity Distribution Rate Applications – Chapter 2, July 12, 2018, Page 50 states that

> **If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non- residential class.**

The current fixed charges for all rate classes are higher than the minimum system with PLCC adjustment as calculated in the cost allocation model, an amount that is commonly referred to as the ceiling.

NOTL Hydro notes that there is no requirement for it to lower fixed charges below the calculated ceiling. It proposes to not change the fixed charge for the GS < 50 kW and GS > 50 to 4,999 kW rate as these rate classes are already above the ceiling. NOTL Hydro proposes to reduce the fixed charges for Street Lighting and Unmetered Scattered Load customers to the ceiling.

For Large Use rate class, NOTL Hydro has decided to fix the variable rate at the same rate as the GS > 50 to 4,999 kW rate class, which resulted in a variable charge of $4,538.81 – an amount which "appeared reasonable given a review of Large User fixed rates across the province."

a) Why has NOTL Hydro decided to set the fixed charge for street light at the ceiling when rates are proposed to decrease, and it was possible to maintain the fixed/variable split?

b) Why has NOTL Hydro decided to lower the fixed charge for unmetered scattered load when it had the option to maintain the fixed charge and

doing so would have resulted in a smaller increase to the variable charge than was proposed?

c) Please provide a brief description of the review conducted for the Large User fixed rate across the province.

d) Has NOTL Hydro considered alternatives for the Large Use rate class rate design?

i. If so, please explain options considered and why they were dismissed.

ii. If not, please explain why not.

RESPONSE

a) NOTL Hydro is open to adjusting the fixed/variable split for street light customers.

b) Due to the minimal difference between the current fixed rate of $21.20 and the calculated ceiling of $20.15, NOTL Hydro chose to reduce the fixed rate to the ceiling. The total difference in fixed rate revenue from unmetered customers is minimal at $27.30 per month ($1.05 x 26 customers). NOTL Hydro is open to adjusting the fixed/variable split for street light customers post settlement conference.

c) NOTL Hydro reviewed the fixed Service Charges for Large Use customers across the province from the 2017 Distribution Rates Database.

d) NOTL Hydro reviewed several different fixed and variable rate designs. NOTL Hydro's goal was to ensure that the fixed rate was not out of line with those of other utilities and believed that a variable rate consistent with the GS>50 rate class was reasonable.

8-Staff-65

Ref: Exhibit 8, Page 30; NOTL Hydro 2019 Tariff Schedule and Bill Impact Model

NOTL Hydro provides the bill impacts by segment analysis in the following table:

Table 8.25: Bill Impact Summary – Segmented Impact

Bill Segment	Residential	GS < 50	GS > 50	USL	Streetlights	Large User
Distribution Rates plus ICM	$ 0.38	$ 0.60	$ 5.71	$ 0.63	$ (669.04)	$ 4,468.66
Rate Riders	$ 1.00	$ 3.20	$ 228.68	$ (0.41)	$ 62.71	$ 8,354.73
Line losses	$ (0.04)	$ (0.10)	$ (3.59)	$ (0.04)	$ (0.53)	$ (132.86)
Transmission	$ (0.32)	$ (0.84)	$ (18.93)	$ (0.33)	$ (3.08)	$ (965.50)
	$ 1.01	$ 2.86	$ 211.87	$ (0.15)	$ (609.94)	$ 11,725.03
	2.61%	3.31%	26.03%	-0.40%	-18.21%	7.19%

a) **Please provide references for the values in Table 8.25 to the Tab 20 of the Bill Impacts model.**

RESPONSE

a) The table below reconciles Table 8.25 with Tab 20 of the Bill Impacts model.

Bill Segment	Residential	GS < 50	GS > 50	USL	Streetlights	Large User
Monthly Service Charge	$ 3.38	$ -	$ -	$ (1.05)	$ (294.00)	$ 4,257.16
Distribution Volumetric Rate	$ (2.48)	$ 3.00	$ 52.73	$ 1.68	$ (375.04)	$ 1,953.00
Rate Rider (ICM)	$ (0.53)	$ (2.40)	$ (47.02)	$ -	$ -	$ (1,741.50)
Distribution Rates plus ICM	**$ 0.38**	**$ 0.60**	**$ 5.71**	**$ 0.63**	**$ (669.04)**	**$ 4,468.66**
Rate Rider (ICM)	$ 0.53	$ 2.40	$ 47.02	$ -	$ -	$ 1,741.50
Fixed Rate Riders	$ 0.16	$ -	$ -	$ -	$ -	$ -
Volumetric Rate Riders	$ 0.23	$ 0.40	$ 24.08	$ 0.56	$ 61.54	$ 783.00
Total Deferral/Variance Account Rate	$ -	$ 0.40	$ 10.57	$ (0.96)	$ 1.17	$ 391.50
GA Rate Riders	$ -	$ -	$ 147.00	$ -	$ -	$ 5,438.73
Additional Fixed Rate Riders	$ 0.07	$ -	$ -	$ -	$ -	$ -
Rate Riders	**$ 1.00**	**$ 3.20**	**$ 228.68**	**$ (0.41)**	**$ 62.71**	**$ 8,354.73**
Line losses on Cost of Power	**$ (0.04)**	**$ (0.10)**	**$ (3.59)**	**$ (0.04)**	**$ (0.53)**	**$ (132.86)**
RTSR - Network	$ (0.24)	$ (0.63)	$ (14.69)	$ (0.25)	$ (2.38)	$ (588.00)
RTSR - Connection and/or Line Transformation Connection	$ (0.08)	$ (0.21)	$ (4.24)	$ (0.08)	$ (0.70)	$ (377.50)
Transmission	**$ (0.32)**	**$ (0.84)**	**$ (18.93)**	**$ (0.33)**	**$ (3.08)**	**$ (965.50)**
	$ 1.01	**$ 2.86**	**$ 211.87**	**$ (0.15)**	**$ (609.94)**	**$ 11,725.03**

8-SEC-33

[Ex.1, p.11, Ex.7, p.14]] With respect to the standby charge proposal:

a. **The Applicant states that it is seeking an "[o]rder establishing a new distribution Standby Charge to be applied to customers with behind the meter generation greater than 1 MW, as described in Exhibit 8". Please provide specific references to where the evidence in Exhibit 8 is located.**
b. **How many customers does the Applicant have who have demanded greater than 1MW?**
c. **Please provide a forecast of how many customers the Applicant would install behind the meter generation with capacity of 1MW or greater during the next 5 years.**
d. **Please provide details and evidence related to the proposal.**
e. **Please provide details and copies of all internal analysis undertaken by the Applicant in determining the structure of the proposed standby charge.**
f. **[Ex.7, p.15] The evidence states that the Applicant consulted with the customer who is expected to be initially impacted by the proposal. Please confirm that this customer is supportive of the proposal.**
g. **Has the Applicant consulted with any other customers who would be affected at some future time if they added behind the meter generation? If so, please provide details.**
h. **Please provide the proposed update to the conditions of service if the proposal is approved.**
i. **[Ex.8, Appendix 8B] The proposed tariff does not include the standby charge. Please provide the proposed wording that would be included if the charge is approved.**

RESPONSE

NOTL Hydro has prepared additional evidence with respect to the Standby Charges that has been filed along with the responses to the interrogatories. Please see exhibit 8, Additional Evidence, filed November 2018.

a) This reference was in error. The evidence is now filed as Exhibit 8, Additional Evidence, filed November 2018.

b) In addition to the Large Use customer, NOTL Hydro has two customers whose demand is a little over 1 MW.

c) NOTL Hydro has recently been approached by a customer looking to install a 500 kW / 1,000 kW battery. Beyond this, NOTL Hydro currently is not aware of any other customers who would be installing significant behind the meter generation of greater than 250 kW over the next five years.

d) The customer has identified the proposed generation to be 2.5 MW and has submitted a request for a Connection Impact Analysis which has now been completed. Please see exhibit 8, Additional Evidence, filed November 2018 for additional evidence.

e) The structure was determined in consultation with the affected customer who proposed this structure. The customer was familiar with the use of this structure at Kingston Utilities. NOTL Hydro was comfortable with the structure so is proposing it. Additional analysis is included with the additional evidence.

f) Confirmed. The following was received from the customer in an e-mail; the name of the customer has been redacted. *"Tim - xxx, the customer affected by these two proposed rate classes, have reviewed the new service classifications and proposed "Large User" and "Standby Power" rates outlined in Exhibit 7 of NOTL Hydro's pending 2019 Cost of Service rate application. As mentioned in your submission, xxx fully support NOTL Hydro's proposed "Large User" and "Standby Power" rate classes as outlined in the most recent EB-2018-0056 OEB filings."*

g) As mentioned above, NOTL Hydro has recently been contacted by a customer about a battery project that would meet the Standby Charge requirements. This customer is being notified of the rate application. Beyond this, NOTL Hydro currently is not aware of any other customers who would be installing significant behind the meter generation of greater than 250 kW over the next five years.

h) The requirements for different types of embedded generation (FIT, Net metering < 10 kW, Net metering > 10 kW) are detailed in Appendix 5 of the Conditions of Service. An additional section will be added to Appendix 5 for Load Displacement Generation that will include when the Standby Charge will be applicable and how it will be applied.

i) The proposed wording is included with the additional evidence.

8.0-VECC-45

Reference: Exhibit 8, page 7

a) **Why for the GS<50 and GS>50 classes is NOTL only proposing to not change the monthly service charge whereas for the Street Lighting and USL classes it is proposing to reduce the rate to the maximum value per the cost allocation model?**

RESPONSE

a) NOTL Hydro is open to adjusting the fixed/variable split for street light and USL classes. Street Lighting monthly service charge was reduced as the overall revenue requirement for this class was reduced. Due to the minimal difference between the current USL fixed rate of $21.20 and the calculated ceiling of $20.15, NOTL Hydro chose to reduce the fixed rate to the ceiling. The total difference in fixed rate revenue from unmetered customers is minimal at $27.30 per month ($1.05 x 26 customers).

8.0-VECC-46

Reference: Exhibit 8, pages 19-22 and Exhibit 3, pages 50-51 & NOTL 2019 Cost Allocation Model, Tab O3.6

a) With respect to Tab3.6, please indicate which of the activities listed are performed by Utilismart.

b) What is the basis for the $2.00/month cost that NOTL attributes to its own activities associated with microFIT customers.

c) Please explain why the costs as derived in Tab O3.6 were not used as the basis for determining the adder required to compensate NOTL for its activities.

d) With respect to the changes proposed to the Specific Service Charges, why were specific service charges only updated for the six charges discussed in Exhibit 8 at pages 20-22?

e) In particular, why was the Disconnect/reconnect at Pole – after regular hours charge updated but the Disconnect/reconnect at Pole – during regular hours charge was not?

f) The Application indicates (Exhibit 8, page 20, line 12) that the disconnect /reconnect charge is only levied on the disconnection. Under what circumstance would NOTL undertake a disconnection after hours such that the "after regular hours" rate would apply?

g) Under what circumstances (if any) would the disconnect/reconnect charge apply to an "after regular hours" reconnection?

h) The Application states that NOTL does not use load control devices on a regular basis. When are such devices used?

i) Please provide the derivation of the proposed $320 charge for Service Call – customer owned equipment – after regular hours.

j) Does NOTL apply the Service Call – customer owned equipment – after regular hours even in situations where there is a safety risk to the customer.

RESPONSE

a) Microfit meters are currently read by Savage Data Inc. as the ODS for NOTL Hydro and paid through a manual process in Excel. Utilismart will provide the capability for NOTL Hydro to pay Microfit customers through its Northstar billing system, provide customers with access to their generation data, and provide IESO settlement information that NOTL Hydro can utilize for its monthly 1598 filings.

b) The $2.00 is intended to cover the costs associated with mailing invoices (email or regular mail), EFT charges and cheque preparation, and labour required to maintain the data in the Utilismart system to ensure accurate billing and settlements.

c) NOTL Hydro is open to using the amount in table O3.6 to determine the adder requirement however some of these expenses may be duplicated in the services provided by Utilismart. The proposed new charge is also consistent with that charged by a large number of LDCs.

d) NOTL Hydro reviewed all of the specific service charges. NOTL Hydro updated the charges where the current time requirements and labour cost were not in line the specific service charge amounts from NOTL Hydro's previously approved rates.

e) NOTL Hydro's review of the cost to Disconnect/reconnect at the pole – after hours charge of $185 was not sufficient to cover the costs associated with this service as it required two lineman paid double time for a minimum of 2 hours (see table 8.17). The current charge of $185 was sufficient to cover this service during regular hours.

f) NOTL Hydro only charges Disconnect/reconnect charges when the service is reconnected. NOTL Hydro does not apply the service to disconnections.

g) The only time the after regular hours rate would apply is when a customer requests to be reconnected outside of business hours.

h) Load control devices are used if requested by the customer and can be installed in compliance with applicable regulatory requirements..

i) The service charge for customer owned equipment after regular hours was derived using the same methodology as Disconnect/reconnect at the meter charge – after hours (see table 8.16)

j) Yes

9 | Deferral & Variance Accounts

INTERROGATORY RESPONSES

9-Staff-66

Ref: Exhibit 9, Page 37

NOTL Hydro explains the GA rate used to bill the customers and accrue the unbilled:

> **NOTL Hydro bills non-RPP customers on the actual GA rate. The GA rate used to calculate unbilled revenue from January through November 2017 was based on the previous months actual GA rate as the actual GA rate for the reporting month is not available at the time unbilled accounting entries are processed. Unbilled revenue for December 2017 was trued-up to the actual amount billed and is therefore based on the actual GA rate.**

Staff understands that the actual GA rate for the current month is published by the IESO on the tenth business day of the following month.

a) **Regarding the customers with calendar month billings, please confirm whether or not NOTL Hydro uses the actual GA rate of the load month to bill the customers (for example, use July 2018 actual GA rate to bill the customer with July consumption).**
b) **Regarding the customers with billing cycle spanning over the calendar months (for example, June 16th to July 15th), please provide the details how NOTL Hydro bills the GA to these customers (please explain the proration method, the rate used, and the months the rates related to etc.) Please use an illustrative example as necessary.**

RESPONSE

a) Confirmed that NOTL Hydro uses the actual GA rate of the load month to bill customers.

b) The majority of NOTL Customers bill on calendar month from the first of the month to the first of the month, inclusive. The actual GA rate, effective date is input for the first of each month, therefore no pro-ration between rate effective dates would be necessary. Some of NOTL Hydro's customers are billed based on when the meter was physically read. The GA for these customers is pro-rated if the billing period crosses over more than one month. The proration is based on the days billed in each month. For example if a customer's billing period was from June 28 – July 31 (June 3 days, July 30 days = 33 total billed days) the GA calculation would be as follows:

   GA calculation= total usage / total billed days x number of days June x June actual GA rate + total usage / total billed days x number of days July x July actual GA rate

9-Staff-67

Ref: GA Analysis Workform

In the GA Analysis Workform for 2017, under reconciling item 5 (significant prior period adjustments), the Applicant has indicated that there is a $101,913 adjustment for a historical billing error impacting one customer.

a) Please confirm which years this billing error pertains to.
b) Please describe the nature of the error, how it occurred, and whether there are any IESO settlement ramifications as a result
c) Did this billing error require a reallocation of GA costs between RPP and Non-RPP customers? If so, please explain and, if necessary, provide the principal adjustment to reallocate costs between Accounts 1588 and 1589.

RESPONSE

a) The billing error pertains to the billing period from August 2015 to March 2018.

b) The billing error was discovered during a quality assurance test on interval data after a meter change on the account. The billing multiplier applied to the customer was double what the actual multiplier on the account should have been. All the bills have been cancelled and subsequently rebilled in 2018. The variance will be captured through NOTL Hydro's annual 1598 reconciliation.

c) This error did not require a reallocation of GA costs between RPP and non-RPP customers.

s

9-Staff-68

Ref: GA Analysis Workform; Exhibit 9, Page 21

In the GA Analysis Workform for 2017, under reconciling item 9, NOTL Hydro has indicated that there is a $42,891 adjustment for 2017 as a result of using estimates for embedded generation, rather than actuals. Staff notes that it is not evident if a corresponding adjustment was made to Account 1588.

a) Please confirm whether or not a corresponding adjustment was made to allocate this amount between accounts RPP and non-RPP customer groups affected by the embedded generation reporting adjustment.

b) If a corresponding adjustment was made in Account 1588 for the embedded generation amount; please confirm if an RPP settlement claim adjustment was made, if not please explain.

c) If an adjustment is required, please quantify in the same manner as prepared in Table 9.14: Generation Estimates Adjustment.

RESPONSE

a) No adjustment was made to allocate this amount between RPP and non-RPP customers.

b) NOTL Hydro plans to undertake a review of generation estimates provided to the IESO versus the actual generation for those months. The difference in GA billed to NOTL Hydro as a result of the 2016 and 2017 use of estimates for generation is currently in account 1589 and has been adjusted in the 2019 DVA Continuity Schedule. Following the review NOTL Hydro will settle the amount with the IESO.

c) NOTL Hydro does not believe an adjustment is required at this time.

9-Staff-69

Ref: GA Analysis Workform

NOTL Hydro includes a reconciling item with respect to the line loss for $69,662 in the GA Analysis Workform.

a) **Please provide details and explain how the applicant calculated the amount of $69,662 for the difference between the approved total system losses and those actually incurred.**

RESPONSE

a) Calculation of difference in loss factor

	Reference	Total
Total Load kWh (including generation)	A	203,734,811
Class A (including losses at 1.0379)	B	2,957,271
Total Class B Load kWh (including generation)	C = A -B	200,777,540
Actual Consumption kWh (Base Amount)	D	194,059,583
Actual Loss Factor	E = C / D	1.0346
OEB Approved Loss Factor	F	1.0379
Billed Consumption kWh @ OEB approved Loss Factor	G = D x F	201,414,442
Variance Total Load and Billed Consumption kWh	H = G - C	636,902
Actual GA Rate (weighted average)	I	0.10938
Difference between Total Load and Billed Consumption $	J = H x I	$69,662

9-Staff-70

Ref: GA Analysis Workform

NOTL Hydro has identified that prior amounts accrued in 2015 and 2016 for a Notice of Dispute with the IESO have been settled and recorded on an actual basis in 2017.

a) **Please confirm whether or not, at this time, there are any other outstanding disputes with the IESO with respect to the cost of power or global adjustment charges incurred in 2017; if so, please explain the nature of the dispute and quantify any estimated impacts on the commodity account balances.**

RESPONSE

a) There are no outstanding disputes with the IESO.

9-Staff-71

Ref: GA Analysis Workform

NOTL Hydro includes a reconciling item of $47,862 on the GA Analysis Workform for the difference between the actual invoiced GA and the calculated GA portion for NOTL Hydro.

a) **Please confirm whether or not the entire amount of $47,862 was the adjustment made by the IESO, i.e. the adjustments for total global adjustment charges for all customers (RPP and Non-RPP customers). If so, please confirm whether the adjustment amount was allocated to RPP customers and Non-RPP Class B customers.**

b) **If a) is confirmed, please explain why 100% of the difference is shown as a reconciling item impacting non-RPP customers in the GA Analysis Workform for Account 1589, rather than allocating a portion of the difference between RPP and non-RPP customers. Please also update the GA Analysis Workform for this reconciling item as applicable.**

c) **If the $47,862 only relates to non-RPP customers please confirm that the amount related to the account 1588 portion was settled as a RPP settlement true up adjustment and when.**

RESPONSE

a) $47,862 was the entire amount of the adjustments.

b) The process utilized by NOTL Hydro as described in 2.9.3.3.4 calculates the GA attributable to RPP customers based on actual consumption billed at the OEB approved loss factor multiplied by the actual GA rate. The remaining GA is attributed to non-RPP customers; therefore, the entire amount is currently in account 1589 and is a reconciling item for the GA Workform.

c) n/a

9-Staff-72

Ref: Exhibit 9, Page 46; The OEB letter issued on May 23, 2017 for “Guidance on Disposition of Accounts 1588 and 1589”

NOTL Hydro indicates that it performs the RPP settlement true up on an annual basis:

> **The true-up process is completed once all billings for the reporting period have been processed through the billing system. The last billings for 2017 were completed in mid- February 2018. While the true-up was competed in 2018 all entries were booked to 2017.**

The OEB issued a letter to all electricity distributors regarding the “Guidance on Disposition of Account 1588 and 1589”. It states that:

> **RPP settlement true-up claims should be conducted monthly and if not, at a minimum on a quarterly basis. The year-end RPP settlement true-up claim for the last quarter of a year must be completed no later than the settlement claim with the IESO for the final month of the first quarter of the following fiscal year.**

a) Please confirm whether or not NOTL Hydro trues up its RPP settlements annually

i. If so, please explain why NOTL Hydro has not followed the guidance in the OEB letter issued on May 23, 2017. And please provide NOTL Hydro’s plan to conform to the guidance.

ii. If not, please provide NOTL Hydro’s RPP settlement true-up frequency (quarterly or monthly).

RESPONSE

a) Confirmed

i. NOTL Hydro plans to complete an annual reconciliation for 2018 and implement quarterly reconciliations in the first quarter of 2019

ii. n/a

9-Staff-73

Ref: Exhibit 9, Pages 32-33 and Page 36

NOTL Hydro provides the rate rider calculations for Group 1 DVAs, Group 2 DVAs, Account 1568 and Account 1589 Global Adjustment based on the assumed load forecast of the large user customer of 5MW.

a) Please provide the rate rider calculations under the scenarios of 10MW and 15MW for the large use customer respectively.

RESPONSE

a) Subsequent to our application, NOTL Hydro received a revised DVA Continuity Schedule for the OEB. Below are the Rate Rider Calculations from the revised model with the projected interest rate changed to 2.17% based on the most recent rate published by the OEB. The updated model is being filed in response to OEB Staff interrogatory #1.

i. Revised Model – Large User 5MW

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL	kWh	73,998,981	-$ 44,558	- **0.0006**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	-$ 23,960	- **0.0006**
GENERAL SERVICE 50 TO 4,999 KW	kW	212,896	-$ 46,308	- **0.2175**
STREET LIGHTING	kW	2,475	-$ 496	- **0.2006**
UNMETERED	kWh	251,508	-$ 141	- **0.0006**
LARGE USER	kW	60,000	-$ 13,051	- **0.2175**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 128,514**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	**Units**	**# of Customers**	**Allocated Group 2 Balance**	**Rate Rider for Group 2 Accounts**
RESIDENTIAL	# of Customers	8,152	$ 83,618	**$ 0.85**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 47,321	**$ 0.0011**
GENERAL SERVICE 50 TO 4,999 KW	**kW**	212,896	$ 93,456	**$ 0.4390**
STREET LIGHTING	**kW**	2,475	$ 1,002	**$ 0.4048**
UNMETERED	kWh	251,508	$ 284	**$ 0.0011**
LARGE USER	**kW**	60,000	$ 26,339	**$ 0.4390**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
Total			**$ 252,019**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	**Units**	**kWh**	**Allocated Global Adjustment Balance**	**Rate Rider for RSVA - Power - Global Adjustment**
RESIDENTIAL	kWh	1,780,312	-$ 3,219	- **0.0018**
GENERAL SERVICE LESS THAN 50 KW	kWh	6,394,270	-$ 11,560	- **0.0018**
GENERAL SERVICE 50 TO 4,999 KW	kWh	76,701,807	-$ 138,664	- **0.0018**
STREET LIGHTING	kWh	779,154	-$ 1,409	- **0.0018**
UNMETERED	kWh	-	$ -	**-**
LARGE USER	kWh	23,308,825	-$ 42,138	- **0.0018**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
Total			**-$ 196,989**	

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in months) | **12**

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Account 1568 Balance**	**Rate Rider for Account 1568**
RESIDENTIAL	# of Customers	8,152	$ 40,646	**0.4155**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 39,732	**0.0009**
GENERAL SERVICE 50 TO 4,999 KW	**kW**	212,896	$ 57,017	**0.2678**
STREET LIGHTING	**kW**	2,475	$ 65,313	**26.3920**
UNMETERED	kWh	251,508	$ -	-
LARGE USER	**kW**	60,000	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 202,708**	

ii. Large User – 10MW

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Group 1 Balance (excluding 1589)**	**Rate Rider for Deferral/Variance Accounts**
RESIDENTIAL	kWh	73,998,981	-$ 40,639	- **0.0005**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	-$ 21,743	- **0.0005**
GENERAL SERVICE 50 TO 4,999 KW	**kW**	212,896	-$ 41,929	- **0.1969**
STREET LIGHTING	**kW**	2,475	-$ 449	- **0.1816**
UNMETERED	kWh	251,508	-$ 128	- **0.0005**
LARGE USER	**kW**	120,000	-$ 23,633	- **0.1969**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 128,521**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL	# of Customers	8,152	$ 75,706	**$ 0.77**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 42,843	**$ 0.0010**
GENERAL SERVICE 50 TO 4,999 KW	kW	212,896	$ 84,613	**$ 0.3974**
STREET LIGHTING	kW	2,475	$ 907	**$ 0.3665**
UNMETERED	kWh	251,508	$ 257	**$ 0.0010**
LARGE USER	kW	120,000	$ 47,693	**$ 0.3974**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
Total			**$ 252,019**	

1

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	1,780,312	-$ 2,664	**- 0.0015**
GENERAL SERVICE LESS THAN 50 KW	kWh	6,394,270	-$ 9,567	**- 0.0015**
GENERAL SERVICE 50 TO 4,999 KW	kWh	76,701,807	-$ 114,761	**- 0.0015**
STREET LIGHTING	kWh	779,154	-$ 1,166	**- 0.0015**
UNMETERED	kWh	-	$ -	**-**
LARGE USER	kWh	46,617,651	-$ 69,749	**- 0.0015**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
Total			**-$ 197,906**	

2

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in months) | 12

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL	# of Customers	8,152	$ 40,646	**0.4155**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 39,732	**0.0009**
GENERAL SERVICE 50 TO 4,999 KW	kW	212,896	$ 57,017	**0.2678**
STREET LIGHTING	kW	2,475	$ 65,313	**26.3920**
UNMETERED	kWh	251,508	$ -	-
LARGE USER	kW	120,000	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 202,708**	

i. Large User – 15MW

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL	kWh	73,998,981	-$ 37,398	- **0.0005**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	-$ 19,909	- **0.0005**
GENERAL SERVICE 50 TO 4,999 KW	kW	212,896	-$ 38,306	- **0.1799**
STREET LIGHTING	kW	2,475	-$ 411	- **0.1659**
UNMETERED	kWh	251,508	-$ 116	- **0.0005**
LARGE USER	kW	180,000	-$ 32,387	- **0.1799**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 128,526**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL	# of Customers	8,152	$ 69,161	**$ 0.71**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 39,140	**$ 0.0009**
GENERAL SERVICE 50 TO 4,999 KW	**kW**	212,896	$ 77,299	**$ 0.3631**
STREET LIGHTING	**kW**	2,475	$ 829	**$ 0.3348**
UNMETERED	kWh	251,508	$ 235	**$ 0.0009**
LARGE USER	**kW**	180,000	$ 65,355	**$ 0.3631**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
Total			**$ 252,019**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	1,780,312	-$ 2,272	- **0.0013**
GENERAL SERVICE LESS THAN 50 KW	kWh	6,394,270	-$ 8,160	- **0.0013**
GENERAL SERVICE 50 TO 4,999 KW	kWh	76,701,807	-$ 97,882	- **0.0013**
STREET LIGHTING	kWh	779,154	-$ 994	- **0.0013**
UNMETERED	kWh	-	$ -	**-**
LARGE USER	kWh	69,926,476	-$ 89,235	- **0.0013**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
Total			**-$ 198,543**	

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in months) | **12**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL	# of Customers	8,152	$ 40,646	**0.4155**
GENERAL SERVICE LESS THAN 50 KW	kWh	41,877,513	$ 39,732	**0.0009**
GENERAL SERVICE 50 TO 4,999 KW	kW	212,896	$ 57,017	**0.2678**
STREET LIGHTING	kW	2,475	$ 65,313	**26.3920**
UNMETERED	kWh	251,508	$ -	-
LARGE USER	kW	180,000	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 202,708**	

9-Staff-74

Ref: Exhibit 9, Page 49; Appendix 9C Draft Accounting Order

NOTL Hydro has prepared the Accounting Order on the basis that 5,000 kW per month is the best estimate available for this customer. Staff notes that NOTL Hydro has indicated that the customer's estimated consumption range is from 4MW to 20MW.

a) Please confirm that NOTL Hydro plans to dispose either negative or positive balances in the new variance account, what customer groups NOTL Hydro proposes to return/recover the amounts from, and how NOTL Hydro plans to allocate the variance account balances to the respective customer classes.
b) Please provide any information available of the consumption patterns of comparable customers of similar sizes and similar industries.
c) As of the current date, has NOTL Hydro received any new information from the prospective Large Use Customer on their business plans, legal uncertainties, market demands, or any other factors that could assist NOTL Hydro in determining the customer's monthly consumption patterns?
d) As of the current date, does NOTL Hydro have any knowledge or information with respect to the prospective Large Use Customer's intentions of maintaining operations within the service territory of the Applicant?
e) If the answers to c) and d) above are No, please update any new information received during the process of this rate application before the record-closing date.

RESPONSE

a) NOTL Hydro confirms that it plans to dispose of either negative or positive balances in the new variance account with its IRM following the audit of the financial statements each fiscal year. NOTL Hydro plans to allocate the balance between all customer classes based on the distribution revenue from each class in that year.

b) NOTL Hydro does not have any information available of the consumption patterns of comparable customers of similar sizes and similar industries.

c) No.

d) NOTL Hydro is not privy to the prospective large use customer's business intentions beyond what is publicly available. However, the customer has purchased additional property adjacent to its original property and has spent, and is continuing to spend, what appears to be millions of dollars upgrading both properties. The customer has also invested significantly in establishing itself as a member of the community. NOTL Hydro therefore anticipates that this customer intends to maintain its operations for the foreseeable future.

e) No new information has been received but NOTL Hydro will keep the parties abreast of any relevant new information as it arises.

9-SEC-34

Has the OEB undertaken any audits of the Applicant's operations or regulatory accounting practices since its last rebasing? If so, please provide copies of any reports.

RESPONSE

As supplied in response to 1-SEC-2:

1. **RRR Audit** – The OEB performed an audit of NOTL Hydro's RRR (Reporting & Record Keeping Requirements). It focused on appointments with customers as well as new services connected on time. This is a confidential report and we are not able to share it.

9.0-VECC-47

Reference: Exhibit 9, pages 49-50

a) Please confirm that the requested variance account would track variances in the annual variable distribution revenues for the one customer concerned until NOTL's next COS-based rate application.

b) When will the balances the account be refund to/collected from customers (e.g., will the account be cleared periodically during the IRM period or only at the time of the next COS-based application)?

c) When the account balance is refunded to/recovered from customers to which customer classes will it be allocated and now will the allocation be done?

d) What additional facilities is NOTL installing to meet the customer's forecasted increase in load and to what extent are these facilities being funded by capital contributions from the customer?

e) Was an economic evaluation undertaken (per the DSC) to determine if a capital contribution was required? If yes, what was the customer load forecast used that was used in the evaluation?

RESPONSE

a) Confirmed

b) NOTL Hydro plans to clear the balance on an annual basis through the IRM rate filings.

c) NOTL Hydro proposes to allocate the account balance to all the account classes based on revenues.

d) NOTL Hydro has installed a new feeder line with all the required protection and control devices at both the NOTL Hydro MTS and the customer site. This equipment has the capacity to provide a full 20 MW load. The full cost of the upgrade was paid for by the customer.

e) Due to the significant uncertainty of the future load, no economic evaluation was undertaken.

9.0-VECC-48

Reference: E9, pg. 24-25

a) **With respect to IFRS Transition costs (Account 1508) please explain the nature of the incremental labour costs of $35,125.**

RESPONSE

a) Primarily contract labour to assist with conversion of PP&E and overtime related to the IFRS conversion.

9.0-VECC-49

Reference: E9/pg.16

a) **Please explain why the amounts recorded in account 1508 of $2,635,716 and $132,988 are being requested to be moved to fixed asset/depreciation (balance sheet)?**

RESPONSE

a) These amounts relate to the ICM for the new transformer that was purchased and installed in 2015. There is not a request to move them at this time as they are listed in the table of accounts not for disposition. Subsequent to an audit of their final balances the request will be made for their movement from account 1508 to fixed assets and accumulated depreciation. This will be done as part of the annual IRM process.

APPENDICES

List of Appendices:

- 1.SEC.10A – Advocacy Files **PDF**
- 1.SEC.12A – Data required for Cost Benchmarking **EXCEL**
- 2.SEC.16A – SGF Agreement **PDF**
- 2.SEC.16B – Project Overview **PDF**
- 2.SEC.16C – SGF-C Budget **EXCEL**
- 2.SEC.16D – Smart Grid Funding Application **PDF**
- 4.STAFF.54.1 – 2017 Final Results Report (CDM) **EXCEL**
- 4.STAFF.54.2 – 2011-2015 CDM Persistence Results **EXCEL**
- 7.VEC.39A – Weighting Factors **EXCEL**