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Ontario

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2009 ELECTRICITY DISTRIBUTION RATES

Thunder Bay Hydro Electricity Distribution Inc.

EB-2008-0245

March 11, 2009

INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (“Thunder Bay” or the “Applicant”) is a licensed electricity distributor serving approximately 49,500 customers in the City of Thunder Bay and Fort William First Nation Reserve. Thunder Bay is owned by the City of Thunder Bay. Thunder Bay filed its 2009 rebasing application (the “Application”) on September 8, 2008. Thunder Bay requested approval of its proposed distribution rates and other charges effective May 1, 2009. If a final rate order is not issued in time for a May 1, 2009 effective date, Thunder Bay requested that its proposed rates be declared interim effective May 1, 2009. The Application was based on a future test year cost of service methodology.

The Vulnerable Energy Consumers’ Coalition (“VECC”), the School Energy Coalition (“SEC”), the Energy Probe Research Foundation (“Energy Probe”) and the Association of Major Power Consumers in Ontario were granted intervenor status in this proceeding.

This submission reflects observations and concerns which arise from Board staff’s review of the pre-filed evidence and interrogatory responses made by Thunder Bay, and are intended to assist the Board in evaluating Thunder Bay’s application and in setting just and reasonable rates. Staff has determined that comments on the issues of Payment in Lieu of Income Taxes, Working Capital Allowance and Lost Revenue Adjustment / Shared Savings Mechanism are not necessary.

THE APPLICATION

In its original application, Thunder Bay requested a revenue requirement of $18,671,941 (including revenue from the proposed smart meter adder) to be recovered in rates effective May 1, 2009[1].

It should be noted that Thunder Bay has subsequently proposed a change to its smart meter rate adder for 2009 that would increase the revenue requirement by approximately $427,772[2]. In addition, Thunder Bay proposed other changes that it has stated have revised the requested revenue requirement to $18,848,140. The following is a breakdown of Thunder Bay’s revenue requirement as revised from its original application:

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[1] E8/T1/S1 – Rate Design Overview and E3/T3/S1/p1 – Summary of Other Distribution Revenue

[2] Response to Board staff supplemental IRs – Appendix A (Smart Meter Revenue Requirement Calculation)

2009 Test Year Revenue Requirement

	As Filed	As Revised	Decrease(Increase) from Original Filing
OM&A	$ 12,340,964	$ 11,949,581	$ 391,383
Amortization	4,573,436	4,473,436	100,000
Return on Rate Base	1,437,190	1,429,293	7,897
Low Voltage	-	-	-
PILS	970,138	909,938	60,200
Transformer Allowance	410,405	410,405	-
Smart Meters Service Revenue Requi	742,598	1,173,277	(430,679)
Service Revenue Requirement	$ 20,474,731	$ 20,345,930	$ 128,801
Revenue Offset	(1,802,790)	(1,497,790)	(305,000)
Base Revenue Requirement	**$ 18,671,941**	**$ 18,848,140**	**$ (176,199)**

The Applicant provided the above breakdown of its revenue requirement and a revised reconciliation table on March 6, 2009 to correct certain minor errors in the original filing of the table (filed along with the responses to supplemental interrogatories), to reflect the impact of amortization changes and to adjust for the exclusion of any impacts from regulatory asset balances in the interest revenue offset. The Applicant confirmed changes that it has proposed since the filing of the original application and the closing of the evidentiary stage of this hearing.

It should be noted that the March 6 filing still contains inconsistencies between the table above and the detailed revenue requirement reconciliation table labeled Adjustments to Thunder Bay Hydro’s 2009 Cost of Service Application (the “Adjustments” table). For example, the change in OM&A identified in the Adjustments table is $685K while the above table shows a change of $391K. There are inconsistencies with the amortization and the return numbers as well. In its reply submission, Thunder Bay should clarify these inconsistencies and confirm any further changes that it wishes to make following the review of parties’ submissions and the resulting updated total revenue requirement requested for 2009, and provide updated bill impacts. Any further changes made to the revenue requirement should not involve new evidence.

LOAD FORECAST

Exhibit 3 of the application discusses how the customer count and load forecast are developed. The kWh forecast and the kW forecast for appropriate classes is presented by customer class. Variance analyses are presented in support of the forecasts.

Customer Forecast

Background

Thunder Bay is seeking Board approval for a test year customer forecast of 63,335 customers/connections. The test year forecast is approximately 0.4% higher (or 247 customers/connections) than the 2006 Actuals and 1% higher (or 358 customers/connections) than 2007 Actuals. The bridge and test year customer forecast is derived by extrapolating the 2007 actuals by the geometric mean of annual historical growth rates. In response to Board staff IR #31, Thunder Bay confirmed that the test year forecast is based entirely on the geometric mean of historical growth and that it did not rely on any external sources when developing the forecast. In the absence of such supporting evidence, Board staff analysed observed trends and historical customer levels to test the reasonableness of the proposed forecast.

Customer Count Forecast

2009 Test Year Customer Count Forecast (E3/T2/S4/p13)		
Rate Classes	No. of Customers	Proportion of Total
Residential	44,635	70.5%
GS<50 kW	4,466	7.1%
GS 50 to 999 kW	511	0.8%
GS 1000 to 4999 kW	19	0.0%
Streetlights	13,091	20.7%
Sentinel Lights	176	0.3%
Unmetered Loads	437	0.7%
TOTAL	**63,335**	**100%**

Discussion and Submission

The residential, GS<50, GS 50 to 999 kW and GS 1000 to 4999 kW rate classes make up over 78% (or 49,631 customers) and are the focus of this submission. From 1999 to 2007 these four rate classes have experienced an average annual increase of approximately 106 customers per year. Consistent with this level of increase Thunder Bay is forecasting an increase of 107 customers in 2008 and 111 customers in 2009. This increase in the customer count represents an average annual growth rate of +0.2%.

For the purposes of setting rates in certain 2008 EDR cases, the Board accepted customer forecasts using the arithmetic mean[3]. The forecasts were developed by extrapolating actual customer data by applying a growth rate based on the arithmetic mean of historical growth rates. In Thunder Bay's case, a customer forecast based on arithmetic mean would not be materially different from the proposed forecast developed using the geometric mean of historical growth rates. Board staff estimates a forecast (residential, GS<50, GS 50 to 999 kW and GS 1000 to 4999 kW rate classes) based on the arithmetic mean is higher than the proposed forecast by approximately 12 customers (or 0.02%). On a total customer count basis, this difference is slightly higher at 19 customers.

Board staff also compared the test year forecast for the above four rate classes to a forecast generated using a simple linear trend method. The trend method relies on the underlying linear trend in the historical data to estimate the future values. The trend method produces a forecast that is 0.11% (or 52 customers) higher than the proposed test year forecast. As illustrated in response to Board staff IR #31 b), this increase of 52 customers is attributed to an increase of 31 customers in each of the residential and GS< 50 kW rate classes. The increase in the residential and GS<50 kW rate class customer count is offset by a reduction of 10 customers in the GS 50 to 999 kW class. The forecast for the GS 1000 to 4999 kW rate class is unchanged at 19 customers.

Board staff submits that while the difference between a customer forecast based on geometric mean and arithmetic mean is negligible, the forecasts generated using the trend method suggest that, based on a linear trend across nine years of data, the proposed customer forecast for the residential and GS<50 kW rate classes is understated by 62 customers or approximately 0.13%. However, the impact on the residential class only appears to be negligible at 0.07%. The impact on the GS<50 kW class appears to be much higher at 0.7% but staff notes that this class represents only 14% of the total load. The proposed forecast for the GS 50 to 999 kW rate class is 511 customers, compared to the trend estimate of 501 customers. However, the proposed forecast of 511 customers appears reasonable given that on a 2008 actual year-to-date basis this rate class already has 509 customers[4], which is more that the 2008 forecast of 504 customers[5].

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[3] Board Decision - Halton Hills Hydro's 2008 rates case (EB-2007-0696), page 5
[4] Response to Energy Probe IR # 13
[5] E3/T2/S1/p 13 – Weather Normalized Load and Customer/Connection Forecast

Board staff also notes the proposed customer forecast is based entirely on historical growth and no external sources were relied on in the development of the forecast or used to test the reasonableness of the test year estimates[6].

Load Forecast

Background

Thunder Bay is seeking Board approval for a test year forecast of 992.7 GWh. This represents a 4.8% (or 50.1 GWh) decline from 2006 Actual. The residential GS<50 kW, GS 50 to 999 kW and GS 1000 to 4999 kW rate classes account for approximately 99% of the total load, are considered to be weather sensitive and are the focus of this submission. The test year load in these four classes is forecasted to decline by 4.8% (or 49.5 GWh) compared to 2006 Actuals. While the t-statistic (the measure of the significance of the independent variables in a regression equation) of each of the regression coefficients[7] appear reasonable, Board staff will comment below on the methodology and variables used in the regression equation. The class specific forecasts are:

Load Forecast[8]

Rate Classes	GWh
Residential	337.8
GS<50 kW	144.0
GS 50 to 999 kW	304.7
GS 1000 to 4999 kW	194.1
Streetlights	10.6
Sentinel Lights	0.1
Unmeterd Loads	1.3
TOTAL	**992.7**

Discussion and Submission

Thunder Bay's test year load forecast is developed by merging a total system-wide load forecast developed using an econometric method with a load forecast based on the product of average use per customer and test year customer count. Thunder Bay's load forecast was developed based on the following steps:

[6] Response to Board staff IR # 31
[7] Response to Energy Probe IR # 11
[8] E3/T2/S1/p 2/Table 2 - Weather Normalized Load and Customer/Connection Forecast

1. The total system weather normalized purchased energy forecast was developed based on a multifactor regression model that incorporated historical load, weather, and economic data.
2. The weather normalized purchased energy forecast (from Step 1) was adjusted for CDM and loss of load. This estimate was further adjusted by a historical loss factor to produce a weather normalized billed energy forecast.
3. A non-normalized forecast of billed energy by rate class was developed based on a forecast of customer numbers and historical usage patterns per customer.
4. For the weather sensitive rate classes, the non-normalized billed energy forecast (from Step 3) was adjusted to ensure that the total non-normalized billed forecast by rate class was equivalent to the total weather normalized billed energy forecast (from Step 2) determined by the regression equation.

In Board staff's view, the method of forecasting total system-wide energy based on a single regression equation does not take into account the effect of class specific drivers of demand. For example, the proposed method assumes that weather has the same impact across all rate classes. This assumption may not be appropriate given that weather impacts the consumption of a residential customer differently than it does the consumption of a larger user. This fact is further supported by the information provided in Table 15[9], where Thunder Bay indicates that the weather sensitivity of its residential and general service rate classes vary considerably, ranging from 100% to 59%.

Thunder Bay's forecasting method also assumes that Ontario GDP is an appropriate driver for all rate classes. GDP is a measure of total goods produced and will likely have a significant impact on commercial/industrial load more so than residential load; however, the single equation method does not make this distinction.

It is unclear to Board staff whether Thunder Bay's load forecast would be higher or lower (and to what extent), had Thunder Bay addressed the above variables. For example, in response to Board staff IR #35, Thunder Bay indicated that it does not prepare annual weather normalized load forecasts on a regular basis and does not have a methodology to weather normalize actual load data. As a result, Thunder Bay was unable to respond to a number of Board staff questions on testing historical forecast errors. For the purpose of this Application, given the detailed analysis undertaken by Thunder Bay in developing the load forecast, Board staff is of the view that Thunder

[9] E3/T2/S1/p16 - Weather Normalized Load and Customer/Connection Forecast

Bay's proposed load forecast is rigorous enough to reasonably underpin Thunder Bay's 2009 rates.

For future applications, and given the above limitations, the Board may wish to require Thunder Bay to develop class specific econometric load forecasts (that are added up to derive the total test year forecast) for its next cost of service rate filing, at which time additional years of consumption data will also be available.

Weather Normalization

Background

Thunder Bay's total system-wide load forecast is based on normal weather. The weather normal forecast is based on 12-years of average HDD and CDD as reported by Environment Canada for Thunder Bay's AWOS weather station. To test the appropriateness of the 12-year average weather normalization method, Board staff tested the accuracy of forecasts based on the proposed method in prior years (2006, 2007 and 2008)[10]. Board staff also compared the accuracy of forecasts based on the proposed method with those based on the 20-year trend method[11]. The 20-year trend method is the current Board approved method used for determining the weather normal forecast for the large natural gas utilities. The forecast error of the various scenarios are provided in the table below:

Forecast Accuracy of Proposed 12-Year Average Method

	Actual HDD	Forecast HDD	Forecast Error	% Forecast Error	Actual CDD	Forecast CDD	Forecast Error	% Forecast Error
Test Year 2006	5,039	5,401	363	7%	115	70	- 44	-39%
Test Year 2007	5,449	5,455	6	0%	91	65	- 25	-28%
Test Year 2008	5,411	5,539	128	2%	56	83	27	49%

Forecast Accuracy of 20-Year Trend Method

	Actual HDD	Forecast HDD	Forecast Error	% Forecast Error	Actual CDD	Forecast CDD	Forecast Error	% Forecast Error
Test Year 2006	5,039	5,352	314	6%	115	75	- 40	-35%
Test Year 2007	5,449	5,403	- 46	-1%	91	81	- 10	-11%
Test Year 2008	5,411	5,310	- 101	-2%	56	83	27	49%

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[10] Response to Board staff IR # 32
[11] Response to Board staff IR # 33

Discussion and Submission

Board staff notes that, with the exception of the large variances in the CDD forecast[12], the variance between actual HDD and forecast HDD for the proposed methodology is reasonable. When comparing the accuracy of forecasts based on the proposed method with those derived using the 20-year trend method, the magnitude of the errors is similar. Board staff submits that the proposed 12-year average method exhibits a similar level of accuracy to the 20-year trend method. Board staff notes that a load forecast developed using the 20-year trend weather normalization method will reduce the proposed load forecast by -0.3%[13] (or 3,292,918 KWh).

OPERATIONS, MAINTENANCE AND ADMINISTRATION

Background

For the 2009 Test year, Thunder Bay is requesting approval for $12,340,963 in OM&A expenses excluding taxes and amortization expenses (see table below)[14]. This represents a 2.4% increase over Thunder Bay's 2007 actuals and a 12.1% increase from its 2006 actuals. Thunder Bay's 2009 Test Year OM&A represents a 3.5% increase from the 2008 bridge year.

Board staff notes that the 2006 and 2007 actuals contain a significant non-recurring item, being $357K and $323K respectively in CDM 3rd tranche spending[15]. The year over year changes, using an adjusted 2007 actual excluding this amount, are presented in rows 12-15 in the table below. On an adjusted basis the increase from 2007 actual to the 2009 test year is 5.2% as opposed to 2.4% on an unadjusted basis.

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[12] Staff is not concerned with the large variances in CDDs. CDDs make up a relatively smaller amount of degree days compared to the total.

[13] Response to Board staff IR # 36 b)

[14] This is Thunder Bay's OM&A as filed and does not reflect any changes identified in Thunder Bay's supplementary IR responses.

[15] E4/T2/S2/p.5-6 – Variance Analysis on OM&A Costs

	Summary of OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
1	Operation	$2,011,898	$2,713,521	$2,784,785	$2,752,849	$3,024,765
2	Maintenance	$2,977,751	$2,650,405	$3,271,159	$2,996,067	$3,049,733
3	Billing and Collection	$2,432,919	$2,284,014	$2,286,306	$2,414,133	$2,392,006
4	Community Relations	$169,039	$547,031	$502,544	$195,316	$228,339
5	Administrative and General Expenses	$2,911,130	$2,813,268	$3,206,840	$3,561,117	$3,646,120
6	**Total**	**$ 10,502,737**	**$ 11,008,239**	**$ 12,051,634**	**$ 11,919,482**	**$ 12,340,963**
7	**year on year increase**			$ 1,043,395	-$ 132,152	$ 421,481
8	**year on year % increase**			9.5%	-1.1%	3.5%
9	**% increase 2006 to 2009**					12.1%
10	**% increase 2007 to 2009**					2.4%
11						
12	2006 and 2007adjusted Actual *		$ 10,650,836	**$ 11,728,438**		
13	**year on year increase (2007 adjusted)**			$ 1,077,602	$ 191,044	
15	**year on year % increase (2007 adjusted)**			10.1%	1.6%	
14	**% increase 2007 (adjusted) to 2009**					5.2%
16	* Note: 2006 and 2007 OM&A adjusted for CDM 3rd Tranche spending of $357,403 and $323,196 respectively					

Over the 2003 to 2007 period Thunder Bay's OM&A actual expenses, as confirmed in the response to Board staff IR #3, increased by approximately 1.8% annually and by about 1% annually when using 2007 actual (adjusted). During this period the increase in the number of residential and general service customers averaged approximately 1% annually.

<u>Major elements of the increase in OM&A</u>

The table below, prepared by Board staff using information taken directly and/or derived from pre-filed evidence and interrogatory responses, highlights the major changes/reasons between the 2007 actual (adjusted), the 2008 bridge and 2009 test years. [16]

[16] The summary prepared by Board staff assumes that on average the inflationary impact on Thunder Bay has been 2% per annum. The major component amounts have been calculated on this basis.

	in '000 ($ approximate)	2008 vs 2007	2009 vs 2008	
	Year-on year increase	**$ 225**	**$ 422**	**account # if applicable**
	COMPONENTS			
a	inflation @ 2%	$ 241	$ 247	
b	PCB Program	$ (128)	$ 251	5035
c	forestry (tree trimming/line clearing)	$ (32)	$ 183	5135
d	line transformer maintenance *	$ (315)	$ (39)	5160
e	bad debt expense	$ 80	$ -	5335
f	executive/mgt salaries in excess of inflation	$ 146	$ (30)	5605
g	injuries and damages	$ 85	$ 12	5640
h	increase in overheards capitalized	$ -	$ (105)	5105
i	compensation/staffing and miscl. other items	$ 148	$ (97)	
	Total	**$ 225**	**$ 422**	

* note: 2007 actual included PCB related costs

Evidentiary sources in addition to E4-T2-S1 p. 32-35

b	E1-T2-S3-p.6-8; Board staff IR #9 and supplemantary IR #3
c	Board staff IR #11; E1T2-S3 p.3-6
d	E4-T2-S2 p.5
h	E4-T2-S2 p.2

Discussion and Submission

Inflation

Thunder Bay indicated that it used a 2% inflation rate to forecast 2009 O&MA and notes that the 2% was based on the CPI as reported by the Bank of Canada; in this regard the average CPI for 2007 (Jan. to Dec.) and 2008 (Jan.-June) was 2.15% and 2.07% respectively. [17]

Board staff has no concerns with the provision in 2009 OM&A for inflation. With respect to the other items in the list, Board staff makes submissions on the following.

Polychlorinated Biphenyls (“PCB”) Program

Thunder Bay, in its response to Board staff IR #9, indicated that it is proposing to spend approximately $3.5 million, comprised of OM&A, Capital and the associated Asset Retirement Obligations (“AROs”), between 2008 and 2020 to comply with legislative requirements pertaining to treating and disposing PCB contaminated transformers. Thunder Bay’s plan includes eliminating all PCB in concentrations of >500 PPM and all PCBs in concentrations of >50 PPM in environmentally sensitive areas by the end of

[17] Response to Board Staff IR #4

2009, and the remaining concentrations by 2020. The plan provides for the replacement of 38 Transformers in 2009, 23 annually thereafter until 2019, and 3 in 2020 at which time all 271 affected transformers will have been replaced.[18] 2025 is the removal from service deadline in the legislation for PCB >50 PPM in non-sensitive areas.

The table below (derived from the response to Board Staff IR #9) summarizes the expenditure plan from 2009 to 2020.

PCB Plan (annual costs)	# of Transformers	Capital	OM&A	Asset Retirement Obligations	TOTAL
2009	38	$179K	$201K	$81K	$462K
2010 to 2019	23	$108K	$122K	$58K	$288K
2020	10	$15K	$15K	$42K	$72K

Board staff notes that Thunder Bay has identified three types of costs related to their 2009-2020 PCB program. First, Thunder Bay identified that $179K in capital expenditures related to transformer replacement will be incurred in 2009. Staff notes that the number of transformers to be replaced in subsequent years drops to 23. During the term of Thunder Bay's 3rd Generation IRM plan (likely over 2010, 2011, and 2012) staff notes that the annual recovery related to depreciation expense will be based on the higher 2009 amount but using the half year rule. Staff notes that for this interim period, the impact of embedding a higher capitalized amount in rates is likely immaterial.

Second, Thunder Bay identified $201K in OM&A costs for 2009. In Board Staff supplementary IR #3, Board staff noted the drop in planned OM&A related costs between 2009 and subsequent years. Board staff asked Thunder Bay to comment on the appropriateness of Thunder Bay's recovery in rates of approximately $80K annually for costs that are not planned to occur during the term of Thunder Bay's 3rd Generation

[18] Board staff notes that Thunder Bay, in response to Board staff IR #9, updated its PCB plan outline as originally filed in order to make it comply with the current legislation. While the updated plan's total costs increased by about $279K, the annual cost for the years 2010-2020 decreased by about $266K since the pole transformer replacement timeline was extended from 2014 to 2020. Compared to the as-filed required amounts, this increases the 2009 total cost by approximately $59K, from $403K to $462K.

IRM plan. Thunder Bay responded that the OM&A costs presented in the filing were not the full 2009 expenditures but were the average of costs anticipated in 2009, 2010 and 2011 and so the number provided for 2009 was appropriate. Staff notes that the revenue requirement Adjustments table, provided by Thunder Bay as an attachment to their responses to Board staff supplemental interrogatories, showed a reduction of $80K in OM&A attributed to the PCB program resulting in a 2009 OM&A amount for rate setting purposes of $148K. Staff notes that this is the average of the 2009, 2010 and 2011 OM&A forecasted costs as revised by Thunder Bay in response to Board staff IR #9 c).

In confirming this adjustment, staff notes that the original amount included in operations account 5035 – Overhead Distribution Transformers was $341K for the test year. Thunder Bay did not submit a revised OM&A continuity schedule; however, staff notes that if one reduces the $341K by $80K the result is $260K. The amount included historically in this account is $117K (2006 actual). The difference is $143K.

Staff observes that if Thunder Bay was to include the 2012 year in the calculation, the annualized OM&A that would be used for setting 2009 rates would be $142K.

Third, Thunder Bay identified $749K in AROs for the term of the plan. Staff notes that the Canadian Institute of Chartered Accountants Handbook[19], defines an ARO as "a legal obligation associated with the retirement of a tangible long-lived asset that an entity is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppels." Thunder Bay's PCB liabilities appear to meet the definition of an ARO. In response to Board staff supplemental IR #3 d), it appears that Thunder Bay has identified depreciation and accretion expenses associated with the ARO for rate setting purposes. Under accounting requirements, the depreciation expense relates to the amortization of costs, arising from the obligation, which are capitalized in a fixed asset (e.g., transformer), and the accretion expense relates to the increase in the carrying amount of the obligation due to the passage of time. On an annualized basis, Thunder Bay has included $67,300[20] in depreciation and accretion expenses for costs associated with destruction of oil, solid waste and transport. These costs appear to be related to old transformers that will be removed from service. From a regulatory perspective, where depreciation and accretion expenses associated with the ARO are

[19] Section 3110, Asset Retirement Obligations

[20] Response to Board staff supplemental IR #3 d)

allowed in rates, the costs arising from the ARO (e.g., destruction of oil, solid waste and transport costs) when settled at “retirement” should not be included in future rates as this would constitute a double counting of costs.

Thunder Bay is also claiming a return of $3,239 on the ARO included in rate base. While this amount is lower than it normally would have been had Thunder Bay requested the maximum approved ROE (now at 8.01% whereas Thunder Bay is requesting an ROE of 3.75% and weighted cost of capital of 1.91%), staff is of the view that the accretion expenses of $21,941 should not be included in the revenue requirement as it represents the carrying amount of the ARO. Since the applicant is claiming a return on the underlying ARO asset in rate base (i.e., ARO component added to the net fixed asset values), it appears inappropriate in principle that it should also recover the accretion expense.

Overall, Board staff has no concerns with the quantum proposed or with the accounting treatment afforded by Thunder Bay for rate setting purposes (with the exception of the annualized OM&A costs which should be averaged over four years instead of three and any accretion expense approved for recovery). Staff notes that Thunder Bay’s proposal is based on new Federal Government legislation that accelerates the removal and complete destruction of all PCB’s in service and storage. Thunder Bay appears to have provided a comprehensive plan to address all known contaminated transformers and the plan is scheduled to be completed in advance of the 2025 deadline. The Board will have an opportunity to review the status of Thunder Bay’s implementation of its proposed plan in or around 2013 when Thunder Bay files for its next rebasing application.

Tree Trimming and Line Clearing Operations

In 2007 Thunder Bay spent $545K on Tree Trimming and Line Clearing Operations and plans to spend $523K and $767K in 2008 and 2009 respectively. In 2006 Thunder Bay spent $286K while the 2006 EDR budget was $327K. Thunder Bay explained the spending increase since 2006 as follows:

> “… regular scheduled forestry practices for line clearing were downsized in the past [part of an overall cost reduction strategy] resulting in vegetation growing relatively unchecked into the power lines causing many unscheduled power interruptions and increasing the safety risk to the public and power line workers. Present levels of vegetation that are in proximity to overhead lines will require 10 years of intense management in

> order to reduce both hazardous situations and achieve a sustainable trimming cycle." [21]

Thunder Bay indicated that beyond 2009, this level of expenditure will be required until 2016 to get to a sustainable level. Staff notes that this reflects an acceleration of Thunder Bay's vegetation management cycle from ten years to seven years to align with Thunder Bay's current overall rehabilitation strategy. The trend for vegetation management seems to follow that of capital expenditures; that is, as Thunder Bay has previously followed an approach of cost minimization, increased costs are now necessary to deal with the consequences arising from the decision to minimize costs.

Board staff notes that the spending on line clearing averaged approximately $340K (including inflation) annually, with a low of $275K in 2003 to a high of $545K in 2007 [22]. In 2008 Thunder Bay forecast to spend approximately 5% less that it did in 2007. Given the historical variability and despite the estimated costing provided in E1/T2/S3 p.3-8 – Shared Services, staff is of the view that an increase in the range of 75% to 100% of the historical average is more than sufficient to fund a sustainable forestry program.

Thunder Bay also requested additional funding in the amount of $16K for its forestry education and awareness programs on the basis that this investment should reduce, in the long term, tree trimming costs. Board staff suggests that Thunder Bay provide an update on the status and success of this program in its next re-basing application.

Regulatory Costs

The table below summarizes Thunder Bay's regulatory costs as staff understands them from the evidence. Thunder Bay records its regulatory expenses in two accounts, neither of which is account 5655 – Regulatory Expenses.

[21] E4/T2/S2/ p.4 - Variance Analysis on OM&A Costs
[22] E1/T2/S3/p.4 – Shared Services

Regulatory Related Costs in OM&A		2006	2007	2008	2009
Account 5630 (Outside Services)					
	oral hearing consulting	$ -	$ 23,154		
	other consulting		$ 9,934		
	rebasing consulting (note1)			$ 25,000	$ 33,000
		$ -	$ 33,088	$ 25,000	$ 33,000
Account 5665 (Miscl. & General) (note 2)					
	cost awards	$ 1,030	$ 7,485	$ 9,100	$ 9,523
	cost assessment	$ 114,633	$ 113,753	$ 119,600	$ 126,527
	other	$ 800	$ 4,184	$ 1,300	$ -
		$ 116,463	$ 125,422	$ 130,000	$ 136,050
Total		**$ 116,463**	**$ 158,510**	**$ 155,000**	**$ 169,050**

Note1: provision in 2009 reflects 3 year amortization of $100K in consulting costs related to rebasing.
Note 2: excludes ESA costs
Source: Board Staff IR #19, Energy Probe Supplmentary IR # 7

Board staff notes that the projected consulting costs for the 2009 proceeding, estimated to be $99K, are amortized over three years. The Board may wish to amortize costs related to the 2009 EDR proceeding over 4 years as the next cost of service review would occur in 2013 under the 3rd generation IRM plan. Amortizing the projected total over 4 years would reduce the 2009 OM&A by approximately $8K. With respect to the quantum, Board staff notes that Thunder Bay attested to the fact that the 99K figure was an estimate exclusive of technical conference and oral hearing costs[23].

With respect to the recording of regulatory costs, the Board may wish to direct Thunder Bay to utilize the appropriate account (5655), as described in the *Accounting Procedures Handbook for Electric Distribution Utilities*.

Non Recurring Expenses

In response to Board staff IR #18, Thunder Bay indicated that there is $255K in the 2009 test year budget for Meter-Reading costs, which are expected to decrease to $125K in 2010 and $25K in 2011 and 2012 as a result of the Smart Meter Implementation Plan.

All other expenditures being equal, during 2010, 2011 and 2012 Thunder Bay's shareholder will realize a pre-tax gain of approximately $590K. This equates to

[23] Response to Energy Probe supplemental IR #8

approximately 1.5% of the OM&A budget during the period in question. Board staff submits that the Board may wish to adjust Thunder Bay's 2009 revenue requirement to ensure that the ratepayers benefit from this expected cost reduction.

Thunder Bay Hydro Corporation Board of Directors Costs

In response to Energy Probe IR #18 and Energy Probe supplemental IR #6, Thunder Bay indicated that there are costs in its OM&A related to Thunder Bay Hydro Corporation's Board Honorarium that should be removed. Thunder Bay did not identify the amounts but did indicate that the relevant costs would be removed from OM&A in the final reconciliation of the revenue requirement. Staff is unsure if this statement refers to the filing of the draft rate order or if it refers to the reconciliation table provided by Thunder Bay as an attachment to Thunder Bay's responses to Board staff's supplemental interrogatories. The latter table identified $14,743 removed from OM&A and $14,785 as the total reduction to the revenue requirement. In its reply submission, Thunder Bay should confirm the dollar amount including the 4 digit account that is used to record the costs.

RATE BASE

Background

Thunder Bay documented its rate base in Table 1 in E2/T1/S1 – Rate Base Overview. This is summarized in the following table, which also includes working capital, accumulated depreciation and annual depreciation expense. Board staff also added annual percentage changes and other statistics to better understand and demonstrate Thunder Bay's capital asset spending over time.

Summary of Thunder Bay's Rate Base, Depreciation and Working Capital Allowance

Description	2006 Board-approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Gross Fixed Assets	$ 117,366,079	$ 128,359,838	$ 132,593,627	$ 137,977,953	$ 145,434,516
Accumulated Depreciation	$ 58,223,541	$ 68,017,440	$ 71,981,194	$ 76,881,949	$ 81,830,062
Net Book Value	$ 59,142,538	$ 60,342,398	$ 60,612,433	$ 61,096,004	$ 63,604,454
Average Net Book Value	$ 59,043,741	$ 59,742,468	$ 60,477,416	$ 60,854,219	$ 62,350,229
Working Capital (Base)	$ 80,701,290	$ 80,899,106	$ 85,177,351	$ 84,859,730	$ 85,462,799
Working Capital Allowance	$ 12,105,194	$ 12,134,866	$ 12,776,603	$ 12,728,960	$ 12,819,420
WCA Factor	15%	15%	15%	15%	15%
Rate Base	$ 71,148,935	$ 71,877,334	$ 73,254,018	$ 73,583,178	$ 75,169,649
Annual Depreciation			$ 3,963,754	$ 4,900,755	$ 4,948,113
Accumulated Depreciation as a % of GFA	49.61%	52.99%	54.29%	55.72%	56.27%
Change in GFA			$ 4,233,789	$ 5,384,326	$ 7,456,563

Annual percentage change:	2006 Board-approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test	3 year average growth rate (geometric)
Gross Fixed Assets		9.37%	3.30%	4.06%	5.40%	4.25%
Accumulated Depreciation		16.82%	5.83%	6.81%	6.44%	6.36%
Net Book Value		2.03%	0.45%	0.80%	4.11%	1.77%
Average Net Book Value		1.18%	1.23%	0.62%	2.46%	1.43%
Working Capital Allowance		0.25%	5.29%	-0.37%	0.71%	1.85%
Rate Base		1.02%	1.92%	0.45%	2.16%	1.50%

Discussion and Submission

Thunder Bay's rate base shows only small increases, averaging 1.50% per annum from 2006 to the 2009 test year. Both average Net Fixed Assets and Working Capital Allowance show similar trends.

Thunder Bay has documented that it has been operating under a "rate minimization" approach since 1994. In addition to minimizing the cost of capital recovered in rates, it has stated that capital and even operating expenditures in areas such as vegetation/forestry management were reduced. Board staff makes further comments on these areas elsewhere in this submission.

With respect to rate base, the impacts can be seen in Table 1 above. While Thunder Bay is increasing its capital expenditures in recent years, there is only a very slight increase in net fixed assets. Further, accumulated depreciation as a percentage of Gross Fixed Assets is increasing over time.

Thunder Bay is proposing increases to capital expenditures to rehabilitate parts of its network. Board staff submits that the record supports Thunder Bay's proposal for 2009.

As a general observation, Thunder Bay's network is getting older. Staff submits that the underspending by Thunder Bay historically has been a major factor. Board staff makes further comments on Thunder Bay's long-term capital planning under Capital Expenditures and Cost of Capital.

Beyond the comments made above and elsewhere in this submission, Board staff takes no issue with Thunder Bay's proposed 2009 rate base.

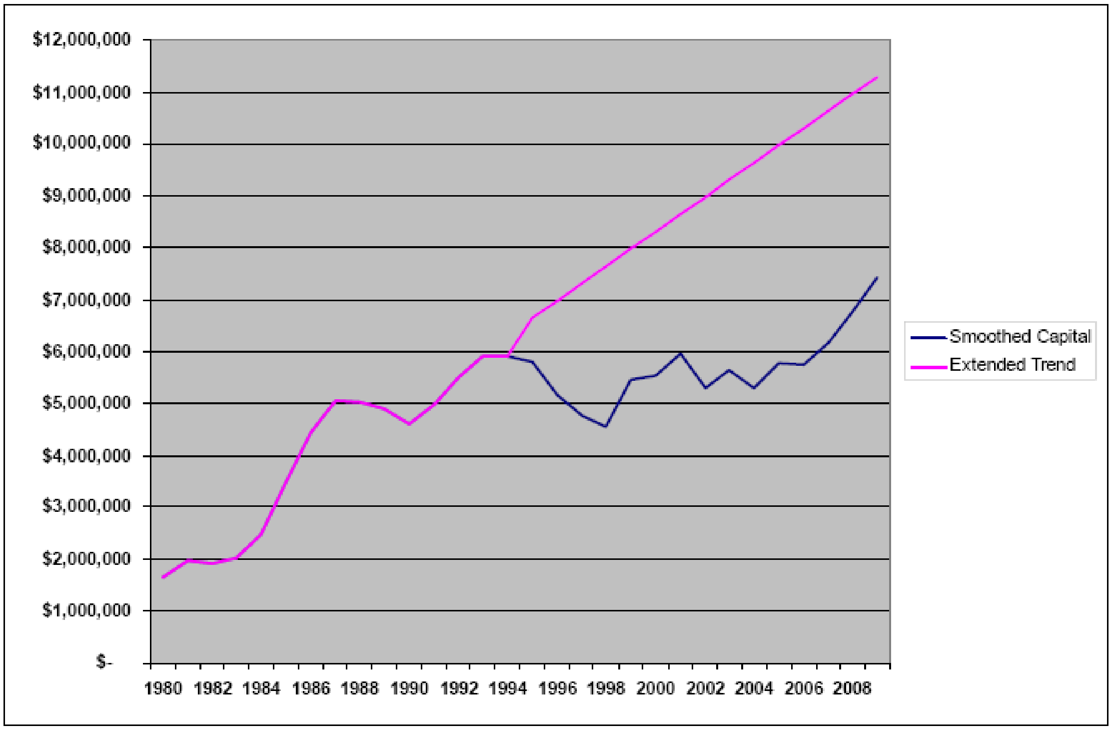
Capital Expenditures

Background

Thunder Bay documented its capital expenditures in E2/T3/S1 – Overview and Capital Budget By Project. In Appendix A of E2/T3/S1, Thunder Bay provided a chart showing actual capital expenditures since 1980. This is duplicated below. One point raised by Thunder Bay throughout its Application is the fact that it has been operating on a "rate minimization" approach in accordance with its shareholder's desire to minimize the rate impacts on its ratepayers. Thunder Bay started to reduce capital expenditures in 1994, as shown by the blue actuals (lower line) in the chart below. Thunder Bay included a trend line, shown in magenta (higher line), which shows the actuals from 1980 to 1993 if they were continued.

Historical Review of Capital Expenditures

1980 - 2008



Clarification on certain capital expenditures was provided by interrogatory responses. In particular, Thunder Bay provided the data depicted in the above graph in response to Board staff IR #22. Supplemental interrogatories were also asked to further explore Thunder Bay's rate minimization approach and the increased capital that Thunder Bay stated is required to sustain and rehabilitate its distribution network.

Discussion and Submission

Board staff does not take issue with Thunder Bay's proposed capital expenditures of $8.2 million for 2009.[24] In Board staff's view Thunder Bay has provided reasonable explanations in support of the various capital projects which are required to handle growth, and to sustain and rehabilitate parts of its network.

Accumulated depreciation, as a fraction of gross fixed assets, has increased. Board staff interprets this as a signal of an aging network.

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[24] Ref: Response to Board staff IR #22. This amount is total capital expenditures, excluding contributed capital, water heaters, and the Thunder Bay building. The "actuals" shown in the chart are smoothed.

Board staff observes that service reliability indicators submitted by Thunder Bay (reproduced below) show worsening performance for System Average Interruption Duration Index (“SAIDI”) and System Average Interruption Frequency Index (“SAIFI”), while Customer Average Interruption Duration Index (“CAIDI”), a measure of how long, on average, an interrupted customer is without power during an out-of-service incident, is reasonably stable and reasonable for a larger urban utility.

YEAR	SAIDI	SAIFI	CAIDI
2003	1.01	1.81	0.56
2004	1.96	2.72	0.72
2005	1.94	2.82	0.69
2006	1.62	0.52	0.80
2007	2.00	3.30	0.61

Source: E1/T2/S1– Summary of Application
Appendix A - Achieved Levels of Service Quality Indicators

Thunder Bay included detailed tables showing its service quality and reliability performance over recent years. The statistics for SAIDI and SAIFI are consistent with the need for system rehabilitation, however overall performance does not indicate major concerns. The stability of CAIDI does not point to any concerns with Thunder Bay’s efforts to manage outages when they occur. Generally, Board staff takes no issue with the evidence provided.

Deteriorating reliability, as depicted in the SAIDI and SAIFI statistics, is consistent with the effects of an aging network. Board staff views under spending on capital expenditures from 1994 to 2006 as a major factor, and one that Thunder Bay has begun to address.

Notwithstanding this, Board staff expresses some concern over Thunder Bay’s rate minimization approach, both with respect to capital investments and with respect to Cost of Capital (discussed elsewhere in this submission). In its response to Board staff supplemental IR #12, the Applicant provided further information on the historical situation of Thunder Bay as a municipal utility operating on a “Power at Cost” basis and a rate minimization model. Thunder Bay indicated that its decisions to reduce capital spending beginning in 1994, and the eventual introduction of the rate minimization model, are unrelated. Nevertheless, Board staff's concern is prospective and relates to the impacts on the utility and its ratepayers stemming from the historical rate minimization and/or under spending which now necessitate significantly higher expenditures.

In this respect, rate minimization is a false premise. While customers have experienced rates lower than they would have otherwise, Thunder Bay now finds itself in a situation whereby Thunder Bay's future customers may be asked to pay higher rates to recover increased expenditures in order to rehabilitate deteriorating parts of the network. Board staff also observes the false economy in Thunder Bay's forestry management, where the utility is proposing significantly higher operating costs than it would need on a long-run basis to be able to redress historical under spending. This "feast or famine" approach does not seem reasonable and does not seem to offer economical benefits. Further, as mentioned above, Thunder Bay's customers may now be experiencing some deterioration in reliability which the utility must now address. In Board staff's view, Thunder Bay should take a longer-term view of the investments it needs to sustain the network and to handle changes in demand, and to smooth capital expenditures. In so doing, it should also consider the need for and its ability to attract and retain capital financing.

Board staff makes the following submission on the trend analysis shown in the above chart. In Board staff supplemental IR #12, staff sought an analysis from the utility that would take into account customer growth and inflation. Staff submitted a spreadsheet comparing the data used to develop the two trend lines above with real capital expenditures (i.e. adjusted for inflation) and customer growth. Staff asked Thunder Bay to input customer numbers and to confirm all data. The purpose of the question was to establish a more robust trend line that would better reflect a reasonable extrapolation of the "what if" scenario. Thunder Bay did not provide the revised spreadsheet with its customer numbers, but confirmed the numbers that Board staff entered in the spreadsheet provided with the interrogatory. Thunder Bay disagreed with Board staff's approach and suggested that this approach would oversimplify the data. While Board staff notes that the analysis premised in the interrogatory does not take into account all factors, staff submits that the analysis suggested would be superior to the trend line shown by Thunder Bay.

While Thunder Bay did not provide the revised spreadsheet, Board staff prepared the following summary, based on the spreadsheet numbers confirmed by Thunder Bay and its interrogatory response to the request, to demonstrate the change that occurred over time, and specifically between 1980 to 1994 and from 1994 onwards.

Annual Growth Rates (Geometric)

	Capex	Number of Customers	GDP-IPI (National)	Capex (real $)
1980-1994	10.68%	1.07%	4.45%	5.96%
1994-2007	-0.96%	0.33%	1.70%	-2.62%
1980-2007	4.91%	Not provided	3.12%	1.74%

Staff observes that both customer growth and inflation (as proxied by the percentage change in the Implicit Price Index of the Canadian Gross Domestic Product (Final Domestic Demand) ("GDP-IPI (FDD)")[25], declined in the period 1994 to 2007, along with Thunder Bay's capital expenditures. In addition to Thunder Bay's adoption of "rate minimization" and all else being equal, the decline in both customer growth and in inflation from 1980 to 1994 would also have influenced lower annual capital expenditure changes. Based on this, Board staff views that the "extended trend" line in the Historical Capital Expenditure table above is an overestimate of what Thunder Bay's annual capital expenditures would have been if it had not embarked on "rate minimization". Based on lower rates of inflation and customer growth since 1994, staff submits that any trending in "normal" capital expenditures would be lower than the "extended trend" line shown in the chart.

The importance of this is not to challenge Thunder Bay's capital expenditures proposed for 2009, but to give a better sense of what is an appropriate level of annual capital expenditures needed in the short- to mid-term to sustain Thunder Bay's network, including those expenditures needed to redress historical under-investment. In Board staff's view, the trend shown in Thunder Bay's application should be given no significant weight. For example, the $8.2 million proposed by Thunder Bay is not a conservative estimate (as the graph might suggest) but one that may in all likelihood be commensurate with Thunder Bay's current system needs including system rehabilitation. As a result, expenditures in future rate applications should be evaluated in the same light.

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[25] GDP-IPI (FDD) is an accepted Government statistic that is used as a proxy by the Board for the rate of inflation in incentive rate adjustment mechanisms.

Thunder Bay has extensively documented the Asset Management program that it is developing to aid it in its operations and decision making. This is discussed in E2/T1/S1/p.3-19 – Rate Base Overview. Staff observes that the documentation provided regarding 2008 and 2009 capital programs in Appendices B and C (respectively) of E2/T3/S1- Overview and Capital Budget By Project is largely traditional in nature. It is Board staff's view that Thunder Bay's Asset Management program should contain a more disciplined and informed perspective for investing in and operating its network. It should also result in Thunder Bay being able to estimate and support its annual capital expenditures based on a more realistic forecast as noted above. Board staff submits that, in its next Cost of Service rebasing rate application, Thunder Bay should file a more rigorous Asset Management plan in support of its proposed capital investments.

Depreciation Expense

Background

Thunder Bay documented its depreciation expense in E2/T2/S4 – Accumulated Depreciation Table and E4/T1/S1 – Review of Operating Costs. Board staff has summarized the annual depreciation expense as shown on Table 1 of E4/T1/S1 below.

Description	2006 Board-approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test	Annual % change: 2009 test year over 2006 actual
Depreciation Expense	$ 4,056,140	$ 4,382,390	$ 4,564,773	$ 4,526,557	$ 4,573,436	1.43%

Further explanation and correction of Thunder Bay's depreciation expense and in particular the depreciation rates it uses, were provided in response to Board staff interrogatories.

Discussion and Submission

In general, Board staff observes that Thunder Bay's annual depreciation expense is relatively flat. With the exception of the depreciation rate for computer hardware, Board staff has no concerns with Thunder Bay's methodology for the proposed depreciation expense.

Board staff observes that Thunder Bay complies with the Board's policies and uses the depreciation rates as documented in Appendix B of the 2006 *Electricity Distribution Rate Handbook* (the "2006 EDRH"), with the exception of Computer Hardware.

Thunder Bay has documented[26] that it uses a three-year amortization rate for computer hardware, in contrast with five years as documented in Appendix B of the 2006 EDRH, and has been doing so since December 2004. Board staff notes that this is the first time that this has come to the attention of the Board. As stated in Thunder Bay's response to Board staff supplemental IR #10, Thunder Bay did not raise this matter in its 2006 EDR application (RP-2005-0020/EB-2005-0419), despite the instructions in the 2006 EDRH.

In the response to Board staff supplemental IR #10, Thunder Bay stated that it has adopted a three-year depreciation for computer hardware, after considering the policies of similar companies and the costs of extended warranties. However, Thunder Bay has not identified the comparator firms it has used, nor does it have a formal study supporting the higher depreciation rate. Board staff notes that most electricity distributors use the guideline five-year rate documented in the 2006 EDRH. Staff also notes that the depreciation or amortization is an estimate of the *average* expected useful economic life of the class of assets; some assets will break down or wear out and require replacement sooner, while others may last longer. A three year depreciation rate and the corresponding replacement of computer hardware is costly. No evidence has been provided to establish that such frequent expenditures are necessary.

All things being equal, Thunder Bay's three-year depreciation and replacement of computer hardware would be more costly and result in higher rates for its customers. Board staff also notes that Thunder Bay, through its affiliate, Thunder Bay Hydro Utility Services Inc., provides services, including CIS and billing, for other distributors in North Western Ontario. Faster computer depreciation would result in higher costs passed through in service costs and, ultimately, in higher rates for distributors that are serviced by Thunder Bay through its affiliated company.

Board staff submits that no justification has been provided for a three-year depreciation rate for computer hardware. As a result, Thunder Bay should use the standard five-year depreciation rate as documented in the 2006 EDRH.

[26] Response to Board staff IR #25, Energy Probe IR #7 and Board staff supplemental IR #10.

Cost of Capital

Background

The Cost of Capital pertains to the cost required to compensate investors and lenders for the monies provided to fund the assets that the firm uses to produce the goods and services to its customers. It compensates for the opportunity cost for the time that the money is invested until recovery, as well as the risk of recovering their investments, based on the business risk of the firm in its market(s) relative to the risks of investing elsewhere. The Cost of Capital relates to the return on the rate base of the regulated firm. There are several parameters that comprise the cost of capital for the Board's rate-making purposes:

1) Capital structure (the proportion of rate base financing through debt (long- or short-term) or equity (common shares or preferred shares));
2) Long-term debt rate;
3) Short-term debt rate;
4) Return on Equity ("ROE"); and
5) Return on preferred shares.

These components combine together to determine the weighted average cost of capital ("WACC"). Multiplied by the rate base, this produces the net income relating to the expected profitability of the firm, and also directly influences the tax or PILs expense borne by the firm and to be recovered in rates.

The Board has documented its Cost of Capital methodology in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"), issued December 20, 2006. While the Board Report is a guideline, departures from the methodology in the Board Report must be adequately supported.

In Exhibit 5 of its Application, Thunder Bay proposed its Cost of Capital for purposes of setting 2009 rates. This is summarized in the following table.

Cost of Capital Parameter	**Thunder Bay Hydro's Proposal**
Capital Structure	56.7% debt (composed of 52.7% long-term debt and 4.0% short-term debt) and 43.3% equity
Short-Term Debt	4.47%, but to be updated in accordance with section 2.2.2 of the Board Report, as confirmed in response to Board staff IR #24.

Long-Term Debt	0.21%, as a weighted average of affiliated and third-party debt (Ref: E5/T1/S1, E5/T1/S3 and response to Board staff IR #27).
Return on Equity	3.75%.
Return on Preference Shares	Not applicable
Weighted Average Cost of Capital	1.91% as proposed, but subject to change as the short-term debt rate is updated per the Board Report at the time of the Board's Decision.

As noted, Thunder Bay has affirmed that the deemed Short-term Debt Rate would be updated based on Bank of Canada, Consensus Forecasts, and TSX data for January 2009 in accordance with the methodologies documented in the Board Report. On February 26, 2009, the Board issued a letter to all distributors announcing the updated Cost of Capital parameters to be used for rate-setting in 2009 Cost of Service electricity distribution rate applications. These updated parameters are:

Return on Equity:	8.01%
Deemed Long-term Debt Rate:	7.62%
Deemed Short-term Debt Rate:	1.33%

Discussion and Submission

Since coming under the Board's regulatory oversight, Thunder Bay has adopted a rate minimization approach. The City of Thunder Bay has not required a return on equity. Thunder Bay's debt financing, through the City of Thunder Bay, has been minimal. In previous rate applications, Thunder Bay has requested an ROE which is less than what the Board has allowed. In 2006, Thunder Bay requested and was granted an ROE of 2.93%. Thunder Bay Hydro has continued its practice of requesting a reduced ROE; in this Application, they are requesting an ROE of 3.75%.[27]

Thunder Bay's practice of requesting a reduced ROE combined with its reduced capital investments to maintain and grow its network under "rate minimization", have maintained low rates for ratepayers. However, given that Thunder Bay requires larger capital expenditures to rehabilitate its network, it needs to attract and retain capital financing, primarily with third party financial institutions. The cost of capital, when factored into rates, impacts on the utility's financial viability and on its ability to attract

[27] An exception is that Thunder Bay has stated that it requires an ROE of 7.90% to be able to recover the principal and interest of smart meters being installed and financed through debt. Board staff's comments on Thunder Bay's smart meter programme are discussed elsewhere in this submission.

and retain capital financing. For this reason, Board staff is of the view that Thunder Bay's proposed ROE of 3.75%, which is an increase over previous equity returns, reflects a longer term view of its need for capital and should facilitate the utility's ability to attract and retain other capital financing if necessary. Board staff does not oppose Thunder Bay's proposed ROE. When it next applies to rebase its rates, Thunder Bay should give further consideration to its capital requirements and the return necessary to attract and retain capital, and explain how its approach is consistent with its improved Asset Management plan discussed above.

Thunder Bay's actual long-term debt for 2009 is forecasted to be $34.6 million at a weighted average rate of 0.21%. The long-term debt is based on debt owed to the shareholder, with a debt rate of 0% ($33.5 million), and forecasted debt financing for smart meter investments in the amount of $1.1 million. While Thunder Bay has indicated that the smart meter financing is not finalized, it believes that the financing can be achieved at a rate of 6.0%. The Board policy is that new debt with unspecified terms would attract the current deemed long-term debt rate, recently announced at 7.62%. In response to Board staff supplemental IR #14, Thunder Bay indicated that it did not expect that the long term debt would be in place by the end of April 2009 and so it assumed a rate of 6.0% based on the 6.1% approved for 2008. Staff notes that Thunder Bay submitted its supplemental interrogatories on February 11, 2009 and that the Board announced the new rates on February 24, 2009. In light of Thunder Bay's belief that this new debt can be realized at a rate of 6.0%, Board staff does not oppose Thunder Bay's proposal although the Board may wish to consider that a strict application of the Board's policy would require Thunder Bay to use the known deemed rate of 7.62%.

Subject to the comments above, Board staff submits that Thunder Bay's proposals for Cost of Capital, as amended through discovery, should comply with the guidelines documented in the Board Report.

Smart Meters

Background

Thunder Bay is not a distributor explicitly or implicitly named in the regulation as being previously authorized to deploy smart meters. However, on June 25, 2008, the Government enacted O. Reg. 238/08 amending O. Reg. 427/06 which authorizes any distributor which "has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc."[28]

In its original Application, Thunder Bay proposed to increase the smart meter funding adder, currently approved at $0.27 per month per metered customer, to $1.25, and advised that it was in the process of meeting the requirements of the amended regulation through participation in and compliance with the London Hydro RFP process.

On October 22, 2008, the Board issued *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery* (the "Smart Meter Guideline") to establish guideline policies and filing requirements on cost tracking and applications for cost recovery in light of the amended regulations.

In the responses to Board staff IR #28 and #29, Thunder Bay filed supporting documentation in accordance with section 1.4 of the Smart Meter Guideline. Thunder Bay stated that it plans on starting smart meter deployment in 2009, and that it intends to deploy approximately 49,000 smart meters this year. This would represent full deployment in 2009. Thunder Bay estimated that smart meter expenditures in 2009 will be $8,960,950 with an estimated average installation cost of $182.50 per installed smart meter. OM&A costs for 2009 were estimated at $260K. Thunder Bay is not seeking approval for capital and operating costs incurred to date or in 2009, but will track actual costs, and revenues received by way of the funding adder, in established deferral accounts for review and disposition in a subsequent application.

It should be noted that in the Adjustments table and in the response to Board staff supplemental IR #15, Thunder Bay identified adjustments for smart meter related costs in OM&A. Thunder Bay showed a decrease of $600,319 followed by an increase of

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[28] Section 8, O. Reg. 427/06, s. 1 (1); O. Reg. 153/07, s. 1 (1); O. Reg. 235/08, s. 2 (1-4).

$425,186 for a net decrease of $175,133. Thunder Bay identified these costs as "Meter and Service OM&A". The $425K number is identified as a three year annualized number. It is not readily apparent why Thunder Bay has made this adjustment to the 2009 revenue requirement when all its proposed smart meter costs for 2009 are included as part of the smart meter rate adder, outside of the base revenue requirement. Thunder Bay's explanation in response to Board staff supplemental IR #15 is confusing. If in fact these costs are included in OM&A, Thunder Bay should identify in its reply submission the four digit OM&A account number where these costs reside and confirm that these costs are not related to smart meter implementation costs but rather the forecasted costs of servicing smart meters annually based on an average three year cost estimate.

In response to Board staff supplemental IR #15, Thunder Bay revised its request for the smart meter adder from $1.25 to $1.97. This reflected slight changes in capital and operating expenses and the treatment of smart meters as being wholly debt-financed at 6.00%. Thunder Bay stated that these new figures represent updated current costs based on the results of recent contract negotiations affected by such items as volume purchase rates and price adjustments. Thunder Bay identified additional costs due to:

i. conversion of over 500 three-phase GS < 50 kW customers who will need to be upgraded to meet Measurement Canada requirements; and
ii. increased use of Thunder Bay's own staff to handle more difficult smart meter installations and conversions.

Discussion and Submission

The Smart Meter Model

Thunder Bay submitted a PDF copy of a spreadsheet in Appendix A in response to Board staff supplemental IR #15. The spreadsheet was marked as being a "Smart Meter Model (Updated by Board Staff in November 2008)". Board staff confirms that neither the Board nor Board staff has provided a Board-approved model to determine smart meter costs and recovery, with the exception of the model that was issued in January of 2007. The January 2007 Smart Meter model was specifically designed for the May 1, 2007 rate adjustments under the 2nd Generation Incentive Regulation Mechanism then in effect. No similar model has been provided by the Board or by Board staff.

In its original application, Thunder Bay proposed a smart meter rate adder of $1.25 based on a debt/equity split of 60/40 consistent with the Applicant's capitalization used to determine its base distribution rates. The debt and equity rates used were 6.00% and 3.75% respectively (with the latter consistent with its application proper).

In the response to Board staff IR #29 and Energy Probe IR #29 d), Thunder Bay revised its request for the ROE stating that it would require an ROE of 7.90% for smart meter investments to be able to recover the principal and carrying costs of the smart meters over the expected 15-year life, as shown in the smart meter model filed with the original application. Thunder Bay provided a calculation showing the funding shortfall that would result from using a 3.75% ROE. Thunder Bay did not file a revised smart meter model. The proposed rate adder remained at $1.25.

Board staff submitted supplemental interrogatories to address the appropriateness of using an ROE different from the one used to generate the base distribution rates and one that is greater than the debt rate identified specifically for the financing of smart meters (6.0%). Thunder Bay's responses to the supplemental interrogatories will be addressed below.

Board staff is concerned with the inputs and outputs of the model due to the curious shortfall that resulted when using a 3.75% ROE. Board staff has two general concerns.

First, in terms of capital financing, particularly through equity, it is unusual and illogical to require a different equity return for different types of assets. Equity, or the shareholders' investment in the firm, is not tied to specific assets. While the 7.90% ROE for smart meters is below the recently announced ROE of 8.01%, it is materially different from Thunder Bay's requested ROE of 3.75%.

Second, Board staff does not understand the logic behind the need for an ROE of 7.90% to be able to recover, over the 15-year life, the principal and carrying costs of smart meters which Thunder Bay has stated are being financed 100% through debt at 6.00%.

In its response, Thunder Bay stated, "Due to the weighted average of the funding structure and rate of return, and the need to recover $4.4M in interest costs, formulaically, all other things given, the rate of return for equity funding needs to approximate 7.9% as presented in the response."[29] This response did not demonstrate how, formulaically, this is so. While Thunder Bay provided a calculation in response to Energy Probe IR #29 identifying the shortfall that would occur using a 3.75% ROE with a debt/equity split of 60/40, Thunder Bay chose to file a PDF version of the smart meter model and Board staff has been unable to verify the formulas and the resulting calculations in that model.

However, in the same interrogatory response, Thunder Bay revised its request once again stating that "using a 100% debt rate in the Smart Meter Model would more appropriately achieve the required funding of the Smart Meter project." Staff notes that the debt rate used in the PDF copy of the Smart Meter Model in Appendix A of the response is 6.00%.

Staff also notes that Thunder Bay has provided updated costs for 2009 reflecting the deployment of 49,000 smart meters. While it would be preferable for Thunder Bay to use the standard treatment for calculating the smart meter adder (i.e. to use the utility's debt/equity split in determining the proxy return and to use the associated rates), staff has no concerns with Thunder Bay using the 100% debt rate at 6.00% in light of the fact that this is a known variable for 2009.

Carry Over of Seed Money

Thunder Bay's proposal in the supplemental interrogatory response is premised on not applying the funding adder revenues collected since May 1, 2006 to determine the 2009 smart meter funding adder, but instead to defer application of funding adder revenues until the determination of an updated funding adder for 2010. Thunder Bay estimated that this would reduce the 2010 funding adder from $3.17 per month per metered customer to about $2.34, and would smooth the impact of smart meter cost recovery over the period of 3rd Generation IRM.

As Thunder Bay has only made this proposal in response to supplementary interrogatories there has been no opportunity to test this revision. Board staff notes that Thunder Bay's proposal is atypical in that it defers the use of the funding adder revenues, in one sense a form of prepaid or contributed capital from ratepayers, to a subsequent year. At the same time however, the smoothing effect would seem logical. Staff notes that the Smart Meter Guideline is silent on the use of revenue from historical rate adders for determining updated rate adders.

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[29] Response to Board staff supplemental IR #15 a)

Staff notes that the proposal would increase the monthly bill for metered customers by $0.72, before taxes, over that proposed in the original Application. The revised smart meter funding adder of $1.97 is larger than that proposed for most distributors, but is in line with some other applications currently before the Board.

Board staff submits that Thunder Bay has complied with the policies and filing requirements of the Smart Meter Guideline and is becoming authorized under regulation. Further, Thunder Bay is not seeking recovery of amounts invested in or expensed with respect to smart meter implementation in this application; all such costs will be reviewed and disposed of for recovery in a future application, in accordance with the Smart Meter Guideline. Hence, Board staff does not oppose Thunder Bay's proposal to increase the smart meter funding adder to either $1.25, as proposed in the original application, or to $1.97 per month per metered customer, as proposed in response to supplemental interrogatories.

COST ALLOCATION AND RATE DESIGN

Loss Factors

Background

Thunder Bay has proposed a decrease in its total loss factor ("TLF") from the current approved 4.57% to 4.48% for secondary metered customers < 5000 kW, and a corresponding increase for primary metered customers from 3.52% to 3.43%. Thunder Bay seeks approval of an increase in the TLFs for customers larger than 5000 kW, from 1.45% to 1.55%, and from 0.45% to 0.55% for secondary metered and primary metered customers respectively.

The changes in the factors are the result of an increase in the Supply Facilities Loss Factor ("SFLF") together with a decrease in the Distribution Loss Factor ("DLF"). The updated information underlying both is based on annual data 2003 – 2007, and was provided in the response to Board staff IR #48.

Discussion and Submission

Board staff submits that the requested TLFs for customers < 5000 kW are reasonable. Staff notes that other distributors have also requested a change to the default SFLF[30]. Staff has no concerns with the requested change as Thunder Bay supported its request by providing actual historical data regarding the losses on the supply facilities that specifically service Thunder Bay. Thunder Bay noted that the default 1.0045 number was based on a provincial average provided by the Board in the 2000 *Electricity Distribution Rate Handbook* to be used by distributors in the absence of available data. Thunder Bay noted that the 1.055 figure is an updated number specific to this situation.

Staff notes that there is no rate class for customers above 5000 kW, but that a TLF has been approved for this size category in the past. Staff submits that the separate loss factors do no harm, and that the proposed factors are based on the SFLF in the same way as other distributors that do have customers in this range. Thunder Bay should confirm in its reply submission whether it wants to continue to include this TLF on its tariff schedule.

Revenue to Cost Ratios

Background

Thunder Bay updated its Informational Filing (EB-2007-0001), and filed the results in E7/T1/S3 – Amended Cost Allocation Filing. The update consists of corrected data on the number of Streetlighting and Unmetered Scattered Load ("USL") connections, as well as a correction of a clerical error identified by the Applicant. The revised revenue to cost ("R/C") ratios are found in the first column below.

In response to VECC IR #7c), Thunder Bay provided an alternative run of the cost allocation model that reflects the removal of costs and revenues associated with $413,327 of transformer ownership allowance. The resulting R/C ratios are reproduced in the second column below.

Thunder Bay's application involves a re-balancing of class revenues to better reflect the results of the cost allocation model. The proposed R/C ratios for 2009 are shown in the third column. The cost allocation underlying these ratios is the same as the Informational Filing, not the version produced for the VECC interrogatory. For convenience, the Board's policy range for each class is shown in the final column.

[30] Westario Power Inc. – 2009 COS application EB-2008-0250

Revenue to Cost Ratio [%]

Customer Class	Updated Cost Allocation Run 2	Response to VECC IR 7c	Application: Exhibit 7 / Tab 1 / Schedule 2	Board Policy Range
Residential	126.08	128.71	119.13	85 – 115
GS < 50 kW	113.61	115.55	113.61	80 – 120
GS 50-999 kW	65.96	66.09	72.98	80 – 180
GS 1000 - 4999 kW	60.17	43.41	70.09	80 – 180
Street Lights	13.51	14.03	41.75	70 – 120
Sentinel Lights	105.21	109.17	105.21	70 – 120
USL	111.25	114.91	111.25	80 – 120

Thunder Bay proposes to further increase distribution rates for the two larger general service classes in two equal steps so that each class will reach a R/C ratio of 80% in 2011. It also proposes to increase the distribution rates for Streetlights in two additional equal steps to reach a ratio of 70%[31].

In response to VECC IR #6 b), Thunder Bay provided a set of ratios in which the residential class would pay lower rates to reach a ratio of 115%, and other classes would be as proposed except that additional revenue would be gained from the two larger general service classes. The general service class ratios that would result from this higher revenue turned out to be approximately 80% for both classes[32].

[31] Response to Energy Probe IR #27 a)
[32] Response to VECC IR #6 b)

Discussion and Submission

Board staff submits that the ratios proposed for 2009 in the third column above and the movement to 80% and 70% by 2011 for the two larger general service classes and the streetlighting class respectively are consistent with those that were accepted in a number of cost-of-service applications in 2008. As a result, staff has no concerns with the proposed R/C ratios.

During the course of the evidentiary stage, Thunder Bay provided a number of scenarios for its R/C ratios in response to interrogatories. Staff provides comments below on why selected scenarios may not be appropriate for the Board to rely on.

Staff notes that the existing and proposed ratio for the GS 1000 – 4999 kW class is significantly affected by how Transformer Ownership Allowance is handled in the cost allocation study. Staff submits that the logic in the cost allocation model in the format provided to distributors is internally inconsistent, and that the adjustment requested by VECC corrects the inconsistency. However, Board staff also notes that cost allocation is an imprecise procedure, and many factors can affect the outcome in addition to the Transformer Ownership allowance. The range of acceptable ratios shown in the final column of the table reflects this situation.

In this instance, for example, the 19 customers in the GS 1000 – 4999 kW class are allocated 24.3% of the cost of Thunder Bay's primary voltage facilities. As a result, approximately 16% of the cost of all poles, conduit and conductors are allocated to this class (along with this allocation goes a proportionate share of operating costs and administrative overheads)[33]. Further, the same class is allocated a share of the transformer load in proportion to its total load, not just the load served by Thunder Bay's transformers[34]. In short, before accepting that the existing ratio is accurately stated at 43.4%, the Board may wish to consider that other inputs and reasonable assumptions also influence the R/C ratio of this class and other classes. For example, Thunder Bay's cost allocation results are influenced to some extent by its split of assets into primary and secondary voltage functions, and by its allocation of transformer costs to all loads in the GS 1000-4999 kW class rather than only those that use the utility's transformer equipment.

[33] Response to Board staff IR #41 – Information Filing - Worksheets I4 and E2
[34] Response to Board staff IR #41 – Information Filing – Worksheet I8

Staff also submits that the bill impact in the GS 1000 – 4999 kW class may be unacceptably high, if distribution rates were increased consistent with moving the ratio halfway from 43.4% to 80% as suggested in Board staff supplemental IR #16 b). Staff is unconvinced by the calculations that Thunder Bay filed in response to this interrogatory and submits that the impact of moving to a ratio of 60% (calculated using VECC's adjusted version of the model) would be more adverse to the class than what is presented in the response as a rate decrease of 3.84%.

Monthly Fixed Charges

Background

Thunder Bay proposed to maintain its fixed/variable split unchanged for all customer classes. The revenue proportions from Monthly Service Charges ("MSC") and volumetric charges are found at E8/T1 /S1/Table 5 – Rate Design Overview, and the resulting charges are derived and shown in Tables 6 and 7.

The calculations of floors and ceilings for MSC's are available in worksheet O2 of the updated cost allocation study and can be compared with the rates approved in 2006. The latter are above the ceiling for four classes, as shown in the first column in the following table. The same pattern is found with the fixed charges in the application, shown in the final column[35].

[35] Response to VECC IR #8 a)

Monthly Service Charges

Units: $ / month	2006 Approved MSC	Cost Allocation Ceiling (2006)	Application 2009
Residential	11.15	10.15	11.26
GS 50 – 999 kW	185.29	110.97	224.18
GS 1000 – 4999 kW	1,622.25	332.62	2,069.12
USL	8.45	6.15	9.26

Discussion and Submission

An interrogatory pointed out that Monthly Service Charge and the volumetric charge to the GS 1000 – 4999 kW class were being increased by different percentages, and the fixed/variable split could not remain unchanged in this situation[36]. Thunder Bay clarified that the fixed/variable split is calculated using the volumetric rate net of the transformer ownership allowance, as well as being net of rate riders. When calculated using the net rate, the split for the GS 1000-4999 kW class would be unchanged from the current split. On the other hand, because the allowance is being maintained unchanged in absolute terms at $0.60 while the MSC and the net volumetric rate are being increased equally in percentage terms, there is a change in the split when all factors are included.

Board staff submits that Thunder Bay's proposal to maintain its fixed/variable split unchanged is consistent with previous Board decisions[37]. It has been established that the split should be calculated on distribution rates net of adders and rate riders. Calculating the split with the volumetric rate net of the Transformer Ownership Allowance is a useful extension of this reasoning.

The Board has noted that it will not require that an existing Monthly Service Charge above the ceiling must be brought down to or below the ceiling[38]. Thunder Bay's proposed charges, described in the table above, are consistent with previous decisions. Staff submits that the relationship between the fixed charges being submitted for 2009

[36] Response to Board staff IR #43
[37] 2008 COS Decision, Sioux Lookout, EB-2007-0785, p. 22-23
[38] *Application of Cost Allocation for Electricity Distributors*, November 28, 2007, EB-2007-0667, p.12-13

would have approximately the same relationship to the ceiling calculation of a cost allocation study if one were done for the test year, given that the fixed/variable split is being maintained unchanged in the Application.

In a related matter, staff notes that most distributors have handled the charge for Smart Meters as a rate adder, whereas Thunder Bay's Application presents it as a rate rider, i.e. a separate line on the tariff for each class. Staff does note that it has been the Board's practice to embed the smart meter rate as an adder to the base distribution MSC. The Board's administration of future IRM rate changes by way of the 3rd generation IRM model accommodates for changes to smart meter rate adders in IRM years.

Retail Transmission Service Rates

Background

Thunder Bay provided 30 months of its costs of Network and Connection transmission services, together with its revenues from its Retail Transmission Service ("RTS") rates. It calculated monthly ratios of cost to revenue, and for a 24-month subset of the months it calculated the average cost to revenue ratio for each of Network and Connection. It proposed retail rates that would be based on the currently approved rates, adjusted by the 24-month ratio described above.

Thunder Bay refined its calculations by using a narrower 12-month subset during which the wholesale rates and retail rates were uniform. Starting from the Uniform Transmission Rates in that period and prorating to the current ones, Thunder Bay was able to produce a forecast of its 2009 Network and Connection costs[39] at $4.6 million for Network and $3.7 million for Connection. It also calculated RTS Rates for each class that would recover the forecasted costs[40].

Discussion and Submission

Thunder Bay has expressed some misgivings about its forecast of Network and Connection costs, pointing out that the accuracy is affected by changes in the composition of loads and in how this affects the charge determinants from the IESO[41]. Nonetheless, Thunder Bay indicated in response to Board staff supplemental IR #19

[39] Response to Board staff IR #43 b)
[40] Response to Board staff supplemental IR #19 b)
[41] Response to Board staff IR #46 b)

that it has revised its request for RTS Rates that are designed to recover the cost forecast. Board staff submits that the methodology in Thunder Bay's interrogatory responses appears to be an improvement over the previous approach, and supports Thunder Bay's revised rates.

Other Distribution Revenue

Background

Revenue offsets decrease the need for revenue from distribution rates. Thunder Bay originally forecasted $1,802,790 in revenue offsets for 2009, compared to more than $2 million actual in 2007. Thunder Bay provided a breakdown of its revenue offsets in E3/T3/S1 –Summary of Other Distribution Revenue.

Discussion and Submission

In response to Board staff IR #40, Thunder Bay provided a description of several changes to the revenues and costs of the regulated distributor, in accounts 4375 and 4380, and its forecasts of a smaller profit margin than in prior years. Staff does not have any objection to these changes to the Revenue Offset. The changes are explained by Thunder Bay, and they mirror changes in its transactions with unregulated affiliates.

The other major change is a decrease in account 4405 - Interest and Dividend Income from actuals of $606K in 2006 and $565K in 2007, down to $439K in each of the forecasted bridge and test years. In response to Energy Probe supplemental IR #5, Thunder Bay adjusted the 2009 number to $195K citing the drop in interest rates since the original filing of the application. In the revenue requirement Adjustments table provided by Thunder Bay, it appears that Thunder Bay used a rate of 1.3%. Staff notes that this is a reasonable market based rate.

On a related matter, Staff notes that it appears from the continuity schedule provided that Thunder Bay used the prescribed interest rates for purposes of generating the variance and deferral account balances.

For account 4405, Thunder Bay also noted that should the OEB order disposition of the regulatory asset balances, the amount in account 4405 would be reduced further to $130,000. In the revised Adjustments table submitted by Thunder Bay on March 6, 2009, Thunder Bay corrected the amount for account 4405 to $130,000. Staff notes that interest associated with variance or deferral account balances should not impact t the revenue requirement in the form of Other Distribution Revenue and that this latest adjustment proposed by Thunder Bay is appropriate. The net effect is that Thunder Bay's revised base revenue requirement is increased by $309,000.

Specific Service Charges

Background

Thunder Bay proposes to remove three specific service charges from its tariff, and to recover the cost of providing the services with a charge for time and materials. The services in question are all for installation and removal of Temporary Service in various situations. The existing approved charges are

- $500 for overhead service with no transformer;
- $300 for underground with no transformer; and
- $1000 for overhead with transformer.

Discussion and Submission

Thunder Bay submitted that the cost of providing the temporary service connections varies to such an extent that applying a standard charge is inequitable even with the three different charges available. Staff notes that the requested change has no impact on the revenue offset[42]. The forecast of revenue in Account 4235 - Miscellaneous Service Revenues is constant at the 2008 bridge year level, which is higher than previous years. Staff submits that Thunder Bay's request to discontinue the standard charges for temporary services is reasonable.

Deferral and Variance Accounts

Background

Thunder Bay is not requesting disposition of any variance or deferral account balances. In response to Board staff IR #47 a), Thunder Bay provided the following balances representing principal transactions to December 31, 2007 and interest to April 30, 2009. The total balance is ($2,139,323), excluding the second group of accounts listed below.

[42] Response to Board staff IR #45

Account Number	Account Description	Total ($)
1508	Other Regulatory Assets – Sub-Account – OEB Cost Assessments	157,660
1508	Other Regulatory Assets – Sub-Account – Pension Contributions	594,221
1518	Retail Cost Variance Account - Retail	152,132
1525	Misc. Deferred Debits – incl Rebate Cheques	1,516
1548	Retail Cost Variance Account - STR	173,811
1582	RSVA - One-time Wholesale Market Service	70,494
	Sub-Total	**1,149,833**
1555	Smart Meter Capital and Recovery Offset	(170,202)
1556	Smart Meter OM&A	(70,833)
1562	Deferred PILs	(1,630,731)
1563	Deferred PILs Contra Account	-
1565	CDM Expenditures and Recoveries	(25,880)
1566	CDM Contra Account	25,880
1590	Recovery of Regulatory Asset Balances	298,853
	Sub-Total	**1,572,913**
1580	RSVA – Wholesale Market Service Charge	(2,129,452)
1584	RSVA – Retail Transmission Network Charge	(671,317)
1586	RSVA – Retail Transmission Connection Charges	(647,640)
1588	RSVA – Power (including Global Adjustment)	159,251
	Sub-Total	**(3,289,158)**

In order to allow the Board to evaluate the reasonableness of disposing certain of the remaining accounts, Board staff posed interrogatories, and Thunder Bay calculated hypothetical rate riders, for two scenarios. The first scenario would dispose of the RSVAs only. The second scenario would dispose of the balances in all deferral and variance accounts except for the second group of accounts in the table above

Discussion and Submission

Board staff notes that Thunder Bay has followed the Board's guidelines and is using its Deferral and Variance Accounts in a manner consistent with the definition in the Board's *Accounting Procedures Handbook* and with the procedures outlined in the *Regulatory Asset Filing Guidelines.*

Board staff notes that the calculated rate riders are quite different in the two scenarios, with the first leading to a debit rider and the second leading to rebates for all classes. For example, under the first scenario, disposing of accounts 1508, 1518, 1525, 1548, and 1582 entails a rate rider for Residential customers of $0.0017 per kWh for one year. Under the second scenario, disposing of the same accounts plus accounts 1580, 1584, 1586, and 1588 entails a rate rebate of $0.0016 per kWh[43].

Board staff notes that the separate initiative that the Board will undertake for the review of the commodity account 1588 (RSVA-Power) and other related RSVAs has not yet been established. The rules or guidelines with respect to that process are not yet known. Although it has been the Board's practice not to dispose of RSVAs (with few exceptions) until such time as the initiative noted above is established, given the magnitude of the accounts, staff suggests that the Board may wish to dispose of all deferral and variance account balances at this time (with the exception of the shaded accounts above).

- All of which is respectfully submitted –

[43] Response to Board staff IR $47 b) and d)