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.

# SETTLEMENT PROPOSAL

**Filed:** March 31, 2017

**Thunder Bay Hydro Electricity Distribution Inc.**

**EB-2016-0105**

**Settlement Proposal**

# Contents



## 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

## Settlement Proposal

**Filed with OEB:** March 31, 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.

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 Adiustment | 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 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.

<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 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 % | B $ | B % | C $ | C % | Total A + B + C $ | Total % |
|---|---|---|---|---|---|---|---|---|---|
| RESIDENTIAL SERVICE CLASSIFICATION - RPP | kWh | $ 3.60 | 16.0% | $ 2.98 | 11.7% | $ 1.23 | 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% |

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

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** | | | **$ 12,375.20** | **$ (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%** |

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

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) | -$ 0.7353 | 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%** |

Settlement Figure 8B – Proposed Large User Bill Impacts

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 | 65,070,093 | 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 | 65,070,093 | 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 evidences several benefits 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 2011 | 2012 | 2013 | 2014 | 2015 | 5-Year Average |
|---|---|---|---|---|---|---|---|
| | ***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 2011 | 2012 | 2013 | 2014 | 2015 | 5-Year Average |
|---|---|---|---|---|---|---|---|
| | ***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>l,OOOkW 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 |