Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0245

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 or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009.

BEFORE: Cynthia Chaplin
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER

June 3, 2009

BACKGROUND

Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay" or the "Company") filed an application with the Ontario Energy Board on August 22, 2008, under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the rates that it charges for electricity distribution to be effective May 1, 2009. Thunder Bay is the licensed electricity distributor serving approximately 49,500 customers in the City of Thunder Bay and the Fort William First Nation Reserve.

Thunder Bay is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. In an effort to assist distributors in preparing their applications, the Board issued the *Filing Requirements for Transmission and Distribution Applications* on November 14, 2006. Chapter 2 of that document outlines the filing requirements for cost of service rate applications, based on a forward test year, by electricity distributors.

Thunder Bay filed a request with the Board by letter dated November 22, 2007 indicating it wished to self-nominate for the purposes of having its rates rebased for 2009. Accordingly, Thunder Bay filed a cost of service application based on 2009 as the forward test year.

Thunder Bay requested a revenue requirement of $18,671,941 to be recovered in new rates effective May 1, 2009. The application indicated that the existing rates would produce a revenue deficiency of $1,414,077 for 2009. The resulting requested rate increase was estimated as 11.98% on the distribution component of the bill for a residential customer consuming 1,000 kWh per month.

The Board assigned the application file number EB-2008-0245 and issued a Notice of Application and Hearing dated October 1, 2008. The Board approved four interventions: the Vulnerable Energy Consumers' Coalition ("VECC"); the School Energy Coalition ("SEC"); Energy Probe Research Foundation ("Energy Probe"); and the Association of Major Power Consumers in Ontario ("AMPCO"). The Board received one letter of comment regarding Thunder Bay's requested increase to its return on equity.

Procedural Order No.1 was issued on November 14, 2008. The Board made provision for written interrogatories and a transcribed technical conference. On January 26, 2009 the Board issued Procedural Order No.2 converting the technical conference to a supplemental round of interrogatories and providing dates for submissions. VECC, SEC and Energy Probe filed interrogatories and made submissions. Board staff also posed interrogatories and made submissions. Thunder Bay's reply argument was filed on March 23, 2009.

During the proceeding, Thunder Bay proposed certain changes to its revenue requirement resulting in a revised proposal of $18,728,836. Thunder Bay submitted revised bill impacts, including an increase of 13.71% on the distribution component of the bill for a residential customer consuming 1,000 kWh per month.

The full record is available at the Board's offices. The Board has chosen to summarize the record to the extent necessary to provide context to its findings.

THE ISSUES

The following issues were raised in the submissions of Board staff, VECC, SEC and Energy Probe and are addressed in this Decision:

- Load Forecast;
- Operating, Maintenance & Administrative Expenses;
- Payments in Lieu of Taxes;
- Capital Expenditures;
- Assessment of Asset Conditions and Asset Management Plan;
- Depreciation;
- Working Capital;
- Cost of Capital and Capital Structure;
- Cost Allocation and Rate Design;
- Deferral and Variance Accounts; and
- Smart Meters.

LOAD FORECAST

Thunder Bay's load forecast was developed in four steps. First, the Company developed a multi-factor regression analysis of monthly wholesale purchases for the distribution system from 1996 to 2007. Second, the forecast was adjusted for losses to produce a weather-normalized forecast using average weather conditions over this period. Third, a further adjustment was applied to account for the loss of industrial load and for the impact of recent CDM programs. Fourth, forecast total use for each customer class was developed using customer count forecasts and then adjusting these forecasts based on relative weather sensitivity of each class so that the sum of the individual class forecasts equalled the total billed kWh forecasts developed in the first three steps. Energy Probe referred to this approach as the “top-down” approach.

Thunder Bay’s proposed load forecast for 2009 is as follows:

Load Forecast[1]

Rate Classes	GWh
Residential	340.8
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
Unmetered Loads	1.3
TOTAL	**995.7**

Board staff raised a number of concerns with Thunder Bay’s approach:

- The customer number forecast used only variables related to historical growth and used the geometric mean rather than the previously accepted arithmetic mean; customer numbers were not used as an explanatory variable in the regression equation used in forecasting total purchased kWhs;
- Class specific demand drivers, such as weather, were not used, and the Ontario GDP was used for all classes; and
- The method used a 12 year average weather normalization model as opposed to a 20 year average.

Board staff submitted that while Thunder Bay should look to improve its load forecasting approach, the 2009 forecast is reasonable. Board staff noted that Thunder Bay’s approach was fairly comprehensive and that an analysis conducted by Board staff that adjusted for some of the above factors did not result in any material changes to the forecast.

[1] Response to Board staff interrogatory #51

VECC and Energy Probe also expressed a number of concerns regarding Thunder Bay's 2009 load forecast. VECC's concerns covered a broad range of issues such as the lack of customer numbers as an explanatory variable in the regression equation, the use of an outdated economic outlook, and the manner in which Thunder Bay reconciled its non-weather normalized forecast with the forecasted weather normalized use. Notwithstanding these concerns, VECC concluded that Thunder Bay's 2009 forecast should be accepted (subject to two adjustments discussed below). However, VECC noted that this should not be viewed as acceptance of Thunder Bay's load forecast methodology. VECC submitted that the Board should direct Thunder Bay to work with other distributors to develop a more comprehensive and integrated approach to load forecasting.

Thunder Bay calculated a loss factor that is different from the proposed Tariff sheet loss factors for purposes of adjusting the load forecast. Thunder Bay used total actual purchases and total actual billed energy (including those for large customers) to determine the average historical total loss factor for 2000 to 2007. In its original application, Thunder Bay determined this number to be 4.7%. VECC argued that the use of a 4.7% loss factor to adjust the forecasted purchases for 2008 and 2009 was not appropriate. VECC noted that Thunder Bay's response to Energy Probe interrogatory #23 indicated that the average loss factor over the 2003 to 2007 period was 3.8%. The Board notes that the 3.8% figure does not reflect supply facility losses and is in effect the historic average distribution loss factor, including losses related to large customers.

VECC submitted that the 3.8% number should be used to translate the forecast purchases into billed energy. Energy Probe suggested that rather than using the 3.8% number that was proposed by VECC, the Board should use 4.1%. Energy Probe noted that if the loss factor using the original data was determined based on the same period as the revised calculation (i.e. 2003-2007 rather than 2000-2007) the number would be 4.4%. Therefore, since this represents a 0.6% difference, the original loss factor of 4.7% should be adjusted downward to 4.1%. The Board notes that Energy Probe's number includes supply facility losses.

Thunder Bay responded that the revisions it made to its loss factors related to the correction of the double counting of the supply facilities loss factor component of the total loss factor used for billing purposes. Thunder Bay argued that the loss factor proposed to appear on the Tariff sheet is not the same as the one used for purposes of calculating the load forecast. Thunder Bay submitted that the loss factor to be used for the load forecast should be the 4.7% number which represents the average difference between total actual purchased and total actual billed amounts from 2000 to 2007.

VECC also disagreed with Thunder Bay's adjustments for the impact of CDM programs undertaken between July 2006 and December 2007. Thunder Bay originally reduced its 2009 load forecast by 12.9 GWh to account for CDM impacts. Thunder Bay indicated that the difference between forecast and actual consumption for 2007 was as high as 17.7 GWh but that this difference is too high, demonstrating that there was not sufficient history to influence the regression analysis results. In response to Board staff interrogatory #51, Thunder Bay revised its CDM adjustment from 12.9 GWh to 9.7 GWh.

VECC noted that there were other years (2000 and 2003) where an even larger difference occurred between forecast and actual load, and that after accounting for industrial losses the forecast value is virtually the same as the actual value for 2007. VECC concluded that the load forecast should not be adjusted for CDM programs.

Energy Probe submitted that the average use figures for the weather sensitive classes (Residential, GS <50kW and GS 50 to 999kW) are based on actual consumption, and are not normalized for weather. Energy Probe submitted that the result is that the calculated changes in average use for the weather sensitive customer classes are heavily influenced by the actual weather. Energy Probe submitted that a more accurate approach would be to use the normalized average consumption figures as calculated by Hydro One based on 2004 data. Energy Probe submitted that the volumes shown in the following table should be added to the total forecast.

Class	Average Use	Customers	Incremental Volumes
Residential	(8,034 – 7,830)	44,635	9,105,540
GS <50kW	(32,747 – 32,235)	4,466	2,286,592
GS 50 to 999 kW	(576,928 – 596,325)	511	(9,911,867)
Total			**1,480,265**

Thunder Bay did not agree with Energy Probe's submission regarding the adjustments for average use. Thunder Bay stated that it appears that Energy Probe is using a method, previously rejected by intervenors, to increase Thunder Bay's load forecast.

In terms of the overall approach, the Company argued that the proposed “top down” approach is appropriate because it has been used by Toronto Hydro and accepted by the Board in previous applications; and because Thunder Bay has the data required for this type of calculation, such as the exact amount of kWhs purchased from the IESO and others for use by customers of Thunder Bay. In Thunder Bay’s view, Energy Probe’s “bottom up” approach is problematic in that the monthly billed kWhs required for each class is dependant on other monthly variables such as billing cycle meter reading schedules which may include consumption from a previous month. Also, Thunder Bay suggested that relating billed monthly amounts to a variable such as heating degree days is not logical since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed.

Board Findings

The Board accepts Thunder Bay’s load forecast, subject to two adjustments.
The Board will not accept the 9.7 GWh adjustment for CDM impacts. The Company based this adjustment on the difference between forecast and actual load. The Board finds there is insufficient evidence to support the conclusion that the difference is in fact attributable to CDM impacts.

The Board will not adopt the adjusted (distribution) loss factor as proposed by VECC. The Board finds Thunder Bay’s explanation of the use of the total loss factor to adjust the forecast to be reasonable. However, the Board will not accept either Thunder Bay’s or Energy Probe’s total loss factor numbers. The Board notes that the calculation supporting the 4.7% figure proposed by Thunder Bay includes purchases and billings over the eight year period 2000 to 2007, whereas the most recent five years are used to establish the factors approved on the Tariff sheet. Also, since Thunder Bay has forecasted no large customers as part of its test year customer base the Board finds that it would be appropriate for Thunder Bay to apply the approved Tariff sheet total loss factor for secondary metered customers below 5,000 kW only. The Board addresses the level of the loss factors later in this Decision. The Board notes that Thunder Bay has provided no rationale for why the total loss factor used to convert the load forecast to billing quantities should not be the same total loss factor that appears on its Tariff sheet.

The Board will not adopt the recommendation by Energy Probe that the 2004 Hydro One NAC data be used. There are some shortcomings to Thunder Bay’s forecast approach, a number have been noted by the intervenors in addition to Energy Probe’s submission regarding the average use levels. However, the Board is satisfied that Thunder Bay has developed a more rigorous approach than that used by many distributors in the 2008 cases and concludes that the adoption of the 2004 NAC data is not warranted at this time. The Board encourages Thunder Bay to continue developing its forecast methodology and expects that many of the issues identified by Board staff and intervenors regarding the methodology will be addressed in the next rebasing application.

OPERATING, MAINTENANCE and ADMINSTRATIVE EXPENSES (“OM&A”)

The table below shows the components of the proposed OM&A expenses for 2009 and compares them with previous years.

Summary of OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Operation	$2,011,898	$2,713,521	$2,784,785	$2,752,849	$3,024,765
Maintenance	$2,977,751	$2,650,405	$3,271,159	$2,996,067	$3,049,733
Billing and Collection	$2,432,919	$2,284,014	$2,286,306	$2,414,133	$2,392,006
Community Relations	$169,039	$547,031	$502,544	$195,316	$228,339
Administrative and General Expenses	$2,911,130	$2,813,268	$3,206,840	$3,561,117	$3,646,120
Total as filed	**$ 10,502,737**	**$ 11,008,239**	**$ 12,051,634**	**$ 11,919,482**	**$ 12,340,963**
CDM 3rd Tranche adjustment		($357,403)	($323,196)		
Total OM&A (adjusted for CDM)	**$ 10,502,737**	**$ 10,650,836**	**$ 11,728,438**	**$ 11,919,482**	**$ 12,340,963**

The 2009 Total OM&A of $12,340,963 is a 3.5% increase over 2008 Bridge and a 5.2% increase over 2007 actual (adjusted for CDM). On an unadjusted basis the increase between 2007 actual and 2009 test is 2.4%.

On March 6, 2009, Thunder Bay filed *Adjustments to Thunder Bay Hydro’s 2009 Cost of Service Application* (the “Adjustment Table”) to update its filed evidence to reflect the changes it had agreed to in responses to certain interrogatories. Thunder Bay also enclosed with its final submission a financial summary of agreed-to changes including, where necessary, updates to its March 6, 2009 adjustments.

In its final submission, Thunder Bay reduced its requested 2009 OM&A from $12,340,963 to $11,913,121 (a difference of $427,842) to reflect the following:

	2009 OM&A		
	as filed	**revised**	**adjustment**
PCB	$228,000	$141,750	($86,250)
PCB related adjustments (accretion/ARO)			($23,781)
Meter Service and Maintenance	$600,319	$453,000	($147,319)
Smart Meter Reading	$255,000	$107,500	($147,500)
4-year amortization of EB-2008-0245 proceeding costs	$33,000	$24,750	($8,250)
Thunder Bay Hydro Corporation Board of Directors Honorarium	$14,743	$0	($14,743)
Total			**($427,843)**

Inflation

With respect to the inflation assumptions, Thunder Bay indicated that a 2% inflation rate was used to forecast 2009 OM&A. The 2% was based on an analysis of the 2007 and 2008 Consumer Price Index (“CPI”) as reported by the Bank of Canada. Thunder Bay noted that the average CPI for 2007 was 2.15% and for the first six months of 2008 was 2.07%. No issues were raised by parties on the 2009 inflation forecast.

Board Findings

The Board is satisfied that the 2% inflation rate used to forecast 2009 OM&A values is reasonable. This figure is also consistent with that applied in other recent cost of service decisions.

Compensation

Compensation costs, including salaries, base wages, overtime, incentive payments and benefits, are forecast to be approximately $11.4 million in 2009. This is a 7% increase from 2008 and a 12.4% increase from 2007. Thunder Bay noted that $6.2 million of its total compensation costs would be charged to OM&A.

Thunder Bay’s performance management system includes a merit pay system for non-union employees, which is performance based and is applied every six months until 100% of base salary is achieved. There is an incentive pay system for the President and Vice-President, Power Systems, which pays out an annual average of $15,000 each.

The salary increases in 2008 will average 21% for the executive, 8.5 % for management, 11% for non-union staff and 2.7% for unionized staff.[2] Thunder Bay noted that outside consultant expertise and the industry management compensation information provided in the annual Management Salary Survey completed by the Mearie Group, assisted the Company in its decision to increase the salaries for its executives.

VECC expressed some concern with executive and management compensation but did not propose that 2009 OM&A be reduced. While acknowledging that it did not have any basis to suggest that Thunder Bay's executive team should be compensated at a level below the mean level of comparable entities, VECC submitted that: (i) it is not aware of any instance in which a utility has proposed that its average compensation level for any employee group should be below the mean or median of comparables; (ii) unless all comparable entities have exactly the same compensation level for each group of employees, some will be below the average and some will be above it; (iii) if every utility with an employee group with an average compensation level below the mean of its comparator group attempted to increase its own group compensation to the comparator mean, the mean itself would be forever increasing (since nobody would be employing personnel that were "below average" on a sustained basis); and (iv) while the unionized employee group's increase is more moderate, the average increases in 2008 for the management and non-union groups appears high, especially considering recent levels of inflation.

Board Findings

The Board has no concerns with respect to the increase in compensation costs associated with any category. The proposed 21% increase for the Executive group appears to be large, but the Board accepts that the increase attributable to the filling of a vacancy, as well as compensation increases is reasonable. The Board accepts the compensation costs as proposed by Thunder Bay.

Tree Trimming and Line Clearing Operations

Thunder Bay is proposing to spend $767,000 in 2009 in its Tree Trimming and Line Clearing Operations ("Forestry Program"). This level of spending is higher than recent historical levels as indicated in the table below.

[2] See Exhibit 4 /Tab 2 / Schedule 4 /page 11

2006 EDR	2006 Actual	2007 Actual	2008 Budget
$327,000	$256,000	$545, 000	$523,000

Thunder Bay explained that an increase is required because:

> … regular scheduled forestry practices for line clearing were downsized in the past [as 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.[3]

Thunder Bay indicated that this higher level of expenditure will be required until 2016 to get to a level of cost which can be sustained at a lower level.

Board staff submitted that this circumstance 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. Increased costs are now necessary to deal with the consequences arising from the past decision to minimize costs. Board staff pointed to the historical variability in spending that ranged from $275,000 in 2003 actual to $545,000 in 2007 actual, followed by a 5% decline in the 2008 budget. Board staff estimated that the average annual spending, adjusted for inflation, was approximately $340,000 and viewed an increase in the range of 75% to 100% of the historical average as more than sufficient to fund a sustainable Forestry Program.

SEC also expressed concern with the accelerated spending, as compared to historical levels. However, in recognition of reductions Thunder Bay is making to its revenue requirement in the form of its return on equity and other reductions in its OM&A, SEC did not propose cuts to the 2009 Forestry Program.

Thunder Bay responded that while it agrees expenditures in the range of $517,000 (or $3,336/km) is sufficient for a sustainable Forestry Program, funding of $767,000 (or $7,058/km) is required to re-establish the corridors to a level which then can be sustained.

[3] See Exhibit 4 /Tab 2 /Schedule 2 / p.4 – Variance Analysis on OM&A Costs

Board Findings

The Board is satisfied that the planned enhanced vegetation management program is justified and achievable, and approves the Company's proposal.

Meter Reading and Meter Service and Maintenance Costs

Thunder Bay indicated that $255,000 in meter reading costs were included in its original 2009 test year OM&A and that these were forecast to decrease to $125,000 in 2010 and $25,000 in 2011 and 2012 as a result of Thunder Bay's Smart Meter Implementation Plan. Board staff, Energy Probe, SEC and VECC submitted that meter reading costs should be averaged over a four year period (2009-2012). In response, Thunder Bay accepted this recommendation and reduced its requested 2009 OM&A by $147,500.

Thunder Bay stated that $600,319 in meter service and maintenance costs were included in its original 2009 OM&A. Thunder Bay reduced its 2009 OM&A by $147,319 in response to Energy Probe's submission that the capitalization of smart meters installed in 2009 should be amortized over four (rather than three) years.

Board Findings

The Board accepts Thunder Bay's proposals related to meter reading and meter maintenance and service, as revised. The Draft Rate Order arising from this Decision should reflect all necessary calculations to demonstrate the amortization of these costs over four years.

2009 Regulatory Costs

Thunder Bay forecasted the total cost associated for the 2009 rate rebasing application to be $99,000. Thunder Bay included $33,000 in its 2009 OM&A, based on a three year amortization.

Board staff, Energy Probe, SEC and VECC submitted that the regulatory costs related to the 2009 rate rebasing proceeding should be amortized over a four year period, which would result in an annualized cost of $24,750. In its reply submission, Thunder Bay agreed to amortize the costs over a four year period (2009-2012) thereby reducing its 2009 OM&A by $8,250.

Board staff noted that Thunder Bay records its regulatory expenses in two accounts: 5630 (Outside Service) and 5665 (Miscellaneous and General). Board staff submitted that the Board may wish to direct Thunder Bay to utilize the appropriate Account 5655, Regulatory Expenses, for recording regulatory costs, as described in the *Accounting Procedures Handbook for Electric Distribution Utilities*.

Board Findings

The Board accepts Thunder Bay's proposal as amended in its final submission. The Board directs the Company to record its regulatory costs in Account 5655.

Thunder Bay Hydro Corporation Board of Directors Costs

Thunder Bay included the entire Board Honorarium of $14,743 for the Thunder Bay Hydro Corporation Board in its 2009 OM&A. Thunder Bay Hydro Corporation is the holding company that owns the electricity distribution company.

In response to an interrogatory, Thunder Bay indicated that costs associated with the Board Honorarium should be removed from OM&A expenditures, in that no services are provided to the Company by the Thunder Bay Hydro Corporation Board. In its reply submission, Thunder Bay removed this cost.

Board Findings

The Board accepts the Company's proposal as amended.

Polychlorinated Biphenyls ("PCB") Program

Thunder Bay indicated that it has a plan in place which, over the 2008 to 2020 period, would ensure compliance with legislative requirements pertaining to the treatment and disposition of PCB contaminated transformers.[4] The plan provides for the elimination of all PCB in concentrations of >500 PPM (parts per million) and all PCBs in concentrations of >50 PPM in environmentally sensitive areas by the end of 2009, and the remaining concentrations by 2020. The legislation sets 2025 as the deadline for the remaining concentrations. Thunder Bay expects to spend approximately $3.4 million, comprised of OM&A, Capital and the associated Asset Retirement Obligations ("AROs"), to execute the plan.

[4] Chlorobiphenyl Regulations and the Storage of PCB Material Regulations of the Canadian Environmental Protection Act, 1999 (CEPA1999)

The table below summarizes the expenditure plan from 2009 to 2020 (in thousands). [5]

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

With respect to the recovery of costs pertaining to the AROs related to the PCB plan, Board staff submitted that Thunder Bay's proposed treatment may result in over-recovery due to double counting.

Staff noted that in accordance with the Canadian Institute of Chartered Accountants Handbook, Thunder Bay's treatment of its PCB liabilities appear to meet the definition of an ARO. In response to Board staff supplemental IR #3 d), Thunder Bay identified depreciation and accretion expenses associated with the ARO for rate setting purposes. Staff noted that the depreciation expense described by Thunder Bay includes estimated disposal costs capitalized in the fixed asset account (e.g., transformer), and the accretion expense designed to interest-improve the carrying amount of the equivalent obligation due to the passage of time. Staff noted that on an annualized basis, Thunder Bay included $67,300 in depreciation and accretion expenses for costs associated with destruction of oil, solid waste and transport.[6]

Board staff submitted that from a regulatory perspective, where depreciation and accretion expenses associated with the ARO are 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.

Staff noted that Thunder Bay also claimed 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 allowed ROE, Board staff was of the view that the accretion expense 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

[5] Board staff interrogatory #9 and supplemental interrogatory #3.
[6] These costs appear to be related to old transformers that will be removed from service.

the underlying ARO asset in rate base (i.e., ARO component is added to the net fixed asset values), it appears inappropriate in principle that it should also recover the accretion expense.

VECC agreed with Board staff regarding the inappropriateness of recovering the accretion expenses in addition to the return and also submitted that it would be more appropriate to recover ARO costs that will be incurred in the future on a sinking fund basis rather than treating the costs as a rate base item, i.e., as an investment in a utility asset that is used and useful in providing services to ratepayers continuously as long as it is in rate base.

Thunder Bay responded that it failed to see that there is any double counting of costs. Thunder Bay noted that it has capitalized as an ARO the discounted costs for "Oil Destruction, Destruction of PCB Solid Waste Material, Additional Destruction and Transport" expected over the plan horizon of 2008 to 2020. This represents future costs of disposal related to an asset that is used and useful in providing services to ratepayers. The discounted cost of $512,186 will be amortized over the 12 year period. Additionally, the period "accretion costs" (similar to interest expense) of $189,294 will be charged to income over the 12 year period ending 2020. As Thunder Bay actually incurs the costs and provides for payment of such, the accounting treatment will be to draw-down the ARO liability reflected on the balance sheet (these payments will not affect income).

Thunder Bay further explained that it had originally included accretion as part of its OM&A costs for the purpose of the calculation of the revenue requirement. However, to be consistent with their inclusion of the asset in rate base, Thunder Bay argued that the appropriate treatment would be to show the ARO liability as a component of long term debt in the cost of capital. Thunder Bay submitted that this would increase the weighted cost of debt by 0.09% (i.e. to 0.30%) and increase the 2009 revenue requirement by $11,200. This adjustment was reflected in Thunder Bay's reply submission.

Board Findings

The Board finds that Thunder Bay's proposed quantum of costs related to the new assets and associated OM&A costs are reasonable as shown in the above table under Capital and OM&A. Thunder Bay has proposed a comprehensive plan to replace all known contaminated transformers and the plan is scheduled to be completed in advance of the legislated deadline.

The Board is left to decide the regulatory treatment of the ARO in the revenue requirement, absent the specific details of the accounting treatment of the ARO including key assumptions or calculations. The Board proceeded on the basis that there are two key rate recovery issues to be addressed: 1) whether to allow recovery of costs to be incurred for the disposal and handling of PCB-contaminated transformers arising from the set up of the ARO (i.e., depreciation and accretion expenses); and 2) whether the ARO amounts added to the underlying asset values (asset retirement costs) should be allowed in the rate base and eligible to receive a return.

On the first issue, the estimated total depreciation and accretion expenses arising from the ARO will amount to the total cash flows expected to retire the PCB-contaminated transformers in the future (i.e., date of the asset retirement). Provided that Thunder Bay has calculated these expenses under the GAAP accounting requirements,[7] it would be reasonable to recover these expenses in rates as they represent, on an annual basis, the costs needed to satisfy the obligation to retire the assets in the future. As such, they may be included in the revenue requirement as proposed by the Company.

With respect to the second issue, under the GAAP accounting requirements when an ARO liability is recognized, an amount equal to the ARO is concurrently added to the asset base of the underlying asset for which the obligation was established. This component, referred to as the asset retirement costs (“ARC”), is depreciated over the remaining useful life of the asset. In addition, customers are paying the return of capital through depreciation of the ARC and providing a return on capital through the accretion expense. To also allow a return by including the undepreciated ARC in rate base would be double counting. Board staff and VECC did not support inclusion of the accretion expenses in the revenue requirement as long as Thunder Bay continued to propose receiving a return.

Given that the return of capital and return on capital are already provided through depreciation of the ARC and accretion of the ARO, no further return is required. To give effect to this, the unamortized ARC should be excluded from the rate base and the ARO should not be included in the calculation of the weighted cost of debt, thus avoiding double counting of either the return of or the return on capital associated with asset retirement.

[7] In accordance with the Canadian Institute of Chartered Accountants Handbook, Section 3110, Asset Retirement Obligations.

Lost Revenue Adjustment Mechanism (“LRAM”) and Shared Savings Mechanism (“SSM”)

The LRAM is designed to compensate distributors for lost revenues due to CDM activities, while the SSM provides an incentive for distributors to aggressively implement CDM programs.

In its original application, Thunder Bay applied for the approval and recovery of an LRAM amount of $468,321 and an SSM amount of $106,024, for a combined total of $574,345, relating to programs delivered in 2005, 2006 and 2007. The LRAM amount relates to programs funded through the third tranche mechanism and through the Ontario Power Authority (“OPA”). The SSM amount relates only to programs funded through the third tranche mechanism. As a result of interrogatories, Thunder Bay revised the LRAM amount to $383,073, which reduced the total claim to $489,097.

Thunder Bay proposed that the LRAM and SSM amounts be recovered through volumetric rate riders applicable to the Residential, GS<50 kW, GS>50 kW, GS 1,000 to 4,999 kW, Street Light, Sentinel Lighting and Unmetered Scattered Load rate classes over a period of three years. Thunder Bay is not requesting the recovery of carrying charges.

VECC submitted that for the purposes of setting rates for 2009, the LRAM and SSM amounts related to 2005 and 2006 programs are acceptable as a practical matter. With respect to CDM measures implemented in 2007 and after, VECC submitted that: (i) the most recent input assumptions should be used (e.g. OPA); (ii) there should be an adjustment in the case that persistence is less than 100%; and (iii) there should be verification of claimed savings by an independent third party.

SEC submitted that the requested LRAM and SSM amounts should not be recovered in the absence of an independent review.

Energy Probe submitted that as an alternative, Thunder Bay could reduce its requested recovery ($489,097) by 10% to $440,187. Energy Probe stated that this approach would be similar to the option provided to distributors for the recovery of regulatory assets where the distributors had an option for a comprehensive review or a minimum review that reduced the claim by 10%.

Thunder Bay submitted that the evidence it has filed supports its application for recovery of lost revenues and shared savings; however, in response to Energy Probe’s suggested reduction, Thunder Bay proposed that a 10% reduction of the amounts sought for the 2007 delivery year would be appropriate as 2007 is the year that the independent third party review was made part of the CDM Guidelines. It was Thunder Bay's position that the reduction is appropriate only for those programs funded by third tranche CDM dollars, since the OPA has asserted that its programs have undergone third party evaluations.

Thunder Bay submitted that its total LRAM and SSM amount for the 2007 delivery year is $167,446. If OPA programs are excluded, the total LRAM and SSM amount for the 2007 would be $117,168. If a 10% reduction were applied to this total, Thunder Bay stated that this would reduce the total LRAM and SSM amount for the 2007 delivery year by $11,717, which the Company stated would be appropriate.

Board Findings

The Board accepts Thunder Bay's proposal to reduce its requested LRAM and SSM claim by $11,717 in the absence of a third party review. The Board approves the recovery of the LRAM and SSM total of $477,380 by means of the three-year volumetric rate riders proposed by Thunder Bay.

PAYMENTS IN LIEU OF TAXES ("PILs")

Thunder Bay forecasted a PILs allowance of $970,138 for 2009, composed of $800,672 for combined Federal and Provincial Income Taxes and $169,466 in Capital Taxes, as shown in the following table[8].

Summary of Actual and Proposed PILs Allowance

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Income Taxes	$ 1,092,369	$ 1,109,218	$ 737,431	$ 655,911	$ 800,672
Large Corporation Tax	$ 21,095				
Ontario Capital Tax	$ 235,550	$ 230,440	$ 218,391	$ 165,897	$ 169,466
Total Taxes	$ 1,349,014	$ 1,339,658	$ 955,822	$ 821,808	$ 970,138

Thunder Bay provided a summary of its actual and estimated PILs in response to Board staff interrogatory #30. Further information on specific details and issues of Thunder Bay's PILs were provided in response to Board staff interrogatory #30 and Energy Probe interrogatories #24 and #25.

[8] Exhibit 4 /Tab 3 /Schedule 1

Board staff, VECC, and SEC did not make submissions with respect to Thunder Bay's proposal for PILs. Energy Probe made a submission and addressed the following components:

- Capital taxes;
- Income Taxes (both with respect to tax rates and the January 27, 2009 Federal Budget; and
- Updating of Regulatory Taxable Income.

Thunder Bay responded to each of these points in its reply submission.

Capital Taxes

Energy Probe disagreed with Thunder Bay's calculation of its forecast 2009 capital taxes of $10,499.[9] Energy Probe noted that this was based on a rate base figure of $90,318,279, significantly different than the 2009 forecasted rate base of $75,169,648. Energy Probe further submitted that the increase of $15 million reflects the average amount of taxable capital in excess of rate base in 2006 and 2007, as documented in the response to Energy Probe interrogatory #24 d).

Energy Probe submitted that, based on Thunder Bay's response to Energy Probe interrogatory #41, the $15 million addition reflects amounts for regulatory assets, employee future benefits, UCC differences, goodwill and customer deposits, and that these components are either recovered elsewhere in the revenue requirement or should not be recoverable. Energy Probe submitted that goodwill is not recoverable, and employee future benefits are not a current period expense. If Energy Probe's changes were accepted the 2009 proposed capital tax would be reduced from $169,466 to $135,382.

In its reply submission, Thunder Bay disagreed with Energy Probe's arguments. Thunder Bay advised that it followed option 2 from the 2006 OEB Tax Model (used for the 2006 EDR applications), which allows distributors to base the capital tax calculation on actual values from (or consistent with) actual tax schedules. Thunder Bay noted that this option will produce a higher rate base and hence higher capital tax than option 1, used by many distributors, which uses the regulatory rate base. Thunder Bay also disagreed with Energy Probe's position that the additional costs are reflected elsewhere in its revenue requirement. Finally, Thunder Bay clarified that goodwill was not reflected

[9] Energy Probe's submission, March 13, 2009, pp. 18-19

in the rate base for capital tax purposes, but that the entry related to CEC amounts of organization costs.

Income Taxes – tax rates

Thunder Bay used a combined tax rate of 30.72%, consisting of a Federal Tax rate of 19%, an Ontario tax rate of 14%, and an Apprenticeship Tax credit rate of 2.28354%. Energy Probe submitted that the Apprenticeship Tax Credit rate was derived incorrectly. Energy Probe submitted that Thunder Bay should apply the combined Federal and Provincial tax rate of 33.0% (applicable to firms with taxable income in excess of $1.5 million), and then deduct the apprenticeship credit of $59,524.

In reply, Thunder Bay agreed with Energy Probe's submission, but stated that its model, which translates the apprenticeship tax credit into a negative tax rate, accomplishes the same outcome.

Federal Budget

Energy Probe noted that the January 29, 2009 Federal Budget introduced changes that may affect Thunder Bay's 2009 regulatory taxable income. In particular, the Capital Cost Allowance for Class 50 computers and system hardware acquired after January 27, 2009 and before February, 2011 increases from 55% to 100%. Energy Probe noted that Thunder Bay has forecast a capital addition to Class 50 of $77,310 in 2009. Energy Probe submitted that updating to reflect the recent Federal Budget would increase the CCA deduction in 2009 from $4,405,206 to $4,461,256.

In its reply submission, Thunder Bay indicated that it would update its PILs allowance to reflect the Federal Budget at the time of the Board's Decision.

Board Findings

The Board finds that, with respect to capital taxes and income taxes, Thunder Bay has applied Board guidance in an acceptable manner.

The Board notes, as with other areas, that Thunder Bay's PILs is affected in the 2008 bridge and 2009 test years by recent changes in Thunder Bay's rate base and operations. Further, Thunder Bay's PILs, both historically and for the bridge and test years, are heavily influenced by the low ROE that Thunder Bay has factored into its rates.

The Board notes that Thunder Bay has generally complied with the Board's policies with respect to the calculation of its PILs allowance. The Board also notes that there may be changes elsewhere in the Decision, particularly with respect to rate base and capital and operating expenses, that could have flow-through impacts on taxable income and hence on the PILs allowance. The Board notes the general acceptance of Energy Probe and Thunder Bay of the Board's general policy that the PILs allowance should accurately reflect the most current information.

In filing its Draft Rate Order, Thunder Bay should incorporate all known income and capital tax changes into its PILs calculations for 2009 that have arisen since the application was filed.

The Board therefore directs Thunder Bay to update its PILs allowance to reflect all of the findings in this Decision, and to reflect this in its revenue requirement and proposed distribution rates to implement this Decision. Thunder Bay should provide a summary of the PILs allowance and updated calculations in support of its Draft Rate Order.

CAPITAL EXPENDITURES

Thunder Bay provided the following information on historical and forecasted capital expenditures:

Year	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total capital expenditures (excluding Smart Meters)	$6,424,274	$5,784,747	$6,568,215	$8,270,854

Board staff submitted that it had no issues with Thunder Bay's proposed capital expenditures of $8.3 million for 2009. Board staff observed that Thunder Bay had provided reasonable support and explanations for its proposed spending. Board staff further observed that accumulated depreciation, as a percentage of gross fixed assets, has increased, which staff interpreted as a signal of an aging network. Staff also interpreted worsening, but not yet problematic, system reliability as a supporting signal of an aging network.

While there was general support for Thunder Bay's proposed capital expenditures, Board staff and intervenors made submissions on the following specific issues:

- "Rate Minimization";
- Contingencies;

- Capital Contributions and Grants; and
- The Kam River Crossing.

"Rate Minimization"

Board staff noted Thunder Bay's plan for increased capital expenditures over an extended period to address issues with its aging network. Board staff observed that this follows a period from 1994 to about 2006 when Thunder Bay operated under a "rate minimization" approach by which Thunder Bay helped to keep rates low by limiting spending on forestry management and capital expenditures and on the earned return on assets. This approach has continued in this application insofar as Thunder Bay and its shareholder have not sought a full rate of return and have also sought to limit capital and some operating expenses. Board staff questioned the prudence of this approach in the long-run, stating that while ratepayers benefited historically from lower rates, the end result of this approach may cause current and future customers to face service issues and increased expenditures for vegetation management and sustaining capital to rehabilitate Thunder Bay's distribution system.

Board staff also questioned the trend analysis which Thunder Bay had presented. While Board staff did not question Thunder Bay's proposed 2009 capital expenditures, staff submitted that the Company's longer-term estimate may be inflated. Staff also submitted that in future rate applications, Thunder Bay should consider the capital requirements required to sustain the network and to address historical under-investment in a more rigorous manner. VECC was in general agreement with Board staff's comments, and agreed that Thunder Bay should file a more rigorous asset management plan at the time of its next rebasing application.

In reply, Thunder Bay provided an explanation of the "rate minimization" model under which it has operated, in accordance with the expectations of its shareholder, the City of Thunder Bay. Thunder Bay explained that this is, in part, a continuation of the "power at cost" principle under which distributors previously operated as municipal electrical utilities. Thunder Bay's approach was feasible for a period of time, in part due to low economic growth. Rate minimization allowed the Company, on behalf of its shareholder, to keep rates low in order to support local development. Thunder Bay stated that historical decisions to keep rates low and to remain efficient had, in some circumstances, unintended longer term consequences, and agreed with Board staff's comments about past under spending in forestry management and capital expenditures.

Thunder Bay did wish to assure parties that past and current management and investment strategies are not influenced by the “rate minimization” concept.

Contingencies

SEC and Energy Probe noted that recent capital projects by Thunder Bay had come in significantly under-budget, referencing the Frankwood rebuild and the Kam River crossing. The intervenors noted that the Frankwood rebuild was Thunder Bay’s first large scale rebuild and that “a sizeable contingency was included in the budgeted amount.” SEC and Energy Probe submitted that Thunder Bay also had a contingency amount built into 2009 capital projects, and estimated the 2009 capital budget contingency at $417,084. Both SEC and Energy Probe submitted that the contingency should not be recoverable in rates and should be removed from the proposed rate base.

Thunder Bay responded that the estimates of all capital projects are the expected required amounts, including contingencies. Contingencies are factored into cost estimates, and may be implicit or explicit in the estimates. Thunder Bay submitted that it has chosen to clearly illustrate the contingency of each project to demonstrate the confidence in the project estimate for both internal and rate-making purposes. Finally, the Company submitted that as it gains experience, it expects that contingencies will be at a level of 10% or lower. Thunder Bay submitted that a reduction of $417,014, as suggested by SEC and Energy Probe, was not warranted.

Capital Contributions and Grants

VECC noted that Thunder Bay had included contributions and grants in the amount of $1 million in each of 2006 and 2007, while it had forecast lower amounts of about $650,000 for each of 2008 and 2009. VECC noted that Thunder Bay, in response to Energy Probe interrogatory #8, stated that the forecasts were for cash contributions and excluded contributions in kind. The response indicated that contributions and grants to September 30, 2008 were $1,118,350, far in excess of the 2008 bridge year forecast of $646,000. Finally, VECC noted that in response to Energy Probe supplemental interrogatory #43 a), Thunder Bay’s cash contributions to December 31, 2008 were $1,095,369.

VECC submitted that Thunder Bay had under-forecast its contributions and grants for the 2008 bridge and 2009 test years. VECC submitted that the contributions and grants in 2008 should be approximately $1.7 million. It accepted that the business cycle could impact amounts in 2009, but submitted that the 2009 test year estimate of $650,000 should be increased by at least $600,000.

In its reply, Thunder Bay submitted that there should be no adjustments to contributed capital. It submitted that variances in budget to actual capital are offset by the capital contributions. As such, the net impact on rate base is nil. Thunder Bay submitted that, if it were to update the capital contributions, it would have to symmetrically increase the capital.

Kam River Crossing

Energy Probe noted that of the three major capital projects that Thunder Bay had planned for 2008, two were completed and put in service in 2008. However, the Kam River crossing, with a forecast capital budget of $801,129, was delayed and would not go into service until early 2009. Energy Probe submitted that this project should be removed from the 2008 year-end rate base and treated as work-in-progress. If put in service in 2009, the asset's capital costs would be included in 2009 capital additions (and transferred out of work-in-progress). Energy Probe noted that this adjustment would decrease 2009 depreciation expense by $16,025 and 2009 rate base by $376,531, and there would be a corresponding CCA reduction for income tax purposes.

In reply, Thunder Bay noted that its capital projects are reviewed throughout the year, and may come in under or over budget, or be re-prioritized. Thunder Bay noted that its budget and plan is updated as circumstances warrant. It also noted that its actual 2008 capital expenditures, net of contributions and work-in-progress, was $5.536 million compared to the bridge year forecast of $5.530 million; as such, Thunder Bay submitted that the $800,000 adjustment to opening assets due to the Kam River delay was not warranted but did not provide specific reasons for its position.

Board Findings

The Board has considered Thunder Bay's past practice of rate minimization and has taken this into account when considering Thunder Bay's Asset Management plans. The Board's findings on Thunder Bay's Asset Management plans are found in the next section below.

The Board accepts the Company's evidence with respect to the inclusion of contingencies in its capital spending plan. As a general rule, the explicit description of contingency costs is desirable. The Board recognizes that the establishment of contingency costs is not an exact science and is an area where experience will lead to more accurate assumptions.

The Board also accepts Thunder Bay's evidence and submissions with respect to capital contributions.

With respect to the Kam River project, the Board is satisfied that the Company's evidence is sufficient to support its proposal. Thunder Bay has, to the Board's satisfaction, explained the reasons beyond the control of Thunder Bay's management, for the deferment of the Kam River completion. Further, Thunder Bay noted in its reply submission that actual 2008 capital expenditures, net of CWIP and contributed capital is $5.536M, not materially different than the projection of $5.530M.[10]

Assessment of Asset Conditions and Asset Management Plan

Thunder Bay has extensively documented the Asset Management program that it is developing to aid it in its operations and decision making[11].

Board staff submitted that Thunder Bay's adoption of Asset Management is encouraging, and should result in better decisions being made with respect to investments and operational expenditures so the Company can continue to provide quality and reliable electricity distribution services in a cost effective manner. Board staff recommended that an updated and detailed Asset Management plan should be filed in the Company's next rebasing application. VECC concurred with this proposal. Thunder Bay did not address this matter in its reply submission.

Board Findings

The Board believes that asset condition assessments and Asset Management plans are an important component of operating, maintenance, and capital expenditure proposals, particularly when significant expenditures are contemplated. However, the Board also recognizes that work in this area must take account of the particular circumstances of the utility. The Board is satisfied that Thunder Bay's approach to this issue is appropriate in the circumstances, and expects that Thunder Bay will continue in its efforts and that appropriate documentation will be filed in Thunder Bay's next cost of service rebasing application.

[10] Thunder Bay Reply submission, March 24, 2009, p. 13, ll. 312-3
[11] Exhibit 2 / Tab 1 / Schedule 1/page 3 / l.13 to page 19 / l. 23.

Depreciation

Thunder Bay forecast depreciation expense of $4.6 million for 2009. In general, Thunder Bay has followed the Board's guidelines with respect to depreciation/amortization expense. The average annual percentage change from 2006 actual to 2009 test year is a 1.43% increase.

Board staff and Energy Probe raised issues in the following areas:

- Depreciation Rate for Computer Hardware;
- Depreciation Rate for Computer Software; and
- Other Minor Adjustments.

Each of these issues is discussed below.

<u>Computer Hardware</u>

Thunder Bay uses a three year amortization rate for computer hardware, and it has been doing so since December 2004.[12]

Board staff noted that the Board's guideline depreciation rate for computer hardware is five years, as documented in Appendix B of the *2006 Electricity Distribution Rate Handbook ("*EDRH*")*. Thunder Bay stated that it adopted the three year depreciation rate after considering the policies of similar companies and the costs of extended warranties. However, Board staff observed that Thunder Bay did not have a formal study supporting the three year rate. Board staff also observed that most electricity distributors use a five year amortization for computer hardware, and that Thunder Bay did not raise this issue in its 2006 EDR application. Board staff submitted that Thunder Bay had not justified its accelerated rate and should adopt the five year rate as documented in the 2006 EDRH.

Energy Probe supported the position that Thunder Bay should use the five year amortization rate on a going-forward basis, citing the same evidence as Board staff.

In its reply, Thunder Bay stated that in the absence of a detailed depreciation study it will adopt the five year depreciation rate for computer hardware going forward. It further indicated that it will decide whether to proceed with a depreciation study, depending on the cost.

[12] See responses to interrogatories Board staff #25, Energy Probe #7 and Board staff supplemental #10.

Computer Software

Thunder Bay amortizes computer software over three years. Energy Probe submitted that Thunder Bay should use a five year depreciation rate for computer software. While acknowledging that Appendix B of the 2006 EDRH does not specify a depreciation rate for computer software, Energy Probe stated that the next closest account is computer hardware, for which a five year asset life is applicable. Energy Probe further submitted that a review of other 2008 and 2009 electricity distributor cost of service applications indicates that most use a 20% depreciation rate (i.e. five year life) for all IT assets, including software.

Thunder Bay disagreed with Energy Probe's proposal, stating that the Board has not provided direct guidance on the amortization of computer software, and the rapid pace of technology supported its adopted three year amortization of software.

Thunder Bay also responded that the amortization of computer hardware and software, based on a five year life for hardware and a three year life for software, would be a reduction in depreciation expense of $129,691.[13]

Other Minor Adjustments

Energy Probe submitted that there should be some further minor adjustments to depreciation expense and the resulting net book value of assets incorporated in rate base. The impact of these changes, as documented in Energy Probe's submission, would be a reduction to depreciation expense of $4,782 and an increase in rate base of $1,309. Thunder Bay did not respond to these proposals.

Board Findings

With respect to the depreciation rate for computer hardware, the Board's guideline rate is five years, as documented in the 2006 EDRH. Based on the Board's experience, most Ontario electricity distributors have adopted the five year amortization rate for computer hardware. While these rates are "guidelines", the onus is on an applicant to provide evidence in support of a different rate. In their submissions, Board staff and intervenors pointed out that Thunder Bay did not provide reasons supporting the use of a three year depreciation rate for its computer hardware; in its reply submission, Thunder Bay revised its proposal by adopting a five year depreciation rate. The Board approves Thunder Bay's revised proposal to adopt a five year amortization for computer

[13] Thunder Bay reply submission, March 24, 2009, p. 14, ll. 357-363

hardware going forward, and directs Thunder Bay to reflect this in its revised revenue requirement as part of its Draft Rate Order.

With respect to the appropriate depreciation rate for computer software, the Board acknowledges that no guideline rate is specified in the 2006 EDRH. While some utilities use, and the Board has approved, an amortization rate of five years, the Board notes that, equally commonly, a rate of three years is adopted by electricity and gas utilities and the Board has accepted such a rate, and does so in this application.

Given the lack of materiality, the Board finds that Thunder Bay will not be required to address the Other Minor Adjustments outlined above.

The Board approves Thunder Bay's depreciation expense as revised for computer hardware, subject to any further revisions which are required as a result of the Board's findings throughout this Decision.

Working Capital

Thunder Bay proposed a working capital allowance ("WCA") of $12,819,420, based on the standard Board methodology of 15% of the sum of Cost of Power and controllable expenses. Thunder Bay agreed that the WCA should be updated to reflect updated forecast commodity prices and the current retail transmission service rates.

Energy Probe accepted the approach used by Thunder Bay but submitted that the 15% methodology may be overstating the required WCA and recommended that the Board direct Thunder Bay to prepare a working cash (lead lag) study for its next rebasing application.

Thunder Bay disagreed with Energy Probe's proposal that a lead-lag study be conducted on the basis of the cost of such a study, and suggested that the standard Board guideline of 15% of cost of power and controllable expenses should continue to apply.

Energy Probe noted that, in its response to Energy Probe interrogatory #34, Thunder Bay corrected an error in the cost of power calculation due to the elimination of the MUSH (municipalities, universities, schools and hospitals) sector eligibility for RPP effective May 1, 2009. The impact is a reduction of $475,629 in the working capital component of rate base. Energy Probe submitted that Thunder Bay's adjustment was appropriate.

Finally, Energy Probe observed that Thunder Bay had allocated $295,567 of depreciation expense to OM&A expenses. Energy Probe pointed out that as depreciation expense is not a controllable expense, it should not be included in the determination of working capital. Energy Probe noted that Thunder Bay has removed the depreciation expense, which is reflected as a reduction of $44,335 in the Adjustments Table filed with the responses to supplemental interrogatories.

Board Findings

The Board concludes that the most accurate data should be used in the calculation of working capital, and notes that Thunder Bay and Energy Probe agree with this approach. With the exception of Energy Probe's submission of the appropriateness of the general 15% working capital guideline formula, there is agreement amongst parties on Thunder Bay's proposal, as adjusted through the discovery process.

Thunder Bay has followed the Board's *Filing Requirements for Transmission and Distribution Applications* dated November 14, 2006 which allows the Company to apply a 15% factor to derive the allowance for working capital. The Board will not require Thunder Bay to prepare a lead lag study for its next rebasing application. The Board does not believe that such a cost is warranted at this time.

The Board directs Thunder Bay to update the cost of power to reflect the price contained in the April 2009 RPP price report, $0.06072/kWh. With respect to the level of wholesale transmission service rates to be used in the calculation, the Board will address this matter later in this Decision under Retail Transmission Service Rates. With respect to the MUSH sector, the Board notes that RPP eligibility for this sector has been extended to November 2009, and therefore the Board will not require the adjustment advocated by Energy Probe for this factor.

COST OF CAPITAL and CAPITAL STRUCTURE

On December 20, 2006, the Board issued the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"). The Board Report provides the Board's policy guidelines for determining the capitalization and cost of capital to be used for electricity rate-setting.

In Section 6 of its application, Thunder Bay documented its requested Cost of Capital. This is summarized in the following table:

Cost of Capital Parameter	**Thunder Bay'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.
Long-Term Debt	0.21%, as a weighted average of several affiliated and third-party debt instruments. (References: E6/T1/D2/Attachment and response to Board staff IR #25)
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.

In its 2006 distribution rates application, Thunder Bay requested, and the Board approved, an ROE of 2.93%. In this application Thunder Bay requested an ROE of 3.75%. As noted, Thunder Bay has affirmed that the deemed Short-term Debt Rate and deemed Long-Term Debt Rate, as applicable, 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 24, 2009, the Board issued a letter documenting the updated Cost of Capital parameters to be used in determining distribution rates for 2009 cost of service applications. The updated Cost of Capital parameters are documented in the following table:

Cost of Capital Parameter	**Updated Value for 2009 Cost of Service Applications**
Return on Equity	8.01%
Deemed Long-term Debt Rate	7.62%
Deemed Short-term Debt Rate	1.33%

SEC noted that Thunder Bay's WACC is far below that of most other distributors, and accepted Thunder Bay's explanation of its rate minimization approach. Board staff also observed that Thunder Bay has adopted a rate minimization approach, and has not required a market-based return on equity, as its shareholder, the City of Thunder Bay, has not demanded any equity return. Board staff did not oppose Thunder Bay's proposal as, in Staff's view, the increase facilitates the Company's ability to attract and retain capital, especially in light of increasing capital expenditures to rehabilitate its distribution network. Board staff submitted that Thunder Bay should give further consideration to aligning its cost of capital with its asset management plans and its increasing capital expenditures, and should file documentation on how its proposed cost of capital relates to its asset management plan, asset condition, and capital requirements at the time of its next cost of service proceeding.

Board staff did not oppose Thunder Bay's evidence that it could obtain the new long-term debt at 6.0%, but noted that strict application of the guidelines in the Board Report suggest that the deemed long-term debt rate of 7.62% should apply.

Energy Probe submitted that the debt rate for the forecast new debt should not be 6.0%, as proposed by Thunder Bay or the Board's updated deemed long-term debt rate of 7.62%. Energy Probe submitted that a rate of 5.67% should apply, corresponding to a 25-year term loan offered to municipal distribution companies through Infrastructure Ontario. Energy Probe submitted that the higher rates should not apply, as Thunder Bay has indicated that the new debt will not be in place by May 1, 2009. Thunder Bay has not indicated what rate will apply or whether the debt will be with an affiliate or third-party. Regardless, Energy Probe submitted that Thunder Bay should not pay more for the loan than it can get from a third party such as Infrastructure Ontario.

In reply, Thunder Bay clarified that while it believes that it may be able to obtain the new debt at a rate around 6.00%, it also believes that the new debt should be afforded the updated deemed long-term debt rate of 7.62%. Thunder Bay, in its reply submission, did not address Energy Probe's argument that the new debt should be allowed a rate of 5.67%.

Board Findings

The Board finds that Thunder Bay's proposed capitalization and cost of capital complies with the guidelines established in the Board Report. Accordingly, the Board finds that Thunder Bay's 2009 distribution rates will be based on a deemed capital structure of 56.7% debt (52.7% long-term; 4% short-term) and 43.3% equity, in accordance with the Board's established transition process.

The Board approves Thunder Bay's proposed ROE of 3.75%, and also determines that the deemed short-term debt rate of 1.33%, as announced in the Board's letter of February 24, 2009, will apply.

Energy Probe has argued that the new long-term debt should attract a cost of 5.67% on the basis of rates available from Infrastructure Ontario. However, this information was introduced for the first time through argument and the Board does not accept it as evidence in this proceeding. Thunder Bay in its reply requested the Board's deemed rate of 7.62%, but its original evidence was for a forecast rate of 6.0%. The Board accepts the original forecast as a reasonable estimate of the cost of debt in the market and this will be applied to Thunder Bay's new long-term debt.

The table below sets out the Board's conclusions for Thunder Bay's deemed capital structure and cost of capital:

Board-approved 2009 Capital Structure and Cost of Capital for Thunder Bay

Capital Component	% of Total Capital Structure	Cost rate (%)
Long-Term Debt	52.7	0.21
Short-Term Debt	4.00	1.33
Equity	43.3	3.75
Weighted Average Cost of Capital		**1.79**

COST ALLOCATION AND RATE DESIGN

The following issues are addressed in this section:

- Line Losses;
- Revenue to Cost Ratios;
- Other Distribution Revenue; and
- Retail Transmission Rates.

Line Losses

Thunder Bay 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 decrease for primary metered customers from 3.52% to 3.43%. The factors are based on 2003 to 2007 data, and the changes in the factors are the result of an increase in the Supply Facilities Loss Factor from 0.45% to 0.55% together with a decrease in the Distribution Loss Factors ("DLF"). Thunder Bay's proposed DLF for 2009 is 3.90%.

Board staff and Energy Probe submitted that the requested TLFs for customers < 5000 kW are reasonable. VECC submitted that the data supports TLFs that are slightly lower, and Thunder Bay's response was that the difference is due to rounding in the calculations.

Thunder Bay sought approval of an increase in the TLFs for customers larger than 5000 kW. It subsequently withdrew this request because there are no customers in this size range.

Board Findings

The Board finds that Thunder Bay's TLFs as set out in its response to interrogatories are appropriate. The TLF's are:

Secondary metered < 5000 kW	1.0448
Primary metered < 5000 kW	1.0343

Revenue to Cost Ratios

The following table sets out Thunder Bay's current and proposed revenue to cost ratios. Columns 2 and 3 are representative of the existing ratios. The ratios in column 2 include certain corrections to Thunder Bay's Informational Filing, as described in Exhibit 7 / Tab 1 / Schedule 2. The ratios in column 3 are a variation of the Informational Filing which excludes the $413,327 Transformer Ownership Allowance from cost and class revenues. The ratios proposed by Thunder Bay for 2009 are in column 4. The Board's target ranges, as established in the Board Report, *Application of Cost Allocation for Electricity Distributors*, EB-2007-0667, are set out in column 5.

Revenue to Cost Ratio [%]

1	2	3	4	5
Customer Class	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

VECC submitted that Thunder Bay's cost allocation studies, including revised models provided in response to interrogatories, continue to suffer from an inconsistency in the model related to miscellaneous revenue, as well as an imbalance between total revenue and revenue requirement. VECC submitted its own calculations that would overcome these problems. VECC also submitted revised revenue to cost ratios that would result from Thunder Bay's proposed rates.

Thunder Bay did not agree with VECC's suggested approach. The Company submitted that the ratios from the Informational Filing, as adjusted, (column 2) are the preferable reference point for re-balancing class revenues, pending development and approval of an alternative by the Board.

Most submissions on individual classes concerned the GS 1000 – 4999 kW class. SEC submitted that the impacts of moving to 80% would be too high if the 43% ratio were adopted as the starting point. SEC pointed out that the increase in the distribution portion of the bill was calculated as 31% when 60.17% was used as the starting point in the first set of interrogatories. Energy Probe submitted that the ratio should be moved to 80% without phasing in, which would result in a total bill impact of 7.15%, which is within the 10% threshold.

Board staff submitted that the implications of adopting the revised ratios in column 3 are not part of the record. Moving to the Board's policy range from a starting point of 43% entails a much larger increase than moving from 60%, and the record does not contain a reliable estimate of the bill impact for this situation. Staff submitted that achieving an 80% ratio by 2011 is appropriate. VECC submitted that a phase-in period would be appropriate, with half in the first year and the remainder over one or two years.

Thunder Bay responded that the starting point for re-balancing should be the ratios originally filed, and that the increased rates that are implied by moving the ratio from 60% to 70% are more reasonable, particularly with the current economic downturn.

Concerning other classes, VECC submitted that the Residential class should be the only class ratio decreased as a result of revenue re-balancing, because it is the only one with a ratio above its range. There were no submissions to the contrary. Energy Probe submitted that the ratios for the GS 50 – 999 kW class should be moved to 80% in 2009, rather than being phased in as proposed by Thunder Bay. Along with the same recommendation for the GS 1000-4999 kW class, this would enable the ratio for the Residential class to be lowered. Both VECC and Energy Probe submitted that Thunder Bay's proposal to phase-in changes was appropriate for the Street Lighting rates, with 50% of the re-balancing in the first year and the remainder over two years.

Board Findings

The Board is satisfied that the revision argued for by VECC with respect to the exclusion of the transformer ownership allowance from cost and class revenues should be adopted. The ratios reflected in column 3 of the above table are therefore the starting point for our consideration of changes within and between classes. It can be seen from the table that there are several classes that fall outside the respective Board policy ranges. It has been the Board's approach in other cost of service rebasing decisions to migrate nonconforming ratios into Board policy ranges over varying periods of time. The Board will adopt this approach in this case as well.

Of particular note is the GS 1000 to 4999 kW class which currently materially under contributes to the Company's revenue requirement. While bringing the ratio into line with Board policy ranges is important, the Board considers it equally important to accomplish that migration without undue hardship to any class of customers. In the case of this rate class the Board requires that the ratio evolve in equal increments to the lower boundary of the Board policy range by the time of the next scheduled rebasing, which may occur in four years. The additional revenues received from this class as a result of this evolution should be directed exclusively to the Residential class. Once the Residential class falls within the Board policy range the additional revenues should be allocated to all the rate classes which remain above 100% in proportion to their respective contributions of revenue.

For the GS 50 - 999 kW class, the shortfall is smaller and the impact of rebalancing is less and therefore the Board will require that the ratio be moved to the bottom of the range over two years.

The Board approves the Company's proposals with respect to Street Lights, Sentinel lights and Unmetered Scattered Load.

Other Distribution Revenue

In its original application, Thunder Bay proposed $1,802,790 in revenue offsets, revising this number to $1,497,790 by the time the record closed.

Specific Service Charges

Thunder Bay proposed to remove three specific service charges from its Tariff, all relating to the installation and removal of Temporary Service in various situations. The Company submitted that the cost of providing the temporary service connections varies so much that applying a standard charge is inequitable even with the three existing charges. Thunder Bay proposed to recover the cost of providing the services with a charge for time and materials. Board staff submitted that Thunder Bay's request to discontinue the standard charges for temporary services is reasonable.

Regulatory Interest

The majority of the decrease in the revenue offset total from the time of the original filing of the application is attributed to account 4405 – Interest and Dividend Income. In response to an Energy Probe interrogatory[14] Thunder Bay adjusted the 2009 amount to $195,000 from $439,000, citing the drop in interest rates since the filing of the application, and then made a further adjustment to $130,000 to account for the removal of regulatory asset interest. Staff noted that the 1.3% interest rate used by Thunder Bay for its revised calculations is a reasonable market based rate and that interest associated with variance or deferral account balances should not impact the revenue requirement in the form of Other Distribution Revenue. Energy Probe supported these revisions.

[14] Response to Energy Probe supplemental interrogatory #5

Proceeds on Disposal – Meters

In its submission, Energy Probe noted that Thunder Bay had not forecast any proceeds from the disposal of meters as they are replaced with smart meters. Energy Probe further noted that the net book value of the meters is approximately $2.2 million and observed that Thunder Bay is seeking ways to gain the greatest return possible on these investments. Energy Probe did not recommend an adjustment to the revenue offset total at this time, but did request that a deferral account be established to record the proceeds from the disposition of the meters. Energy Probe argued that the proceeds from the disposition of the replaced meters should be used to offset the stranded costs of these assets. Thunder Bay did not address this issue in its reply submission.

Non-Utility Operations

Energy Probe submitted that Thunder Bay has under forecast the net revenues associated with non-utility operations. Thunder Bay proposed $7,000 as the 2009 net amount for accounts 4375 – Revenue from non-utility operations and 4380 – Expenses from non-utility operations. Energy Probe submitted that the Board should increase this amount to $25,000 given that the historical numbers were $24,000 for 2006, $29,000 for 2007 and $42,000 for 2008 to the month of November. Energy Probe noted that no explanation for the significant decrease was provided by the Company. Energy Probe further noted that the average of the above figures is $31,000.

In its reply submission, Thunder Bay stated that it did provide an explanation for the decrease in response to Energy Probe interrogatory #14 d). In that response, Thunder Bay noted that the significant decrease in the net income from accounts 4375 and 4380 is due to the sale of the Water Heater Rental assets by its affiliate, Thunder Bay Hydro Energy Services Inc., in 2008. Thunder Bay stated that the increase to $25,000 is not appropriate.

Board Findings

The Board finds that Thunder Bay's proposals with respect to Other Distribution Revenue, as revised during the course of the proceeding, are reasonable and should be reflected in the Draft Rate Order. The Board finds that a deferral account of the kind proposed by Energy Probe is unnecessary. By letter dated January 16, 2009, the Board has already indicated that any meter salvage value should be tracked in Account 1555 and used to offset the capital costs of the replacement smart meters. The Board is also satisfied with Thunder Bay's explanation of the decrease in revenues from non-utility operations.

Retail Transmission Service ("RTS") Rates

The Board issued a guideline, *Electricity Distribution Retail Transmission Service Rates [G-2008-0001]* on October 22, 2008 indicating the process to be used by distributors to adjust RTS rates to reflect changes in the Ontario Uniform Transmission ("UT") rates. The changes in the UT rates are shown in the following table.

Uniform Transmission Rates

	Current Rate ($/kW/month)	**Effective rate on January 1, 2009 ($/kW/month)**	**Effective increase**
Network Service Rate	2.31	2.57	11.3%
Line Connection Service Rate	0.59	0.70	18.6%
Transformation Connection Service Rate	1.61	1.62	0.6%

Thunder Bay has experienced over and under recovery of its wholesale transmission costs in recent years. The Company submitted revised retail rates that were designed to reflect the new UT rates as well as to correct, in an approximate manner, for the most recent disparities. In response to interrogatories, Thunder Bay refined its calculations.

Board staff supported the RTS rates calculated by Thunder Bay in response to Board staff supplemental interrogatory #19 b). There were no other submissions concerning RTS rates.

Board Findings

The Board finds that Thunder Bay's proposal is acceptable. The Board also directs Thunder Bay to use the January 1, 2009 UT rates in determining the Working Capital Allowance.

DEFERRAL AND VARIANCE ACCOUNTS

Thunder Bay did not apply for disposition of any deferral or variance accounts. In response to an interrogatory, the Company provided a continuity table showing the balance of each account at year-end 2007 and forecast interest adjustments to April 30,

2009. The balances of the deferral and variance accounts are shown in the following table.

Deferral and Variance Accounts

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	**1,149,834**
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)	159,252
	Sub-Total	**(3,289,157)**
1555	Smart Meter Capital and Recovery Offset	(170,202)
1556	Smart Meter OM&A	(70,833)
1562	Deferred PILs	(1,830,731)
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	**1,772,913**

Thunder Bay provided regulatory asset rate riders that would recover or refund the aggregate balance of two hypothetical combinations of the accounts. The first scenario comprises accounts 1508, 1518, 1525, 1548, and 1582, which sum to $1,149,834. The second scenario comprises these same accounts, and also accounts 1580, 1584, 1586, and 1588, which sum to a net credit of $2,139,323.

Board staff submitted that the Board might wish to evaluate the reasonableness of rate riders which would dispose of all of the deferral and variance account balances in the second scenario.

VECC supported disposition of the larger group of accounts. It submitted that a refund over three or four years would be appropriate. Energy Probe also supported disposition of the larger group, on the grounds that under the other scenario it would be unfair to charge a positive rate rider while the same customers are owed a refund from other accounts. Energy Probe recommended a period of at least two years in the case of a positive rate rider, but did not make a term recommendation in the case of a refund.

Board Findings

The Board has announced an initiative to consider on a generic basis certain of the deferral and variance accounts, but that process is still in the early stages. The RSVA balances are large and the Board finds that these amounts should be disposed of at this time. A rebasing application is an appropriate time at which to consider disposition of each account. The Board finds it appropriate to dispose of all the accounts, except the two PILS accounts (which are subject to a review in a separate proceeding), account 1590 (which the Board has typically not disposed of until the final balance can be verified), and the smart meter and CDM tracking accounts (which will be reviewed at a later date).

The Board finds that a two year disposition period is appropriate.

The Board directs Thunder Bay to include documentation in its Draft Rate Order which shows the monthly amount to be refunded, allocation of each account to each rate class and confirmation of the length of the disposition period.

SMART METERS

Thunder Bay proposed to increase the smart meter funding adder from $0.26 per month per metered customer to $1.25. Thunder Bay stated that it was becoming authorized under the amended regulation pursuant to and in compliance with the London Hydro RFP process.

The Government of Ontario filed amendments to three smart metering regulations, namely O. Reg. 427/06 (*Smart Meters: Discretionary Metering and Procurement Principles*), O. Reg. 426/06 (*Smart Meters: Cost Recovery*), and O. Reg. 393/07 (*Designation of Smart Metering Entity*). Thunder Bay stated that it qualified for the increased adder since amendments to O. Reg. 427/06 will authorize metering activities for distributors pursuant to and compliant with the *Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase 1 Smart Meter Deployment* issued on August 14, 2007 by London Hydro Inc.

On October 22, 2008, the Board issued its Guideline G-2008-0002, *Smart Meter Funding and Cost Recovery*. Guideline G-2008-0002 outlines requirements for applicants wishing to request a $1.00 smart meter funding adder. The Board noted that the standard $1.00 funding adder would provide funding for distributors which are authorized and clearly intend to install smart meters in the test year. Guideline G-2008-0002 established informational requirements to be provided in support of a request for an increased smart meter funding adder of $1.00 per month per metered customer, and also additional filing requirements where a distributor proposed a unique funding adder amount. Thunder Bay has opted for the latter.

In its original Application, Thunder Bay stated that it intends to install approximately 49,000 meters, representing full deployment, during the test year at an estimated cost per meter of $182.50 and a total capital cost of $8,960,950. Thunder Bay estimated its OM&A costs related to smart meters for 2009 to be $260,000. Thunder Bay also provided a smart meter funding model in support of its proposed funding adder of $1.25.

In response to Board staff supplemental interrogatory #15, Thunder Bay revised its smart meter funding adder to $1.97. This reflected some changes in estimated capital and operating expenses, and a treatment of smart meters as being wholly financed with debt at 6.00%. The revision also reflected Thunder Bay's proposal to defer application of existing funding adder revenues to offset 2010 amounts, so as to defer future rate impacts.

Thunder Bay has not included any capital costs for smart meters in its rate base, nor is it including operating expenses related to smart meters in its revenue requirement. Smart meter funding adders, and capital and operating costs related to smart meters, will continue to be recorded in established deferral accounts 1555 and 1556, for review and disposition in a future application.

Smart Meter Model

As Thunder Bay is requesting a unique smart meter funding adder, Guideline G-2008-0002 requires the Company to provide a detailed calculation of the proposed amount. Thunder Bay provided a PDF version of an Excel model to support the proposed adder of $1.25. In Appendix A of the response to Board staff supplemental interrogatory #15 b), Thunder Bay provided an updated smart meter model supporting the revised proposed funding adder of $1.97.

In its submission, Board staff noted that the PDF version of the smart meter model provided in the response to Board staff supplemental interrogatory #15 was labeled as "Smart Meter Model (Updated by Board Staff in November 2008)". While neither the Board nor Board staff had provided a Board-approved model to determine smart meter costs and recovery, a model was issued in January 2007 for use with the 2007 EDR applications under 2nd Generation IRM. Staff observed that Thunder Bay's use of the January 2007 model resulted in unusual and illogical proposals being put forward by the Company:

a. Thunder Bay stated that it required a 7.90% ROE for smart meter recovery, different from its proposed ROE of 3.75%.[15] This is unusual and illogical as equity, or the shareholders' investment in the firm, is not tied to specific assets; and
b. As Thunder Bay has indicated that it expects to fund smart meters through 100% debt, requiring a 7.90% ROE on the deemed equity portion to be able to fully recover costs over the 15 year expected life of smart meters purchased at 6.00% debt does not seem logical.

To address these issues, Thunder Bay revised the supporting model to assume 100% debt financing at 6.00% in support of the proposed revised smart meter funding adder of $1.97.

[15] Response to Board staff interrogatory #29

Carry over of seed money

In the response to Board staff supplemental interrogatory #15 b), Thunder Bay revised its smart meter proposal to $1.97 per month. Thunder Bay stated that this increase, from the original proposed amount of $1.25 reflected certain increased cost estimates, related to:

- Conversion of over 500 three-phase GS < 50 kW customers whose services will need to be upgraded to meet Measurement Canada requirements; and
- Increased use of Thunder Bay staff to perform the work on more complicated meter installations and conversions.

The increase also reflects a deferment of smart meter funding revenues collected since May 1, 2009; Thunder Bay now proposed to not apply funding adder revenues collected against the 2009 revenue requirement costs of smart meters being installed, but instead to use them to offset the 2010 smart meter revenue requirement. Thunder Bay stated that this approach would smooth the rate impacts over the next few years until the smart meter assets are fully reflected in rate base.

In its submission, Board staff observed that Guideline G-2008-0002 does not stipulate the treatment of funding adders. Board staff did not specifically oppose Thunder Bay's revised proposal.

VECC supported Thunder Bay's proposal to increase the funding adder to $1.97 per month per metered customer.

Board Findings

In a number of the 2008 distribution rate applications, the Board permitted a number of applicants, not then authorized to deploy smart meters, to collect an increased amount by way of the smart meter rate adder in anticipation of that authorization forthcoming through legislation or regulation. In the Board's view, increasing the rate adder to $1.97 per month per meter going forward would provide Thunder Bay with funds to support the rollout in 2009, as planned, and avoid rate shock upon completion of smart meter deployment.

The Board issued Guideline G-2008-0002 to provide guidance to distributors for the implementation of smart meters when a distributor becomes authorized, and to aid in the review of smart meter funding and cost recovery. As noted by staff, Guideline G-2008-0002 does not specify when the smart meter funding adder revenues collected are to be used. The common treatment applies the revenues collected currently against the costs of current smart meters, in a manner akin to contributed capital; however, the Board expects that Thunder Bay's proposal to defer application until 2010 will result in the benefits described by Thunder Bay. Further, no party has opposed Thunder Bay's revised proposal, and the Board anticipates that its approval should mitigate rate increases over the next few years.

The Board finds that Thunder Bay has complied with legislation and with the Board's Guideline G-2008-0002, and so approves an increased smart meter funding adder of $1.97 per month per metered customer. In so finding, the Board makes no determination of the prudence and reasonableness of Thunder Bay's estimated smart meter costs, which will be reviewed in a future application when Thunder Bay applies for disposition of the smart meter variance account balances.

IMPLEMENTATION

The Board has made findings in this Decision which change the 2009 distribution rates from those proposed by Thunder Bay.

The Board issued an Interim Rate Order on April 16, 2009 making Thunder Bay's current rates interim, which allows for an effective date as early as May 1, 2009. Thunder Bay was three weeks late in filing its application, but the Board has determined that an effective date of May 1, 2009 remains appropriate.

In developing its Draft Rate Order, Thunder Bay is directed to establish the 2009 rates assuming a 12 month recovery period. The implementation date of the Final Rate Order will be July 1, 2009. Thunder Bay is also directed to calculate rate riders that would recover two months of foregone revenue. Thunder Bay should propose an appropriate time period for recovery giving due consideration to bill impacts. The current interim rates are in effect until the Board approves the Final Rate Order.

As the 2009 rates will be implemented beginning July 1, 2009, for the rate riders to dispose of approved deferral and variance account balances, Thunder Bay is directed to calculate the rate riders to collect the balances from customers over a period of 22 months rather than 24 months.

In filing its Draft Rate Order, it is the Board's expectation that Thunder Bay will not use a calculation of the revised revenue deficiency to reconcile the new distribution rates with the Board's findings in this Decision. Rather, the Board expects Thunder Bay to file detailed supporting material, including all relevant calculations showing the impact of this Decision on Thunder Bay's proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form excel spreadsheet, which can be found on the Board's website. Thunder Bay should also show detailed calculations of the revised retail transmission service rates and variance account rate riders reflecting this Decision.

RATE ORDER

A Rate Order decision will be issued after the processes set out below are completed.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. The Board will determine eligibility for costs in accordance with its Practice Direction on Cost Awards. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

All filings with the Board must quote the file number EB-2008-0245, and be made through the Board's web portal at www.errr.oeb.gov.on.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca. If the web portal is not available you may e-mail your documents to the attention of the Board Secretary at BoardSec@oeb.gov.on.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

THE BOARD DIRECTS THAT:

1. Thunder Bay shall file with the Board, and shall also forward to intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 14 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

2. Intervenors shall file any comments on the Draft Rate Order with the Board and forward to Thunder Bay within 7 days of the date of filing of the Draft Rate Order.

3. Thunder Bay shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order within 7 days of the date of receipt of Intervenor submissions.

4. Intervenors shall file with the Board and forward to Thunder Bay their respective cost claims within 30 days from the date of this Decision.

5. Thunder Bay shall file with the Board and forward to intervenors any objections to the claimed costs within 44 days from the date of this Decision.

6. Intervenors shall file with the Board and forward to Thunder Bay any responses to any objections for cost claims within 51 days of the date of this Decision.

7. Thunder Bay shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto**,** June 3, 2009

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary