# Board Staff Supplemental Interrogatories
# 2009 Electricity Distribution Rates
# Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay)
# EB-2008-0245

## GENERAL

**1. Ref: Energy Probe IR #2**

In response of Energy Probe #2 a), Thunder Bay stated:

"Rates in the period of 2000 to 2007 were set in accordance with our costs and corresponding revenue requirement as they are today. From 2000 to 2002 the regulator was Ontario Hydro and in 2003 that regulator became the OEB."

a. Please confirm that, pursuant to Bill 35, Thunder Bay became subject to regulatory oversight by the Ontario Energy Board effective April 1, 1999.

b. Please confirm that Thunder Bay's unbundled distribution rates in 2001 and distribution rate adjustments per the first-generation PBR plan for May 1, 2002 were approved or set by Decisions and Orders of the Ontario Energy Board.

## OPERATING COSTS

**2. Ref: E2/T3/S1 –Capital Budget Overview , E4/T2/S2 – Variance Analysis of OM&A Costs, Board staff IR #2**

Board staff IR #2 requested Thunder Bay to identify, individually, maintenance and capital programs, if any, that Thunder Bay may consider as a candidate for a deferral, cut, or partial adjustment, given the current economic situation. In response, Thunder Bay ranked the following OM&A programs.

1 - Asbestos Removal (subject to a review of the level of activity required to meet environmental regulations)
2 - Substation Maintenance & Testing; and
3 - Recloser & Line Switch Maintenance.

Please provide the amounts budgeted for these programs in the 2009 OM&A forecast.

***PCB Removal***

**3. Ref:** E1/T2/S3/p6-8**– Changes in Methodology (PCB Removal)**
**Board staff IR #9**

Thunder Bay's total PCB program cost is estimated to be $3.4M. Thunder Bay has included costs in 2009 ($461K) for the purpose of eliminating all PCBs in concentrations of >500 PPM and all PCB's in concentrations of >50 PPM in environmentally sensitive areas as per the legislation. The legislation requires that all remaining PCB's (>50 PPM in non-sensitive areas) be removed from service by 2025.

a. In response to Board staff IR #9,Thunder Bay indicated that $179K in 2009 and $108K thereafter (to 2020) are the amounts that are forecasted to be charged to capital regarding the PCB program. The table on page 9 of the response identifies $380K and $230K respectively under the heading of "transformer replacement". It is not readily apparent why there is a difference between the amounts for capital on page 7 and the amounts for transformer replacement on page 9. Please provide an explanation.

b. Please explain why Thunder Bay has elected to phase out all remaining PCBs by 2020 (at a total cost of $3.4M) when the legislation allows the phase out to extend to the end of 2025.

c. For 2009 only, Thunder Bay has proposed spending of $461K, ($179k in capital and $282K in OM&A) on the PCB program. For the remaining years of the PCB program to 2020, Thunder Bay is estimating annual costs of $278K, ($108K in capital and $170K in OM&A). As currently structured, Thunder Bay's rates under 3$^{rd}$ Generation IRM will recover approximately $110K more annually for PCB treatment-related OM&A than will be required in the remaining years of the program. Please explain why Thunder Bay feels it is appropriate to have rates for the subsequent years of the PCB program reflect the OM&A costs that are necessary for 2009 only, and to have such rates in place until the date of the next rebasing of Thunder Bay's distribution rates.

d. In response to Board staff IR #9 e), Thunder Bay indicated that all the transformers will have been fully amortized on retirement and as such there will be no write-offs or stranded costs. Please indicate whether asset retirement obligations ("ARO") were set up for these transformers in light of the requirements under the previous environmental legislation. If so, has Thunder Bay included ARO related depreciation or accretion expenses in the revenue requirements of previous rate applications? If so, please provide the amounts of these expenses.

***Compensation***

**4. Ref: E4/T2/S2/p2 – Variance Analysis of OM&A Costs, E4/T2/S4 – Employee Compensation, Board staff IR #10**

The response to Board staff IR #10 c) revised the total amounts for compensation for the years 2006-2009. Thunder Bay also explained that " …further, the amount originally reported as total salary, wages and benefits charged to OM&A only included direct OM&A expenses, (the overhead accounts had not been considered) and did not include overtime." It is not clear whether or not the updated compensation amounts presented on page 12 include overhead accounts and overtime. Please confirm.

***Forestry Management***

**5. Ref: E1/T2/S3/p.3 – Changes in Methodology (Forestry Management), Board staff IR #11**

a. In Board staff IR #11, Board staff requested the Forestry Management related expenditures for 2006 EDR and 2008 Forecast. The latter was provided but not the former. Please provide the expenditure level for Forestry Management included in Thunder Bay's approved 2006 revenue requirement.

b. Thunder Bay is proposing that its vegetation management budget be inflated by approximately 50% for a period of 8 years to rectify historical under spending. Please explain to what extent undergrounding initiatives would mitigate the need for vegetation management in some areas of Thunder Bay's service area.

***Purchased Services***

**6. Ref: E4/T2/S3 – Shared Services, Board staff IR #16**

The purchased service listing in the response to Board staff IR #16 indicates $307K in 2008 and $312K in 2009 for the rental of office space (from the City of Thunder Bay) and that the price was negotiated.

a. Please provide the date the lease was signed with the city, the number of square feet rented and the cost per foot negotiated.

b. Please provide the comparative benchmarks Thunder Bay used/uses in its negotiations to ensure a market price.

### *Regulatory Costs*

**7. Ref: E1/T3/S2 –Pro Forma Financial Statements, Board staff IR #19**

In the table provided in the response to Board staff IR #19, Thunder Bay identified the accounts it uses to record “regulatory“-type costs and the respective amounts.

a. Please confirm whether or not the amounts noted reflect full costs or are only the yearly amortized costs. If the latter, please provide the amortization term.

b. Under account “5655” costs described as “Ontario Energy Board- Cost Awards and Assessments” are presented (i.e. 2006 - $116K, 2007 -$125K, 2008 -$130K and 2009- $136K). Please breakout these amounts between “Cost Awards” and “Assessments”.

### *Meter Reading Costs*

**8. Ref: E4/T2/S1 –OM&A Costs Table, Board staff IR #18**

In response to Board staff IR #18, Thunder Bay indicated that meter reading costs are expected to diminish from $250K in 2009 to $125K in 2010 and then to $25K in 2011. This is due to the smart meter implementation plan that calls for nearly 100% deployment in 2009. If Thunder Bay plans for nearly 100% deployment in 2009, then why is there not a higher decline forecasted in meter reading costs for 2010?

## RATE BASE

### *Capital Expenditures*

**9. Ref: E2/T2/S3/Table 1 – Variance Analysis on Gross Assets, Energy Probe IR#4**

In its original application, Thunder Bay projected a capital cost of $861,909 for the Tarbutt Street Area Conversion/Rebuild for 2008, but the response to Energy Probe IR#4 indicates that actual costs to complete the project were $1,062,486. Board staff calculates this as a cost overrun of $200,577 or 23.3% over budget. Please explain the reasons for the cost overrun.

**10. Ref: Board staff IR#25 and Energy Probe IR#7 – Amortization Rate for Computer Hardware**

Thunder Bay states that it uses a 3-year amortization rate for computer hardware, except for printers, and confirms that this differs from the Board’s standard guideline of 5-year depreciation for computer hardware.

A review of Thunder Bay's 2006 EDR application does not highlight any deviation from the Board's guideline on amortization rates documented in Appendix B of the *2006 Electricity Distribution Rate Handbook* (the "Handbook"). However, section 4.1 of the Handbook required a distributor to document and support variances from the Board's guidelines on amortization rates.

a. Please confirm whether Thunder Bay has previously documented, requested and received approval from the Board for a depreciation rate of 33.3% for computer hardware. If so, please provide references and details.

b. How long has Thunder Bay used a 3-year depreciation life for computer hardware?

c. If Thunder Bay has changed its useful economic life for computer hardware to 3 years since its 2006 distribution rate application, please provide an explanation. Please provide supporting documentation, including any amortization study to justify the 3-year economic life for computer hardware.

**11. Ref: E2/T2/S3/Tables 1 and 2 – Variance Analysis on Gross Assets, VECC IR#10**

a. For 2008, please provide a disaggregation of "All Other Infrastructure Capital" by account according to the following table format:

| | Account | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1830 | 1835 | 1840 | 1845 | 1850 | 1855 | 1860 | Total |
| Conversion/Rebuild (Sum of B81106, B81213, B81304) | | | | | | | | |
| Station Fencing/Grounding/ Wholesale Revenue Meter Upgrade (Sum of B82122 and B82315) | | | | | | | | |
| Other Infrastructure Capital Projects (Sum of A801, A811-A817, A821 and A822) | | | | | | | | |
| Total | $440,017 | $323,349 | $113,018 | $174,073 | $459,232 | $562,470 | $589,309 | $2,661,468 |

b. For 2009, please provide a disaggregation of “All Other Infrastructure Capital” by account according to the following table format:

| | Account | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1830 | 1835 | 1840 | 1845 | 1850 | 1855 | 1860 | Total |
| Conversion/Rebuild (Sum of B91221, B91230, B91237) | | | | | | | | |
| Other Infrastructure Capital Projects (Sum of A901, A911-A917, A921 and A922) | | | | | | | | |
| Total | $840,470 | $993,274 | $106,570 | $180,016 | $866,643 | $575,942 | $47,194 | $3,610,109 |

**12. Ref: E2/T3/S1/Appendix A – Historical Review of Capital Expenditures, Board staff IR#22**

In response to Board staff IR #22, Thunder Bay provided the historical capital expenditures and the trended data as shown in E2/T3/S1/Appendix A. Thunder Bay also explained how it developed the extended trend line, on which Thunder Bay has based its conclusion that if it had not adopted rate minimization and under spent on capital beginning in 2004, its annual capital expenditures would be between $11 million and $12 million for 2009 rather than the $7.6 million proposed for 2009 (excluding smart meters). Thunder Bay explained that the trend was developed by extrapolating from 1994 data using Excel.

Board staff makes the following observations regarding Thunder Bay’s trend analysis:

- The capital expenditures are nominal, not real. In other words, the data are not adjusted for inflation.
- Growth in customers and demand is not accounted for in the analysis.

While more sophisticated econometric analyses can be done, a relatively easy analysis can be done by adjusting capital expenditures for inflation, and also comparing the average annual growth rates in real capital expenditures and customers over different periods.

Board staff has prepared the attached spreadsheet to facilitate this analysis. The data shown in the spreadsheet are as follows:

| | |
|---|---|
| Column A | Year |
| Column B | Annual Capital Expenditures (from response to Board staff IR #22) |
| Column C | Smoothed Capital Expenditures (from response to Board staff IR #22) |
| Column D | Extended Capital Expenditures (from response to Board staff IR #22) |
| Column E | Number of Customers (to be filled in) |
| Column F | GDP-IPI – Implicit Price Index (price deflator) for National Gross Domestic Product. Annualized from quarterly series. This is the same price deflator series which annual growth rate is used as the proxy for the inflation adjustment for the 2nd and 3rd Generation IRM plans. Source: Statistics Canada Series V1997757. |

Column G		Real capital expenditures.  Column B divided by Column F.

The spreadsheet also calculates the average annual geometric growth rate for the following periods:

- 1980 to 1994
- 1994 to 2007; and
- 1980 to 2007.

a. Please confirm whether or not Thunder Bay accounted for inflationary pressures and customer growth when preparing its original capital expenditures trend.

b. Please confirm or correct the data provided in the attached table.

c. Please provide Thunder Bay's number of customers for the period 1980 to 2007 inclusive, and calculate the growth rates as per the attached excel spreadsheet.

d. Please provide Thunder Bay's observations and comments on whether there have been changes in inflation rates and customer growth in Thunder Bay in the two periods: 1980-94 and 1994-2007.  Please provide Thunder Bay's comments on whether lower inflationary pressures on capital prices and labour rates, combined with lower customer growth, ignoring Thunder Bay's adoption of a rate minimization approach, would have lead to lower expected capital expenditures since 1994 than those estimated by Thunder Bay's "extended trend".

e. Based on the results of the spreadsheet and the analysis above, please provide an estimate of capital expenditures for the 2010 to 2014 period that would be sufficient to sustain the network, accommodate customer growth and rehabilitate the network in light of past capital under spending.

***Smart Meters***

**13. Ref:  Board staff IR#28**

In response to Board staff IR #28 a) i), Thunder Bay explained that costs related to: i) Changes to ancillary systems; and ii)  Costs associated with Repair and Replacement of Customer Owned Equipment, are not included in the 2009 rate base and revenue requirement, or in the calculation of the funding adder.  The aggregate capex and opex for these areas amount to approximately $600,000 for i) and $560,000 for ii).

a. Please provide further explanation of what changes to ancillary systems are necessary.

b. Please provide further explanation of what is meant by “Costs associated with Repair and Replacement of Customer Owned Equipment”. Is this related to replacement of defective meter bases?

c. Please provide Thunder Bay’s proposal for tracking and recovery of the above costs, if they are not recovered by way of the revenue requirement or factored into the smart meter funding adder.

***Cost of Capital***

**14. Ref: Board staff IR #27, Energy Probe IR#26**

In response to Energy Probe IR#26, Thunder Bay indicated that it has not yet determined if the forecasted debt for 2009 capital funding ($1.1M), which is not yet in place, will be with an affiliated party or a third party institution. Thunder Bay has taken the position that the forecasted interest rate of 6% is should be applicable to the loan, although it is not in yet in place.

The Board’s deemed long-term debt rate, as documented in section 2.2.1 and Appendix A of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors*, issued December 22, 2006, is intended as a proxy for what would constitute a market-based rate, based on currently available information, where no contracted rate is established. If Thunder Bay has not established the terms and rates for this forecasted debt, please explain why the rate for this new debt should be 6.0% rather than the Board’s deemed long-term debt rate, which is based on January 2009 data.

**15. Ref: Exhibit 6 – Revenue Deficiency Overview, Board staff IR#29, Energy Probe IR #29**

Thunder Bay states that it requires a return on equity of 7.90% to be able to fully recover the capital costs for smart meter deployment in 2009, as shown by the tables provided in the response to Energy Probe IR#29. This is in contrast with its proposed ROE of 3.75%. Board staff notes that concepts of debt financing and return on equity are routinely applied at an aggregate level for financing of the firm’s capital investments, rather than on a project basis.

a. In the tables shown in the response to Energy Probe IR#29, Thunder Bay demonstrated that an ROE of 7.90% is required to be able to fully recover the capital investment plus debt servicing costs (interest) on the 2009 smart meter capital expenditures over a 15 year economic life. Thunder Bay also stated that it will fund smart meters fully through debt financing. Thunder Bay stated that it has assumed a debt rate of 6.0% for purposes of calculating the rate adder.

Please explain why a rate higher than the assumed 6.0% debt interest rate would be necessary to fully recover the principal and interest on the deemed equity portion.

b. Shareholders' equity is not specifically tied to assets invested. Furthermore, economic regulatory rate-setting is based on allowing the firm to recover necessary and prudently incurred costs, including the opportunity to earn a market-based return on shareholders' equity, and taking into account market conditions and the business risk of the firm and industry relative to the overall market. Finally, the target return varies over time. When a utility rebases rates through a cost of service application, the allowed ROE will be set explicitly. For rate adjustments as part of IRM plans, the inflation adjustment in part accounts for changes in the cost of capital parameters. Thunder Bay, in accordance with the Board's *Guideline G-2008-0002: Smart Meter Costs and Recovery*, and with general regulatory rate-setting policy, will eventually be applying for recognition of smart meter capital costs in rate base.

   Taking into account the above regulatory principles and practices, please explain Thunder Bay's rationale for proposing a different ROE for smart meter investments (7.90%) versus its proposed ROE of 3.75% for other shareholder equity.

## COST ALLOCATION, RATE DESIGN AND VARIANCE ACCOUNTS

***Revenue to Cost Ratios***

**16. Ref: E7/T1/S3/p.17, VECC IR # 7c), VECC IR # 8a)**

In response to VECC IR #7 c), Thunder Bay provided a version of the Cost Allocation model in which the cost of the Transformer Ownership Allowance is excluded, which can be compared with the version in the pre-filed evidence which includes it as a "cost" item. The result of excluding the allowance is higher revenue-to-cost ratios for the classes that have transformer-related costs allocated to them, and lower revenue-to-cost ratios for those classes that do not have transformer-related costs allocated to them. In particular, the revenue-to-cost ratio of the General Service 1000-4999 kW class is 60.17% in the application and 43.41 % in the response to VECC IR #7c).

a. The revenue inputs to the Cost Allocation model for the General Service 1000-4999 kW class in 2006 are $1,158,847 and $789,375, in the pre-filed and VECC runs respectively. Please confirm that analogous amounts for 2009 are $1,069,706 and $1,402,432, as provided in response to VECC IR #8a). If these are not the analogous revenues, please provide the 2009 numbers that would be considered analogous to the 2006 data inputs.

b. Please provide the Monthly Service Charge and volumetric rate for the General Service 1000-4999 kW class that was approved for 2006 and hypothetical rates that would have produced sufficient revenue in 2006 in the VECC version such that the ratio would have been 60% instead of 43%.

c. Does Thunder Bay consider the original filing or the modified version provided in VECC IR #7c) to be a more valid representation of the revenue-to-cost ratio for the class in question?

**17. Ref: E8/T1/S9/Appendix A /p.7, Energy Probe IR # 27 c)**

In the prefiled evidence, an increase in the revenue-to-cost ratio for the General Service 50-999 kW class from 66% to 73% is accomplished by increasing the Monthly Service Charge by 20.37% and the volumetric rate by 18.29% (ref: second from last column, p. 7 of 12). In the response to Energy Probe, an increase of twice as much (from 66% to 80%) is accomplished with increases of 31.96% and 28.70%. These calculated increases are approximately 1.5 times the increase that was applied for, whereas one might have expected them to be 2 times as much. Please confirm that the hypothetical rates provided in response to the Energy Probe interrogatory are correct, together with an explanation for the seeming anomaly identified here. Alternatively, please provide a corrected calculation of the rates and impact in the response to the interrogatory.

**18. Ref: E8/T1/S9/Appendix A/p.9, ; Energy Probe IR# 27 d)**

In the prefiled evidence, an increase in the revenue-to-cost ratio for the General Service 1000-4999 kW class from 60% to 70% is accomplished by increasing the Monthly Service Charge by 26.72% and the volumetric rate by 15.67%. In the response to Energy Probe, an increase of twice as much (from 60% to 80%) is accomplished with increases of 44.86% and 26.31%. Again, these calculated increases are approximately 1.5 times the increase that was applied for, whereas one might have expected them to be 2 times as much. Please confirm that the hypothetical rates provided in response to the Energy Probe interrogatory are correct, or alternatively provide a corrected calculation of the rates and impact in the response to the interrogatory.

***Retail Transmission Service Rates***

**19. Ref: Board staff IR #46 b), c)**

In response to Board staff IR #46 b), Thunder Bay provided a forecast of the wholesale cost of transmission service. In response to Board staff IR #46 c), Thunder Bay provided a forecast of its revenue from the proposed Retail Transmission Service Rates. There is a shortfall in the Network revenue of approximately 5% ($4.3M vs $4.6M), and a shortfall in the Connection revenue of approximately 10% ($3.7M vs. $3.3M).

a. Please explain why Thunder Bay is proposing RTSRs that produce a shortfall instead of a simple pass-through of the forecast cost.

b. Please provide a calculation of Network and Connection RTSRs, similar to those in the tables in response to part c) of Board staff IR #46, that would produce revenues close to the forecast wholesale cost.

***Deferral and Variance Accounts***

**20. Ref: E1/T3/S1/Attachment A/page 45 - 2007 Audited Financial Statements, Board staff IR #47 a), d)**

The December 31, 2007 balances for Accounts 1584 and 1586 provided in the continuity schedule are credits of $671,317 and $647,640 respectively (including interest to April 30, 2009). The balances reported in the 2007 Audited financial Statements in Exhibit 1 at year-end 2007 were ($825,305) and ($589,654) respectively. Please reconcile the two sets of numbers. If the Board were to order disposition of the balances in accounts 1584 and 1586, which set of figures should it rely on?

***Rural or Remote Electricity Rate Protection***

**21. Ref: E8/T1/S6 – Proposed Rate Schedule for 2009, Board's December 17, 2008 Letter to All Licensed Electricity Distributors and Retailers Re: Rural or Remote Electricity Rate Protection**

In its December 17, 2008 letter, the Board announced a change to the RRRP rate from 0.10 cents per kWh to 0.13 cents per kWh. The Board also directed all distributors that have current rate applications before the Board to submit the Board's December 17, 2008 letter as an update to their evidence along with a request that the RRRP change in their tariff sheet be revised to 0.13 cents per kWh effective May 1, 2009. As of this date, Thunder Bay has not updated its application for this change.

Please confirm that Thunder Bay is updating its application to reflect the change to the RRRP rate.