Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2018-0056

NIAGARA-ON-THE-LAKE HYDRO INC.

Application for electricity distribution rates and other charges

beginning May 1, 2019

BEFORE: **Michael Janigan**
Presiding Member

April 11, 2019

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1 INTRODUCTION AND SUMMARY

This is a Decision and Order of the Ontario Energy Board (OEB) on an application filed by Niagara-on-the-Lake Hydro Inc. (NOTL Hydro) to change its electricity distribution rates effective May 1, 2019 (the application). Under the *Ontario Energy Board Act, 1998*, distributors must apply to the OEB to change the rates they charge their customers.

NOTL Hydro provides electricity distribution services to approximately 9,406 residential and commercial customers in the Town of Niagara-on-the-Lake (Town).

NOTL Hydro requested the OEB approve its rates for five years using the Price-Cap Incentive rate-setting (Price-Cap IR) option available under the *"Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach"*[1], as most recently set out in the *Handbook for Utility Rate Applications.* Under the Price-Cap IR option, rates are determined on a cost of service basis for 2019, and adjusted mechanistically for the next four years through a price cap adjustment based on inflation and the OEB's assessment of NOTL Hydro's efficiency.

NOTL Hydro and intervenors participated in a settlement conference and filed a partial settlement proposal with the OEB on January 10, 2019. On February 8, 2019, the OEB accepted the partial settlement proposal (see Schedule A attached). The following issues were not settled:

- Issue 1.1 Capital: the unsettled issue relates to the prudence of NOTL Hydro's underground conversion project since its last rebasing (impacting 2019 opening rate base) and its proposed test year expenditures for the underground conversion project (impacting 2019 net additions and rate base)
- Issue 1.2 Operations, Maintenance & Administrative Expenses (OM&A)
- Issue 2.1 & 2.2 Revenue Requirement: the unsettled issue relates to the cost of long-term debt regarding the applicable interest rates to one promissory note and two loans from the Town
- Issue 3.2 Cost Allocation: the unsettled issue is whether NOTL Hydro should include the Incremental Capital Module (ICM) revenue in distribution revenue at current rates in the cost allocation model

[1] Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach, October 18, 2012

- Issue 4.2 Deferral and Variance Accounts (DVAs): the appropriate disposition period of Group 2 DVAs and the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)
- Issue 5.3 Transmission Gross Load Billing: the unsettled issue is whether NOTL Hydro should apply the transmission gross load billing for Load Displacement Generators (LDG), with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation

The OEB has made the following findings on the unsettled issues:

- Issue 1.1 Capital: The OEB approves the amount of $335,000 for the Old Town portion of the underground conversion project and general underground capital work. This amount reflects a $125,000 reduction to the amount requested by NOTL Hydro for the Virgil portion of the project.

- Issue 1.2: OM&A Expense: The OEB approves a 2019 OM&A budget envelope of $2,671,367.

- Issue 2.1 & 2.2 Cost of Long-term Debt: The OEB approves the use of the OEB's 2019 deemed long-term debt rate of 4.19% on the promissory note with the Town. The OEB approves the new interest rates applicable to the two Town loans effective April 1, 2019 for inclusion in the NOTL Hydro's cost of debt.

- Issue 3.2 Cost Allocation: The OEB approves the incorporation of ICM revenues into existing distribution revenues for cost allocation purposes.

- Issue 4.2 Disposition Period of Group 2 DVAs and LRAMVA: The OEB approves the clearance of Group 2 DVAs and the LRAMVA over two years with a reduction of $5,000 to the principal balance being recovered to reflect the difference in interest costs.

- Issue 5.3 Transmission Gross Load Billing: The OEB approves NOTL Hydro's proposed transmission charge for the Large Use rate class.

2 THE PROCESS

NOTL Hydro filed its application on August 23, 2018 for 2019 rates. The OEB issued a Notice of Application on September 7, 2018, inviting parties to apply for intervenor status. School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC) applied for and were granted intervenor status and cost eligibility.

The OEB held a community meeting on October 9, 2018 where OEB staff and NOTL Hydro made presentations. A summary of the community meeting was posted on the record of this proceeding. The customers that attended the community meeting asked questions and expressed concerns about a new transformer, bill impacts from rate riders, self-generation, street light revenue reduction and whether the generation from the new large business customer will impact residential rates.

The OEB issued Procedural Order No. 1 on October 10, 2018 with a timetable for a written discovery process, the filing of a proposed issues list and a settlement conference. On December 6, 2018, the OEB issued its Decision on Issues List in which it approved a final issues list that was proposed by OEB staff and agreed upon by the intervenors. A settlement conference was held on December 10 and 11, 2018.

NOTL Hydro, SEC and VECC (the Parties) filed a partial settlement proposal with the OEB on January 10, 2019. OEB staff was not a party to the settlement proposal, but participated in the settlement conference in accordance with the role of OEB staff set out in the OEB's *Practice Direction on Settlement Conferences*. OEB staff filed its submission regarding the partial settlement proposal on January 17, 2019.

On February 8, 2019, the OEB issued a Decision and Procedural Order No. 4 in which it accepted the partial settlement proposal with respect to NOTL Hydro's application. Procedural Order No.4 also set out the dates for a written hearing of the six unsettled issues. All Parties and OEB staff filed written submissions with respect to the unsettled issues.

3 DECISION ON THE UNSETTLED ISSUES

3.1 Capital – Underground Conversion Project

Background

In this application, NOTL Hydro proposed to continue an underground conversion project that was started in 1987. The project consists of continuing conversion of the oldest segment of the existing 4 kV distribution system to underground as well as converting the supply to 27.6 kV. NOTL Hydro stated that the voltage conversion project is to be completed by the end of 2034.

Besides a number of benefits to reliability, safety and the environment, NOTL Hydro referenced a Town by-law which stated that the installation of new overhead plant is prohibited as a means of preserving the heritage nature of the Old Town. In its updated evidence, NOTL Hydro clarified that the Town by-law was a legacy by-law of the NOTL Hydro-Electric Commission that was passed in 1989, and not a by-law of the Town, and that it was adopted as a company policy when NOTL Hydro was incorporated in 2000.

NOTL Hydro further clarified that the spending of $460,000 in the test year, subject to the OEB's determination, is comprised of three parts:

- The underground conversion in Old Town of $215,000
- The Virgil portion of the project along Highway 55 of $125,000 that is not voltage conversion and to be done as part of the region's road widening work
- The general underground work of $120,000 including moving distribution lines for reasons other than voltage conversion; replacing pad-mount transformer or conduit, capital repairs etc.

In its argument-in-chief, NOTL Hydro submitted that its underground voltage conversion program is appropriate and necessary. NOTL Hydro submitted that there should be no issue as to the prudence of amounts already spent, and the forecast costs for 2019 and beyond are appropriate and reasonable.

SEC stated that it does not oppose the program in its entirety. SEC proposed a reduction of $230,000 (50%) to the underground capital budget of $460,000 in 2019. VECC argued that NOTL Hydro misled the OEB and the parties in the 2014 cost of service proceeding on the authority and the breadth of the underground conversion project. VECC submitted that the OEB could disallow portions of the proposed underground investment but it did not specify the amount to be disallowed. VECC submitted that, alternatively, the OEB could allow the underground conversion project in Old Town only, adjust the proposed OM&A budget to compensate the ratepayers for the higher costs incurred and to be incurred under the existing capital program, and direct NOTL Hydro to develop a comprehensive undergrounding plan for its next cost of service application.

OEB staff submitted that it supports the underground conversion program and general underground work but not the underground work for the Virgil portion of the project. Based on the historical average underspending, as a percentage, and the historical accumulated underspending, OEB staff proposed a reduction of $95,000 to the underground budget in the test year.

With respect to NOTL Hydro's customer engagement regarding the underground conversion project, SEC noted that customers voiced their concerns about the associated costs and that the program should not be done for cosmetic reasons. VECC submitted that customers were not engaged in a meaningful way because NOTL Hydro did not provide comparative costs or a reliability analysis in order for customers to have an informed opinion. OEB staff noted that customers apparently did not object to the Old Town portion of the project.

NOTL Hydro argued, in its reply submission, that it did not knowingly provide incorrect information in its 2014 cost of service application and therefore did not mislead the OEB in that application. NOTL Hydro submitted that the proposed opening rate base (inclusive of underground conversion program) should be approved as filed. With respect to the proposed amount of underground conversion spending proposed for 2019, NOTL Hydro submitted that the entire budgeted amount of $460,000 is needed. However, if the OEB believes that a reduction is necessary, NOTL Hydro agreed with the approach taken by OEB staff which arrived at a reduction of $95,000 in the test year.

Findings

The OEB approves the amount of $335,000 for the underground conversion projects, which includes the Old Town project and general underground capital work. This amount reflects a $125,000 reduction to the amount requested by NOTL Hydro for the entire undergrounding project budget.

The OEB agrees with VECC that this project is a substantial commitment in an expanding capital budget. It requires careful cost benefit analyses for each component and reasonable and insightful evidence of customer engagement.

The NOTL Hydro's substantiation of the Old Town conversion project has been somewhat confused by previous misstatements concerning the effect of an old NOTL Hydro-Electric Commission by-law, and some apparent lack of clarity concerning the extent that the proposed expenditures have met with customer approval. VECC expresses concern that the project may be driven by tourism and aesthetic interests rather than utility service needs.

However, in assessing the complete evidentiary record, the OEB finds that the Old Town project request is reasonable and prudent. The OEB notes that the capital request is part of a project that has been ongoing, and continued in NOTL Hydro's 2014 approved cost of service application. It was also recognized in the distribution system plan.

While customer engagement has not been precise, there also does not appear to be substantial customer opposition to the continuation of the Old Town project as it has been communicated to customers by NOTL Hydro. The OEB agrees with OEB staff that there are benefits to customers that accrue from undergrounding and voltage conversion that include reliability, safety, lower maintenance and environmental enhancement beyond the aesthetic improvements.

The OEB finds that the principal rationale supporting the Virgil project is associated with coordination of the undergrounding with highway repair. However, it does not include voltage conversion, lacks a robust cost/benefit analysis, and may overstate the capital work budget in the test year by not fully recognizing the cost synergies associated with coordination with the proposed roadwork. The project also does not engage a significant urban area. The OEB does not approve the Virgil project's inclusion in NOTL Hydro's 2019 capital budget.

As OEB staff has set out, there has been significant underspending in the capital program since 2014. The Virgil project may still be able to be managed within the capital spending envelope of $335,000 provided in this Decision and Order.

3.2 OM&A Expense

Background

NOTL Hydro proposed a 2019 OM&A budget of $2,974,186 in the application, which was reduced to $2,964,765 after the first round of interrogatories. The proposed budget was 38% higher than NOTL Hydro's OEB-approved budget in 2014. NOTL Hydro's 2014 to 2019 OM&A expenses are set out in Table 1 below:

Table 1 2014-2019 OM&A Expenses ('000)

	2014	2014	2015	2016	2017	2018	2019
	Approved	Actual	Actual	Actual	Actual	Unaudited Actual	Forecast
OM&A	$2,155	$2,208	$2,323	$2,532	$2,595	$2,839	$2,965
						% Increase over 2014 Approved	38%

NOTL Hydro stated that the proposed OM&A budget is necessary to maintain and operate its distribution and transmission assets and distribution business.

In its argument-in-chief, NOTL Hydro used a higher-level approach to evaluate the 2019 OM&A budget. The high-level approach starts with the 2014 approved OM&A budget adjusted for an accounting standard change of $130,784, applying the inflation and growth factors and adding the costs related to the new and increased services to determine the 2019 OM&A budget. NOTL Hydro stated that this approach was used by the OEB in its decision on Thunder Bay Hydro's 2017 rates.[2]

NOTL Hydro stated that a discrete and significant contributor to the OM&A increase is the $130,784 adjustment due to the accounting standard changes. This adjustment is related to the costs of senior management's time that were capitalized under Canadian General Accounting Principles (CGAAP) in the 2014 cost of service application and that are now expensed and included within the 2019 OM&A budget under International Financial Reporting Standards (IFRS). NOTL Hydro stated that the adjustment is needed for an "apples-to-apples" comparison and it was not a new cost in the OM&A budget for the test year.

[2] EB-2016-0105

NOTL Hydro used three of the growth factors out of the five used by Pacific Economics Group (PEG) in the total cost benchmarking to measure the impact of growth on the OM&A expense. These three factors are customer growth, load growth and system peak growth. NOTL Hydro stated that the other two factors (increase in distribution lines and acceleration in customer growth) are not used because NOTL Hydro has seen no noticeable change for these two factors.

All parties, including OEB staff, provided their submissions on this evaluation approach and proposed a reduction to the OM&A budget. SEC proposed a reduction of $374,424 based on its approach of deriving the expected OM&A budget based on the 2014 approved OM&A expense adjusted for the accounting change of $130,784 and applied with the inflation, stretch factors and customer growth. VECC proposed a reduction ranging from $400,000 to $500,000. The reduction of $500,000 appears to be based on the difference between NOTL Hydro's proposed OM&A budget and the OM&A budget derived by VECC using the 2014 approved OM&A adjusted by the Bank of Canada inflation factor and customer growth. OEB staff proposed a reduction of $215,000 mainly consisting of the accounting change adjustment, its related inflation and growth and part of the new and increased services.

SEC accepted the accounting adjustment made to the OEB-approved amounts and stated that that it is appropriate to reflect the changes in capitalizing certain executives' costs due to the transition to IFRS. VECC did not comment on the accounting adjustment.

OEB staff opposed the accounting adjustment of $130,784 and submitted that NOTL Hydro should have identified the $130,784 OM&A increase that was related to the senior management's salaries and benefits during NOTL Hydro's process of changing the capitalization policy and should have presented this item in its 2014 cost of service application. OEB staff noted that the OEB, in its letter[3] issued in 2012, required all electricity distributors to change their capitalization and depreciation policies to be consistent with the OEB's regulatory accounting policies as set out for modified IFRS. One main difference between the capitalization policies under CGAAP and IFRS is that only directly attributable costs are allowed to be capitalized in the capital assets under IFRS. NOTL Hydro stated, in its reply submission, that even assuming that OEB staff is correct that NOTL Hydro should have expensed the costs, the ratepayers have not

[3] The OEB's letter issued on July 17, 2012 to all Electricity Distributors

been harmed since the costs were included in the rate base in the 2014 cost of service application.

Both VECC and SEC commented on the growth factors used by NOTL Hydro to quantify the impact of customer growth on the OM&A expense. OEB staff did not make submissions on the growth factors. VECC used customer growth only to quantify the impact of customer growth on the OM&A budget. SEC opposed the use of load and system peak growth factors to quantify the impact of the growth on OM&A. SEC stated that while load and system peak growth do impact costs, there is no evidence that they materially impact OM&A as opposed to capital costs. SEC submitted that NOTL Hydro's proposal for the inflation and growth adjustment went farther than the OEB's decision[4] for Canadian Niagara Power Inc. NOTL Hydro argued, in the reply submission, that SEC's approach improperly excludes the impact of load growth, which is a significant driver of OM&A costs, especially for a distributor like NOTL Hydro that has transmission assets. NOTL Hydro did not comment on the reason for including the growth factor of system peak.

NOTL Hydro attributed $237,040 of the OM&A increase to the new and increased services over five years. NOTL Hydro submitted that these extraordinary costs should be included in the 2019 OM&A budget because these costs are not accommodated in a budget that simply increases for inflation and growth. In addition, it stated that the OEB has allowed for additional extraordinary expenses in its decision on Innpower Corporation's 2017 rates.[5] Both SEC and VECC proposed not including any additional costs related to the new and increased services. SEC submitted that most of the costs related to the new and increased services should be included in the OM&A budget that is derived for inflation and growth. OEB staff submitted that a reduction of 1.5% out of the 11% proposed OM&A increase due to new and increased services would be appropriate.

SEC, VECC and OEB staff all commented on NOTL Hydro's OM&A costs per customer. All parties noted that the OM&A per customer in 2017 actual, 2018 and 2019 forecast are trending negatively, and submitted that this trend also supports reducing the proposed test year OM&A budget. NOTL Hydro submitted that the actual OM&A cost per customer has never been significantly different from the industry average during any year since 2010 to 2017 when the last actual data is available. Furthermore, it stated

[4] EB-2016-0061
[5] EB-2016-0085

that it has maintained its ranking within cohort three throughout the current incentive rate-setting term.

In its reply submission, NOTL Hydro stated that a key way to evaluate the OM&A budget in the test year is to look at the most recent actual expenditures. NOTL Hydro submitted that applying this approach to the 2018 actual OM&A of $2,838,525 would result in a 2019 OM&A budget very close to the as-filed budget. NOTL Hydro submitted that the OEB approve the as-filed 2019 OM&A budget forecast and it will support continued safe, reliable and responsive service to NOTL Hydro's customers.

Findings

The objective of the OEB's approval of a distribution utility's cost of service application is to provide it with sufficient revenue to safely, reliably, and efficiently operate the utility. The approval of the OM&A budget is a significant component of the regulatory exercise which is intended to achieve both the recognition of prudent proposed expenditures and encourage continuous improvement in utility performance.

NOTL Hydro, OEB staff and intervenors have made submissions as to relevant aspects of NOTL Hydro's performance that support their position as to the quantum of the OM&A budget that should be approved. While the various measurements of performance have been examined, the OEB has not approached the setting of this budget with a view to rewarding NOTL Hydro's past performance achievements as claimed by the applicant, or remedying a perceived decline in performance, as argued by OEB staff and intervenors.

The fixing of the OM&A budget, however, is assisted by reference to accepted parameters measuring sources of cost increases to utility expenses including inflation and customer growth. The development of a guide in the form of an envelope approach to the budget helps provide a yardstick that avoids micromanagement of the regulated utility and helps the regulator cope with any asymmetries of information that can be present. In this application, the OEB has determined to use this guide to assist in evaluating the reasonableness of the NOTL Hydro's request for a 38% increase in OM&A.

In doing so, the OEB has used the 2014 OEB approved OM&A budget and applied escalators including inflation, minus NOTL Hydro's cohort stretch factors ,as well as customer growth factors multiplied by the recommended PEG elasticity factor. The resulting calculations are set out in Table 2 below:

Table 2: 2019 OM&A Budget based on Escalators

	2014 OEB Approved	2014	2015	2016	2017	2018	2019
		ACTUAL					Forecast
Total OM&A	2,155,262						
Customer Growth %		0.62%	3.36%	3.13%	2.02%	1.55%	1.93%
Escalators							
Inflation		0.00%	1.60%	2.10%	1.90%	1.20%	1.70%
Stretch Factor		0.00%	0.30%	0.30%	0.30%	0.30%	0.30%
Customer Growth (Growth x PEG Elasticity of 0.4485)		0.28%	1.51%	1.40%	0.91%	0.70%	0.87%
Total Escalator		**0.28%**	**2.81%**	**3.20%**	**2.51%**	**1.60%**	**2.27%**
Adjusted OM&A - Based on Escalators	**2,155,262**	**2,161,224**	**2,221,889**	**2,293,029**	**2,350,478**	**2,388,019**	**2,442,148**

NOTL Hydro submitted that, for this purpose, any base 2014 OM&A amount should include the cost of capitalized employees by adding $130,784 to the 2014 OEB-approved figure. The OEB declines to depart from the actual OM&A approved number that helped fashion 2014 rates for the purpose of calculating the base amount that must be escalated to derive a final figure.

NOTL Hydro also suggested additional load and peak growth factors as escalators to the 2014 OEB-approved OM&A. However, there is no indication that any increases caused by these factors would not be captured in whole or in part by the customer growth factor.

This envelope must then be adjusted to recognize expenditures that are not simply improvements, updates, or changes to operations driven by management operational decisions or directions. It is expected that the escalation factors noted above should accommodate the costs of such changes. However, there are expenditures in NOTL

Hydro's 2019 budget that recognize new requirements that must be met by the utility that have arisen since 2014. These include new responsibilities as follows:

Cyber Security	$30,000
OEB charges	$9,540
Survey	$13,988
Locates	$36,566
Pole Rental	$8,341
Total	**$98,435**

In addition to these items, the effect of the above noted accounting change of $130,784 should be included in the 2019 OM&A approved amount.

The resulting OM&A envelope for 2019 would project to $2,671,367 comprehending an increase of $516,105 (24%) over the 2014 OEB-approved amount. The OEB finds this amount to be reasonable.

3.3 Cost of Long-term Debt

Background

NOTL Hydro's proposed long-term debt consists of five debt instruments, two from third parties (CIBC and Infrastructure Ontario) and three from the Town. NOTL Hydro's overall proposed rate for long-term debt for 2019 is 3.95%.

The outstanding issues relate to NOTL Hydro's long-term debt regarding the three debt instruments from the Town (two demand loans and a promissory note).

The promissory note with the Town was originally issued in 2000 with an actual interest rate of 7.25%. In 2018, the note was renewed for an additional ten years for the same interest rate. For rate-making purposes, NOTL Hydro has used the 2019 deemed long-term debt rate of 4.13% for the cost of this promissory note. SEC opposed the use of the deemed debt interest rate for the promissory note. SEC proposed that the interest rate should be reduced from 4.13% to 3.48%, which is the rate obtained from a Schedule A bank in December 2018 when NOTL Hydro was finding out the rates for the purpose of the two Town loans. SEC submitted that it is not reasonable for NOTL Hydro to not undertake the due diligence to renew the promissory note. VECC did not comment on the promissory note in its submission. OEB staff submitted that NOTL

Hydro's use of 2019 deemed long-term debt rate for the promissory note with the Town is appropriate.

NOTL Hydro updated the interest rates on two Town loans from 3% to 3.5% after the settlement conference. SEC submitted that it has two major concerns regarding the updated interest rate of 3.5% for the two Town loans as below:

- First, if the OEB accepts both the new rate and effective date, for ratemaking purposes the debt rates built into the test year should not be the 3.5%, but a lower amount reflecting the pro-rated portion of the test year in which the new higher rate is expected to be in place.
- Second, there is no reason that NOTL Hydro should acquiesce to a March 1st effective date. The two loans require a minimum of 90 and 45 day notice respectively. As of the filing of the supplementary interrogatories on January 30th, legal notice had not been given.

VECC took the timing of the update as an issue and stated that the OEB should not make the proposed adjustment until signed loan agreements are proffered. OEB staff submitted that the updated interest rate on the two Town loans is appropriate given the due diligence conducted by NOTL Hydro.

In its reply submission, NOTL Hydro provided a link to the Town council meeting minutes to show that on March 4, 2019, the Town approved proceeding with the new demand loans with an interest rate of 3.5%, effective as of March 1, 2019. NOTL Hydro stated that the Town had provided a notice in a letter on December 19, 2018 regarding the recall for the two Town loans. NOTL Hydro submitted that it does not agree with SEC that the updated rates associated with the demand loans should be pro-rated to reflect only the period when the new rates should be in effect during the 2019 calendar year. However, it stated, that if the OEB were to choose to take this approach, then the proper way is to treat the new rates as being in place for 9 of 12 months, meaning that the effective rate associated with the demand loans is 3.375% (equal to (3%*3 months plus 3.5%*9 months, divided by 12).

The agenda and minutes of the town council of March 11, 2018 available on the website referenced by NOTL Hydro in its reply argument shows that the new loan agreements were approved by the Town council on March 11, 2019, to be effective April 1, 2019.

Findings

The OEB approves the use of the OEB 2019 deemed long term debt rate of 4.19% for the cost of the long term debt associated with the promissory note.

The OEB agrees with the SEC submission that the new interest rates for the loans approved on March 11, 2019 by the Town should be prorated for the purpose of the calculation of the debt rates for the test year. This means that new interest rates on the loans effective on April 1, 2019 will be recognized for a nine month period of the test year. The OEB approves the new interest rates applicable to the two loans as of that date for inclusion in the NOTL Hydro's cost of debt.

SEC has referenced the notice period of 45 days and 90 days provided in the old loan agreements that was required to be given by the town in order to call (i.e. demand payment of) the loans. This was not done by the Town. As of January 30, 2019, as set out in the response to SEC Supp-47, the Town had not called the loans. Instead, the Town and NOTL Hydro embarked on a renegotiation process that culminated in the approval of new loan agreements referenced above.

SEC raises the issue whether it was prudent, and in keeping with its obligation to its ratepayers for NOTL Hydro to agree to new loan interest terms with the town when there was no call on the loans, and thus no urgency to have the new interest rates commence on a date when repayment was not contractually necessary.

The OEB notes that the new loan agreements with the Town continue to have benefit for NOTL Hydro because of the absence of restrictive covenants that might limit the utility's financial flexibility. In addition, NOTL Hydro believed that, if renegotiation was required by the utility, the town might be easier to deal with than another lender. While the appearance of fair dealing between shareholder and the utility is usually best preserved through observance of the provisions of formal arrangements between the parties, the renegotiation of the existing loans without a formal call for payment, was not imprudent on the part of NOTL Hydro. As well, the new interest rates are less than the OEB deemed long-term debt rate. The new loan agreements with the Town are approved for the purpose of the calculation of NOTL Hydro's cost of capital subject to the pro-rating of the new interest rate in the test year as set out previously.

3.4 Cost Allocation – Inclusion/Exclusion of ICM Revenues in the Distribution Revenue

Background

NOTL Hydro proposed to include ICM revenue in its determination of revenue at existing rates for the purpose of cost allocation and the resulting revenue to cost ratios. NOTL Hydro stated that it did so because the project associated with the ICM will be included in 2019 base rates and this approach is a fair way to assess rate impacts derived from its updated revenue requirement.

SEC and OEB staff did not support NOTL Hydro's proposed approach of including the ICM revenue in the existing distribution revenues for the cost allocation. Both SEC and OEB staff acknowledged that NOTL Hydro's approach is a reasonable approach, however, the proposed approach is not consistent with the OEB's existing practice. SEC and OEB staff referenced a number of the OEB's previous decisions[6] to support that the calculation of revenue at existing rates only including the previously approved base distribution rates. SEC submitted that NOTL Hydro's proposed approach reduces the bill impacts for residential customers at the expense of other classes of customers. OEB staff noted that an ICM is analogous to the smart meter funding adder, where smart meter funding adder revenue was not included as part of distribution revenue in determination of revenue to cost ratios, and it would be appropriate to apply the same treatment to ICMs.

VECC supported NOTL Hydro's proposed approach. VECC stated that the proposed approach is reasonable because the ICM is a mechanism similar to the capital expenditures in a cost of service rate application and it is logical to include the ICM revenues since customers are currently paying the ICM rate riders as part of the cost of their distribution service.

NOTL Hydro submitted, in its reply submission, that consistency with treatment of ICMs in OEB's previous applications is not a sufficient reason to deny NOTL Hydro's

[6] OEB Staff referenced to the OEB's decisions for Innpower Corporation's 2017 rates EB-2016-0085, Wellington North Power's 2016 rates EB-2015-0110, Alectra Utilities – Powerstream rate zone's 2016 rates EB-2015-0003, Festival Hydro's 2015 rates EB-2014-0073, Oakville Hydro's 2014 rates EB-2013-0159 and Hydro Hawkesbury's 2014 rates EB-2013-0139. SEC also referenced to three additional OEB's decisions: Toronto Hydro's 2015 rates EB-2014-0116, Centre Wellington Hydro's 2013 rates EB-2012-0113 and Kingston Hydro's 2016 rates EB-2015-0083.

proposal. It also stated that NOTL Hydro is not unduly favoring one customer class over another.

Findings

The OEB approves the incorporation of ICM revenues into existing distribution revenues for cost allocation purposes. The OEB notes that this has not been the practice to date, but accords with the reality that ICM revenues form part of the development of rates based on capital spending requirements. As such, these revenues emanate from a process that is similar to the OEB approval of such expenditures upon rebasing. The difference is simply that such spending arises within the Incentive Rate Mechanism (IRM) period. The ICM revenues should thus be considered part of the utility's revenue requirement and incorporated into the cost allocation model.

3.5 DVAs and LRAMVA – Disposition Period

Background

NOTL Hydro stated, in its argument-in-chief, that due to an error outside its control, the impact of the DVA rate riders communicated to NOTL Hydro's customers at the open house was incorrectly stated to be negligible, when in fact it has a significant impact. As a result, NOTL Hydro proposed the disposition of the Group 2 DVAs and LRAMVA over a two-year period instead of a one-year period in order to reduce the bill impacts. In addition, NOTL Hydro submitted that both the Group 2 DVAs (mainly Account 1508 Deferred IFRS costs and Accounts 1518 and 1548 Retail Settlement Variance Accounts) and the LRAMVA were aggregated over multiple years so there should be no inherent requirement to have them repaid in one year rather than over two or more years.

SEC and VECC did not support the proposed two-year disposition period. Both parties stated that there is no need to mitigate or smooth the bills when the NOTL Hydro's proposed bill impact is less than 10%, and the 10% is usually the threshold that the OEB uses for a bill mitigation. SEC submitted that the OEB should reject NOTL Hydro's proposal, unless NOTL Hydro is willing to forego the collection of interest on the additional year's balance. VECC understood that the one-year disposition period is a strict criteria set by the OEB and submitted that there is no reason for NOTL Hydro to depart from the one-year default recovery period for the Group 2 DVAs and LRAMVA balances. However, VECC acknowledged that the two-year recovery period does have merit from a rate smoothing perspective.

OEB staff supported the two-year disposition period and submitted that NOTL Hydro has provided adequate explanation for the two-year disposition request, especially given that NOTL Hydro communicated negligible bill impacts from the rate riders to its customers in the open houses.

NOTL Hydro, in its reply submission, stated that the proposed approach is in the interests of ratepayers, and proposed to forego the additional $5,000 interest on the additional year of recovery.

Findings

The OEB approves the clearance of Group 2 DVAs and the LRAMVA over two years with a reduction of $5,000 to the principal balance being recovered to reflect the difference in interest costs.

3.6 Transmission Gross Load Billing

Background

NOTL Hydro is seeking the OEB's approval to have the Retail Transmission Rate – Line and Transformation Connection Service Rates for LDG, with a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation, applied on a gross load billing basis. This is consistent with how the Independent Electricity System Operator (IESO) bills NOTL Hydro for Line Connection and Transformation Connection Services as Hydro One applies gross loading billing on such terms. NOTL Hydro proposed to use the same wording as is used in the 2019 tariffs and rates for Entegrus Powerlines Inc. (Entegrus).[7]

SEC submitted that it is unsure what the OEB's expectation is at this time for distributors applying for gross load billing. However, it acknowledged that the proposed approach has merit. VECC submitted that NOTL Hydro's proposal to use gross load billing should be accepted by the OEB subject to some suggested wording changes. VECC stated that it is appropriate for NOTL Hydro to establish its billing determinants

[7] EB-2018-0024

for Line and Transformation Connection Services using the same approach as the IESO uses for billing these services to NOTL Hydro.

OEB staff submitted that the wording in Entegrus' tariffs is not adequate to support the same wording in NOTL Hydro's tariff without further considerations. OEB staff submitted that NOTL Hydro should follow a more recent OEB decision[8] for Enwin Utilities (Enwin)' 2018 rates which stated that the OEB may review this matter further on a generic basis and provide information in due course.

NOTL Hydro, in its reply submission, stated that the OEB's plan to review the matter on a generic basis is not adequate reason to refrain from approving NOTL Hydro's proposal in this proceeding. NOTL Hydro submitted that it is not appropriate for the other customers to pay costs caused by a Large Use customer class where such costs can be directed to the Large Use class. The fact that NOTL Hydro has not applied this transmission gross load billing before now is because there has been no customer causing upstream gross load billing costs. NOTL Hydro submitted that approving its current proposal will not impair the OEB's ability to look at the question of transmission gross load billing on a generic basis at a later time. If the OEB directs an approach that is different from what is in place for NOTL Hydro, it can implement that different approach at that time.

Findings

The OEB approves NOTL Hydro's proposed transmission charge for the Large Use rate class. In doing so the OEB notes the following:

1. All parties did not object to the proposal on the basis of accepted principles of cost allocation and rate design.
2. The proposal prevents a potential subsidy to the NOTL Hydro's Large Use customer that will be solely served by a proposed combined heat power plant to be installed by this customer. Hydro One's practice of "gross load billing" will otherwise fail to recognize that only one customer will benefit from the generation from the plant. This same result might obtain for future LDG customers without adoption of the proposed transmission charge.

[8] EB-2017-0037

3. The NOTL Hydro's proposal is consistent with the billing for Line and Connection and Transformation Services by the IESO.

4. The proposal was developed by NOTL Hydro in consultation with the Large Use customer that will be served by the above-noted plant.

OEB staff have submitted that the issue of the proposed transmission charge should be governed by the determination of the OEB in the recent Enwin decision.[9] In that decision, the OEB declined to approve Enwin's proposed change of approach to its current determination of transmission gross load billing, suggesting that the OEB may review this matter in a generic proceeding.

The OEB notes that the Enwin decision arose in the context of an IRM application. IRM applications are designed to be mechanistic and provide relief through the application of a regulatory framework that has already been established in a preceding rate rebasing. In this application, NOTL Hydro is seeking relief in its 2019 cost of service application. In such application, the setting of rates must be determined on the basis of the reasonableness of the incurrence of utility expenses and the correct allocation of those expenses in rates. Consistency across utilities in the approach to rate design is a desirable goal, but the OEB agrees with NOTL Hydro that approval of its proposal should not impair OEB consideration of this issue on a generic basis in the future, if the regulator chooses to do so.

The OEB agrees with VECC's submission that the definition of "renewable energy" for the purpose of the NOTL proposed transmission charge should be the same as that used in the 2019 Uniform Transmission Rates (UTR) and that gross load billing be applicable only to generation capacity installed after October 30, 1998, consistent with the UTR.

[9] EB-2017-0037

4 IMPLEMENTATION

NOTL Hydro shall include the cost consequences of the partial settlement proposal, updated to incorporate the findings in this Decision and Order on the unsettled issues, in its calculation of its revenue requirement for recovery from customers.

The OEB expects NOTL Hydro to file detailed supporting material showing the impact of this Decision and Order on the overall revenue requirement, the allocation of revenues between classes and the derivation of base rates.

SEC and VECC are eligible for cost awards in this proceeding. The OEB has made provision in this Decision and Order for these intervenors to file their cost claims. The OEB will issue its cost awards decision after the following steps are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. NOTL Hydro Inc. shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision and Order, no later than April 18, 2019. NOTL Hydro Inc. shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.
2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to NOTL Hydro Inc., no later than April 25, 2019.
3. NOTL Hydro Inc. shall file with the OEB and forward to intervenors, responses to any comments on its draft Rate Order no later than May 2, 2019.
4. Intervenors shall submit their cost claims no later than April 25, 2019.
5. NOTL Hydro Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs May 2, 2019.
6. Intervenors shall file with the OEB and forward to NOTL Hydro Inc. any responses to any objections for cost claims no later than May 9, 2019.
7. NOTL Hydro Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, EB-2018-0056, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a USB memory stick in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Registrar at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Tina Li at Tina.Li@oeb.ca and OEB Counsel, Ljuba Djurdjevic at Ljuba.Djurdjevic@oeb.ca.

ADDRESS

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

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto April 11, 2019

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

SETTLEMENT PROPOSAL

FILED ON JANUARY 10, 2019

DECISION AND ORDER

NIAGARA-ON-THE-LAKE HYDRO INC.

EB-2018-0056

APRIL 11, 2019

SETTLEMENT PROPOSAL

Niagara-on-the-Lake Hydro Inc.

2019 Cost of Service Distribution Rates Proceeding

January 10, 2019

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Appendices

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the “OEB” or the “Board") in connection with the Application of Niagara-on-the-Lake Hydro Inc. (NOTL Hydro), for an order or orders approving changes to the distribution rates that NOTL Hydro charges for electricity distribution and other charges to be effective May 1, 2019.

On September 7, 2018, the OEB issued its Notice of Application in this proceeding. In Procedural Order No. 1, dated October 10, 2018, the Board established the process to address the application, up to and including a Settlement Conference and presentation of any Settlement Proposal.

A Settlement Conference was held on December 10 and 11, 2018, and discussions continued after that time. Karen Wianecki acted as facilitator for the Settlement Conference. This Settlement Proposal arises from the Settlement Conference.

NOTL Hydro and the following intervenors, as well as Ontario Energy Board technical staff (OEB Staff), participated in the Settlement Conference:

School Energy Coalition (SEC)
Vulnerable Energy Consumers Coalition (VECC)

The intervenors listed above participated in the Settlement Conference and subsequent discussions. Any reference to “the Parties” in this Settlement Proposal is intended to refer to NOTL Hydro and the intervenors listed above.

OEB Staff is not a Party to the Settlement Proposal. Although it is not a Party to the Settlement Proposal, once the Settlement Proposal is filed, OEB Staff will file a submission commenting on two aspects of the settlement: whether the settlement represents an acceptable outcome from a public interest perspective, and whether the accompanying explanation and rationale is adequate to support the settlement. Also, as noted in the Practice Direction on Settlement Conferences, OEB Staff who participated in the Settlement Conference are bound by the same confidentiality and privilege rules that apply to the Parties to the proceeding.

All items in NOTL Hydro’s Application and pre-filed evidence were addressed by the Parties during the Settlement Conference. These matters have been considered under the topic headings included in this Settlement Proposal. These topic headings address the key items required for NOTL Hydro’s 2019 rates to be approved, and include all items set out in the Board-approved Issues List in this proceeding (see Appendix “A” for the OEB approved list of issues and sub-issues, as well as a Table of Concordance showing where each of the issues on the Issues List is addressed in this Settlement Proposal). As set out herein, the Parties have reached complete agreement on all but six items in this Application (the Settled Items). The remaining six items have not been resolved, and the

Parties propose that each of them be determined by the Board (the "Unsettled Items). No other issues or proposals were addressed by the Parties during the Settlement Conference or are addressed in this Settlement Proposal.

Where in this Settlement Proposal, the Parties "accept" the evidence of NOTL Hydro, or the Parties "agree" to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and is binding and enforceable in accordance with its terms. As set forth below, this Settlement Proposal is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act*, *1998*, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

Best efforts have been made to identify all of the evidence that relates to each Settled Item. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The supporting evidence for each Settled Item is identified individually by reference to its exhibit or interrogatory number in an abbreviated format.

The evidence in support of the Settlement Proposal also includes the Appendices to this document. The Parties acknowledge that the Appendices were prepared by NOTL Hydro. While the intervenors have reviewed the Appendices, the intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

The Settlement Proposal describes the agreements reached on the Settled Items. The Settlement Proposal provides a direct link between each Settled Item and the supporting evidence in the record to date and/or the additional evidence attached to hereto. In this regard, the Parties are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the Settled Items and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the Settled Items.

None of the Parties can withdraw from the Settlement Proposal except in accordance with Rule 30 of the *Ontario Energy Board Rules of Practice and Procedure*. Further, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions Parties might take with respect to the same issue in future proceedings, whether for NOTL Hydro or other applicants.

The Parties acknowledge that all data, documents or information provided and any discussions, including negotiations, admissions, concessions, offers and counter-offers occurring during the course of the Settlement Conference (settlement information), including subsequent related discussions, are privileged and confidential and without prejudice in accordance with (and subject to the exceptions set out in) the Board's *Practice Direction on Settlement Conferences* (see pages 5-6 of the OEB's *Practice Direction on Settlement Conferences*, as revised October 28, 2016).

It is fundamental to the agreement of the Parties that none of the provisions of this Settlement Proposal are severable. If the Board does not accept the provisions of the Settlement Proposal in their entirety, there is no Settlement Proposal (unless the Parties agree that any portion of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the OEB.

OVERVIEW

The Parties are pleased to advise the OEB that they have reached an agreement with respect to most issues in this proceeding (the Settled Items). This agreement on the Settled Items is subject to any updates that will be required to reflect and implement the Board's decisions on the Unsettled Items (which are described below).

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2019 rates, incorporation of all applicable laws and the Approved Issues List (found at Appendix "A"). If accepted, this Settlement Proposal will support approval of most aspects of NOTL Hydro May 1, 2019 rates – final rates will be prepared after the Unsettled Items are determined.

A summary of the changes in NOTL Hydro's revenue requirement resulting from answers to Interrogatories (as summarized in response to Staff Interrogatory #1) and from this Settlement Proposal as compared to NOTL Hydro's filing is provided in Table 1 below.

The outstanding items (the Unsettled Items) are the following:

(i) Rate Base and capital expenditures, specifically the underground conversion program/projects (replacing older overhead distribution lines with a higher voltage underground system);

(ii) OM&A cost forecast of $2,964,765 for the Test Year;

(iii) the cost of NOTL Hydro's long-term debt;

(iv) Cost Allocation and Rate Design, specifically, the proposal to include previous ICM rate rider in revenue at current rates for the purposes of determining the appropriate R/C ratios, which have an impact on rate design;

(v) whether NOTL Hydro's proposal for gross load billing should be approved; and

(vi) disposition period of agreed upon Group 2 deferral and variance account balances.

NOTL plans to file updated evidence on a number of unsettled issues, and the Parties agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on that evidence. As a result, the Parties agree that the Board should defer any request for submissions and/or consideration of which unsettled issues should be heard in writing, and for which issues the OEB should hold an oral hearing, until responses to those interrogatories have been provided.

Table 1. Summary of Changes in Revenue Requirement

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 1,771,030	5.77%	$ 30,698,011	$ 28,964,816	$ 2,172,361	$ 1,157,365	$ 109,828	$ 2,974,186	$ 6,047,363	$ 502,939	$ 5,544,424	$ 50,401
3-STAFF-36	Updated Load Forecast tab 10.1 to reflect CDM impact of 3,770,854 consistent with tab 10	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 502,939	$ 5,544,138	$ 53,904
	Change	-$ 233	0.00%	-$ 4,046	-$ 53,952	-$ 4,046	$ -	-$ 53	$ -	-$ 286	$ -	-$ 286	$ 3,503
2-STAFF-23	Updated Other Revenue for the assumption of 100 Bell Canada poles 100 x $43.63	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 507,302	$ 5,539,775	$ 49,541
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,363	-$ 4,363	-$ 4,363
2-STAFF-46	Updated Other Revenue to reconcile Share Services mark-up in Appendix 2-N to Other Revenue Appendix 2-H	$ 1,770,796	5.77%	$ 30,693,964	$ 28,910,864	$ 2,168,315	$ 1,157,365	$ 109,775	$ 2,974,186	$ 6,047,077	$ 507,793	$ 5,539,284	$ 49,050
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 491	-$ 491	-$ 491
2-STAFF-23	Updated Pole Attachment expense (account 5095) to reflect assumption of 100 Bell Canada poles 100 x $43.63	$ 1,770,777	5.77%	$ 30,693,637	$ 28,906,501	$ 2,167,988	$ 1,157,365	$ 109,771	$ 2,969,823	$ 6,042,691	$ 507,793	$ 5,534,898	$ 44,664
	Change	-$ 19	0.00%	-$ 327	-$ 4,363	-$ 327	$ -	-$ 4	-$ 4,363	-$ 4,386	$ -	-$ 4,386	-$ 4,386
4-STAFF-47	Reduced Intervenor cost estimate from $75,000 to $50,000 based on 2 intervenors in this case vs. an estimate of 3 in the original submission	$ 1,770,756	5.77%	$ 30,693,262	$ 28,901,501	$ 2,167,613	$ 1,157,365	$ 109,766	$ 2,964,823	$ 6,037,664	$ 507,793	$ 5,529,872	$ 39,638
	Change	-$ 22	0.00%	-$ 375	-$ 5,000	-$ 375	$ -	-$ 5	-$ 5,000	-$ 5,027	$ -	-$ 5,027	-$ 5,027
Updated Information	Moved the disposal of the T1 transformer fron 2019 test year to 2018 bridge year	$ 1,764,473	5.77%	$ 30,584,366	$ 28,901,501	$ 2,167,613	$ 1,150,110	$ 100,905	$ 2,964,823	$ 6,015,265	$ 507,793	$ 5,507,473	$ 17,239
	Change	-$ 6,282	0.00%	-$ 108,896	$ -	$ -	-$ 7,255	-$ 8,861	$ -	-$ 22,399	$ -	-$ 22,399	-$ 22,399
2-STAFF-13 2-VECC-14	Updated Appendix 2-BA to include actual disposals year to date and forecast disposals for the remainder of the year	$ 1,762,622	5.77%	$ 30,552,276	$ 28,901,501	$ 2,167,613	$ 1,146,311	$ 99,119	$ 2,964,823	$ 6,007,829	$ 507,793	$ 5,500,037	$ 9,803
	Change	-$ 1,851	0.00%	-$ 32,090	$ -	$ -	-$ 3,799	-$ 1,786	$ -	-$ 7,436	$ -	-$ 7,436	-$ 7,436
Updated Information	Updated Leap amount based on revised Service Revenue Requirement	$ 1,762,622	5.77%	$ 30,552,272	$ 28,901,444	$ 2,167,608	$ 1,146,311	$ 99,119	$ 2,964,765	$ 6,007,771	$ 507,793	$ 5,499,979	$ 9,745
	Change	-$ 0	0.00%	-$ 4	-$ 58	-$ 4	$ -	-$ 0	-$ 58	-$ 58	$ -	-$ 58	-$ 58
4-STAFF-49	Updated PILs model to move Building & Fixture additions from CCA class 47 (8%) to CCA class 1b (6%)	$ 1,762,622	5.77%	$ 30,552,272	$ 28,901,444	$ 2,167,608	$ 1,146,311	$ 99,553	$ 2,964,765	$ 6,008,205	$ 507,793	$ 5,500,413	$ 10,178
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ 434	$ -	$ 434	$ -	$ 434	$ 434
Settlement Proposal	Update 2018 capital spend to mosre recent capital forecast for 2018	$ 1,761,984	5.77%	$ 30,541,220	$ 28,901,444	$ 2,167,608	$ 1,128,766	$ 96,495	$ 2,964,765	$ 5,986,964	$ 499,484	$ 5,487,480	-$ 2,754
	Change	-$ 638	0.00%	-$ 11,051	$ -	$ -	-$ 17,545	-$ 3,058	$ -	-$ 21,241	-$ 8,309	-$ 12,932	-$ 12,932
Settlement Proposal	Add 2 GS<50 customers to the 2019 customer count	$ 1,762,015	5.77%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 96,502	$ 2,964,765	$ 5,987,003	$ 499,496	$ 5,487,507	-$ 5,449
	Change	$ 31	0.00%	$ 541	$ 7,208	$ 541	$ -	$ 7	$ -	$ 38	$ 12	$ 26	-$ 2,696
Settlement Proposal	Update OEB Cost of Capital Parameters to 2019 values	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 499,496	$ 5,488,947	-$ 4,009
	Change	$ 2,321	0.01%	$ -	$ -	$ -	$ -	-$ 881	$ -	$ 1,440	$ -	$ 1,440	$ 1,440
Settlement Proposal	Update Retail Service Charges EB-2015-0304	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 506,635	$ 5,481,808	-$ 11,148
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,139	-$ 7,139	-$ 7,139
Settlement Proposal	Remove collection of account changes	$ 1,764,336	5.78%	$ 30,541,761	$ 28,908,652	$ 2,168,149	$ 1,128,766	$ 95,621	$ 2,964,765	$ 5,988,443	$ 482,447	$ 5,505,995	$ 13,039
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 24,188	$ 24,188	$ 24,188
Settlement Proposal	Reduce loss factor for Large Use Customer from 1.0373 to 1.0045	$ 1,764,252	5.78%	$ 30,540,302	$ 28,889,192	$ 2,166,689	$ 1,128,766	$ 95,602	$ 2,964,765	$ 5,988,340	$ 482,447	$ 5,505,892	$ 12,936
	Change	-$ 84	0.00%	-$ 1,460	-$ 19,460	-$ 1,460	$ -	-$ 19	$ -	-$ 103	$ -	-$ 103	-$ 103
Settlement Proposal	Update interest rate on 2015 loans from the Town from 3.0% to 3.5%	$ 1,807,009	5.92%	$ 30,540,302	$ 28,889,192	$ 2,166,689	$ 1,128,766	$ 95,602	$ 2,964,765	$ 6,031,096	$ 482,447	$ 5,548,649	$ 55,693
	Change	$ 42,756	0.14%	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,756	$ -	$ 42,756	$ 42,756
Settlement Proposal	Add an additional 2 GS<50 customers to the 2019 customer count	$ 1,807,040	5.92%	$ 30,540,840	$ 28,896,373	$ 2,167,228	$ 1,128,766	$ 95,609	$ 2,964,765	$ 6,031,135	$ 482,447	$ 5,548,687	$ 54,901
	Change	$ 32	0.00%	$ 539	$ 7,182	$ 539	$ -	$ 7	$ -	$ 39	$ -	$ 39	-$ 791

NOTL Hydro has prepared the Appendices and Tables to this Settlement Proposal on the following basis: (a) any updates to NOTL Hydro's filing arising from the answers to interrogatories have been reflected in the relevant materials; (b) all impacts from the Settlement Proposal have been reflected in the relevant materials; and (c) the Unsettled Items have been reflected on an as-filed basis (including the impact of updated evidence related to the cost of long-term debt and the proposal to clear the LRAMVA and Group 2 Accounts over two years). The updated RRWF is provided at Appendix "B".

The proposed Bill Impacts that will result from this Settlement Proposal are set out Appendix "E".

Proposed tariffs are included in Appendix "E". The Total Revenue and Base Revenue Requirement agreed to as part of this Settlement Proposal for the Test Year are $6,031,135 and $5,548,687 respectively. This translates into a Grossed-up Revenue Deficiency of $54,901.

Details of the settlement on the Settled Items, along with a description of the Unsettled Items, are set out in the balance of this document.

THE SETTLED AND UNSETTLED ITEMS

1. <u>Rate Base</u> - Is the rate base element of the revenue requirement reasonable and has it been appropriately determined in accordance with OEB policies and practices?

With the exception of the unsettled issue described below, the parties are in agreement that the 2019 Base of $30,540,840, which has been updated to take account of NOTL Hydro's most recent capital expenditure forecast for 2018, is reasonable.

The unsettled issue related to the prudence of NOTL Hydro's underground conversion project/program since its last rebasing (impacting opening 2019 Opening Rate Base) and its proposed test year expenditures for underground conversion program, described in section 2 (impacting 2019 net additions and Closing Rate Base).

The Parties agree that NOTL Hydro will file updated evidence on the issue of the prudence of its underground conversion project/program spending. The Parties further agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on any updated evidence on this unsettled issue.

Working Capital, as part of this calculation, been updated to reflect:

a) the revised customer forecast forming part of this Settlement Proposal (see Item 5); and

b) the impact on Cost of Power resulting from the update to the loss factors applicable to the Large User rate (see Item 8).

The Parties accept the evidence of NOTL Hydro that the rate base calculations, after making the adjustment to the working capital and the in-service additions for 2019, as detailed in this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 4 below outlines NOTL Hydro's Rate Base calculation. An updated fixed asset continuity schedule has been included in Appendix "B" as well as a live version being filed on RESS.

Table 2. – Summary of Cost of Power

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Electricity Projections	$23,015,166	($47,890)	$22,967,276	($3,672)	$22,963,605
Wholesale Market Service	$832,836	($1,783)	$831,053	($2,274)	$828,779
Transmission Network	$1,521,236	($3,214)	$1,518,022	$826	$1,518,848
Transmission Connection	$451,219	($916)	$450,303	$212	$450,515
Rural Rate Assistance	$69,403	($149)	$69,254	($189)	$69,065
IESO Smart Meter Entity	$65,815	$ -	$65,815	$27	$65,842
Total Cost of Power	$25,955,675	($53,952)	$25,901,724	($5,070)	$25,896,653

Table 3. – Summary of Working Capital

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Controllable Expenses	$3,009,141	($9,421)	$2,999,720	$ -	$2,999,720
Cost of Power	$25,955,675	($53,952)	$25,901,724	($5,070)	$25,896,653
Working Capital Base	$28,964,816	($63,372)	$28,901,444	($5,070)	$28,896,373
Working Capital Rate %	7.50%	0.00%	7.50%	0.00%	7.50%
Working Capital Allowance	$2,172,361	($4,753)	$2,167,608	($380)	$2,167,228

Subject to the determination of the Unsettled Item related to the underground conversion program (see Item 2, below), the Parties have agreed that the 2019 Test Year capital additions of $5,848,590 are reasonable.

The Parties accept the evidence of NOTL Hydro that the Net Depreciation is correctly determined from the above is $1,128,766. Continuity Schedules are provided at Appendix "B".

Table 4. Summary of Rate Base

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Gross Fixed Assets (average)	$56,132,843	($961,368)	$55,171,475	($20,788)	$55,150,687
Accumulated Depreciation (average)	($27,607,193)	$820,382	($26,786,811)	$9,737	($26,777,075)
Net Fixed Assets (average)	$28,525,650	($140,986)	$28,384,663	($11,051)	$28,373,612
Allowance for Working Capital	$2,172,361	($4,753)	$2,167,608	($380)	$2,167,228
Total Rate Base	$30,698,011	($145,739)	$30,552,272	($11,432)	$30,540,840

Evidence: The evidence in relation to this issue includes the following:

Exhibit 2	Rate Base
I.2.STAFF.10-30	Staff Interrogatories #10-30
I.2.SEC.13-24	SEC Interrogatories #13-24
I.2.VECC 3-14	VECC Interrogatories #3-14
Supplementary Responses	Supplementary Responses to Staff 25 and 27 and VECC 8

2. <u>Distribution System Plan and capital expenditures</u> - Are NOTL Hydro's proposed capital expenditures appropriate and have the trade-offs with the proposed level of Operating Cost been given adequate consideration?

Subject to one Unsettled Item described below, for the purposes of settlement the Parties accept the evidence of NOTL Hydro that the level of planned capital expenditures, as summarized in Table 5 below, and the rationale for planning and pacing choices are appropriate to maintain system reliability, service quality objectives and the reliable and safe operations of the distribution system, is appropriate.

Similar to the unsettled issue discussed in section 2, there no agreement on NOTL Hydro's proposed underground conversion projects in the Olde Towne and Virgil areas of the service territory. The forecast capital cost for these projects in 2019 is $460,000 (see Distribution System Plan, filed at Exhibit 2, at pages 35 and 55 – 58). The Parties agree that all issues about the underground conversion projects should be determined by the Board.

The Parties agree that NOTL Hydro will file updated evidence on the issue of the reasonableness of its proposed underground conversion project/program Test Year expenditures. The Parties further agree that Intervenors and Board Staff be permitted the opportunity to ask interrogatories to file on any updated evidence on this unsettled issue.

The Parties acknowledge that NOTL Hydro retains the full discretion to manage its capital spending in the Test Year and beyond in accordance with the actual operating conditions it experiences in any year.

Table 5. Planned Capital Expenditures

	Initial Application	Interrogatories	Settlement Proposal
System Access	$835,500	$835,500	$835,500
System Renewal	$1,097,000	$1,097,000	$1,097,000
System Service	$3,832,340	$3,832,340	$3,832,340

General Plant	$83,750	$83,750	$83,750
Total Assets	**$5,848,590**	**$5,848,590**	**$5,848,590**

Evidence: The evidence in relation to this issue includes the following:

Exhibit 2	Rate Base
I.2.STAFF.10-30	Staff Interrogatories #10-30
I.2.SEC.13-24	SEC Interrogatories #13-24
I.2.VECC 3-14	VECC Interrogatories #3-14
Supplementary Responses	Supplementary Responses to Staff 25 and 27 and VECC 8

3. Operating Costs

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties agree that the 2019 Test Year operating expenses related to Depreciation/Amortization, Property Taxes and PILs are reasonable. There is no agreement on the forecast OM&A expenses for the 2019 Test Year.

Table 6. Summary of Operating Costs

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
OM+A Expenses	$2,974,186	($9,421)	$2,964,765	$ -	$2,964,765
Depreciation/Amortization	$1,157,365	($11,054)	$1,146,311	($17,545)	$1,128,766
Property taxes	$34,955	$ -	$34,955	$ -	$34,955
Income taxes (grossed up)	$109,828	($10,275)	$99,553	($3,944)	$95,609
Other expense	$ -	$ -	$ -	$ -	$ -
Total Operating Costs	$4,276,333	($30,750)	$4,245,584	($21,489)	$4,224,095

OM&A

NOTL Hydro's 2019 Test Year OM&A forecast is $2,964,765. There is no agreement on this portion of NOTL Hydro's operating costs. The Parties agree that all issues about the OM&A expenses should be determined by the Board.

Depreciation

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept that NOTL Hydro has correctly calculated depreciation. Accounting for NOTL Hydro's most recent capital expenditure forecast for 2018, the depreciation amount is $1,128,766.

Table 7. Summary of Change in Depreciation

		Depreciation Expense				
OEB Class	**OEB Account**	**Initial Application**	**Adjustments**	**Interrogatory Response**	**Adjustments**	**Settlement Proposal**
1611	Computer Software	67,001	-	67,001	876	67,877
1815	Transformer Station Equipment - Normally Primary Above 50kV	190,683	(7,255)	183,428	2,255	185,682
1820	Transformer Station Equipment - Normally Primary Below 50kV	-	-	-	-	-
1825	Storage Battery Equipment	22,117	-	22,117	-	22,117
1830	Poles, Towers & Fixtures	122,877	(2,698)	120,179	(571)	119,608
1835	Overhead Conductors & Devices	91,281	(595)	90,686	2,355	93,041
1840	Underground Conduit	76,029	-	76,029	(819)	75,210
1845	Underground Conductors & Devices	196,571	-	196,571	(4,248)	192,324
1850	Line Transformers	162,827	(506)	162,322	(301)	162,021
1855	Services	107,184	-	107,184	(5,851)	101,333
1860	Meters	149,180	-	149,180	(721)	148,460
1908	Buildings & Fixtures	20,723	-	20,723	(13)	20,710
1915	Office Furniture & Equipment	6,186	-	6,186	-	6,186
1920	Computer Equipment - Hardware	15,074	-	15,074	(1,667)	13,407
1940	Tools, Shop & Garage Equipment	10,979	-	10,979	1,142	12,121
1955	Communications Equipment	336	-	336	-	336
1980	System Supervisor Equipment	45,791	-	45,791	(9,983)	35,809
1995	Contributions & Grants - Credit	(127,476)	-	(127,476)	-	(127,476)
	Total	**1,157,365**	**(11,054)**	**1,146,311**	**(17,545)**	**1,128,766**

Property Taxes and PILs

The Parties accept NOTL Hydro's forecast of property taxes for the Test Year, as set out above in Table 6.

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, Parties accept that NOTL Hydro has correctly calculated PILs in the amount of $95,609.

The live PILs workform has been filed on the Board's website.

Table 8. PILs Summary

Particulars	Initital Application	Interrogatories	Settlement Proposal
Determination of Taxable Income			
Utility net income before taxes	$1,105,128	$1,099,882	$1,097,027
Adjustments required to arrive at taxable utility income	($800,512)	($823,764)	($831,847)
Taxable income	$304,617	$276,118	$265,180
Calculation of Utility income Taxes			
Income taxes	$80,723	$73,171	$70,273
Total taxes	$80,723	$73,171	$70,273
Gross-up of Income Taxes	$29,104	$26,381	$25,336
Grossed-up Income Taxes	$109,828	$99,553	$95,609
PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$109,828	$99,553	$95,609
Other tax Credits	$ -	$ -	$ -
Tax Rates			
Federal tax (%)	15.00%	15.00%	15.00%
Provincial tax (%)	11.50%	11.50%	11.50%
Total tax rate (%)	26.50%	26.50%	26.50%

Evidence: The evidence in relation to this issue includes the following:

Exhibit 4	Operations, Maintenance & Administration
I.4.STAFF.39-54	Staff Interrogatories #39-54
I.2.SEC.27-30	SEC Interrogatories #27-30
I.2.VECC.24-36	VECC Interrogatories #24-36
Supplementary Responses	Supplementary Responses to Staff 42 and VECC 29 and SEC Supplementary 2

4. Cost of Capital

NOTL Hydro's filing uses the OEB approved deemed capital structure of 4% short term debt, 56% long term debt and 40% equity.

The Parties have agreed that the return on equity (ROE) applicable to NOTL Hydro's cost of capital will be updated to the Board's approved rate for 2019 cost of service applications (8.98%). This item is also subject to any updates that are required to reflect the Board's decisions on the Unsettled Items.

The Parties have agreed that the rate for short-term debt will be updated to the Board's approved rate for 2019 cost of service applications (2.82%). This item is also subject to any updates that are required to reflect the Board's decisions on the Unsettled Items.

There is no agreement on NOTL Hydro's cost of long-term debt. The parties agree that all issues related to this item will be determined by the Board.

Concurrently with this filing of this Settlement Proposal NOTL Hydro has indicated to Parties it will be filing updated evidence about its cost of long-term debt, applying: (i) an updated notional rate associated with a promissory note with the Town of NOTL to reflect the Board's approved long-term debt rate for 2019 cost of service applications (4.13%); and (ii) a proposed increased interest rate on two loans from the Town of NOTL from 3.0% to 3.5%.

While there is no agreement on these items, or even on the appropriateness of NOTL Hydro filing the updated evidence, the Settlement Proposal has been updated to reflect the impact of the updated evidence about long-term debt in the tables, appendices and schedules associated with this Settlement Proposal. Table 9 shows the impact of NOTL Hydro's updated evidence about long-term debt, and Table 10 shows the overall updated Cost of Capital

The Parties further agree that it is appropriate that intervenors and Board Staff be permitted the opportunity to ask interrogatories on the updated evidence or to object to the appropriateness of the filing of the updated evidence, in whole or in part.

Table 9 – Long Term Debt

Initial Application								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 87,308.82
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 58,641.19
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 42,912.05
						$ 6,624,865	**3.71%**	**$ 245,474.55**

Interrogatory Responses								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.16%	$ 87,308.82
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.00%	$ 58,641.19
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.00%	$ 42,912.05
						$ 6,624,865	**3.71%**	**$ 245,474.55**

Updated Evidence								
Description	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Calculated Interest ($)**
Original Promissory Note	Town of NOTL	Affiliated	Fixed Rate	1-Jul-00	Open	$ 2,098,770	4.13%	$ 86,679.19
York TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	29-Aug-03	15	$ -	6.03%	$ -
NOTL TS Demand Installment Loan	CIBC	Third-Party	Fixed Rate	27-Oct-05	15	$ 424,320	6.13%	$ 26,010.81
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-11	15	$ 716,667	4.27%	$ 30,601.68
Town loan - transformer	Town of NOTL	Affiliated	Fixed Rate	1-Feb-15	10	$ 1,954,706	3.50%	$ 68,414.72
Town loan - capital projects	Town of NOTL	Affiliated	Fixed Rate	1-Oct-15	10	$ 1,430,402	3.50%	$ 50,064.06
						$ 6,624,865	**3.95%**	**$ 261,770.46**

Table 10 – Cost of Capital, including LT Debt

Particulars	Initial Application Capitalization Ratio		Cost Rate	Return
Debt				
Long-term Debt	56.00%	$17,190,886	3.71%	$637,782
Short-term Debt	4.00%	$1,227,920	2.29%	$28,119
Total Debt	60.00%	$18,418,806	3.62%	$665,901
Equity				
Common Equity	40.00%	$12,279,204	9.00%	$1,105,128
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,279,204	9.00%	$1,105,128
Total	100.00%	$30,698,011	5.77%	$1,771,030

Particulars	Interrogatory Responses Capitalization Ratio		Cost Rate	Return
Debt				
Long-term Debt	56.00%	$17,109,272	3.71%	$634,754
Short-term Debt	4.00%	$1,222,091	2.29%	$27,986
Total Debt	60.00%	$18,331,363	3.62%	$662,740
Equity				
Common Equity	40.00%	$12,220,909	9.00%	$1,099,882
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,220,909	9.00%	$1,099,882
Total	100.00%	$30,552,272	5.77%	$1,762,622

Particulars	Updated Evidence Capitalization Ratio		Cost Rate	Return
Debt				
Long-term Debt	56.00%	$17,102,569	3.95%	$675,551
Short-term Debt	4.00%	$1,221,612	2.82%	$34,449
Total Debt	60.00%	$18,324,181	3.87%	$710,001
Equity				
Common Equity	40.00%	$12,216,121	8.98%	$1,097,008
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,216,121	8.98%	$1,097,008
Total	100.00%	$28,384,663	5.92%	$1,807,009

Evidence: The evidence in relation to this issue includes the following:

Exhibit 5	Cost of Capital
I.5.STAFF.55-56	Staff Interrogatories #55-56
I.5. SEC.31-32	SEC Interrogatories #31-32
I.5.VECC.37	VECC Interrogatory #37
Exhibit 5 Additional Evidence	Additional Evidence re. Cost of Long-Term Debt

5. Load Forecast and Other Revenue

Customer Forecast

The Parties have agreed the 2019 customer count as filed should be increased by 4 GS < 50 kW customers and that with this change it is a reasonable forecast of customer count for use in setting rates. This takes account of additional information provided by NOTL Hydro in response to VECC clarification question #50-part c.

Table 11. Customer Forecast

Class	**Initial Application**	**Settlement Proposal**
Residential	8,152	8,152
GS<50	1,338	1,342
GS>50 (50 to 4999)	131	131
Large Use	1	1
Street Light (connections)	2,187	2,187
Unmetered Scattered Load	26	26

Load Forecast

The Parties have agreed with NOTL Hydro's as-filed load forecast updated for an additional 4 GS<50 kW customers as reflected in Table 11. Table 12 below, provides the agreed 2019 CDM Adjusted Forecast which includes the 2016 and 2017 actual verified results. NOTL Hydro agrees that any future calculations for LRAM or CDM will exclude the impact of the CHP generation unit expected to be operated by the Large Use customer.

Table 12 – CDM Adjusted Load Forecast (kWh) for 2019

Customers or Connections					
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	8,152	0	8,152	0	8,152
GS<50	1,338	0	1,338	4	1,342
GS>50	131	0	131	0	131
Unmetered	26	0	26	0	26
Streetlights	2,187	0	2,187	0	2,187
Large User	1	0	1	0	1
TOTAL	**11,835**	**0**	**11,835**	**4**	**11,839**

Consumption (kWh)					
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	73,998,981	(100,283)	73,898,698	0	73,898,698
GS<50	41,877,513	(139,557)	41,737,956	127,721	41,865,678
GS>50	82,705,771	(237,722)	82,468,049	0	82,468,049
Unmetered	251,508	0	251,508	0	251,508
Streetlights	886,616	0	886,616	0	886,616
Large User	23,308,825	0	23,308,825	0	23,308,825
TOTAL	**223,029,214**	**(477,562)**	**222,551,653**	**127,721**	**222,679,374**

Consumption (kW)

	Actual				
Customer Class Name	**Initial Application**	**Adjustments**	**Interrogatory Responses**	**Adjustments**	**Settlement Proposal**
Residential	0	0	0	0	0
GS<50	0	0	0	0	0
GS>50	212,896	(612)	212,284	0	212,284
Unmetered	0	0	0	0	0
Streetlights	2,475	0	2,475	0	2,475
Large User	60,000	0	60,000	0	60,000
TOTAL	**275,370**	**(612)**	**274,758**	**0**	**274,758**

Table 13 – LRAMVA Thresholds

	2017	2018	2019	Total for 2019
Amount used for CDM threshold for LRAMVA (2019)	3,447,680.00	1,524,390.03	1,045,247.50	6,017,317.53

Other Revenue

The Parties have agreed that Other Revenue as filed is appropriate subject to the following adjustments:

- A reduction in forecast Other Revenue of $24,188 to reflect the expected implementation of the OEB's determination in the Review of Customer Service Rules (EB-2017-0183) that distributors will no longer be permitted to use Collection of Account charges as of May 1, 2019.

- An increase in Retail Service Charges by $7,139 to reflect the expected implementation of the OEB's Energy Retailer Service Charges report (EB-2015-0304).

- Increase in Standard Supply Service – Administrative charge of $12 due an increase of 4 GS<50 customers in the Test Year.

The fourth change relates to the updated capital forecast for 2018 as described in Item 1. The reduction in the estimate for Contributed Capital results in a $8,309 decrease forecast Other Revenue in 2019.

Table 14 below shows NOTL Hydro's updated Other Revenues, as agreed by the parties.

For further discussion of the Service Charges, and the MicroFit Charge, see Item 10, below.

Table 14. Other Revenues and Revenue Offsets

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Proposal
Specific Service Charges	$87,551	$491	$88,042	($24,188)	$63,854
Late Payment Charges	$54,284	$ -	$54,284	$ -	$54,284
Other Distribution Revenue	$310,170	$4,363	$314,533	($1,158)	$313,375
Other Income and Deductions	$50,934	$ -	$50,934	$ -	$50,934
Total Revenue Offsets	$502,939	$4,854	$507,793	($25,345)	$482,447

Change in Other Distribution Revenue	
Retail Service Charges	$7,139
Deferred Revenue	($8,309)
SSS Admin	$12
Total Change	($1,158)

Evidence: The evidence in relation to this issue includes the following:

Exhibit 3	Load and Other Revenue Forecast
I.3.STAFF.31-38	Staff Interrogatories #31-38
I.3.SEC.25-26	SEC Interrogatories #25-26
I.3.VECC.15-23	VECC Interrogatories #15-23
Supplementary Responses	Responses to VECC Supplementary #50 – 54

6. Revenue Sufficiency/Deficiency

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept the evidence of NOTL Hydro that it has calculated the revenue deficiency of $54,901 in accordance with the Board's policies and practices and the agreed elements of the Settlement Proposal discussed herein.

The RRWF is included as Appendix "B" and a live version of the RRWF is on the Board's RESS as part of this Settlement Proposal which incorporates the changes agreed to herein.

Table 15 – Summary of Revenue Sufficiency/Deficiency

Particulars	Initial Application		Interrogatory Responses		Settlement Proposal	
	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$50,401		$10,178		$54,901
Distribution Revenue	$5,494,023	$5,494,023	$5,490,234	$5,490,234	$5,493,786	$5,493,786
Other Operating Revenue Offsets - net	$502,939	$502,939	$507,793	$507,793	$482,447	$482,447
Total Revenue	$5,996,962	$6,047,363	$5,998,027	$6,008,205	$5,976,234	$6,031,135
Operating Expenses	$4,166,506	$4,166,506	$4,146,031	$4,146,031	$4,128,486	$4,128,486
Deemed Interest Expense	$665,901	$665,901	$662,740	$662,740	$710,013	$710,013
Total Cost and Expenses	$4,832,407	$4,832,407	$4,808,771	$4,808,771	$4,838,499	$4,838,499
Utility Income Before Income Taxes	$1,164,555	$1,214,956	$1,189,256	$1,199,434	$1,137,735	$1,192,636
Tax Adjustments to Accounting Income per 2013	($800,512)	($800,512)	($823,764)	($823,764)	($831,847)	($831,847)
Taxable Income	$364,043	$414,445	$365,492	$375,670	$305,887	$360,789
Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax on Taxable Income	$96,471	$109,828	$96,855	$99,553	$81,060	$95,609
Income Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -
Utility Net Income	$1,068,083	$1,105,128	$1,092,401	($5,247)	$1,056,674	$1,146,902
Utility Rate Base	$30,698,011	$30,698,011	$30,552,272	$30,552,272	$30,540,840	$30,540,840
Deemed Equity Portion of Rate Base	$12,279,204	$12,279,204	$12,220,909	$12,220,909	$12,216,336	$12,216,336
Income/(Equity Portion of Rate Base)	8.70%	9.00%	8.94%	-0.04%	8.65%	9.39%
Target Return - Equity on Rate Base	9.00%	9.00%	9.00%	9.00%	8.98%	8.98%
Deficiency/Sufficiency in Return on Equity	-0.30%	0.00%	-0.06%	-9.04%	-0.33%	0.41%
Indicated Rate of Return	5.65%	5.77%	5.74%	2.15%	5.78%	6.08%
Requested Rate of Return on Rate Base	5.77%	5.77%	5.77%	5.77%	5.92%	5.92%
Deficiency/Sufficiency in Rate of Return	-0.12%	0.00%	-0.02%	-3.62%	-0.13%	0.16%
Target Return on Equity	$1,105,128	$1,105,128	$1,099,882	$1,099,882	$1,097,027	$1,097,027
Revenue Deficiency/(Sufficiency	$37,045	$ -	$7,481	($1,105,128)	$40,353	$49,875
Gross Revenue Deficiency/(Sufficiency)	$50,401		$10,178		$54,901	

Evidence: The evidence in relation to this issue includes the following:

Exhibit 6	Revenue Requirement

7. <u>Cost Allocation</u>

Subject to the amendments from NOTL Hydro's filing described below, as well as any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties agree the cost allocation methodology and the allocations reflect OEB policies and are appropriate.

NOTL Hydro's determination of revenue at existing rates for cost allocation purposes includes the impact of the ICM revenue because the project associated with the ICM will be included in 2019 base rates. NOTL Hydro believes that this approach is a fair way to assess rate impacts from its updated revenue requirement. Intervenors are not aware of any other LDC who in its rebasing application after an ICM has applied ICM riders to base rates for the revenue at existing rates calculation. There is no agreement on whether this approach is appropriate. The issue will be determined by the Board. Appendix “H” to this Settlement Proposal shows the impact of including the ICM revenue in distribution revenue at current rates.

NOTL Hydro has agreed to remove the direct allocation to its Large User Customer of the distribution line that will serve its Large User customer and other customers, and instead allocate the costs of that asset to all customers on the same basis as the allocation of costs associated with other like assets. NOTL Hydro has also agreed to update its 4 NCP value for the Large Use Customer as set out in response to VECC clarification question #59.

An updated cost allocation model has been included as Appendix “G” and has been filed on the OEB’s RESS system as part of this Settlement Proposal which incorporates the changes agreed to herein.

Table 16. Summary of Cost Allocation

		1	2	3	6	7	9
	Total	Residential	GS <50	GS >50kW	Large User	Street Light	Unmetered Scattered Load
Distribution Revenue at Existing Rates	$5,492,956	$2,923,268	$1,177,925	$977,428	$124,034	$281,952	$8,350
Miscellaneous Revenue (mi)	$482,447	$304,702	$86,364	$63,375	$10,313	$16,937	$756
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	**$5,975,403**	**$3,227,970**	**$1,264,289**	**$1,040,803**	**$134,347**	**$298,889**	**$9,106**
Factor required to recover deficiency (1 + D)	1.0101						
Distribution Revenue at Status Quo Rates	$5,548,649	$2,952,907	$1,189,868	$987,338	$125,291	$284,810	$8,434
Miscellaneous Revenue (mi)	$482,447	$304,702	$86,364	$63,375	$10,313	$16,937	$756
Total Revenue at Status Quo Rates	**$6,031,096**	**$3,257,609**	**$1,276,232**	**$1,050,713**	**$135,605**	**$301,747**	**$9,190**
Expenses							
Distribution Costs (di)	$931,637	$565,651	$178,720	$123,290	$28,285	$34,341	$1,350
Customer Related Costs (cu)	$862,631	$630,126	$122,984	$81,045	$627	$26,547	$1,301
General and Administration (ad)	$1,205,452	$796,213	$205,208	$140,899	$20,756	$40,609	$1,768
Depreciation and Amortization (dep)	$1,128,766	$633,630	$235,486	$191,020	$37,388	$29,951	$1,290
PILs (INPUT)	$95,602	$50,346	$20,657	$17,708	$4,055	$2,719	$118
Interest	$710,001	$373,903	$153,410	$131,509	$30,111	$20,190	$877
Total Expenses	**$4,934,088**	**$3,049,870**	**$916,465**	**$685,470**	**$121,223**	**$154,356**	**$6,704**
Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	$1,097,008	$577,709	$237,031	$203,192	$46,525	$31,195	$1,356
Revenue Requirement (includes NI)	$6,031,096	$3,627,579	$1,153,496	$888,662	$167,748	$185,551	$8,060
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	$60,395,904	$34,454,054	$12,448,909	$9,572,474	$1,882,192	$1,958,626	$79,649
General Plant - Gross	$7,196,876	$4,038,108	$1,490,532	$1,196,458	$254,026	$208,778	$8,975
Accumulated Depreciation	($26,777,075)	($15,258,743)	($5,568,307)	($4,164,732)	($769,240)	($978,483)	($37,570)
Capital Contribution	($12,442,094)	($8,230,189)	($2,256,303)	($1,382,338)	($176,235)	($381,059)	($15,969)
Total Net Plant	**$28,373,612**	**$15,003,230**	**$6,114,831**	**$5,221,862**	**$1,190,742**	**$807,862**	**$35,085**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$25,889,472	$8,628,863	$4,858,359	$9,566,379	$2,703,848	$102,848	$29,175
OM&A Expenses	$2,999,720	$1,991,991	$506,911	$345,234	$49,669	$101,497	$4,418
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$28,889,192***	***$10,620,853***	***$5,365,270***	***$9,911,613***	***$2,753,517***	***$204,345***	***$33,594***
Working Capital	**$2,166,689**	**$796,564**	**$402,395**	**$743,371**	**$206,514**	**$15,326**	**$2,520**
Total Rate Base	**$30,540,302**	**$15,799,794**	**$6,517,227**	**$5,965,233**	**$1,397,256**	**$823,187**	**$37,604**
	Rate Base Input equals Output						
Equity Component of Rate Base	**$12,216,121**	**$6,319,918**	**$2,606,891**	**$2,386,093**	**$558,902**	**$329,275**	**$15,042**
Net Income on Allocated Assets	**$1,097,008**	**$207,739**	**$359,767**	**$365,243**	**$14,382**	**$147,391**	**$2,486**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$1,097,008**	**$207,739**	**$359,767**	**$365,243**	**$14,382**	**$147,391**	**$2,486**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**89.80%**	**110.64%**	**118.24%**	**80.84%**	**162.62%**	**114.03%**
EXISTING REVENUE MINUS ALLOCATED COSTS	($55,693)	($399,609)	$110,793	$152,141	($33,401)	$113,337	$1,046
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($369,970)	$122,736	$162,051	($32,143)	$116,196	$1,130
RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	3.29%	13.80%	15.31%	2.57%	44.76%	16.53%

Evidence: The evidence in relation to this issue includes the following:

Exhibit 7	Cost Allocation
I.7.STAFF.57-63	Staff Interrogatories #57-63
I.7.VECC.38-44	VECC Interrogatories #38-44
Supplementary Responses	Responses to Staff Supplementary #8 and VECC Supplementary #55-59

8. <u>Rate Design</u>

Subject to any updates that are required to reflect and implement the Board's decisions on the Unsettled Items, the Parties accept the Proposed Tariff and the Parties accept the evidence of NOTL Hydro that it has calculated the Bill Impacts correctly and accept that such impacts are acceptable.

NOTL Hydro has agreed to treat the split between fixed and variable charges for the streetlighting and USL rate classes in the same manner as the GS >50 rate class. With that change, the Parties accept the evidence of NOTL Hydro that all elements of the rate design, including fixed-variable splits and revenue to cost ratios, have been appropriately determined, taking account of OEB policies and practices.

NOTL Hydro has updated the loss factor associated with the Large Use customer class. NOTL Hydro's filing did not include any separate loss factor for this customer class. After having reviewed the applicable loss factor for similar customer classes with other distributors, NOTL Hydro has proposed to update the applicable Tariffs to include the following:

Total Loss Factor – Secondary Metered Customer < 5,000 kW 1.0373 [no change]
Total Loss Factor – Secondary Metered Customer > 5,000 kW 1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW 1.0275 [no change]
Total Loss Factor – Primary Metered Customer > 5,000 kW 1.0045

The only impact on rates from the proposed change will be through the calculation of Cost of Power for the purpose of determining the Working Capital Allowance. This impact (an approximate $1,500 reduction in rate base) is shown in Item 1, above. The Parties accept this change. In agreeing to the Large Use rate, the Parties accept and rely on the evidence of NOTL Hydro that it has consulted with its Large Use customer, and that such customer is amenable to the proposed new Large Use rate.

For discussion of the proposed Standby Charges and the proposed Transmission Gross Load Billing Charge, see Item 10, below.

A copy of the Proposed Tariff is included at Appendix "E". The Proposed Tariff reflects the items described in this Settlement Proposal, including those related to the unsettled items.

Table 17 – Summary of Distribution Rates

Customer Class	Customer and Load Forecast				Distribution Rates	
	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Monthly Service Charge	Volumetric Rate
Residential	kWh	8,152	73,898,698	-	$ 30.47	$ - /kWh
GS<50	kWh	1,342	41,865,678	-	$ 39.41	$ 0.0133 /kWh
GS>50	kW	131	82,468,049	212,284	$ 281.65	$ 2.6169 /kW
Unmetered	kWh	26	251,508	-	$ 21.20	$ 0.0072 /kWh
Streetlights	kW	2,187	886,616	2,475	$ 7.85	$ 7.3887 /kW
Large User	kW	1	23,308,825	60,000	$ 2,829.49	$ 2.6169 /kW

Table 18 - Table Revenue to Cost Ratios

Name of Customer Class	Proposed Revenue-to-Cost Ratio		Policy Range
	Test Year	Price Cap IR Period	
	2019	2020 - 2023	
1 Residential	**90.58%**	**91.09%**	85 - 115
2 GS<50	110.64%	110.64%	80 - 120
3 GS>50	118.24%	118.24%	80 - 120
4 Unmetered	114.03%	114.03%	80 - 120
5 Streetlights	**130.00%**	**120.00%**	80 - 120
6 Large User	100.00%	100.00%	85 - 115

Table 19 – Summary of Fixed Variable Splits

Customer Class	Customer and Load Forecast							Fixed / Variable Splits	
	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable
Residential	kWh	8,152	73,898,698	-	$ 2,980,917	$ 2,980,917	$ -	100.00%	0.00%
GS<50	kWh	1,342	41,865,678	-	$ 1,190,494	$ 634,501	$ 555,993	53.30%	46.70%
GS>50	kW	131	82,468,049	212,284	$ 987,196	$ 442,754	$ 544,442	44.85%	55.15%
Unmetered	kWh	26	251,508	-	$ 8,433	$ 6,614	$ 1,819	78.43%	21.57%
Streetlights	kW	2,187	886,616	2,475	$ 224,278	$ 205,993	$ 18,285	91.85%	8.15%
Large User	kW	1	23,308,825	60,000	$ 157,369	$ 33,954	$ 123,415	21.58%	78.42%

RTSRs

The Parties accept the evidence of NOTL Hydro that it has calculated the RTSRs correctly and agree that they are acceptable.

Table 20 - Proposed RTSRs

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0068	73,708,854		501,767	37.8%	501,767	0.0068
General Service Less Than 50 kW	RTSR - Network	kWh	0.0062	42,276,847		263,475	19.8%	263,475	0.0062
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5322		122,962	311,361	23.4%	311,361	2.5322
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.7367		89,640	245,314	18.5%	245,314	2.7367
Unmetered Scattered Load	RTSR - Network	kWh	0.0062	260,263		1,622	0.1%	1,622	0.0062
Street Lighting	RTSR - Network	kW	1.9093		2,400	4,583	0.3%	4,583	1.9093

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0016	73,708,854		118,331	32.2%	118,331	0.0016
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0016	42,276,847		67,871	18.4%	67,871	0.0016
General Service 50 to 4,999 kW	RTSR - Connection	kW	0.5327		122,962	65,503	17.8%	65,503	0.5327
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	1.2812		89,640	114,846	31.2%	114,846	1.2812
Unmetered Scattered Load	RTSR - Connection	kWh	0.0016	260,263		418	0.1%	418	0.0016
Street Lighting	RTSR - Connection	kW	0.4118		2,400	989	0.3%	989	0.4118

LRAMVA

NOTL Hydro is only seeking clearance of the LRAMVA for 2016 and 2017. The Parties accept that NOTL Hydro has determined the LRAMVA appropriately. The Parties agree the results are acceptable. Table 20 provides a history of LRAMVA actuals versus forecast from 2011 to 2017 and the amounts to be recovered from each rate class.

Table 21 - LRAMVA

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	Street Lighting	Unmetered Scattered Load	General Service 50 - 4,999 kW	Total
		kWh	kWh	kW	kWh	kW	
2011 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2012 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2013 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2014 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2015 Actuals	☐	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2016 Actuals	☐	$22,353.60	$30,305.37	$31,223.24	$0.00	$24,738.05	$108,620.26
2016 Forecast		($4,979.74)	($14,033.57)	$0.00	$0.00	($2,379.45)	($21,392.76)
Amount Cleared							
2017 Actuals		$25,384.05	$36,341.80	$31,743.35	$0.00	$35,082.11	$128,551.31
2017 Forecast		($3,550.37)	($14,279.77)	$0.00	$0.00	($2,419.08)	($20,249.23)
Amount Cleared							
2018 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2019 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
2020 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2020 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared							
Carrying Charges		$1,438.19	$1,398.16	$2,346.80	$0.00	$1,995.69	$7,178.85
Total LRAMVA Balance		**$40,646**	**$39,732**	**$65,313**	**$0**	**$57,017**	**$202,708**

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.STAFF.64-65	Staff Interrogatories #64-65
I.8.SEC.33	SEC Interrogatories #33

I.8.VECC.45-46 VECC Interrogatories #45-46
Supplementary Responses Responses to VECC Supplementary #60 and SEC Supplementary #3

9. Deferral and Variance Accounts

Clearance of Group 1 and Group 2 Accounts

The Parties agree to the clearance of NOTL Hydro's Deferral and Variance accounts as-filed, with one exception. The change from the filing is that the parties have agreed, in the context of the overall partial settlement, that NOTL Hydro will not clear the OEB Cost Assessment Variance Account, because the balance in that account ($16,762) does not meet the relevant materiality threshold.

The Parties also agree that the Group 1 balances are disposed of on an interim basis consistent with Board policy and that the Group 2 balances are settled on a final basis.

The Parties agree that the recovery period for all Group 1 deferral and variance account rate riders will be 1 year.

There is no agreement on the disposition period of Group 2 deferral and variance accounts and the LRAMVA. Concurrently with this filing of this Settlement Proposal NOTL Hydro has indicated to Parties it will be filing updated evidence proposing to clear the accounts over a 2-year period (the original prefiled evidence had proposed a one-year clearance period). The table below sets out the relative impacts of clearance over 1 or 2 years. The Parties agree that the Board should determine this item. The Parties further agree that it is appropriate that intervenors and Board Staff be permitted the opportunity to ask interrogatories on the updated evidence or to object to the appropriateness of the updated evidence

Table 22 – LRAMVA and Group 2 Deferral and Variance Accounts

LRAM	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Bill Impact
Residential	$ 0.42	$ 0.21	$ 0.21	$ 0.21
GS<50	$ 0.0010	$ 0.0005	$ 0.0005	$ 1.00
GS>50	$ 0.2686	$ 0.1343	$ 0.1343	$ 18.13
Steet Lights	$ 26.3920	$ 13.1960	$ 13.1960	$ 382.68
Unmetered	$ -	$ -	$ -	$ -
Large User	$ -	$ -	$ -	$ -

Group 2	Rate Rider 1 Year	Rate Rider 2 Years	Variance	Bill Impact
Residential	$ 0.80	$ 0.40	$ 0.40	$ 0.40
GS<50	$ 0.0011	$ 0.0005	$ 0.0006	$ 1.10
GS>50	$ 0.4104	$ 0.2052	$ 0.2052	$ 27.70
Steet Lights	$ 0.3785	$ 0.1893	$ 0.1893	$ 5.49
Unmetered	$ 0.0011	$ 0.0005	$ 0.0006	$ 0.41
Large User	$ 0.4104	$ 0.2052	$ 0.2052	$ 1,026.00

Table 23 - Deferral/Variance Account Balances and Rate Riders

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

Please indicate the Rate Rider Recovery Period (in months) 12

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	73,898,698	-$ 44,565	- 0.0006
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	-$ 23,992	- 0.0006
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	-$ 46,247	- 0.2179
STREET LIGHTING	kW	2,475	-$ 497	- 0.2009
UNMETERED	kWh	251,508	-$ 141	- 0.0006
LARGE USER	kW	60,000	-$ 13,071	- 0.2179
Total			**-$ 128,514**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

Please indicate the Rate Rider Recovery Period (in months) 12

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	1,777,899	-$ 3,221	- 0.0018
GENERAL SERVICE LESS THAN 50 KW	kWh	6,392,462	-$ 11,580	- 0.0018
GENERAL SERVICE 50 TO 4,999 KW	kWh	76,481,342	-$ 138,544	- 0.0018
STREET LIGHTING	kWh	779,154	-$ 1,411	- 0.0018
UNMETERED	kWh	-	$ -	-
LARGE USER	kWh	23,308,825	-$ 42,223	- 0.0018
Total			**-$ 196,979**	

Rate Rider Calculation for Group 2 Accounts

Please indicate the Rate Rider Recovery Period (in months) 24

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	$ 78,073	$ 0.40
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	$ 44,230	$ 0.0005
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	$ 87,126	$ 0.2052
STREET LIGHTING	kW	2,475	$ 937	$ 0.1893
UNMETERED	kWh	251,508	$ 266	$ 0.0005
LARGE USER	kW	60,000	$ 24,625	$ 0.2052
Total			**$ 235,257**	

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in months) 24

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	0.21
GENERAL SERVICE LESS THAN 50 KW	kWh	41,865,678	$ 39,732	0.0005
GENERAL SERVICE 50 TO 4,999 KW	kW	212,284	$ 57,017	0.1343
STREET LIGHTING	kW	2,475	$ 65,313	13.1960
UNMETERED	kWh	251,508	$ -	-
LARGE USER	kW	60,000	$ -	-
Total			**$ 202,708**	

Specified Customer Revenue Variance Account

The Parties agree to the creation of a Specified Customer Revenue Variance Account that will record the difference between forecast and actual revenues solely from the Large Use customer forecast in NOTL Hydro's application. As explained in the prefiled evidence, the reason for the account is that the load forecast for the one customer that will be included in the Large Use Customer Class is uncertain, and it is quite large relative to NOTL Hydro's total load. The Parties agree that it is appropriate that neither the distributor nor customers bear the benefit or burden of currently unknown variances in the large customer's load, and that a variance account is appropriate. The name of the large customer is set out in Appendix "J" to the Settlement Proposal. The Parties agree that it would be appropriate for Appendix "J" to be filed confidentially with the OEB, pursuant to the OEB's Practice Direction on Confidential Filings.

The account will record the annual difference between forecast revenues from this customer versus the actual revenues from the customer at the current or adjacent location (including any standby charges), regardless of the number of accounts it has, and the rate class(es) they ultimately may end up within The Parties agree that the new account will be cleared annually via a rate rider which will be in effect for one year by allocating the balance of the variance account across customer classes based on customer class revenue. Within each customer class it will be allocated across customers based on kwh.. The Parties agree that the clearance of the account will include the Large Use customer class. A draft updated Accounting Order for the Specified Customer Revenue Variance Account is attached as Appendix "I".

Retail Service Cost Variance Account

Consistent with the expected outcome from the EB-2015-0304 Report of the Ontario Energy Board on Energy Retailer Service Charges, issued on November 29, 2018, the Parties agree that NOTL Hydro will discontinue its Retail Service Cost Variance Account as of May 1, 2019.

Ev*idence:* The evidence in relation to this issue includes the following:

Exhibit 9	Deferral and Variance Accounts
I.9.STAFF.66-74	Staff Interrogatories #66-74
I.9.SEC.34	SEC Interrogatory #34
I.9.VECC.47-49	VECC Interrogatories #47-49
Supplementary Responses	Supplementary Responses to Staff #67 and 71
Exhibit 9 Additional Evidence	Additional Evidence re. Group 2 and LRAM Rate Riders

10. Other

(a) Is the proposed microFIT rate appropriate?

The Parties agree that the proposed MicroFIT monthly service charge of $10.00 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.VECC.46	VECC Interrogatory #46

(b) Are the proposed changes to the Specific Service Charges appropriate?

The Parties agree with the Service Charges proposed in NOTL Hydro's application, with two changes.

First, the Retail Service Charges will be updated to reflect expected updates in the EB-2015-0304 Report of the Ontario Energy Board on Energy Retailer Service Charges, issued on November 29, 2018.

Second, NOTL Hydro will update its approved Service Charges (effective May 1, 2019) to reflect the expected changes resulting from the OEB's Review of Customer Service Rules (EB-2017-0183). NOTL Hydro will remove the Collection of Account, Install/Remove load control device – during regular business hours, and Install/Remove load control device – after regular business hours charges, and will change the name of the "Disconnect/Reconnect" Charge to "Reconnection" and will ensure that its late payment charge is reflected as 1.5% per month (effective annual rate 19.56% per annum or 0.04896% compounded daily).

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design
I.8.VECC.46	VECC Interrogatory #46

(c) Is the proposed transmission gross load billing appropriate?

There is no agreement on this item. The Parties agree that the Board should determine all issues related to this item.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design (Additional Evidence)

(d) Is the proposed distribution standby charge appropriate?

NOTL and VECC accept NOTL Hydro's proposal for a Distribution Standby Charge as set out in the Additional Rate Design Evidence (Exhibit 8), with one change. The change is that the minimum level to which the Distribution Standby Charge will apply is 500kW. As set out in response to SEC Supplementary Interrogatory #3, NOTL Hydro's evidence is that there is one customer who will be immediately impacted by the Distribution Standby Charge, and that customer supports the proposed charge. SEC takes no position on this issue.

Evidence: The evidence in relation to this issue includes the following:

Exhibit 8	Rate Design (Additional Evidence)
I.8.SEC.46	SEC Interrogatory #33
Supplementary Responses	SEC Supplementary Interrogatory #3

Appendix “A”- Approved Issues List and Table of Concordance

Approved Issues List
EB-2018-0056
Niagara-on-the-Lake Hydro Inc.

1. PLANNING

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- ➢ customer feedback and preferences
- ➢ productivity
- ➢ benchmarking of costs
- ➢ reliability and service quality
- ➢ impact on distribution rates
- ➢ trade-offs with OM&A spending
- ➢ government-mandated obligations, and
- ➢ the objectives of the Applicant and its customers

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- ➢ customer feedback and preferences
- ➢ productivity
- ➢ benchmarking of costs
- ➢ reliability and service quality
- ➢ impact on distribution rates
- ➢ trade-offs with capital spending
- ➢ government-mandated obligations, and
- ➢ the objectives of the Applicant and its customers.

2. REVENUE REQUIREMENT

2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

2.2 Has the Revenue Requirement been accurately determined based on these elements?

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?

3.3 Are the applicant's proposals for rate design appropriate?
3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?
3.5 Are the proposed Retail Transmission Service Rates appropriate?

4. ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?
4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the request for a new revenue variance account for the Large User customer appropriate?

5. OTHER

5.1 Is the proposed microFIT rate appropriate?

5.2 Are the proposed changes to the Specific Service Charges appropriate?

5.3 Is the proposed transmission gross load billing appropriate?

5.4 Is the proposed distribution standby charge appropriate?

Concordance Table between Issues List and Settlement Proposal

Issue from Issues List	Where this is addressed in the Settlement Proposal
1.1 Capital Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to: ➢ customer feedback and preferences ➢ productivity ➢ benchmarking of costs ➢ reliability and service quality ➢ impact on distribution rates ➢ trade-offs with OM&A spending ➢ government-mandated obligations, and ➢ the objectives of the Applicant and its customers	Item 1 – Rate Base Item 2 – Distribution System Plan and capital expenditures
1.2 OM&A Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to: ➢ customer feedback and preferences ➢ productivity ➢ benchmarking of costs ➢ reliability and service quality ➢ impact on distribution rates ➢ trade-offs with capital spending ➢ government-mandated obligations, and ➢ the objectives of the Applicant and its customers.	Item 3 – Operating Costs
2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices? **2.2** Has the Revenue Requirement been accurately determined based on these elements?	Item 1 – Rate Base Item 2 – Distribution System Plan and capital expenditures Item 3 – Operating Costs Item 4 – Cost of Capital Item 5 – Load Forecast and Other Revenue Item 6 – Revenue Deficiency/Sufficiency

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?	Item 5 – Load Forecast and Other Revenue
3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?	Item 7 – Cost Allocation
3.3 Are the applicant's proposals for rate design appropriate?	Item 8 – Rate Design
3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?	Item 8 – Rate Design
3.5 Are the proposed Retail Transmission Service Rates appropriate?	Item 8 – Rate Design
4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?	Throughout
4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the request for a new revenue variance account for the Large User customer appropriate?	Item 9 – Deferral and Variance Accounts
5.1 Is the proposed microFIT rate appropriate?	Item 10(a) – Other
5.2 Are the proposed changes to the Specific Service Charges appropriate?	Item 10(b) – Other
5.3 Is the proposed transmission gross load billing appropriate?	Item 10 (c) – Other
5.4 Is the proposed distribution standby charges appropriate?	Item 10(d) - Other

Appendix "B" - NOTL Hydro 2019 Revenue Requirement Work Form 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “C”- NOTL Hydro 2019 Filing Requirements Chapter 2 Appendices 20190110 & NOTL Hydro 2019 Filing Requirements Chapter 2 Appendix 2C 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix "D" - NOTL Hydro 2019 Load Forecast Wholesale 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “E”- NOTL Hydro 2019 Tariff Schedule and Bill Impact Model 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “F”- NOTL Hydro 2019 DVA Continuity Schedule CoS 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix “G” - NOTL Hydro 2019 Cost Allocation Model RUN3 20190110

Included in models filed electronically (through RESS) with the Settlement Proposal

Appendix "H" - Impact of Including ICM in Distribution Revenue at Existing Rates

2019 Rates with ICM included in Revenue at Existing Rates

Customer Class	Distribution Rates: Monthly Service Charge	Distribution Rates: Volumetric Rate		Revenue less Transformer Ownership: Monthly Service Charge	Volumetric Revenues	Tranformer Allowance	Revenue less Transformer Ownership
Residential	$ 30.47	$ -	/kWh	$ 2,980,834	$ -	$ -	$ 2,980,834
GS<50	$ 39.41	$ 0.0133	/kWh	$ 634,501	$ 556,814	$ -	$ 1,191,315
GS>50	$ 281.65	$ 2.6169	/kW	$ 442,754	$ 555,525	$ 11,086	$ 987,193
Unmetered	$ 21.20	$ 0.0072	/kWh	$ 6,614	$ 1,811	$ -	$ 8,425
Streetlights	$ 7.85	$ 7.3887	/kW	$ 205,993	$ 18,285	$ -	$ 224,279
Large User	$ 2,829.49	$ 2.6169	/kW	$ 33,954	$ 157,014	$ 33,600	$ 157,368
				$ 4,304,651	**$ 1,289,449**	**$ 44,686**	**$ 5,549,413**

2019 Rates with ICM excluded from Revenue at Existing Rates

Customer Class	Distribution Rates: Monthly Service Charge	Distribution Rates: Volumetric Rate		Revenue less Transformer Ownership: Monthly Service Charge	Volumetric Revenues	Tranformer Allowance	Revenue less Transformer Ownership
Residential	$ 30.97	$ -	/kWh	$ 3,029,749	$ -	$ -	$ 3,029,749
GS<50	$ 39.41	$ 0.0131	/kWh	$ 634,501	$ 548,440	$ -	$ 1,182,941
GS>50	$ 281.65	$ 2.4248	/kW	$ 442,754	$ 514,745	$ 11,086	$ 957,499
Unmetered	$ 21.20	$ 0.0080	/kWh	$ 6,614	$ 2,012	$ -	$ 8,626
Streetlights	$ 7.85	$ 7.3887	/kW	$ 205,993	$ 18,285	$ -	$ 224,279
Large User	$ 3,790.12	$ 2.4248	/kW	$ 45,481	$ 145,488	$ 33,600	$ 190,969
				$ 4,365,093	**$ 1,228,971**	**$ 44,686**	**$ 5,594,064**

Appendix “I” -
Draft Accounting Order for Specified Customer Revenue Variance Account

Niagara-on-the-Lake Hydro Inc.

DRAFT ACCOUNTING ORDER

Specified Customer Revenue Variance Account

The Specified Customer Revenue Variance Account is established with respect to a Specified Customer that is initially classified in the Large User rate class in NOTL Hydro's 2019 cost of service rate application. This variance account remains applicable irrespective of the Specified Customer's rate classification(s), or if they have multiple accounts at the current or adjacent location.

On a monthly basis the demand revenue from the Specified Customer will be reviewed and any variance from a demand of 5,000 kW will result in a journal entry in the account. Demand revenue will include any standby revenue billed due to the Specified User's behind-the-meter generation displacing demand revenue. The amount recorded will be the difference between actual revenue collected from the Specified Customer and the amount of revenue forecasted to be collected for that period, based on the approved fixed and variable rates in effect during that period

If the demand exceeds 5,000 kW then the entry is:

Dr. 4305 Regulatory Debit

Cr. 1508- sub-account Specified Customer Revenue Variance Account

If the demand is lower than 5,000 kW then the entry is:

Dr. 1508 – sub-account Specified Customer Revenue Variance Account
Cr. 4310 Regulatory Credit

Following the audit of the account's year-end balance, NOTL Hydro will request disposition of the account via a rate rider which will be in effect for one year. A rate rider will be determined for all customer classes including the Specified Customer who is currently forecasted in Large User class.

Assuming the variance account has a credit balance, the monthly recording of the billing of the rate rider will be:

Dr. 1508-sub-account Specified Customer Revenue Variance Account
Cr. 4305 Regulatory Debit

Dr. 4080 Distribution Revenue

Cr. 1100 Customer Accounts Receivable

If the variance account has a debit balance, the entries would be:

Dr. 4310 Regulatory Credit
Cr. 1508-sub-account Specified Customer Revenue Variance Account
Dr. 1100 Customer Accounts Receivable
Cr. 4080 Distribution Revenue

Following the audit of the year in which the last month of the rate rider was billed, any remaining balance in the variance account will be included in the balance requested for disposition in a future period. The rate rider will be determined by allocating the balance of the variance account across customer classes based on customer class revenue. Within each customer class it will be allocated across customers based on kwh.

Appendix “J” - CONFIDENTIAL

Name of Large Use Customer for the Specified Customer Revenue Variance Account

The customer's name is