Ontario

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

DECISION AND ORDER

EB-2016-0105

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Application for electricity distribution rates beginning May 1, 2017

BEFORE: Allison Duff
Presiding Member

Paul Pastirik
Member

September 21, 2017

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1. INTRODUCTION AND SUMMARY

Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay Hydro) filed an application with the Ontario Energy Board (OEB) to change its electricity distribution rates effective May 1, 2017. Under section 78 of the Ontario Energy Board Act, 1998 (OEB Act), a distributor must apply to the OEB to change the rates it charges its customers.

Thunder Bay Hydro provides electricity distribution services to over 50,000 customers in the City of Thunder Bay and the Fort William First Nation.

Thunder Bay Hydro asked the OEB to approve its rates for five years using the Price-Cap Incentive rate-setting option. With this option, the approved 2017 rates are adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of Thunder Bay Hydro's efficiency.

On April 27, 2017, Thunder Bay Hydro filed a partial settlement proposal with the OEB on behalf of the parties to the settlement. The OEB accepted the partial settlement proposal (see Schedule A attached) and held an oral hearing regarding the unsettled issues.

This Decision addresses the unsettled issues. The OEB approves Thunder Bay Hydro's proposed cost of capital of 4.67%, operating expenses of $15.210 million which is a reduction of $0.471 million from the proposed expenses and a capital budget of $11.526 million which is a reduction of $1.0 million from the proposed capital budget.

2. THE PROCESS

The OEB's policy for rate setting is set out in the "*Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach"* (RRFE, now referred to as the RRF). The RRF provides the distributor with performance-based rate application options that support the cost effective planning and efficient operation of a distribution network.

Thunder Bay Hydro filed an application on September 9, 2016 for 2017 rates under the Price-Cap Incentive rate-setting option of the RRF. The OEB issued a Notice of Application on November 9, 2016, inviting parties to apply for intervenor status. The Association of Major Power Consumers in Ontario (AMPCO), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) (collectively the intervenors) applied for, and were granted, intervenor status. OEB staff also participated in this proceeding.

On November 23, 2016, the OEB held a community meeting in the City of Thunder Bay. The OEB and Thunder Bay Hydro made presentations at the meeting, and there were two customer presentations at the meeting as well. A summary of the community meeting was added to the record of the proceeding. The comments during the community meeting focused on the costs of monthly billing, general concerns regarding affordability and rising electricity rates, as well as provincial energy policy. Specifically with respect to Thunder Bay Hydro, customers voiced concerns about the requested rate increase, citing increasingly unaffordable electricity bills.

The OEB issued Procedural Order No.1 on December 5, 2016. This order established, among other things, the timetable for a written interrogatory discovery process, the filing of a proposed issues list and a settlement conference.

A settlement conference was held from February 14, 2017 to February 16, 2017, which was attended by Thunder Bay and the intervenors. A partial settlement proposal was filed on April 27, 2017. OEB staff, which was not a party to the partial settlement proposal, filed a submission in support of it. The partial settlement proposal was approved by the OEB. The remaining unsettled issues were:

- Issues 1.1 and 2.1 Capital
- Issues 1.2 and 2.1 Operations, Maintenance & Administrative Expenses (OM&A)
- Issue 2.1 Cost of Capital

An oral hearing began on April 20, 2017, but was adjourned pending the filing of supplementary evidence by Thunder Bay Hydro related to the unsettled issues. After additional discovery on the supplementary evidence was completed, the oral hearing resumed on June 29, 2017 and June 30, 2017. All parties filed written submissions on the unsettled issues.

3. DECISION ON THE UNSETTLED ISSUES

3.1 OM&A

Background

Thunder Bay Hydro proposed an OM&A budget for 2017 of $15,680,655. A table with year over year OM&A comparisons follows.

Table 1: OM&A 2013 - 2017

Year	OM&A	$ Change	% Change
2013 OEB approved	$14,300,000		
2013 Actual	$13,232,884	($1,067,116)	(7.46%)
2014 Actual	$13,822,518	$589,634	4.46
2015 Actual	$14,244,004	$421,486	3.05
2016 Actual	$15,430,638	$1,186,634	8.33
2017 Proposed	$15,680,655	$250,017	1.62

OEB staff and intervenors argued for reductions from the original budget resulting in recommended OM&A levels ranging from $14.5[1] to $15 million[2], as compared to the proposed test year level of $15.681 million.

Findings

The OEB approves a 2017 OM&A budget of $15.210 million, a reduction of $0.471 million from Thunder Bay Hydro's proposed budget. The OEB makes this reduction after considering the actual 2016 OM&A costs net of one-time costs and the proposed 2017 OM&A increase.

The OEB assessed the reasonableness of the proposed 2017 OM&A expense using two methods:

[1] EB-2016-0105, School Energy Coalition July 13, 2017, p. 19
[2] EB-2016-0105, Ontario Energy Board Staff Submission, July 14, 2017, pp. 19-20

- Calculating the increase over the actual OM&A spend in 2016, net of one-time, non-recurring costs
- Applying an annual inflationary increase to the total OM&A spend in 2013 (adjusted for certain costs related to 2013) and adding other costs incremental to inflation

In this application, Thunder Bay Hydro requested an increase in OM&A costs of $0.250 million over its 2016 actual spend, an increase of 1.62%. While 1.62% seems reasonable as it is below the 2017 approved inflation rate of 1.9%, the OEB finds that the proposed budget must be considered in the context of the increase that occurred in 2016. From 2015 to 2016, OM&A costs increased by $1.186 million or 8.3%. The OEB finds 8.3% to be a significant increase in one year and worthy of further review.

In approving the 2017 budget, the OEB has first considered the one-time items that resulted in the significant increase in the 2016 OM&A. The OEB has determined from the evidence that the total of one-time costs that would not carry on into 2017 was approximately $0.471 million. These costs are outlined in the following table:

Table 2: OEB-Determined 2016 One-Time Costs

	$
Legal Costs related to load transfer	50,000
Renovations to operating centre	168,000
Supervisory Control and Data Acquisition (SCADA) training	40,000
Fire retardant clothing	116,000
Start of monthly billing process	65,000
Collective Bargaining costs	12,000
Electrical Safety Authority (ESA) public safety survey	20,000
Total	**471,000**

Accordingly, the OEB considers $14.960 million to be the appropriate 2016 cost base for costs that will recur in 2017. The OEB finds Thunder Bay Hydro's proposed 2017 OM&A increase of $0.250 million to be reasonable and approves a total 2017 OM&A budget of $15.210 million.

In approving the 2017 budget, the OEB has also assessed the total OM&A increase from 2013 to 2017. The OEB reviewed the total increase as a secondary check of the actual five year spend. In 2013, Thunder Bay Hydro proposed a budget of $14.7 million and the OEB approved $14.3 million, yet the actual spend was lower still at $13.2 million. The company explained that after the 2013 budget was prepared it needed to make some corrections and new information became available.

Starting from the actual spend in 2013 of $13.2 million, the OEB finds it appropriate to add certain costs related to 2013 given the explanations provided by Thunder Bay Hydro as shown in the following table:

Table 3: OEB Adjustments to 2013 Actual OM&A

	$
2013 Actual OM&A	13,232,884
Change in affiliate costs	175,000
Correction of supervisory classification costs	182,000
Pension evaluation costs	190,000
2013 OEB Adjusted OM&A amount	13,779,884

Applying an annual inflation rate of 1.9% from 2013 to 2017 to the 2013 OEB-adjusted OM&A amount of $13.780 million in Table 3, Thunder Bay Hydro's 2017 budget would approximate $14.857 million.

The OEB agrees with SEC's submission that two costs were incremental to inflation, which were the OEB fee assessment cost increase of $118,000 and the move to monthly billing of $221,000. Adding these two increases to the inflation-based estimate, the result is a total 2017 OM&A amount of $15.196 million. The OEB notes that this inflationary-based calculation approximates the OEB's approved 2017 budget of $15.210 million.

For these reasons, the OEB approves for rate-setting purposes an OM&A budget of $15.210 million for 2017.

3.2 Customer Engagement

"Customer feedback and preferences" were unsettled sub-issues under Capital and OM&A on the OEB-approved issues list for this proceeding. The topic of customer engagement was explored extensively during the oral hearing. Thunder Bay Hydro's witnesses provided oral testimony regarding the customer engagement process that included a customer survey and community meetings.

SEC submitted that Thunder Bay Hydro appears to have provided information to its customers in a manner that was misleading. As a result, SEC submitted that for the purpose of Thunder Bay Hydro's 2017 rate order only, the OEB should closely supervise the communications from Thunder Bay Hydro to its customers explaining the drivers and impacts of the 2017 rate increase.

Thunder Bay Hydro submitted that parties appeared to have ignored the detailed evidence of its extensive customer engagement activities undertaken to better understand customer feedback and to ensure its application was responsive to customer preferences. Thunder Bay Hydro submitted that it had made changes to its application, including targeting its grid modernization plan, directly in response to customer needs and preferences.

Thunder Bay Hydro indicated that customer engagement is difficult given the limited time to talk about every issue before a rate case begins. Thunder Bay Hydro committed to move beyond these minimum engagement requirements and create a Local Advisory Committee consisting of key customer stakeholders. The Local Advisory Committee would be able to learn about future utility plans on a regular basis, improving the quality of dialogue and ensuring all of Thunder Bay Hydro's actions were better aligned with customer needs and preferences.

Thunder Bay Hydro submitted that it had taken note of each of the parties' comments and would make continuous improvements to its customer engagement efforts in the future.

Findings

Given the testimony at the oral hearing, the OEB is concerned with the customer engagement evidence filed with the application. The OEB finds that multiple questions and issues were either incorrect or misleading. For example, the survey question regarding a five-year tree trimming cycle was incorrect as Thunder Bay Hydro proposed a seven-year cycle. As a result, the OEB will not rely on all customer survey responses.

The OEB acknowledges Thunder Bay Hydro's commitment to improving its customer engagement activities through a Local Advisory Committee, although the details of this committee were not fully reviewed in the hearing.

The OEB will not supervise Thunder Bay Hydro's communications with its customers regarding this Decision, as suggested by SEC. The OEB's Decision is a publically available document and the OEB's findings are clear. It is a utility's responsibility to manage the relationship with its customers and ensure the accuracy of the information provided to its customers.

3.3 Capital Expenditures and Rate Base

Thunder Bay Hydro's proposed 2017 rate base is $110,301,976, which included a working capital allowance of 7.5% or $10,072,538.

Thunder Bay Hydro's historic and proposed capital expenditures are key inputs into its rate base calculations. Thunder Bay Hydro filed an asset condition assessment report by Kinectrics (ACA Report) and a five-year distribution system plan (DSP) to support its proposed capital expenditures from 2017 to 2021.

Table 4: Capital Expenditures (historical and forecast) 2012 to 2021[3]

Category	Historic Actual Expenditures					Forecast Expenditures				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Actual	Actual	Actual	Actual	Actual					
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*					
System Access	2,864	2,154	2,937	2,412	2,516	2,662	2,422	2,432	2,445	2,505
System Renewal	6,664	5,888	5,994	7,413	7,184	8,380	8,818	8,976	9,217	9,261
System Service	-	-	-	-	1	230	300	280	280	300
General Plant	877	4,246	989	1,345	1,538	1,253	1,360	946	901	969
Total Capital Expenditure	10,405	12,287	9,920	11,171	11,239	12,526	12,900	12,634	12,842	13,036

Thunder Bay Hydro's proposed budget increases in System Renewal were driven by a change in investment strategy for asset replacement. In prior years, the focus was on the decommissioning of aged 4kV substation assets in conjunction with aged wood poles connected to the substation. The strategy was to convert the 4kV network to 25kV through an accelerated wood pole renewal plan. All 4kV power transformers would be removed from service over 10 years.

After reviewing the results from the ACA Report, Thunder Bay Hydro learned that these assets were in better condition than previously assumed, which led to a change in strategy for asset replacement. Thunder Bay Hydro proposed a graduated increase in investment over the next three years to align with the recommendations in the 10-year levelized Flagged for Action plan in the ACA Report. As indicated in the evidence of its expert witness Mr. Tsimberg, the ACA Report provided Thunder Bay Hydro with new information regarding its assets to develop a revised renewal plan and a project priority list. Thunder Bay Hydro indicated that it considered a number of factors in establishing its 2017-2021 capital budgets.

Parties were generally in agreement with Thunder Bay Hydro's proposed expenditures in the System Access, System Service and General Plant categories. The only exception was that AMPCO argued that an 11% reduction in the General Plant category was appropriate.

Intervenor and OEB staff submissions were critical of the level of the proposed capital expenditures in the System Renewal category of $8.4 million, considering it to be excessive. Intervenors submitted that the OEB should reduce the proposed System

[3] EB-2016-0105, Ontario Energy Board Staff Submission, July 14, 2017, p. 4 and Exhibit J2.1

Renewal budget by an amount ranging from $0.5 million[4] to $1.7[5] million. Intervenors also argued that Thunder Bay Hydro should address data gaps in its ACA Report and slow the pace of investment increases in its DSP.

Thunder Bay Hydro's evidence included the following table, which identified data gaps for various categories of assets:[6]

[4] EB-2016-0105, VECC Final Submission, July 14, 2017, p. 13
[5] EB-2016-0105, SEC Final Argument, July 13, 2017, p. 10
[6] EB-2016-0105, Kinectrics Inc., *Thunder Bay Hydro Asset Condition Assessment,* August 11, 2016, p.22

Table 5: Data Assessment by Asset Category

Asset Category		Average DAI	Data Gap
Station Transformers	All	93%	Low-Medium
	4 kV	92%	
	12 kV	93%	
Breakers	Breakers	61%	Low-Medium
Wood Poles	All	100%	Medium-High
	4 kV	100%	
	25 kV	100%	
Distribution Transformers	Pad Mounted Transformers	85%	Low-Medium
	Pole Mounted Transformers	100%	Medium-High
	Vault Transformers	100%	Medium-High
OH Switches	All	42%	High
	4kV In-Line	46%	
	4kV Manual Air Break	29%	
	12 and 25kV In-Line	37%	
	12 and 25kV Manual Air Break	40%	
	12 and 25kV Motorized Load Break	26%	
Underground Switches	25kV Underground Load Break Switches	38%	High
Underground Cables	All	48%	High
	4kV	65%	
	12 and 25kV	47%	

Thunder Bay Hydro also filed its prioritized list of material capital projects and programs. The projects and programs often combine various asset categories[7]:

[7] Application, Exhibit 2, *Distribution System Plan,* p. 143

Table 6: Material Capital Projects and Programs in 2017

OEB Category	Thunder Bay Hydro Project	Project Description	Total Expenditure	Driver	Priority Level	Overall Priority
System Access	A 01	PCB Transformer Replacements	$118,655	Mandated Obligations	P3	8
	A 02	Customer Recoverable System Modifications	$281,092	Customer Requests	P3	10
	A 11	Customer Driven System Expansions	$209,034	Customer Requests	P3	5
	A 12	Residential Service Connections	$445,213	Customer Requests	P3	6
	A 13	General Service Connections	$926,898	Customer Requests	P3	7
	A 14	Expansions for Residential Subdivisions	$230,530	Customer Requests	P3	4
	A 15	System Relocations	$164,881	Third Party Requests	P3	9
	A 21	Meter Installations	$286,129	Mandated Obligations	P3	11
System Renewal	A 16	Small Pole Replacements	$342,512	OH Renewal	P2	3
	A 17	Lines Safety Reports	$761,834	Safety	P2	1
	A 18	Transformer and Switch Replacements	$756,484	Asset Failure Renewal	P2	2
	B11140	25kV Pole Replacements	$584,384	OH Renewal	P4	12
	B12111	Black Bay-Dewe Voltage Conversion	$1,174,112	OH Renewal	P4	14
	B12112	Dewe-Rita Voltage Conversion	$1,489,302	OH Renewal	P4	15
	B1270	Cumming-Brodie Voltage Conversion	$580,677	OH Renewal	P4	16
	B1277	Donald-Mountdale Voltage Conversion	$310,256	OH Renewal	P4	13
	B1298	McDougall-Court Voltage Conversion	$789,716	OH Renewal	P4	19
	B12135	Finlayson - Brodie Voltage Conversion	$893,725	OH Renewal	P4	17
	B14129	Underground Replacements	$376,868	UG Renewal	P4	18
System Service	A	Grid Modernization	$230,375	Reliability	P5	21
General Plant	C	Fleet - Double Bucket Replacement	$450,000	System Maintenance Support	P5	20

Table 5.4.5-5 2017 Material Capital Projects and Programs

In its reply submission, Thunder Bay Hydro stated that it had carefully reviewed its System Renewal plan to identify opportunities to defer spending without affecting lower priority projects. As a result of its review, Thunder Bay Hydro identified one project, the McDougall-Court Voltage Conversion project, for which $0.4 million could be deferred in

2017 without cancelling the project entirely. Thunder Bay Hydro also emphasized the inter-dependencies of its capital expenditure plans and the expertise of its electrical engineering staff. Thunder Bay Hydro questioned the expertise of intervenors to recommend that the OEB reduce its proposed budget and prioritized capital projects.

Findings

The OEB disagrees with Thunder Bay Hydro's reply submission that intervenors, or those without electrical engineering expertise, are not qualified to comment on its capital budget. Thunder Bay Hydro is a natural monopoly. The intervenors in this proceeding represent customer groups that Thunder Bay Hydro serves - customers that will pay for the approved capital expenditures.

The OEB wants to hear from customers, especially regarding significant increases such as the proposed capital budget increase of 11% or $1.3 million from 2016 to 2017. Intervenors were particularly concerned with the proposed increase of $1.2 million in the System Renewal budget from 2016 to 2017 and the cumulative $2.1 million or 29% increase from 2016 to 2021. Again, the OEB was unable to rely on the customer survey responses as it was unable to reconcile these 11% or 29% increases with the 3.5% System Renewal increase, year-over-year for the next five years, indicated in the Decision Partners survey question[8].

Although Thunder Bay Hydro reduced its proposed System Renewal budget by $0.4 million to $8.0 million in its reply submission, this reduction was less than the reductions recommended by intervenors and OEB staff.

The OEB regards 2017 as an important year, as Thunder Bay Hydro indicated that its System Renewal budget was influenced by a change in investment strategy prompted by the ACA Report. The OEB supports Thunder Bay Hydro's move toward a more condition based asset management strategy and enhanced outage reporting.

This is the first five-year DSP that Thunder Bay Hydro has filed and it was driven by the ACA Report. It is a good start. However, the OEB is concerned with the data gaps in the ACA Report and the inherent risk of increased investment without better information. Three asset categories have high data gaps or low data availability indicators. Underground switches, underground cables and overhead switches all have average availability indicators of less than 50%. Yet the proposed project budget for underground replacements is $376,868 and for transformer and switch replacements is

[8] Exhibit 1, Mental Models DSP Survey, Decision Partners, page 25

$756,484. Asset categories with medium-high data gaps were wood poles, pole-mounted and vault distribution transformers.

Thunder Bay Hydro acknowledges these data gaps and plans to acquire more complete and reliable data where economically feasible. Thunder Bay Hydro characterized its investment strategy as “conservative” as it plans a shift in expenditures over a three-year period to align with the levelized Flagged for Action plan suggested by Kinectrics.

The OEB does not find the proposed three-year alignment period to be conservative. It is expensive. It is expensive because Thunder Bay Hydro wants to respond to the ACA Report and replace assets in poor condition, yet is unable to sufficiently decrease expenditures in other asset categories or defer its work-in-progress on assets in better condition that previously assumed.

The OEB finds that the three-year adjustment period should be extended further. An extended alignment period would allow for data acquisition in outage causes and asset condition to inform investment decisions. The OEB agrees with VECC’s submission that an increase in capital spending of this magnitude, with a consequent increase in customer rates, requires robust and accurate asset information.

Further, the evidence suggests that reliability is not an issue. Thunder Bay Hydro’s reliability has been improving overall. The OEB found no evidence in the application of an imminent risk of significant service disruption associated with asset condition. The OEB agrees with SEC’s and OEB staff’s submissions that Thunder Bay Hydro has not demonstrated the customer benefit of the significant proposed increase in capital expenditures in the System Renewal category.

Mr. Tsimberg testified that Thunder Bay Hydro’s prioritization process could be improved to be less subjective[9]. The OEB recommends Thunder Bay Hydro continue to review its 2017 project prioritization beyond the $0.4 million reduction identified in the reply submission. For example, Thunder Bay Hydro submitted that its lowest priority project, Grid Modernization, would be eliminated in 2017 if the proposed capital budget was not approved. The OEB questions Thunder Bay Hydro’s weighting of customer preferences when this project, added in response to customer preferences to improve service reliability for small business and large-use customers, is prioritized last.

[9] Tr. Vol. 3, p. 127

The OEB will set rates based on a reduction of $1.0 million from Thunder Bay Hydro's proposed capital expenditure budget. As a result, the approved 2017 total capital budget for 2017 is $11.526 million, which is a $0.287 increase over the 2016 actual capital budget.

In adjusting its capital expenditure budget and determining its 2017 revised rate base, the OEB acknowledges that Thunder Bay Hydro's management team is still in the best position to prioritize its annual capital spending, given its expertise and knowledge of its system. The OEB will not approve individual budgets for the System Access, System Service, System Renewal and General Plant, thereby allowing Thunder Bay Hydro to prioritize its spending across all capital expenditure categories.

3.4 Cost of Capital

Background

Thunder Bay Hydro noted in its reply submission that no party had opposed its proposed cost of capital. Thunder Bay Hydro argued that this was because its proposed cost of capital complied strictly with the OEB's guidelines and it had voluntarily agreed to use a lower weighted average cost of debt, which benefitted ratepayers with even lower rates, and further demonstrated its ongoing commitment to its Rate Minimization Model.

Findings

The OEB approves Thunder Bay Hydro's 2017 proposed cost of capital, which includes the OEB's deemed ROE of 8.78%, a weighted long-term debt rate of 1.95%, the deemed short-term debt rate of 1.76% and deemed capital structure of 40% equity and 60% debt. The approved weighted average cost of capital is as follows:

Table 7: Approved 2017 Cost of Capital

	Capitalization Rate	Cost Rate
Debt		
Long-term Debt	56%	1.95%
Short-term Debt	4%	1.76%
Total Debt	60%	1.94%
Equity		
Common Equity	40%	8.78%
Preferred Shares	0%	0%
Total Equity	40%	8.78%
Total	100%	4.67%

Thunder Bay Hydro's proposed ROE for 2017 is the OEB's deemed ROE for 2017. This proposal is in contrast to Thunder Bay Hydro's proposal in its last cost of service application for 2013 rates when it proposed a rate lower than the OEB's deemed ROE. The OEB acknowledges that it is appropriate for Thunder Bay Hydro to earn the OEB's deemed rate for 2017 and its proposal is consistent with the OEB's *Review of the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084). The increase will assist in funding Thunder Bay Hydro's capital expenditures and other business needs.

3.5 Renewable Generation Connection Funding Adder

Thunder Bay Hydro noted that Ontario Regulation 330/09 under the OEB Act requires the OEB to calculate the monthly amount to compensate qualifying distributors for rate protection provided to consumers. The rate protection relates to the cost recovery for eligible investments for the purpose of connecting or enabling the connection of a qualifying generation facility to a distribution system.

Thunder Bay Hydro indicated that its only connection project had been cancelled, yet it continued to collect amounts from the Independent Electricity System Operator (IESO) in relation to this project. Thunder Bay Hydro requested approval to return to the IESO $77,016, plus the associated interest of $1,614, which it expects to collect until April 30, 2017.

Findings

The OEB finds that an order is required to address this non-contested issue, included in Thunder Bay Hydro's application. The OEB determines the eligibility of connection investments and periodically issues an order to the IESO to collect and disburse specific amounts based on the approved entitlements. The OEB's last IESO order was issued on June 1, 2017[10].

The OEB directs that the payments from the IESO to Thunder Bay Hydro for the cancelled GEA project be discontinued at the issuance of the next IESO order. Upon issuance of such order, Thunder Bay Hydro is directed to return to the IESO the total amount collected related to the cancelled project plus the associated interest up until the time the payments are discontinued.

Thunder Bay Hydro is directed to provide in its draft rate order filing the amount it expects to return to the IESO, plus the associated interest up to December 31, 2017.

3.6 Effective Date

Thunder Bay Hydro proposed an effective date of May 1, 2017 for its 2017 rates.

VECC was the only party to make a submission on the proposed effective date, submitting that the implementation and effective date should be set after the OEB's rate order is issued.

VECC argued that the delayed timeline in this proceeding was due to three matters, all of which were under the control of Thunder Bay Hydro:

1. Thunder Bay Hydro had filed its application in September 2016, approximately one month later than the OEB recommended date of August 2016 for distributors with rate years beginning on May 1, 2017.
2. Thunder Bay requested an extension for filing interrogatory responses (1 week) and the completion of the settlement proposal (2 weeks).
3. The filing of additional evidence by Thunder Bay Hydro also delayed the proceeding by a further month.

[10] OEB Order EB-2017-0188 issued June 1, 2017

Findings

The OEB denies the proposed effective date of May 1, 2017 for Thunder Bay Hydro's new 2017 rates. The OEB supports setting rates on a prospective basis, enabling customers and the utility to guide their decisions in light of the OEB's rate order.

The OEB has considered the duration and reasons for the delay in this proceeding. The OEB considers some delays to be beyond Thunder Bay Hydro's control, including the timing of the community meetings and the issuance of Procedural Order No. 1. The OEB estimates these delays total one month in duration.

The OEB finds that Thunder Bay Hydro is responsible for other delays to the hearing schedule related to the timing of the application, interrogatory responses and filing of additional evidence which necessitated a second set of interrogatories and responses.

Given the issue date of this Decision and Order, the OEB expects Thunder Bay Hydro to implement the new 2017 rates on October 1, 2017. The OEB approves an effective date of September 1, 2017, which is one month prior to the October 1, 2017 implementation date.

In the draft rate order, Thunder Bay Hydro should calculate the foregone revenue for this one-month period and the rate riders to recover this amount over the remaining seven months of the 2017-2018 rate year from October 1, 2017 to April 30, 2018.

4 IMPLEMENTATION

Thunder Bay Hydro shall incorporate the cost consequences of the approved settlement proposal and the findings in this Decision on the unsettled issues, in its calculation of its revenue requirement for recovery from customers.

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

AMPCO, SEC and VECC are eligible for cost awards in this proceeding. The OEB has made provision in this Decision for these intervenors to file their cost claims at this time in the proceeding. Intervenors should note that the OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order. The OEB will issue its cost awards decision after the following steps are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Thunder Bay Hydro 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, within **7 days** of the date of this Decision and Order. Thunder Bay Hydro shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order. The draft rate order must include the amount Thunder Bay Hydro expects to return to the IESO, plus the associated interest up to December 31, 2017.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Thunder Bay Hydro, within **7 days** of the date of filing of the draft rate order. The OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.

3. Thunder Bay Hydro shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order within **7 days** of the date of receipt of the submission.

4. Intervenors shall submit their cost claims no later than **21 days** from the date of issuance of this Decision and Order.

5. Thunder Bay Hydro shall file with the OEB and forward to intervenors any objections to the claimed costs within **28 days** from the date of issuance of this Decision and Order.

6. Intervenors shall file with the OEB and forward to Thunder Bay Hydro any responses to any objections for cost claims within **35 days** from the date of issuance of this Decision and Order.

7. Thunder Bay Hydro 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-2016-0105**, filed through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ , and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. 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 CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies.

All communications should be directed to the attention of the Board Secretary 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, Martin Davies at martin.davies@oeb.ca and Board Counsel Jennifer Lea at jennifer.lea@oeb.ca.

DATED at Toronto September 21, 2017

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND ORDER

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

EB-2016-0105

SEPTEMBER 21, 2017

EB-2016-0105

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Thunder Bay Hydro Electricity Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2017.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

REVISED SETTLEMENT PROPOSAL

Filed: April 27, 2017

Thunder Bay Hydro Electricity Distribution Inc.

EB-2016-0105

Revised Settlement Proposal

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LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live excel models have been filed together with and form an integral part of this Settlement Proposal:

- A) Thunder Bay Hydro 2017 Load Forecast Settlement – No Manual CDM Adj
- B) Thunder Bay Hydro 2017 Load Forecast Settlement

- TBHEDI_EB_2016_0105_2017_Tax_PILs_Workform_SC
- TBHEDI_EB_2016_0105_2017_Cost_Allocation_Model_SC
- TBHEDI_EB_2016_0105_2017_RRWF_SC_tax_unlock
- TBHEDI_EB_2016_0105_2017 _Bill_Impact_Model_SC
- TBHEDI_ED_2016_0105_2017_DVA_Continuity_SC
- TBHEDI_EB_2016_0105_2017_LRAMVA_Work_Form_SC
- TBHEDI_EB_2016_0105_2017_Chapter2_Appendices_SC

Thunder Bay Hydro Electricity Distribution Inc.

EB-2016-0105

Revised Settlement Proposal

Filed with OEB: April 27, 2017

Thunder Bay Hydro Electricity Distribution Inc. (the "Applicant" or "Thunder Bay Hydro") filed an application with the Ontario Energy Board (the "Board") on September 9, 2016, as amended on October 5, 2016, under section 78 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that Thunder Bay Hydro charges for electricity distribution, to be effective May 1, 2017 (Board Docket Number EB-2016-0105) (the "Application").

The Board issued and Thunder Bay Hydro published a Notice of Application and Hearing dated November 9, 2016 and Procedural Order No. 1 on December 5, 2016, the latter of which required the parties to the proceeding to develop a draft issues list.

Thunder Bay Hydro filed its interrogatory responses with the Board on January 31, 2017, pursuant to which Thunder Bay Hydro updated several models and submitted them to the Board as Live Excel documents. On February 3, 2017, following the interrogatories, OEB staff submitted a proposed issues list as agreed to by the parties and two items that were in dispute. On February 10, 2017, the Board issued its Decision on the Issues List, approving the issues list attached thereto (the "Approved Issues List").

This Settlement Proposal is filed with the Board in connection with the Application. It has been revised in accordance with the oral decision of the Board made April 20, 2017. It supersedes and replaces the settlement proposal that was originally filed with the Board on March 31, 2017.

Further to the Board's Procedural Order No. 1, a settlement conference was convened on February 14, 2017 in accordance with the Board's *Rules of Practice and Procedure* (the "Rules") and the Board's *Practice Direction on Settlement Conferences* (the "Practice Direction"). Mr. Chris Haussmann acted as facilitator for the settlement conference which lasted for 3 day(s).

Thunder Bay Hydro and the following intervenors (the "Intervenors"), participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO");
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

Thunder Bay Hydro and the Intervenors are collectively referred to below as the "Parties".

Ontario Energy Board staff ("OEB staff") also participated in the settlement conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle the 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 binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement 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 Act, the Board has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the Board's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Agreement, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the settlement conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were a) any persons or entities that the Parties engage to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the Board of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by Thunder Bay 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.

Outlined below are the final positions of the Parties following the settlement conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list for the Application attached to the Board's Decision on the Issues List.

The Parties are pleased to advise the Board that they have reached a partial agreement with respect to the settlement of some of the issues in this proceeding. Specifically:

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the Board, the Parties will not adduce any evidence or argument during the hearing in respect of these issues.	# issues settled: **6**
"Partial Settlement" means an issue for which there is partial settlement, as Thunder Bay Hydro and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	# issues partially settled: **1**
"No Settlement" means an issue for which no settlement was reached. Thunder Bay Hydro and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: **3**

If applicable, a Party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue, but in either case such Party takes no position a) on the settlement reached, and b) on the sufficiency of the evidence filed to date.

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the Board does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the Board does accept may continue as a valid settlement without inclusion of any part(s) that the Board does not accept).

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal under s. 39.04 of the Rules of Practice and Procedure, 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 who took on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the Board.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not Thunder Bay Hydro is a party to such proceeding.

Summary

In reaching this partial settlement, the Parties have been guided by the Filing Requirements for 2017 rates, the approved issues list attached as Schedule A to the Board's Decision on the Issues List dated February 10, 2017, and the Report of the Board titled Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach dated October 18, 2012 ("RRFE").

This Settlement Proposal reflects a partial settlement of the issues in this proceeding. The Parties believe that, if accepted by the Board as the Parties request, this Settlement Proposal will narrow the scope of issues to be heard during a hearing. The following is a description of the key areas of disagreement among the Parties that would go to hearing if this Settlement Proposal is accepted:

1. Capital (Issues 1.1 and 2.1): The Parties are not in agreement that the Applicant's proposed capital expenditures for the test year are appropriate.

2. OM&A (Issues 1.2 and 2.1): The Parties are not in agreement that the Applicant's proposed OM&A expenditures for the test year are appropriate.

3. Cost of Capital (Issue 2.1): The Parties are not in agreement that the Applicant's cost of capital for the test year is appropriate.

Other issues, such as depreciation and working capital, remain outstanding only because they are dependent on those three main unsettled issues.

Subject to the foregoing, and based on the evidence and rationale provided below, the parties agree that the partial settlement set out in this Settlement Proposal is appropriate and recommend its acceptance by the Board.

1. CAPITAL AND OM&A

1.1 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;**
- **compatibility with historical expenditures;**
- **compatibility with applicable benchmarks;**
- **reliability and service quality;**
- **impact on distribution rates;**
- **trade-offs with OM&A spending;**
- **government-mandated obligations;**
- **the objectives of Thunder Bay Hydro and its customers; and**
- **the five-year Distribution System Plan.**

No Settlement: The Parties are not in agreement on this issue.

1.2 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;**
- **compatibility with historical expenditures;**
- **compatibility with applicable benchmarks;**
- **reliability and service quality;**
- **impact on distribution rates;**
- **trade-offs with capital spending;**
- **government-mandated obligations; and**
- **the objectives of Thunder Bay Hydro and its customers.**

No Settlement: The Parties are not in agreement on this issue.

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?

Partial Settlement: Subject to the resolution of issues 1.1 and 1.2 and the adjustment to other revenues identified in issue 4.2 below, the parties agree that the other revenues, working capital allowance, depreciation, and PILs have been appropriately determined in accordance with OEB policies and practices.

Specifically, and as further discussed in issue 4.2 below, Thunder Bay Hydro has recorded $38,363 of Other Revenue representing one-fifth of the forecasted gain on sale of the existing properties listed in issue 4.2 in the test year ($195,000 less the original cost of the properties of $3,186 or a $191,814 gain).

The following table provides reconciliation of other revenue accounts from the original application to the updated settlement proposal.

Other Revenue	Original Application Revenue Offsets	IR Adjustments	Interrogatories	Settlement Adjustment	Updated Revenue Offsets
Account					
4080-2-SSS Revenue	(148,000)	0	(148,000)	0	(148,000)
4082-RS Rev	(23,100)	0	(23,100)	0	(23,100)
4084-Serv Tx Requests	(400)	0	(400)	0	(400)
4205-Interdepartmental Rents	0	0	0	0	0
4210-Rent from Electric Property	(499,404)	0	(499,404)	0	(499,404)
4215-Other Utility Operating Income	0	0	0	0	0
4220-Other Electric Revenues	(16,569)	0	(16,569)	0	(16,569)
4225-Late Payment Charges	(380,777)	0	(380,777)	0	(380,777)
4230-Sales of Water and Water Power	0	0	0	0	0
4235-Miscellaneous Service Revenues	(398,500)	0	(398,500)	0	(398,500)
4355-Gain on Disposition of Utility and Other Property	(4,000)	(191,814)	(195,814)	153,451	(42,363)
4360-Loss on Disposition of Utility and Other Property	335,217	(156,060)	179,157	(3,186)	175,971
4362-Loss on Retirement	0	0	0	0	0
4375-Revenues from Non-Utility Operations	(240,082)	0	(240,082)	0	(240,082)
4380-Expenses of Non-Utility Operations	219,876	0	219,876	0	219,876
4385-Non Rate-Regulated Utility Rental Income	0	0		0	0
4390-Miscellaneous Non-Operating Income	(14,712)	0	(14,712)	0	(14,712)
4405-Interest and Dividend Income	(77,000)	0	(77,000)	0	(77,000)
Revenue Offsets	**(1,247,451)**	**(347,874)**	**(1,595,325)**	**150,265**	**(1,445,060)**

The parties are not in agreement that the planned capital or OM&A expenditures in the test year are appropriate (as noted in issues 1.1 and 1.2 above). In addition, the Parties are not in agreement that the Applicant's proposed cost of capital in the test year is appropriate.

Evidence:
Application: Exhibit 2, 2.4.1 , Page 30
Interogatories:2.0-VECC-4; 2-Staff-47; 2-Staff-48; 2-Staff-49; 4-Staff-56; 4-Ampco-24; 4-SEC-29; 4-VECC-32; 4-Staff-61; 4-Staff-62; 4-Staff-63; 4-Staff-64; 4-Staff-66; 4-Staff-67

Table 2-1: Rate Base Calculations from 2.0-VECC-4

Supporting Parties: All

2.2 Has the revenue requirement been accurately determined based on these elements?

No Settlement: Due to the outstanding matters in issue 2.1, the Parties are not in agreement on this issue.

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 energy and demand requirements of Thunder Bay Hydro's customers?

Complete Settlement: Subject to the updates noted below, the parties agree that for the purposes of settlement the proposed load forecast and customer forecast, loss factors, CDM adjustments and resulting billing determinates are appropriate, and to the extent applicable, are an appropriate reflection of the energy and demand requirements of Thunder Bay Hydro's customers.

Thunder Bay Hydro has agreed to update its load forecast model to include 2016 actual customers/connections values. Settlement Table #1 provides the update load forecast reflecting the 2016 actual customers/connections and has been attached as Appendix A.

The Load Forecast has also been updated to reflect the settlement issue 3.3 (below). Specifically, Thunder Bay Hydro has removed from its load forecast the originally proposed Large Use customer rate classification, and allocated this customer into the General Service > 1,000 kW rate classification.

Settlement Table #1 Load Forecast.

Settlement Table #1 Load Forecast			
Customer Class	**Pre Settlement**	**Settlement Adjustment**	**Updated Load Forecast**
	Dated Feb 13/2017		
Residential			
Customers	45,489	38	45,527
kWh	336,114,686	0	336,114,686
General Service < 50 kW			
Customers	4,674	-19	4,655
kWh	142,697,207	0	142,697,207
General Service > 50 - 999 kW			
Customers	467	-7	460
kWh	262,887,881	0	262,887,881
kW	656,995	0	656,995
General Service > 1,000 kW - 4,999kW			**General Service > 1.000 kW**
Customers	21	1	22
kWh	134,982,417	34,349,934	169,332,352
kW	383,102	83,823	466,924
Large User			
Customers	1	-1	0
kWh	36,734,784	- 36,734,784	0
kW	74,268	-74,268	0
Streetlights			
Connections	13,250	24	13,274
kWh	8,2n,945	17,620	8,290,565
kW	23,540	50	23,590
Sentinel Lights			
Connections	171	-7	164
kWh	112,765	-4,n8	108,037
kW	308	-13	295
Unmetered Scattered Load			
Connections	451	-11	440
kWh	2,203,935	- 55,813	2,148,122
Total Above			
Customers/Connections	64,524	18	64,542
kWh	924,006,622	-2.427,7n	921,578,850
kW from applicable classes	1,138,212	9,592	1,147,804

Settlement Table #2 CDM Adjusted Forecast

Settlement Table #2A and #2B provide the CDM impact on billed kWh and kW per customer class.

For the Residential, General Service < 50 kW and General Service > 50 to 999 kW classes the forecast billed amount for 2016 and 2017 is based on a rate class regression analysis and the analysis used a CDM activity variable in all cases. The CDM activity variable assumes the full year results up to the end of 2015 which suggests the 2015 full year results have been included in the forecast resulting from the regression analysis and should not be included in the manual CDM adjustment for these classes. This means using the half year rule for first year programs, the 2017 CDM manual adjustment will be a full year for 2016 programs plus and one half of the full year savings from 2017 programs.

For the General Service > 1,000 kW class, the 2015 savings did not occur until the very end of 2015 and these savings were not included in the 2015 actual results which were used to forecast the billed amount for this class. As a result, the CDM manual adjustment for 2017 will be the full year 2015 and 2016 savings plus one half of the 2017 results.

For the Street Lighting class, the 2015 savings did occur over 2015 which suggest one half of the 2015 results were included in billed forecast for this class. This means the CDM manual adjustment for 2017, will be the one half of 2015 savings plus a full year of 2016 savings plus one half of the 2017 results

Settlement Table #2A CDM Adjusted Forecast kWh

Customer Class	Billed Load Forecast No CDM Adjustment (kWh)	Billed Load Forecast after CDM Adjustment (kWh)	CDM Adjustment (kWh)
Residential	338,048,686	336,114,686	-1,934,000
General Service < 50 kW	143,397,406	142,697,207	-700,199
General Service > 50 - 999 kW	265,484,982	262,887,881	-2,597,102
General Service > 1,000 kW	196,122,889	169,332,352	-26,790,537
Large User	0	0	0
Streetlights	9,589,156	8,290,565	-1,298,590
Sentinel Lights	108,037	108,037	0
Unmetered Scattered Load	2,148,122	2,148,122	0
Total	954,899,278	921,578,850	-33,320,427

Settlement Table #2B CDM Adjusted Forecast - kW			
Customer Class	Billed Load Forecast No CDM Adjustment (kWh)	Billed Load Forecast after CDM Adjustment (kWh)	CDM Adjustment (kWh)
General Service > 50 - 999 kW	663,485	656,995	-6,491
General Service > 1,000 kW	540,798	466,924	-73,873
Large User	0	0	0
Streetlights	27,285	23,590	-3,695
Sentinel Lights	295	295	0
Total	1,231,863	1,147,804	-84,059

Settlement Table #3

Settlement Table #3 provides the details supporting the 2017 LRAMVA threshold amount outlined in Settlement Table #4.

Settlement Table #3 2017 LRAMVA						
	Residential	General Service < 50 kW	General Service > 50-999 kW	General Service > 1,000 kW	Streetlights	Total
2015 Programs Persisting into 2017 (Full Year)	2,457,558	509,178	2,627,750	13,005,537	752,180	19,352,203
2016 Programs Persisting into 2017 (Full Year)	949,700	440,906	1,701,194	13,685,000	615,000	17,391,800
2017 Programs (Full Year)	1,968,600	518,585	1,791,815	200,000	615,000	5,094,000
Total CDM Savings	5,375,858	1,468,669	6,120,759	26,890,537	1,982,180	41,838,003

Settlement Table #4

Settlement Table #4: 2017 Expected Savings for LRAM Variance Account provides the kWh and kW values to be used as the threshold in LRAM Variance Account calculation from 2017 and onwards until the next rebasing cost of service application occurs

Settlement Table #4 - 2017 Expected Savings for LRAM Variance Account						
	Residential	General Service < 50 kW	General Service > 50 - 999 kW	General Service > 1,000 kW	Streetlights	Total
2017 Test - kWh	5,375,858	1,468,669	6,120,759	26,890,537	1,982,180	41,838,003
2017 Test - kW Annual			15,297	74,149	5,640	95,086
2017 Test - kW Monthly			1275	6179	470	7,924

Evidence:
Application: Exhibit 3, 3.2 and 3.3
Interrogatories: 1-Staff-22; 3-VECC-18; 3-VECC-48; 3-VECC-49; 7-VECC-50; 7-VECC-51

Supporting Parties: All

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

Complete Settlement: For the purposes of settlement, the parties agree that the proposed cost allocation methodology and the allocations and revenue-to-cost ratios are appropriate. Thunder Bay Hydro agrees to conduct a review of the weighting factors used in its cost allocation methodology, which review must be filed as part of its next cost of service rate application.

Evidence:
Application: Exhibit 7
Interrogatories: 7-VECC-42; 7-VECC-43; 7-VECC-44; 7-VECC-51

Supporting Parties: All

3.3 Are Thunder Bay Hydro's proposals for rate design including the introduction of a Large Use class appropriate?

Complete Settlement: For the purposes of settlement, the parties agree that the monthly service charge for the General Service < 50 kW, General Service > 50 to 999 kW and General Service > 1,000 kW rate classes would be set at the current rate since the current rate is above the value for Minimum System with PLCC Adjustment (Ceiling Fixed Charge From Cost Allocation Model). This is presented in Settlement Table #5 below.

Settlement Table #5 – Proposed Rate Design

RATE DESIGN	2016 Rate	Pre Settlement	Settlement Adjustment	Settlement Proposal
Residential				
Monthly Service Charge	$15.24	$20.84	($0.55)	$20.29
Distribution Volumetric Rate per kWh	$0.0097	$0.0078	($0.00)	$0.0076
General Service < 50 kW				
Monthly Service Charge	$27.14	$32.83	($5.69)	$27.14
Distribution Volumetric Rate per kWh	$0.0140	$0.0169	$0.00	$0.0184
General Service 50 - 999kW				
Monthly Service Charge	$204.24	$247.95	($43.71)	$204.24
Distribution Volumetric Rate per kW	$2.5993	$3.1361	$0.32	$3.4562
General Service 1,000- 4,999 kW				**General Service > 1,000 kW**
Monthly Service Charge	$2,922.18	$3,506.77	($584.59)	$2,922.18
Distribution Volumetric Rate per kW	$2.3087	$2.6534	$0.25	$2.9038
Large User				**General Service > 1,000 kW**
Monthly Service Charge	$0.00	$4,796.27	($4,796.27)	$0.00
Distribution Volumetric Rate per kW	$0.0000	$2.8045	($2.80)	$0.0000
Streetlight				
Monthly Service Charge	$1.16	$1.17	($0.04)	$1.13
Distribution Volumetric Rate per kW	$7.0017	$7.0863	($0.24)	$6.8498
Unmetered Scattered Load				
Monthly Service Charge	$7.05	$8.53	($0.23)	$8.30
Distribution Volumetric Rate per kWh	$0.0103	$0.0125	($0.00)	$0.0121
Sentinel				
Monthly Service Charge	$6.96	$8.42	($0.22)	$8.20
Distribution Volumetric Rate per kW	$5.5838	$6.7548	($0.18)	$6.5762

For the purposes of settlement, and in consideration of the settlement of the other issues as outlined in this settlement proposal, Thunder Bay Hydro has agreed to withdraw its request to introduce a Large Use rate class and to instead move the single affected customer into the General Service >1,000kW class.

The parties agree that this is appropriate giving due consideration to:

- The considerable positive impact the single affected customer has on the local economy, including as a significant employer in the Thunder Bay area.

- The historical demand data (2003-2015) for the single affected customer demonstrates that this customer is clearly a marginal case. Their demand is sometimes above and sometimes below the 5,000kW threshold. Specifically, between 2004 until early 2011, this customer's demand hovered at below the 5,000kW level. In February 2011, the customer's demand first exceeded 5,000 kW, however demand fell below the threshold the very next month. Between 2011 and 2014, the customer has hovered at or around the 5,000 kW level. More recently, in 2015 and 2016, the customer's demand was hovering at or around the 6,000 kW level.

- There has been no change to the underlying cost to service the customer to justify a change in rate class.

- Economic changes or changes in US trade policy could reasonably be expected to lead to a reduction in this customer's demand below the 5,000kW threshold in the future.

- The calculated monthly bill impacts for the majority of customer classes, including the customer that was originally proposed to move into the Large Use rate class, are improved by moving the customer into the General Service >1,000kW class. This is shown in Settlement Table 6 below.

  - The detail is further shown in Settlement Tables 7 (leave the customer in the General Service >1,000kW class) and 8 (move the customer into the Large Use class) below.

  - Additional detail is shown in Settlement Tables 7A, 7B, 8A, and 8B.

  The majority of Thunder Bay Hydro's customers are worse-off if this customer is moved into a Large Use rate class.

  See Appendix B for a detailed discussion of the factors and additional evidence to explain the benefits that flow to these other customer classes.

- The consultations performed by Thunder Bay Hydro and AMPCO with the specific customer in question indicated a strong preference to minimize bill impacts. As shown in Settlement Table 6 below, this will be best achieved by putting the customer in the General Service >1,000kW service classification.

- Thunder Bay Hydro performed consultations with the other customer representatives that were party to the settlement conference. These customer representatives expressed different views on this settlement:

- AMPCO: The industrial customer benefits from this proposal with lower overall rates, as do all other customers in the GS > 1,000 kW service classification (see Table 6 below).

- SEC: SEC represents schools many of which are in the GS 50-999kW class. To these customers, a small increase in rates is worth it for the positive impact on a significant employer in the City.

- VECC: The settlement is a win-win from the perspective of residential consumers. They benefit from lower rates (see Table 6 below) and they support a major employer and economic engine in the City.

<u>Settlement Table 6 – Comparative Monthly Bill Impact</u>

Settlement Table 6 presents the total monthly bill impacts to all customers when the large user rate class is included, as compared to when the proposed large use customer is excluded and the proposed customer is allocated back into the General Service > 1,000 kW rate classification.

It is noted that there is a small increase to the General Service 50 to 999 kW, and Street Lighting Service Classification. However, both rate classes still experience a net monthly dollar decrease from current rates.

Total Monthly $ Bill Impacts	Including Large Use	Excluding Large Use	Total Monthly Increase / (Decrease) of Removing Request for Large Use Rate Class
RESIDENTIAL SERVICE CLASSIFICATION - RPP	$ 2.24	$ 2.12	$ (0.12)
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	$ 7.49	$ 7.26	$ (0.23)
GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	$ (57.10)	$ (53.00)	$ 4.11
GENERAL SERVICE > 1,000 SERVICE CLASSIFICATION - Non-RPP (Other)	$ (1,004.63)	$ (1,136.21)	$ (131.59)
PROPOSED LARGE USE CUSTOMER CLASS A - Non-RPP (Other)	$ (439.56)	$ (1,635.05)	$ (1,195.50)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	$ 0.46	$ 0.41	$ (0.06)
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	$ 1.49	$ 1.46	$ (0.03)
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	$ (2.62)	$ (2.61)	$ 0.02

Additional Detail – Excluding the Large User Class:

Settlement Table #7 Bill Impact Summary – Excluding Large User Class

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A $	A %	Sub-Total B $	B %	Sub-Total C $	C %	Total A + B + C $	Total %
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 3.60	16.0%	$ 2.98	11.7%	$ 1.21	3.7%	$ 2.12	1.54%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 9.80	17.8%	$ 8.96	14.6%	$ 4.70	5.7%	$ 7.26	1.94%
GENERAL SERVICE 50 to 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 99.20	19.4%	$ (16.95)	-2.6%	$ (115.27)	-10.5%	$ (53.00)	-0.65%
GENERAL SERVICE > 1,000 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 859.53	13.4%	$ (405.64)	-5.2%	$ (1,765.86)	-12.5%	$ (1,136.21)	-1.22%
Proposed Large Use Class A Customer as General Service > 1,000 kW Service Classification - Non-RPP (Other)	kW	$ 3,525.25	20.5%	$ 1,279.27	8.6%	$ (4,299.50)	-10.5%	$ (1,635.05)	-1.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 1.86	16.5%	$ 0.88	6.6%	$ 0.01	0.0%	$ 0.41	0.52%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 2.05	16.3%	$ 1.89	15.4%	$ 1.24	8.2%	$ 1.46	5.79%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (0.36)	-4.4%	$ (1.71)	-18.4%	$ (2.35)	-19.1%	$ (2.61)	-12.29%

Settlement Figure 7A – Bill Impacts to General Service > 1,000kW Service

Settlement Figure 7A presents the bill impact to the average customer in the General Service > 1,000 kW when the customer in question is moved into this class using the settlement adjusted Load Forecast Model, DVA Model, Cost Allocation, and Rate Design.

Customer Class:	GENERAL SERVICE > 1,000 kW SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	531,688	kWh
Demand	1,509	kW
Current Loss Factor	1.0239	Primary Metered
Proposed/Approved Loss Factor	1.0290	

	Current OEB-Approved Rate ($)	Current OEB-Approved Volume	Current OEB-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	$ 2,922.18	1	$ 2,922.18	$ 2,922.18	1	$ 2,922.18	$ -	0.00%
Distribution Volumetric Rate	$ 2.3087	1509.01	$ 3,483.85	$ 2.9038	1509.01	$ 4,381.86	$ 898.01	25.78%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1509.01	$ -	-$ 0.0255	1509.01	$ (38.48)	$ (38.48)	
Sub-Total A (excluding pass through)			$ 6,406.03			$ 7,265.56	**$ 859.53**	**13.42%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.9135	1,509	$ 1,378.48	-$ 0.7353	1,509	$ (1,109.58)	$ (2,488.06)	-180.49%
GA Rate Riders				$ 0.0023	531,688	$ 1,222.88	$ 1,222.88	
Low Voltage Service Charge	$ -	1,509	$ -		1,509	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,784.51**			**$ 7,378.87**	**$ (405.64)**	**-5.21%**
RTSR - Network	$ 2.4136	1,509	$ 3,642.15	$ 1.9141	1,509	$ 2,888.40	$ (753.75)	-20.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7988	1,509	$ 2,714.41	$ 1.3969	1,509	$ 2,107.94	$ (606.47)	-22.34%
Sub-Total C - Delivery (including Sub-Total B)			**$ 14,141.07**			**$ 12,376.20**	**$ (1,765.86)**	**-12.49%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	544,395	$ 1,959.82	$ 0.0036	547,107	$ 1,969.58	$ 9.76	0.50%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	544,395	$ 707.71	$ 0.0021	547,107	$ 1,148.92	$ 441.21	62.34%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	531,687.66	$ 3,721.81	$ 0.0070	531,688	$ 3,721.81	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	544,395	$ 598.83	$ 0.0011	547,107	$ 601.82	$ 2.98	0.50%
Average IESO Wholesale Market Price	$ 0.1130	544,395	$ 61,516.63	$ 0.1130	547,107	$ 61,823.05	$ 306.41	0.50%
Total Bill on Average IESO Wholesale Market Price			**$ 82,645.88**			**$ 81,640.39**	**$ (1,005.50)**	**-1.22%**
HST	13%		$ 10,743.96	13%		$ 10,613.25	$ (130.71)	-1.22%
Total Bill on Average IESO Wholesale Market Price			**$ 93,389.85**			**$ 92,253.64**	**$ (1,136.21)**	**-1.22%**

Settlement Figure 7B – Bill Impacts to the Proposed Large User in General Service >1,000 kW Service Classification

Settlement Figure 7B presents the bill impact to the specific customer in question when they are moved into the General Service >1,000kW class using the settlement adjusted Load Forecast Model, DVA Model, Cost Allocation, and Rate Design.

Customer Class:	Proposed Large Use Class A Customer as General Service > 1,000 kW Service Classification	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	3,061,232	kWh
Demand	6,189	kW
Current Loss Factor	1.0239	Primary Metered
Proposed/Approved Loss Factor	1.0290	

CLASS A
CUSTOMER AS A GS > 1000

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2,922.18	1	$ 2,922.18	$ 2,922.18	1	$ 2,922.18	$ -	0.00%
Distribution Volumetric Rate	$ 2.3087	6189	$ 14,288.54	$ 2.9038	6189	$ 17,971.62	$ 3,683.07	25.78%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	6189	$ -	-$ 0.0255	6189	$ (157.82)	$ (157.82)	
Sub-Total A (excluding pass through)			$ 17,210.72			$ 20,735.98	**$ 3,525.25**	**20.48%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.3724	6,189	$ (2,304.78)	-$ 0.7350	6,189	$ (4,550.77)	$ (2,245.99)	97.45%
GA Rate Riders								
Low Voltage Service Charge	$ -	6,189	$ -		6,189	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 14,905.94**			**$ 16,185.21**	**$ 1,279.27**	**8.58%**
RTSR - Network	$ 2.4136	6,189	$ 14,937.77	$ 1.9141	6,189	$ 11,846.36	$ (3,091.41)	-20.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7988	6,189	$ 11,132.77	$ 1.3969	6,189	$ 8,645.41	$ (2,487.36)	-22.34%
Sub-Total C - Delivery (including Sub-Total B)			**$ 40,976.48**			**$ 36,676.99**	**$ (4,299.50)**	**-10.49%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	3,134,395	$ 11,283.82	$ 0.0036	3,150,008	$ 11,340.03	$ 56.20	0.50%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	3,134,395	$ 4,074.71	$ 0.0021	3,150,008	$ 6,615.02	$ 2,540.30	62.34%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	3,030,620	$ 21,214.34	$ 0.0070	3,030,620	$ 21,214.34	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	3,134,395	$ 3,447.83	$ 0.0011	3,150,008	$ 3,465.01	$ 17.17	0.50%
Transformer Allowance	-$ 0.6000	6,189	$ (3,713.40)	-$ 0.6000	6,189	$ (3,713.40)	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0153	3,134,395	$ 47,956.25	$ 0.0153	3,150,008	$ 48,195.12	$ 238.87	0.50%
Total Bill on Average IESO Wholesale Market Price			**$ 125,240.05**			**$ 123,793.09**	**$ (1,446.95)**	**-1.16%**
HST	13%		$ 16,281.21	13%		$ 16,093.10	$ (188.10)	-1.16%
Total Bill on Average IESO Wholesale Market Price			**$ 141,521.25**			**$ 139,886.20**	**$ (1,635.05)**	**-1.16%**

Additional Detail – Including the Large User Class:

Settlement Table #8 - Bill Impact Summary – Including Large User Class

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A $	Sub-Total A %	Sub-Total B $	Sub-Total B %	Sub-Total C $	Sub-Total C %	Total A + B + C $	Total A + B + C %
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 3.63	16.1%	$ 3.08	12.1%	$ 1.34	4.0%	$ 2.24	1.63%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 9.80	17.8%	$ 9.14	14.8%	$ 4.89	5.9%	$ 7.49	2.00%
GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 91.01	17.8%	$ (25.10)	-3.9%	$ (123.42)	-11.2%	$ (57.10)	-0.70%
GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 853.04	13.3%	$ (340.15)	-4.4%	$ (1,700.37)	-12.0%	$ (1,004.63)	-1.08%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 4,793.57	27.9%	$ 67.04	0.4%	$ (5,511.71)	-13.5%	$ (439.56)	-0.31%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 1.87	16.6%	$ 0.92	7.0%	$ 0.06	0.3%	$ 0.46	0.60%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 2.07	16.5%	$ 1.91	15.6%	$ 1.27	8.3%	$ 1.49	5.89%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (0.38)	-4.6%	$ (1.73)	-18.6%	$ (2.37)	-19.3%	$ (2.62)	-12.38%

<u>Settlement Figure 8A – Bill Impacts to General Service >1,000 – 4,999 kW Service with Large Use Classification</u>

Settlement Figure 8A presents the bill impact to the average customer in the General Service >1,000-4,999 kW class when the specific customer is moved into the Large Use service class using the settlement adjusted Load Forecast Model, DVA Model, Cost Allocation, and Rate Design.

Customer Class:	GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	531,688 kWh
Demand	1,509 kW
Current Loss Factor	1.0239
Proposed/Approved Loss Factor	1.0298

	Current OEB-Approved Rate ($)	Current OEB-Approved Volume	Current OEB-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	$ 2,922.18	1	$ 2,922.18	$ 2,922.18	1	$ 2,922.18	$ -	0.00%
Distribution Volumetric Rate	$ 2.3087	1509.01	$ 3,483.85	$ 2.9019	1509.01	$ 4,379.00	$ 895.14	25.69%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1509.01	$ -	-$ 0.0279	1509.01	$ (42.10)	$ (42.10)	
Sub-Total A (excluding pass through)			$ 6,406.03			$ 7,259.07	**$ 853.04**	**13.32%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.9135	1,509	$ 1,378.48	-$ 0.6876	1,509	$ (1,037.60)	$ (2,416.08)	-175.27%
GA Rate Riders				$ 0.0023	531,688	$ 1,222.88	$ 1,222.88	
Low Voltage Service Charge	$ -	1,509	$ -		1,509	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,784.51**			**$ 7,444.36**	**$ (340.15)**	**-4.37%**
RTSR - Network	$ 2.4136	1,509	$ 3,642.15	$ 1.9141	1,509	$ 2,888.40	$ (753.75)	-20.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7988	1,509	$ 2,714.41	$ 1.3969	1,509	$ 2,107.94	$ (606.47)	-22.34%
Sub-Total C - Delivery (including Sub-Total B)			**$ 14,141.07**			**$ 12,440.69**	**$ (1,700.37)**	**-12.02%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	544,395	$ 1,959.82	$ 0.0036	547,532	$ 1,971.12	$ 11.29	0.58%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	544,395	$ 707.71	$ 0.0021	547,532	$ 1,149.82	$ 442.10	62.47%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	531,688	$ 3,721.81	$ 0.0070	531,688	$ 3,721.81	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	544,395	$ 598.83	$ 0.0011	547,532	$ 602.29	$ 3.45	0.58%
Average IESO Wholesale Market Price	$ 0.1130	544,395	$ 61,516.63	$ 0.1130	547,532	$ 61,871.11	$ 354.48	0.58%
Total Bill on Average IESO Wholesale Market Price			**$ 82,645.88**			**$ 81,756.83**	**$ (889.05)**	**-1.08%**
HST	13%		$ 10,743.96	13%		$ 10,628.39	$ (115.58)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 93,389.85**			**$ 92,385.22**	**$ (1,004.63)**	**-1.08%**

<u>Settlement Figure 8B – Proposed Large User Bill Impacts</u>

Settlement Figure 8B presents the bill impact to the specific customer in question when they remain in the Large Use service classification using the settlement adjusted Load Forecast Model, DVA Model, Cost Allocation, and Rate Design.

Customer Class:	LARGE USE SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	3,061,232	kWh
Demand	6,189	kW
Current Loss Factor	1.0239	
Proposed/Approved Loss Factor	1.0045	

CLASS A CUSTOMER
Primary Metered

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2,922.18	1	$ 2,922.18	$ 4,789.60	1	$ 4,789.60	$ 1,867.42	63.91%
Distribution Volumetric Rate	$ 2.3087	6188.99	$ 14,288.52	$ 2.8006	6188.99	$ 17,332.89	$ 3,044.36	21.31%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	6188.99	$ -	-$ 0.0191	6188.99	$ (118.21)	$ (118.21)	
Sub-Total A (excluding pass through)			$ 17,210.70			$ 22,004.28	**$ 4,793.57**	**27.85%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	-$ 0.3724	6,189	$ (2,304.78)	-$ 1.1361	6,189	$ (7,031.31)	$ (4,726.53)	205.08%
GA Rate Riders				$ -	3,061,232	$ -	$ -	
Low Voltage Service Charge	$ -	6,189	$ -		6,189	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 14,905.92**			**$ 14,972.96**	**$ 67.04**	**0.45%**
RTSR - Network	$ 2.4136	6,189	$ 14,937.75	$ 1.9141	6,189	$ 11,846.35	$ (3,091.40)	-20.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7988	6,189	$ 11,132.76	$ 1.3969	6,189	$ 8,645.40	$ (2,487.36)	-22.34%
Sub-Total C - Delivery (including Sub-Total B)			**$ 40,976.42**			**$ 35,464.71**	**$ (5,511.71)**	**-13.45%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	3,134,395	$ 11,283.82	$ 0.0036	3,075,008	$ 11,070.03	$ (213.80)	-1.89%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	3,134,395	$ 4,074.71	$ 0.0021	3,075,008	$ 6,457.52	$ 2,382.80	58.48%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	3,030,619.70	$ 21,214.34	$ 0.0070	3,061,232	$ 21,428.62	$ 214.29	1.01%
Ontario Electricity Support Program (OESP)	$ 0.0011	3,134,395	$ 3,447.84	$ 0.0011	3,075,008	$ 3,382.51	$ (65.33)	-1.89%
Transformer Allowance	-$ 0.6000	6,189	$ (3,713.39)				$ 3,713.39	-100.00%
Average IESO Wholesale Market Price	$ 0.0153	3,134,395	$ 47,956.25	$ 0.0153	3,075,008	$ 47,047.62	$ (908.63)	-1.89%
Total Bill on Average IESO Wholesale Market Price			**$ 125,239.99**			**$ 124,851.00**	**$ (388.99)**	**-0.31%**
HST	13%		$ 16,281.20	13%		$ 16,230.63	$ (50.57)	-0.31%
Total Bill on Average IESO Wholesale Market Price			**$ 141,521.19**			**$ 141,081.63**	**$ (439.56)**	**-0.31%**

Evidence:
Application: Exhibit 7; 7.2.1; Exhibit 8
Interrogatories: 7-Staff-70; 7-VECC-42; 7-VECC-43; 8-AMPCO-25, 8-AMPCO-26; 8-VECC-45; 8.0-SEC-33

Supporting Parties: All

3.4 Are the proposed Retail Transmission Service Rates appropriate?

Complete Settlement: For the purposes of settlement, the parties agree that the proposed Retail Transmission Service Rates are appropriate.

Evidence:
Application: Exhibit 8, 8.4
Interrogatories: 1-Staff-2

Supporting Parties: All

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?

Complete Settlement: Subject to the resolution of the unsettled issues within Issue 2.1, the parties agree that the impact of any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of those impacts are appropriate.

Evidence:
Application: Exhibit 1; 1.6.6; Exhibit 2; 2.6.9; Exhibit 4; 4.1.3; Table 4-10; Exhibit 9; 9.5.8; 9.5.9
Interrogatories: 4.0-SEC-29; 4.0-SEC-30; 9-Staff-73; 9-Staff-76;

Supporting Parties: All

4.2 Are Thunder Bay Hydro's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation of existing accounts, appropriate?

Complete Settlement: Subject to the one correction and the change noted below, the parties agree that Thunder Bay Hydro's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation of existing accounts, are appropriate.

Specifically, and as discussed in issue 2.1 above, Thunder Bay Hydro has recorded $38,363 of Other Revenue representing one-fifth of the forecasted gain on sale of the existing properties listed below in the test year ($195,000 less the original cost of the properties of $3,186 or a $191,814 gain). Thunder Bay Hydro is also requesting a new variance account to capture the difference between the revenue deficiency impact between the forecasted and actual after tax net gain (or loss) from the sale of real properties during the term of the IRM period immediately following this rebasing application including the following existing properties:

493 John Street, Thunder Bay, Ontario

832 McPherson Avenue, Thunder Bay, Ontario

1000 Mary St. W., Thunder Bay, Ontario

137 Brock Street, Thunder Bay, Ontario

To set up the variance account Thunder Bay Hydro plans to record the revenue deficiency impact of $157,235 ($191,814 gain less $34,579 representing the gross up of the $25,415 PILs cost on the capital gain) and compare this balance with actual net after tax gain or loss on the sale of all real properties during the term of the IRM period immediately following this rebasing application. Thunder Bay Hydro is proposing to record carrying charges in this Variance account.

Thunder Bay Hydro has attached to this settlement its proposed accounting order as Appendix C.

The parties support the other revenue treatment and the creation of the variance account described above.

Correction: Thunder Bay Hydro recorded $563,692 (revised to $562,690 with the change in the Cost of Capital parameters) in OEB account 1575: IFRS-CGAAP Transitional PP&E Amounts. The majority of this amount represented the recognition of a constructive obligation for the decommissioning of station assets. The amount further included a return on rate base component of $26,415 (revised to $25,413 with the change in the Cost of Capital parameters). Thunder Bay Hydro will transfer this balance of $562,690 less the $25,413 (as a Rate of Return component will not be included) to Property, Plant and Equipment and will amortize this asset over the life of associated assets (17 years or $33,099/year). This asset will be excluded from Rate Base for purposes of calculating Rate of Return.

Evidence:
Application: Exhibit 9; 9, 5.8; 9.6
Interrogatories: 2-Staff-48; 4.0-SEC-28; 9.0-SEC-34; 9.0 VECC-46; 9.0-VECC-47; 9-Staff-71; 9-Staff-75; 9-Staff-76; 9-Staff-77

Supporting Parties: All

Appendix A – Thunder Bay Hydro Load Forecast Settlement – CDM Adjusted

Thunder Bay Hydro Load Forecast for 2017 Rate Application	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Weather Normal	2017 Weather Normal
Billed kWh Before CDM	1,039,037,823	1,031,120,516	1,005,493,355	976,724,642	944,010,733	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	948,703,889	954,899,278
CDM Adjustment											22,077,527	33,320,427
Billed kWh After CDM	1,039,037,823	1,031,120,516	1,005,493,355	976,724,642	944,010,733	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	926,626,361	921,578,850
By Class												
Residential												
Customers	44,312	44,389	44,538	44,614	44,736	44,901	44,737	44,942	45,106	45,273	45,415	45,527
kWh	344,985,670	347,356,682	349,640,195	344,727,821	335,588,529	337,212,307	331,142,425	341,035,889	340,024,796	324,673,269	336,497,281	336,114,686
General Service�< 50 kW												
Customers	4,314	4,273	4,257	4,265	4,306	4,340	4,497	4,528	4,578	4,607	4,623	4,655
kWh	141,631,019	140,795,616	140,901,919	137,506,816	132,765,784	135,688,687	133,678,840	136,331,186	139,285,836	137,179,401	138,537,071	142,697,207
General Service� 50 to 999 kW												
Customers	493	501	507	506	507	506	514	512	495	472	463	460
kWh	299,216,793	298,981,716	297,548,977	290,804,127	285,047,817	288,525,140	283,475,241	285,068,374	280,037,460	266,548,348	264,176,175	262,887,881
kW	715,592	728,767	747,849	719,276	723,295	732,497	734,173	722,899	690,827	668,163	660,214	656,995
General Service �1000 kW												
Customers	18	19	19	21	20	19	19	21	21	22	22	22
kWh	241,350,662	230,921,503	204,491,830	189,989,955	177,283,842	183,178,133	188,531,681	187,992,826	193,164,947	198,507,739	176,274,852	169,332,352
kW	675,435	626,041	572,083	530,289	516,956	504,571	517,092	510,032	512,109	535,702	486,068	466,924
Large User												
Customers	0	0	0	0	0	0	0	0	0	0	0	0
kWh	0	0	0	0	0	0	0	0	0	0	0	0
kW	0	0	0	0	0	0	0	0	0	0	0	0
Street Lighting												
Connections	12,962	12,976	13,135	13,039	13,170	13,091	13,172	13,095	13,148	13,197	13,246	13,274
kWh	9,862,693	10,907,926	10,834,527	11,591,322	11,241,250	11,244,632	11,062,692	10,555,414	10,310,975	9,533,361	8,884,824	8,290,565
kW	30,657	30,889	31,499	31,053	31,562	31,850	30,859	29,850	29,217	27,043	25,281	23,590
Sentinel Lighting												
Connections	164	153	150	158	167	148	167	171	172	171	164	164
kWh	134,611	125,582	122,983	129,618	136,868	121,136	141,784	144,894	146,313	112,765	108,037	108,037
kW	374	349	342	360	380	336	381	390	392	308	295	295
Unmetered Scattered Load												
Connections	428	435	457	459	469	470	470	466	462	451	440	440
kWh	1,856,376	2,031,491	1,952,923	1,974,984	1,946,641	1,971,315	1,980,463	1,992,260	2,099,765	2,203,935	2,148,122	2,148,122
Total of Above												
Customer/Connections	62,690	62,745	63,063	63,061	63,374	63,474	63,576	63,735	63,983	64,192	64,372	64,542
kWh	1,039,037,823	1,031,120,516	1,005,493,355	976,724,642	944,010,733	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	926,626,361	921,578,850
kW from applicable classes	1,422,058	1,386,046	1,351,773	1,280,978	1,272,193	1,269,254	1,282,505	1,263,172	1,232,544	1,231,215	1,171,858	1,147,804
Total from Model												
Customer/Connections	62,690	62,745	63,063	63,061	63,374	63,474	63,576	63,735	63,983	64,192	64,372	64,542
kWh	1,039,037,823	1,031,120,516	1,005,493,355	976,724,642	944,010,733	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	926,626,361	921,578,850
kW from applicable classes	1,422,058	1,386,046	1,351,773	1,280,978	1,272,193	1,269,254	1,282,505	1,263,172	1,232,544	1,231,215	1,171,858	1,147,804
Check should all be zero												
Customer/Connections	0	0	0	0	0	0	0	0	0	0	0	0
kWh	0	0	0	0	0	0	0	0	0	0	0	0
kW from applicable classes	0	0	0	0	0	0	0	0	0	0	0	0

Appendix B- Large Use Class versus GS>1,000kW class

This Appendix B explains the sources of the beneficial rate impacts shown in Table 6 of the settlement that accrue to Thunder Bay Hydro's customers arising as a direct result of (1) not creating the proposed Large User rate class; and (2) instead moving the single customer into the GS > 1000kW class.

1. **Loss Factor**

Under the Board's loss factor calculation methodology, all customers except the one directly affected customer would benefit from having a lower loss factor if the affected customer remains in the GS>1000 class. The directly affected customer would have a higher loss factor, which is likely more reflective of the actual losses associated with delivery to that customer, and to all other customers.

If Thunder Bay Hydro introduces a new Large User rate class, Thunder Bay Hydro is required by Appendix 2-R instructions to incorporate the default loss factor applicable to Large Users of 1.0045. Under the Board-stipulated calculation method, the calculation of the remaining loss factor for all other classes excludes the Large User class, with an assumed loss factor of 1%. Using the required methodology, the calculation of the Loss Factor that Thunder Bay Hydro charges all of the other customers goes up to 1.0402.

By contrast, leaving the customer in the GS>1,000kW class means that the overall loss factor for the utility applies to all customers including this customer. All customers will thus have a loss factor of 1.0394 (or 0.0008 less than if the Large Use class is introduced).

If the customer remains in the Large Use class, the loss factor for Thunder Bay Hydro would be as follows:

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2011	2012	2013	2014	2015	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	996,079,734	987,455,833	1,001,934,686	1,002,261,340	976,172,477	992,780,814
A(2)	"Wholesale" kWh delivered to distributor (lower value)	991,445,327	982,419,688	997,113,842	997,719,889	971,956,909	988,131,131
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	25,274,078	27,457,812	30,229,413	30,693,561	37,102,132	30,151,399
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	966,171,249	954,961,877	966,884,429	967,026,328	934,854,777	957,979,732
D	"Retail" kWh delivered by distributor	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	954,980,846
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	25,023,840	27,185,952	29,930,112	30,389,664	36,734,784	29,852,870
F	Net "Retail" kWh delivered by distributor = **D - E**	932,917,512	922,827,174	933,190,731	934,680,429	902,024,034	925,127,976
G	Loss Factor in Distributor's system = **C / F**	1.0356	1.0348	1.0361	1.0346	1.0364	1.0355
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0403	1.0395	1.0408	1.0393	1.0411	1.0402

If the customer is in the GS>1,000kW class, the loss factor for Thunder Bay Hydro would be as follows:

Appendix 2-R
Loss Factors

This needs to be zoomed in to see 2013 and 2014

		Historical Years					5-Year Average
		2011	2012	2013	2014	2015	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	996,079,734	987,455,833	1,001,934,686	1,002,261,340	976,172,477	992,780,814
A(2)	"Wholesale" kWh delivered to distributor (lower value)	991,445,327	982,419,688	997,113,842	997,719,889	971,956,909	988,131,131
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	991,445,327	982,419,688	997,113,842	997,719,889	971,956,909	988,131,131
D	"Retail" kWh delivered by distributor	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	954,980,846
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	957,941,351	950,013,126	963,120,843	965,070,093	938,758,818	954,980,846
G	Loss Factor in Distributor's system = **C / F**	1.0350	1.0341	1.0353	1.0338	1.0354	1.0347
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0396	1.0388	1.0400	1.0385	1.0400	1.0394

2. **Load Forecast**

The demand component of the Load Forecast with the customer in the GS>1,000 kW class is 15,334 kW greater than the sum of the forecasts for the GS > 1,000 kW and Large Use classes, and the volume component is 348,353 kWh lower than the sum of the forecasts for GS>1000 kW and Large Use classes. This is because:

- **With Large Use Class:** The 2017 forecast usage for the Large Use Class is equal to the 2015 actual usage. This is a function of the load forecasting methodology for non-weather sensitive loads, when it is applied to a customer class that only has 1 customer. Because 2017 forecast consumption is the same as 2015 actual, Thunder Bay Hydro used the actual 2015 kW/kWh factor (rather than a 10 year historical average) to arrive at a demand forecast for the large use class in 2017.
- **Without Large Use Class:** By contrast, when this customer is added in the GS>1000 kW class, the 2017 forecast usage for this class is not equal to 2015 actual usage. Because of this, Thunder Bay Hydro used the ten year average kW/kWh factor to arrive at a demand forecast, which is consistent with the methodology utilized for the GS > 50 kW, GS > 1000 kW, and SEL classes. The same CDM adjustment is applied in both scenarios.

Each of the pre-filed and proposed load forecasts are based on the assumptions used. The assumptions used for the newly proposed forecast rely on a longer data set, so more thoroughly include the trends of all affected customers. Both pre-filed and proposed load forecasts are accurate based on their assumptions. The Parties agree that the new proposed forecast (with no Large User class) is likely to reflect the actual billing determinants in 2017 for all GS > 1000kW customers. In addition, the Parties agree that this new load forecast is better than the original in that it results in lower rate impacts as discussed below.

The following table provides the supporting calculation for these differences.

	With Large Use Class Forecast			Without Large Use Class Forecast	Difference
	GS > 1000 kW	Large Use	Total	GS > 1000 kW	
2015 kWh Actual	161,772,954	36,734,784	198,507,739	198,507,739	
2015 Customers Actual	20.9	1.0	21.9	21.9	
2015 Usage Per Customer Actual	7,738,944	36,734,784	9,062,728	9,062,728	
2017 Customers Forecast	20.6	1.0	21.6	21.6	0.0
2017 Usage Per Customer Forecast	7,738,944	36,734,784		9,062,728	
2017 kWh Forecast	159,736,457	36,734,784	196,471,242	196,122,889	-348,353
CDM Adjustment	26,790,537	0	26,790,537	26,790,537	
2017 kWh Forecast After CDM	132,945,920	36,734,784	169,680,705	169,332,352	
Application and Settlement Proposal	Based on 10 Year Average	Based on 2015 Actual		Based on 10 Year Average	
kW/kWh Factor	0.2838%	0.2022%		0.2757%	
2017 kW Forecast	377,322	74,268	451,590	466,924	15,335

The difference causes rates to be lower if no Large User class is introduced since there are more volumetric units to recover distribution costs. The decline in kWh does not affect revenues, since it is not a billing determinant in this class. The increase in kW does affect revenues, and thus revenue per kW – the rate – has to decrease to keep revenues constant. No other classes are affected by this change in the load forecast.

If the customer remains in the Large Use class, the Load Forecast for Thunder Bay Hydro would be as follows:

Forecast Data For 2017 Test Year Projection

Sum of Quantity		
Class	Unit of Measure	2017 Test Year Normalized
Residential	# of Customers	45,527
	kWh	336,114,686
General Service < 50 kW	# of Customers	4,655
	kWh	142,697,207
General Service > 50 to 999 kW	# of Customers	460 kW
		656,995
	kWh	262,887,881
General Service> 1000 kW	# of Customers	21 kW
		377,322
	kWh	132,945,920
Large User	# of Customers	1 kW
		74,268
	kWh	
		36,734,78
	4	
Street Lighting	# of Connections	13,274
	kW	23,590
	kWh	8,290,565
Unmetered Scattered Load	# of Connections	440
	kWh	2,148,122
Sentinel Lighting	# of Connections	164
	kW	295
	kWh	108,037
	# of Customers	
	kW	
	kWh	
Total Check	# of Cust/Con	64,542
	kW	1,132,469
	kWh	921,927,203

If the customer is in the GS>1,000kW class, the Load Forecast for Thunder Bay Hydro would be as follows:

Thunder Bay Hydro		
Forecast Data For 2017 Test Year Projection		
Sum of Quantity		
Class	Unit of Measure	2017 Test Year Normalized
Residential	# of Customers	45,527
	kWh	336,114,686
General Service < 50 kW	# of Customers	4,655
	kWh	142,697,207
General Service > 50 to 999 kW	# of Customers	460
	kW	656,995
	kWh	262,887,881
General Service > 1000 kW	# of Customers	22
	kW	466,924
	kWh	169,332,352
Large User	# of Customers	0
	kW	0
	kWh	0
Street Lighting	# of Connections	13,274
	kW	23,590
	kWh	8,290,565
Unmetered Scattered Load	# of Connections	440
	kWh	2,148,122
Sentinel Lighting	# of Connections	164
	kW	295
	kWh	108,037
	# of Customers	
	kW	
	kWh	
Total Check	# of Cust/Con	64,542
	kW	1,147,804
	kWh	921,578,850

3. **Transformer Allowance**

As a Large User, the customer would no longer benefit from the $0.60 per kW transformer allowance that they currently received in the GS 1,000 – 4,999 kW class.

The reason for this is that, in the cost allocation model no line transformer costs are allocated to the Large Use class which means there are no transformer costs to credit a customer who owns their own transformer. However, there are line transformer costs allocated in the GS 1,000 – 4,999 kW class since there are customers in that class that use Thunder Bay Hydro's line transformers. As a result, the full costs are allocated to the remaining customer classes. Leaving the customer in the GS>1,000 kW class would spread those costs over a larger base; therefore, marginally benefitting all customer classes and the customer in question would continue to receive the $0.60 per kW transformer allowance.

Appendix C- Accounting Order

Accounting Order

Thunder Bay Hydro Electricity Distribution Inc.

EB-2016-0105

Account 1508 Other Regulatory – Sub- Account Gains/ Losses from Sale of Non-Depreciable Property

Thunder Bay Hydro shall establish a new variance account 1508 Other Regulatory Assets – Sub-Account Gains/Losses from Sale of Non-Depreciable Property, effective January 1, 2017, to record the variance between the revenue deficiency impact of the actual and forecast after tax gains/losses from the sale of existing non-depreciable properties.

This account shall capture 100% of the variance between the forecasted and actual after tax net gains/losses on the sale of land including the forecasted properties at:

- 493 John Street, Thunder Bay, Ontario
- 832 McPherson Avenue, Thunder Bay, Ontario
- 1000 Mary St West, Thunder Bay, Ontario
- 137 Brock Street, Thunder Bay, Ontario

The forecast after-tax net gains on the sale of the listed properties are $157,235. The actual after-tax net gain or loss from each of the listed properties, and any other non-depreciable property sold, will be calculated. If the cumulative amount any time during the period 2017-2021 exceeds the forecast amount, the excess, and any additional gains (net of PILs divided by 1 minus the tax rate or “grossed up" PILs impact) after that date, will be added to the account If, on December 31, 2021, the forecasted properties have all been sold and the cumulative after-tax gain/loss does not exceed the forecast amount, the net shortfall will be charged to the account. The variance account will attract carrying charges at the OEB prescribed interest rate and will be settled at the next Cost of Service filing by Thunder Bay Hydro in accordance with Ontario Energy Board policy.

The following is the sample journal entry.

To record the variance between the cumulative actual gains/losses on disposal and the forecasted gain during the COS period:

	Debit	Credit
Dr/Cr. Account 1508 –Gains/Losses From the Sale of Property	$XXX,XXX	
Dr/Cr. Account 4080-Distribution Revenue		$XXX,XXX