PIAC

PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DEFENSE DE L'INTERET PUBLIC
ONE Nicholas Street, Suite 1204, Ottawa, Ontario, Canada K1N 7B7
Tel: (613) 562-4002. Fax: (613) 562-0007. e-mail: piac@piac.ca. http://www.piac.ca

Michael Buonaguro
Counsel for VECC
(416) 767-1666

March 13, 2009

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
EB-2008-0245
Thunder Bay Hydro Electricity Distribution Inc. – 2009 Electricity Distribution Rate Application

Please find enclosed the argument of the Vulnerable Energy Consumers Coalition (VECC) in the above-noted proceeding.

Thank you.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

EB-2008-0245

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF an Application by Thunder Bay Hydro Electricity Distribution Inc. pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity.

FINAL SUBMISSIONS

On Behalf of The

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

March 13, 2009

Michael Buonaguro
Public Interest Advocacy Centre
34 King Street East
Suite 1102
Toronto, Ontario
M5C 2X8

Tel: 416-767-1666
E-mail: mbuonaguro@piac,ca

Vulnerable Energy Consumers' Coalition (VECC)
Final Argument

1 The Application

1.1 Thunder Bay Hydro Electricity Distribution Inc. ("TBH" or "Thunder Bay") filed an application dated September 5, 2008, with the Ontario Energy Board ("the Board") for rates effective May 1, 2009. The original application projected a Test Year distribution revenue requirement[1] of $17,518,938 which included a revenue deficiency of $1,414,077 at existing rates. The increase in distribution revenues required to eliminate this deficiency is 8.78%.

1.2 On February 11, 2009, Thunder Bay responded to supplementary interrogatories and, due to a number of changes to its Application triggered by the interrogatories, revised the Test Year revenue deficiency to $1,055,392.

1.3 On March 6, 2009, Thunder Bay filed a revised "Summary of Adjustments to Thunder Bay Hydro Electricity Distribution Inc. 2009 Cost of Service Application" to reflect "the impact of amortization changes and … exclude any impact of regulatory balances on the interest revenue offset … ."[2] As revised in the March 6, 2009 letter, the distribution revenue requirement (as defined in footnote 1) is $17,264,458, a decrease of $254,480 from the initial amount indicated in the Application. TBH calculates the revised deficiency to be $1,117,815,[3]

1.4 The March 6 revision also shows a decrease in Revenue Offset of $305,000 from the amount forecasted in the Application.[4]

1.5 VECC further notes that taking the $254,480 decrease in distribution revenue

[1] The distribution revenue requirement is the "Base Revenue Requirement" with the "Transformer Allowance" and "Smart Meters" amounts removed.
[2] TBH letter to the OEB of March 6, 2009
[3] The increase in distribution revenue requirement is 6.92%.
[4] In the Application, the offset was $1,802,790 while in the revision it has fallen to $1,497,790.

requirement and the $305,000 decrease in revenue offset together seems to imply an increase of $50,520 in the revised deficiency. However, per the figures above, TBH has revised the revenue deficiency downwards to reflect a decrease of approximately $300,000. It is not clear to VECC how the March revised figures can be reconciled with the information in the Application.[5]

1.6 In its Application, TBH requested an increase in its current smart meter adder of $0.27 per month per metered customer to $1.25 per month per metered customer. However, in response to a Board staff supplementary IR,[6] TBH revised its request upwards to $1.97 per customer per month.

1.7 The following sections contain VECC's final submissions regarding the various aspects of Thunder Bay's Application.

2 Rate Base and Capital Spending

Capital Spending and Rate Base

2.1 Capital spending for the 2008 Bridge Year is projected to be $5,530,013.73 net of $646,000 in contributions and grants.[7]

2.2 In comparison, capital spending for the 2009 Test Year is forecasted to be $7,620,832.50 net of $650,000 in forecasted contributions and grants, reflecting an increase of over $2M.[8]

2.3 The evidence indicates that from while capital spending trended upwards for the period 1980 to 1994, for the period 1994-2008 this upward trend disappeared, and

[5] The revised deficiency of $1,117,815 provided on March 6 does not appear to be grossed up. Grossing it up indicates a deficiency of $1,613,393, or almost $200,000 above the original estimate in the Application, not the $50,520 expected.
[6] Board Staff Supplementary IR #15b)
[7] Exhibit 2/Tab 2/Schedule 1, Table 3
[8] Exhibit 2/Tab 2/Schedule 1, Table 4

for the period 2002 through 2008, capital expenditures by the utility have been relatively flat, ranging from $5.02M to $6.49M on a nominal basis.[9]

2.4 Thunder Bay attributes the break in the trend in 1995, to a decision by the *"then Hydro-Electric Commission of Thunder Bay to implement electricity rate reductions to the utility's customers. A total bill decrease of 1% was implemented in 1995. As this decrease was on the total electricity bill, and the wholesale cost of power was frozen at the time, the impact of this reduction was to reduce the revenue available to fund utility operations and capital investment by approximately 6.7%. … Further rate reductions of .4% and 1% followed in 1996 and 1997 respectively, further reducing funds available to the utility."*[10]

2.5 The evidence further states that *"Over the past two years, the [TBH] Board and management have become increasingly concerned that the recent level of capital expenditure is insufficient to ensure the integrity of the distribution system."*[11] The utility provided, as an illustrative example, the fact that its pole replacement program cycle (55 years) exceeded the expected asset lifespan.[12]

2.6 A risk assessment of TBH's system was conducted in 2006/07 and the assessment concluded that significant increases in asset replacement would be required over a ten-year *"to ensure the safety of employees and the public while maintain reliable service to customers."*[13] In recognition of this, the Board of Directors approved an increase of approximately $1M for asset replacement in 2008 and the utility proposes to subsequently increase capital replacement expenditures by about $300K per year for each year 2009-2011.[14]

2.7 VECC notes that the capital replacement program, in place from 1995 to 2007, is part of what is referred to as a "rate minimization strategy" by TBH. With respect

[9] See Exhibit 2/Tab 3/Schedule 1, Appendix A and the response to Board Staff IR #22a). Note that while these figures exclude contributions in kind, they include cash contributions.
[10] Exhibit 2/Tab 3/Schedule 1, pages 1 and 2
[11] Exhibit 2/Tab 3/Schedule 1, page 1
[12] Ibid
[13] Exhibit 2/Tab 3/Schedule 1, page 2
[14] Exhibit 2/Tab 3/Schedule 1, pages 2 and 3

to this past approach VECC is in general agreement with the comments of Board Staff.[15]

2.8 VECC's view is that a "rate minimization" approach that is to be maintained over a period of a decade or longer, must involve rate minimization subject to considerations of reliability, sustainability, and safety. VECC submits that it is not even a "good practice" to continue, for years, asset replacement cycles that exceed expected asset lives. Furthermore, any minimization approach in the current year should consider increased future costs (discounted) that will be visited on ratepayers due to deferral of capital expenditures necessary to maintain the long-term integrity of the system: these costs can not be deferred in the long run.

2.9 Further, while VECC agrees with Board Staff's interpretation that the behavior of the statistics SAIDI, SAIFI, and CAIDI over the period 2003-2007 does not indicate there are major system concerns[16] as yet, VECC submits that in a capital intensive industry with long-lived capital assets, by the time system reliability, recovery, and safety are reflected in these summary statistics, it may be "too late" in the sense that it may take many years of relatively large, increased capital expenditures to restore the system.

2.10 In this respect, VECC supports Staff's views on TBH's asset management program going forward, i.e., filing a more rigorous plan at its next rebasing proceeding.[17]

2.11 For the current proceeding, while VECC accepts the proposed capital expenditures for the Test Year, VECC does not agree with the impact on rate base that TBH proposes, either for the Bridge Year or the Test Year.

2.12 VECC notes that while "Contributions & Grants" for both 2006 and 2007 were approximately $1M in 2006 and 2007,[18] the forecasted amounts of this item are

[15] Board Staff Submission, March 11, 2009, pages17-21
[16] Ibid, page 20
[17] Board Staff Submission, March 11, 2009, page 23

[18] Exhibit 2/Tab 2/Schedule 1, Tables 1 and 2

$646K and $650K for 2008 and 2009 respectively.[19] This is in spite of the aforementioned significant increases in capital spending for 2008 and 2009.

2.13 In response to an IR,[20] the utility explained that the Bridge and Test Year projections of contributions only reflected cash contributions and not contributions in kind. The response also indicated that as at September 30, 2008, Bridge Year contributions and grants were $1,118,350, far in excess of the forecasted full year cash contributions of $646K.

2.14 In response to a supplementary IR, Thunder Bay indicated that the breakdown of the 2006 contributions and grants amount of $1,045,268.32 was $602,324.32 for cash contributions (57.6%) and $442,944.00 for contributions in kind (42.4%). The breakdown of the comparable 2007 total of $953,374.49 was $691,598.49 for cash (72.5%) and $261,776.00 for in kind (27.5%).[21] For these two years together, in kind contributions contribute 35.3% of the total contributions.

2.15 Further, the response to this IR also indicated that total cash contributions to December 31, 2008 were $1,095,369.41.[22] VECC notes that this is close to double the total contributions that Thunder Bay has forecasted for 2008.

2.16 VECC submits that TBH has significantly under-forecast the total contributions and grants for both 2008 and 2009 and suggests the following adjustments: (i) for 2008, the cash and contributions amount should reflect actuals for the year. If, for some reason, 2008 actuals cannot be used, VECC submits that using the actual total 2008 cash contributions along with the 2006/07 average 35.3% contribution of in kind contributions to total contributions is appropriate. Using this approach, VECC estimates that the in kind contributions for 2008 will be approximately 598K, for a total contribution amount of about $1.7M in the Bridge Year; (ii) for 2009, forecasted cash contributions of $650K appear to be an underestimate also, though VECC accepts that business cycle conditions could possibly reduce cash

[19] Ibid, Tables 3 and 4
[20] Energy Probe IR #8 f) and g)
[21] Energy Probe Supplementary IR #43 a)
[22] Energy Probe Supplementary IR #43 a)

contributions below the comparable Bridge Year figure. In this case, though, utility capital expenditures are likely to be below forecasted for 2009. If the Board accepts TBH's estimate of cash contributions for the Test Year, VECC submits that this amount should be grossed up to reflect in kind contributions in the amount of approximately $600K at the very least.

2.17 Finally, VECC notes that Thunder Bay initially proposed a six-year replacement program for removal of PCB by replacing transformers, with the program ending in 2014.[23] In response to new legislation that took effect in September 2008 and a Board Staff IR,[24] Thunder Bay revised its transformer replacement plan to continue until 2020. The March 6, 2009 update from the utility shows the associated asset retirement obligation is included as a rate base item that increases the 2009 revenue requirement by $3,239 for return on the asset and by an additional component of $21,941 for accretion.

2.18 In respect of this issue, VECC submits (i) that it would be more appropriate to recover costs that will be incurred in the future on a sinking fund basis[25] 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, and (ii) that if the ARO is treated as a rate base component, accretion charges should not be collected in addition to return.

3 <u>Load Forecast and Revenue Offsets</u>

Load Forecast Methodology

3.1 Thunder Bay's load forecast methodology consists[26] of four steps:

- First, a weather normalized forecast of monthly system purchases is developed based on a multifactor regression analysis that includes weather, economic

[23] Exhibit 1/Tab 2/Schedule 3 page 8
[24] Board Staff IR #9c)
[25] That is with recovery from ratepayers annually of amounts that are put into an interest bearing account such that the future value of the funds equals the future liability when it must be retired.
[26] Exhibit 3/Tab 2/Schedule 1, page 4

output and seasonal calendar variables as independent explanatory variables. The regression equation was developed using monthly data for the period 1996-2007[27].

- Second, the forecast is adjusted for losses to produce a weather-normalized billed energy forecast. Average weather conditions over the period 1996-2007 are used to determine the weather normalized forecast[28].
- Third, the projected total sales for 2008 and 2009 are adjusted to account for; a) industrial customers that have recently shut-down or reduced operations and b) CDM programs that have been in place for a relatively short time[29].
- Finally, based on customer count forecasts and trends in non-weather normalized per customer use, forecasts of total (non-weather normalized) use are developed for each customer class. These forecasts are then adjusted (based on the relative weather sensitivity of each class) so that the sum of individual customer class forecasts equals the total billed kWh forecast developed in Steps #1 through #3.

3.2 VECC has a number of concerns regarding Thunder Bay's load forecast methodology. With respect to Step #1, VECC's main issue is that the regression equation for forecasting total purchased kWh does not include number of customers (either in total or by class) as an explanatory variable. VECC notes that Thunder Bay rejected customer count as an explanatory variable on the basis that it was not "statistically significant" and its inclusion reduced the R-squared results[30]. However, as discussed further below, the absence of any linkage between the number of customers in the different classes and total sales can lead to anomalous results. VECC is also concerned that, while the regression model is meant to explain monthly sales, the monthly population data used is simply based on interpolations between 1996, 2001 and 2006 Census data[31].

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[27] Exhibit 3/Tab 2/ Schedule 1, page 4
[28] Exhibit 3/Tab 2/ Schedule 1, page 8
[29] Exhibit 3/Tab 2/ Schedule 1, page 8
[30] Board Staff #34 a)
[31] VECC #2 a)

3.3 With respect to Step #2, Thunder Bay used a 4.7% loss factor to adjust the forecasted purchases for 2008 and 2009 to billing quantities. The 4.7% was based on the average calculated loss factor over the period 2000-2007[32]. However, in response to Energy Probe #23 d) Thunder Bay acknowledges that there was an error in their historical loss factor calculations. The response to the Energy Probe interrogatory indicates that the average loss factor[33] over the 2003-2007 period was 3.8% as opposed to 4.7% calculated for the same period based on the original application[34]. As result, the loss factor used to translate the forecast purchases into bill energy should be reduced to 3.8%.

3.4 With respect to Step #3, VECC notes that the forecast is based on the same economic outlook as used by Toronto Hydro in its EB-2007-0680 Rate Application[35]. In response to VECC # 2 c) a revised forecast was prepared based on a recent GDP outlook prepared by the Ontario Ministry of Finance. However, in VECC's view the resulting revised forecast overstates the impact of the current economic downturn as it includes not only the impact of the lower GDP outlook but also specific adjustments for industrial load loss incorporated in the original forecast. In VECC's view, Thunder Bay's original forecast (adjusted for industrial load losses) is likely a more reasonable projection.

3.5 VECC's other concern with Step #3 is Thunder Bay's proposed adjustment for the impact of CDM programs undertaken between July 2006 and December 2007[36]. Based on the estimated impact of these programs Thunder Bay has adjusted the predicted results for 2006 through 2009. Thunder Bay claims[37] that the difference between predicted and actual for 2007, 17.7 GWh, is too high and that this demonstrates there was not sufficient history to influence the results. VECC disagrees with this assessment for the following reasons:

- There are other years (e.g. 2000 and 2003) where the variation between

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[32] Exhibit 3/Tab 2/Schedule 1, page 11
[33] Based on total for Row A/total for Row D
[34] Exhibit 4/Tab 2/Schedule 6, page 1
[35] VECC #2 b)
[36] Exhibit 3/Tab 2/Schedule 1, page 10 and Board Staff #37 a) – c)
[37] VECC #

predicted and actual varies by more than 17.7 GWh – suggesting that the results observed for 2007 are not unusual[38].

- After one accounts for the industrial losses (18.6 GWh) the predicted value is virtually the same as the actual value for 2007.

As result, VECC submits that while it is reasonable to include the adjustment for industrial load loss (in part due to Thunder Bay's use of an outdated economic outlook), the forecast should not be adjusted for CDM program results that are reflected in the 2006 and 2007 actual reported sales.

3.6 Finally, with respect to Step #3, VECC notes that Thunder Bay has revised the Residential CDM adjustment for 2009 from 11.7 GWh to 8.7 GWh[39].

3.7 VECC also has a number of concerns regarding the fourth step of the Thunder Bay's methodology. This step relies heavily on a customer count forecast that is not tied to the overall purchased/billed kWh load forecast, as discussed above. As a result, changing the forecast customer count for one customer class will impact the total sales forecast for the other (weather sensitive) customer classes.

3.8 In Step #4. VECC also has concerns regarding Thunder Bay's process for determining and adjusting what it deems to be a "non-weather normalized" forecast so that it reconciles with the forecasted weather normalized use[40]. Thunder Bay's forecast of non-weather normalized use in each customer class is calculated based on i) the projected customer count as discussed above and ii) a projected average use per customer which, in turn, is calculated by escalating the actual 2007 per customer use by the average growth rate in the class' per customer use over the 2000-2007 period[41].

3.9 The problem with the second part of this approach is that by using the geometric mean the growth rate calculated only really reflects weather conditions in 2000

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[38] VECC #2 d)
[39] Board Staff #51
[40] Exhibit 3/Tab 2/Schedule 1, pages 13-17
[41] Exhibit 3/Tab 2/Schedule 1, page 13-14 – for all classes except Street Lights

and 2007 and, therefore, is not reflective of year over year weather changes through out the entire period and does not reflect average weather conditions as Thunder Bay suggests[42].

3.10 Finally, with respect to Step #4, VECC has concerns regarding the adjustment process Thunder Bay uses to reconcile its non-weather normal forecast by class with its projection of total weather-normalized loads. Thunder Bay's assumptions that the Residential and GS<50 classes are 100% weather sensitive while GS 50-999 is only 89% weather sensitive and GS 1000-4999 is 59% weather sensitive are based on an interpretation of Hydro One Networks weather normalization work to provide data for Thunder Bay's cost allocation filing[43]. However, in VECC's view, Thunder Bay has not adequately substantiated that Residential and GS<50 customers' loads are 100% weather sensitive[44]. Indeed, VECC submits that it is intuitively obvious that they are not[45].

2009 Load Forecast

3.11 Methodological issues not withstanding, in order to check the overall reasonableness of Thunder Bay's projections for the weather sensitive customer classes, the following table compares Thunder Bay's projected 2009 per customer use with and without the CDM adjustment with the historical average use[46] and the 2004 weather normal use calculated by Hydro One Networks for the Utility's cost allocation filing.

[42] VECC #3 a)
[43] VECC #4 b) and VECC Supplementary #1 a)
[44] VECC Supplementary #1 a)
[45] Both the Residential and GS<50 classes have lighting loads which are not weather sensitive.
[46] Based on the response to VECC #2 d) the average purchases over the 2000-2007 period varied by the weather normal predicted purchases by less than 1%. This suggests that the average use over the period is a reasonable estimate of weather normal use.

Comparison of Per Customer Use Values (kWh)

	Average 2000-06	HON NAC	Thunder Bay's 2009 Forecast As Filed	Excl Adj
Residential	7,981	8,034	7,567	7,830
GS<50	32,859	32,747	32,235	32,336
GS 50-999	618,284	576,928	596,325	596,433

Sources: 1) Data for 2000-2007 taken from Exhibit 3,Tab 2, Sch 2 - Table #9
2) HON NAC - from VECC #3 d)
3) Lakeland's Forecast derived from Exhibit 3, Tab 2, Sch 1, page 20
4) CDM Adjustment based on Board Staff 36 c)

3.12 Thunder Bay's proposed 2009 average per customer use values for Residential and GS<50 customers are less than the comparators. However, once the forecast billed energy is revised to reflect the lower historical loss factor (i.e., 3.8% vs. 4.7%), the values will more closely align. In the case of the GS 50-499 class, Thunder Bay's values are within the range established by the comparators.

3.13 Overall, VECC submits that, subject to correcting the loss factor and revising the CDM adjustment, the 2009 forecasted load by customer class should be accepted by the Board for purposes of setting 2009 rates. However, VECC notes that this acceptance of the value for purposes of setting 2009 rates should not be viewed as an acceptance of Thunder Bay's load forecast methodology. In this regard, VECC submits that, similar to the OEB direction given in the Toronto Hydro case[47], Thunder Bay should be directed to work with other distributors to develop a more comprehensive and integrated approach to load forecasting.

4 Operating Costs

4.1 Thunder Bay originally forecasted OM&A costs of $12,340,964 and Amortization costs of $4,573,436 for 2009.[48] In its March 6, 2009 update, the utility decreased its Test Year OM&A claim by $391,383 to $11,949,581 and decreased its Test

[47] OEB Decision, EB-20070-0680, pages 32-33
[48] Exhibit 4/Tab 2/Schedule 1, page 35

Year amortization claim by $100,000 to $4,473,436.[49]

4.2 With respect to the compensation component, VECC notes the significant increases in 2008 over 2007 in average yearly base wages for the executive, management, and non-union employees. The respective percentage increases in 2008 are 21.7%, 8.6%, and 11.7%.[50]

4.3 VECC notes that TBH has provided a variance explanation in respect the increase in executive salaries, indicating that a Mearie Group salary survey for 2006 and 2007 found that the utility executive team were compensated below the 25th percentile of comparable LDCs. The Board of Directors subsequently determined that these employees should be compensated at the mean of comparable LDCs.[51]

4.4 While VECC does not have any basis to suggest that the TBH executive team should be compensated at a level below the mean level of comparable entities, VECC notes that: (i) VECC 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;[52] (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'd 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 was more moderate, the average increases in 2008 for the management and non-union groups appears high, especially considering recent levels of inflation.

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[49] The decrease in OM&A costs appears to be due to revisions made in response to IRs including the removal of $295,567 in amortization costs originally included in OM&A for working capital allowance and the decrease in amortization appears due to the change in the amortization period for computers.
[50] Exhibit 4/Tab 2/Schedule 4, page 11, Table 3
[51] Exhibit 4/Tab 2/Schedule 2,pages 6 and 7
[52] Similarly with respect to the median

4.5 With respect to non-recurring expenses, in their submissions Board Staff suggests that since meter reading costs are forecast to be $255K in 2009, $125K in 2010, $25K for 2011, and $25K for 2012, "the Board may wish to adjust Thunder Bay's 2009 revenue requirement ... ."[53]

4.6 VECC notes that with respect to OM&A costs in respect of the PCB program, the utility expected a drop in such costs after 2009 and had therefore not used the total 2009 spending for the Test Year revenue requirement but rather the average of expected costs over the period 2009-2011.[54] VECC submits that a similar approach for the PCB program would recover the total costs of $430K over four years by reducing the 2009 revenue requirement to $107.5K and that such an approach is appropriate.

4.7 With respect to regulatory costs for this proceeding, Thunder Bay has estimated costs of $99K and proposes to amortize the total over three years.[55] VECC submits that this cost appears reasonable for the current proceeding but should be amortized over a four-year period.

5 <u>Losses</u>

5.1 In response to a Board Staff IR,[56] TBH noted that the information presented in its Application in respect of loss factors was incorrect and the utility provided a DLF for Secondary Metered Customers < 5,000 kW of 1.0390, a DLF for Primary Metered Customers < 5,000 kW of 1.0287, and a SFLF of 1.0055 as being the correct information to use. TBH subsequently calculated TLFs for these two classes as 1.0448 and 1.0343 respectively.[57]

5.2 VECC accepts the DLFs as corrected along with the SFLF but notes that using the corrected information appears to imply slightly different TLFs for the two classes.

[53] Pages 15 and 16
[54] Board Staff supplementary IR #3
[55] Board Staff IR #19
[56] Board Staff IR #48
[57] Ibid, Table 3

Using the information as corrected, VECC calculates an SLF for Secondary Metered Customers < 5,000 kW of 1.0447 and an SLF for Primary Metered Customers < 5,000 kW of 1.0344.

6 Deferral and Variance Accounts

6.1 The overall balance in the group of accounts that comprises Account #1508, #1518, #1525, #1548, and #1582 is a utility credit (i.e., ratepayer debit) of $1,149,835, while the overall balance in the group of accounts that comprises Account #1580, #1584, #1586, and #1588 is a utility debit (i.e., ratepayer credit) of $3,289,158.[58]

6.2 TBH has calculated the rate rider per kWh for the residential class required to clear the overall balance of $1,149,835 in the first group of accounts over (i) a one-year, (ii) two-year, or (iii) three-year period, as (i) $0.0017, (ii) $0.0008, or (iii) $0.0006 respectively.[59]

6.3 If the first group of accounts and the second group of accounts are combined, the result is an overall ratepayer credit of $2,139,323. TBH has calculated the rate rider rebate per kWh for the residential class required to refund this balance over (i) a one-year, (ii) two-year, or (iii) three-year period, as (i) ($0.0016), (ii) ($0.0008), or (iii) $0.0005 respectively.[60]

6.4 Although TBH has not applied for disposition of any deferral or variance accounts, Board Staff has suggested "that the Board may wish to dispose of all [the aforementioned] deferral and variance account balances at this time... ."[61]

6.5 With respect to clearing any deferral or variance account balances, VECC notes that the magnitude of the overall balance in the first group of accounts is of a magnitude approximately equal to the stated (revised) deficiency while the overall

[58] Response to Board Staff IR #47
[59] Ibid, part b)
[60] Ibid, part d)
[61] Board Staff Submission, March 11, 2009, page 42

balance of the two groups together exceeds the stated deficiency.

6.6 VECC submits that clearing of any balances, either of the first group alone or of both groups together, should neither exacerbate any rate changes that would otherwise be visited on ratepayers[62] nor mask a distribution rate increase in the Test Year effectively temporarily delaying and exacerbating future rate changes.[63]

6.7 As such, if the Board determines that disposal of some balances is appropriate, VECC submits that both groups of accounts should be disposed over a three- or four-year period.

7 Cost Allocation

Results of Thunder Bay's Cost Allocation Informational Filing

7.1 Thunder Bay's Cost Allocation Informational Filing produced[64] the following revenue to cost ratios:

- Residential 126.08%
- GS<50 113.61%
- GS 50-999 65.96%
- GS 1000-4999 60.17%
- Street Lighting 13.51%
- Sentinel Lighting 105.21%
- USL 111.25%

Use of the Cost Allocation Informational Filing Results in Setting 2009 Rates

7.2 Thunder Bay has used the revenues at existing rates and the revenue to cost ratios from its Cost Allocation filing to determine the 100% revenue to cost ratio

[62] For example by clearing only the first group of accounts over a one-year period
[63] For example by clearing both groups of accounts over a one- or two-year period
[64] Exhibit 7/Tab 1/Schedule 2, page 2

values for each customer class[65]. In principle, VECC agrees with this approach. To the extent that the relative loads and customer counts have changed by customer class[66] as between the Cost Allocation filing and 2006, both the relative revenues and cost responsibilities of the different classes will change. However, since no efforts were made to realign the revenue to cost ratios in 2007 or 2008, there is no reason to assume that the current revenue to cost ratio for each class would be any different than those arising from the cost allocation informational filing.

7.3 While agreeing in principle, VECC has three of concerns regarding Thunder Bay's calculations. First, Thunder Bay is proposing to allocate the "cost" of the transformer ownership allowance solely to the GS>50 classes[67]. As a result, Thunder Bay has not included the cost of the transformer ownership allowance in the basic revenue requirement it is allocating to customers using its proposed revenue to cost ratios[68]. VECC agrees with this change and notes that it is consistent with the approach approved for a number of distributors' 2008 rates[69].

7.4 The treatment of transformer ownership allowance in the current OEB Cost Allocation model results in an over allocation of costs to those classes where customers generally do not own their own transformers (e.g. Residential and GS<50). This circumstance arises because the model not only allocates these classes the full cost of the transformers used to serve them but also a share of the discount. In principle the discount is an intra-class issue for those classes where some customers own their transformer and other don't. The Cost Allocation model recognizes that some customers own their transformers. However, unless a discount is introduced for these customers (and paid for by the other customers in the same class) those customers in the class who own their transformer will pay too much and those who don't will not bear full cost responsibility for the transformers they use.

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[65] VECC Supplementary #4 b)
[66] VECC #5 b)
[67] VECC # 7 b)
[68] Exhibit 8/Tab 1/Schedule 1, page 1
[69] For example, Horizon Utilities, Hydro Ottawa and Enersource Mississauga.

7.5 The current Cost Allocation informational filing is inconsistent with this approach as it includes the transformer ownership allowance discount as a cost and allocates it to <u>all</u> customer classes[70]. In VECC # 7 c), Thunder Bay was asked to provide a revised version of its Cost Allocation Informational filing that properly removed the costs and the revenue associated with the transformer ownership allowance. Furthermore, in response to Board Staff Supplementary #16 c), Thunder Bay acknowledged that the current approach is incorrect and offered another approach to deal with the issue.

7.6 VECC agrees that there are two possible ways to adjust the current Cost Allocation informational filing in order to be consistent with Thunder Bay's proposed treatment of the transformer ownership allowance. Indeed, VECC's submission regarding Oshawa PUC's 2008 rates[71], outlined both the approach suggested by Thunder Bay and the one set out in VECC #7 c). However, in VECC's view the approach prescribed in VECC #7 c) is preferable. Since the Cost Allocation filing is not being updated for 2009 costs and loads, in VECC's view it is better to exclude the relevant costs and revenues. Otherwise, since the transformer ownership discount is not being adjusted similar other rates, leaving the 2006 value of the transformer ownership allowance in the Cost Allocation filing will tend to distort the results and lead to issues similar to those noted by Thunder Bay in response to Board Staff #43.

7.7 The following table summarizes the revenue to cost ratios from VECC #7 c):

- Residential 128.71%
- GS<50 115.55%
- GS>50-999 139.76%
- GS 1000-4999 43.41%
- Street Lighting 14.03%
- Sentinel Lighting 109.17%

[70] VECC #7 a)
[71] EB-2007-2007-0710, VECC's Final Submissions, pages 8-9

- USL 114.91%

7.8 VECC's second concern is that Thunder Bay's calculated revenues at 100% cost allocation (per VECC Supplementary #4 b)) do not reconcile with the 2009 Base Revenue Requirement. Summing the individual values results in an overall revenue of $17,243,901 where as the Base Revenue Requirement is $17,518,938. To reconcile the two values Thunder Bay should increase the values attributed to "Existing Rates @100% Revenue to Cost Ratio" reported in the response by 1.59% - the difference between the two totals. Doing so will reduce slightly the proposed revenue to cost ratios for 2009.

7.9 Finally, VECC notes that the revenue to cost ratios reported in the Cost Allocation informational filing (and used by Thunder Bay) include an allocation of miscellaneous revenues to each customer class as part of the ratio determination. However, Thunder Bay has applied the ratio to revenues excluding miscellaneous charges.

7.10 The following table sets out the revenue to cost ratios Thunder Bay has proposed and contrasts them with the ratios that would result from using the same percentage base distribution revenue allocation to customer classes but also incorporating the preceding concerns. The detailed calculations are set out in Appendix A.

Impact of Thunder Bay's Proposed Base Distribution Revenue Allocation

	Thunder Bay's Implied R/C Ratio	Revised R/C Ratio Based on Corrected CA
Residential	119.13%	123.47%
GS<50	113.61%	116.73%
GS 50-999	72.98%	73.15%
GS 1000-4999	70.09%	50.50%
Street Lights	41.75%	37.07%
Sentinel Lights	105.21%	110.27%
USL	111.25%	116.07%

1) Thunder bay Proposed R/C Ratio - Exhibit 7/Tab 1/Schedule 2, page 3
2) Revised R/C based on Appendix A

7.11 Based on the above results it is apparent that the three issues raised in the preceding paragraphs will have a material affect on the determination of revenue to cost ratios. VECC submits that Thunder Bay should be directed to revise its calculation of Revenue to Cost ratios and required base revenue requirement shares accordingly.

Proposed Revenue to Cost Ratios

7.12 The following Table compares the Thunder Bay proposal for 2009 with the current revenue to cost ratios as determined using the CA Informational Filing and in VECC #7 c).

Thunder Bay's Proposed R/C Ratio Shifts

	Revenue/Cost Ratio Starting Point		
	Thunder Bay CA R/C Ratio	VECC #7 c)	Proposed R/C Ratio
Residential	126.08%	128.71%	119.13%
GS<50	113.61%	115.55%	113.61%
GS 50-999	65.96%	66.09%	72.98%
GS 1000-5000	60.17%	43.41%	70.09%
Street Lights	13.51%	14.03%	41.75%
Sentinel Lights	105.21%	109.17%	105.21%
USL	111.25%	114.91%	111.25%

1) Thunder Bay CA & Proposed - Exhibit 7/Tab 1/Schedule 2, page 3

7.13 Thunder Bay's general approach has been to move those customer classes with R/C ratios below the Board's target range half-way to the lower end of the Board's target range. The resulting revenues have been used to reduce the R/C ratio for the Residential class – the only class with a R/C ratio above the Board's recommended ranges.

7.14 VECC agrees that there is no need to adjust the revenue to cost ratios for GS<50, Sentinel Lights and USL. For all three classes the ratios are currently well within the Board's guidelines, even with the revised ratios provided in VECC #7 c)[72]. VECC also agrees there is a need to move the ratios for GS 50-999, GS 1000-4990 and Street Lights up to the lower end of the Board's recommended range for each class.

7.15 In cases where movement all the way to the lower end of the range would lead to significant bill impacts, the Board has adopted an approach[73] whereby 50% of the required adjustment is undertaken in the first year and the balance of the adjustment is made over subsequent year of the IRM period. VECC anticipates that this will be the circumstance for Street Lights and submits that Thunder Bays' proposal to move half way to 70% lower bound for this class is appropriate.

7.16 In the case of the GS 50-999 and GS 1000-4999 classes it is not readily apparent that movement beyond half way to the lower end of the range would cause undue bill impacts. VECC notes that under Thunder Bay's proposal, the total bill impacts for GS 50-999 are in the order of 3% - 5% while the impact for the typical GS 1000-4999 customer is 5.77%[74]. However, with the adjustments recommended by VECC these impacts are likely to increase. Overall, given the current economic conditions, VECC agrees that moving these classes just half way to the 80% lower bound is acceptable.

8 <u>Rate Design</u>

8.1 Thunder Bay is proposing to maintain the fixed-variable split for the Residential class[75]. VECC notes that the proposed customer charge ($11.26) is less than the upper bound of the range established by the Board's guidelines[76]. As a result, VECC submits that Thunder Bay's proposal should be accepted by the Board.

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[72] In its EB-2007-0746 (page 13) Decision the Board concluded that ratios inside the range should not be adjusted.
[73] See EB-2007-0901 (p. 15); EB-2007-0931 (p. 15); and EB-2007-0742 (p. 24)
[74] Exhibit 8/Tab 1/Schedule 9, Appendix A, pages 7-9
[75] Exhibit 8/Tab 1/Schedule 1, page 5
[76] The upper bound established by the Board's Guidelines (page 12) is 120% of the Customer Unit Cost calculated using the Minimum System and PLCC adjustment. In Thunder Bays' case this value is $10.15 resulting in a maximum value of $12.18.

9 Smart Meters

9.1 VECC does not oppose Thunder Bay's request for an increase in the rate adder to $1.97 per metered customer per month.

10 LRAM and SSM

10.1 Thunder Bay is claiming for the years 2005, 2006, 2007, and 2008 an LRAM amount of $468,321 for its 2005-2007 programs and an SSM amount for its 2005-2007 programs of $106,024, for a total recovery of $574,346. The utility proposes to recover this amount by a volumetric rate rider which would be in effect from may 1, 2009 to April 30, 2012.[77]

10.2 The utility has used a "100% persistence" assumption in calculating savings in later years, i.e., it assumes that whatever savings were achieved by measures implemented in 2005, would continue to be fully achieved in each succeeding year.[78]

10.3 VECC notes that the utility did not undertake to have a third-party independent evaluation of its LRAM/SSM claims for 2007 and beyond.[79] VECC further notes that it does not appear that Thunder Bay has used the more recent OPA input assumptions and the free ridership inputs per Toronto Hydro Decision to calculate its LRAM request.

10.4 VECC submits 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.

10.5 However, with respect to CDM measures implemented in 2007 and after, VECC submits 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.

[77] Exhibit 8/Tab 1/Schedule 10, page 6.
[78] Ibid
[79] VECC Supplementary IR #9a)

10.6 With respect to LRAM and SSM claims for 2007 and thereafter, VECC urges that recovery be conditional on third-party verification utilizing the most recent input assumptions available.

11 Recovery of Reasonably Incurred Costs

11.1 VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.

Respectfully Submitted on this 13th Day of March, 2009

Michael Buonaguro
Counsel for VECC

APPENDIX A **THUNDER BAY's 100% COST RESPONSIBILITY BASED ON 2009 REVENUES @ CURRENT RATES**

		Total	Residential	GS <50	GS>50-999	GS 1000-4999	Street Light	Sentinel Light	USL
	Cost Allocation Results - Revenue								
#1	Distribution Revenue	16,137,828	10,663,900	2,740,846	1,762,327	789,375	114,938	11,709	54,733
#2	Miscellaneous Revenue	1,367,052	821,918	284,946	167,866	61,102	28,459	657	2,105
#3	Total Revenue	17,504,880	11,485,818	3,025,792	1,930,193	850,477	143,397	12,366	56,838
#4	Total Revenue %		65.61%	17.29%	11.03%	4.86%	0.82%	0.07%	0.32%
#5	Dx Revenue %		66.08%	16.98%	10.92%	4.89%	0.71%	0.07%	0.34%
#6	Misc Revenue %		60.12%	20.84%	12.28%	4.47%	2.08%	0.05%	0.15%
	Cost Allocation Results - Revenue Requirement								
#7	Revenue Requirement	17504880	8923558	2618490	2920602	1959072	1022368	11327	49465
#8	Revenue to Cost Ratios		128.71%	115.55%	66.09%	43.41%	14.03%	109.17%	114.91%
#9	**Adjustment Factor for Rev=RR**		0.7769	0.8654	1.5131	2.3035	7.1296	0.9160	0.8703
	2009 Rates								
#10	**2009 Dx Revenue at Current Rates**	16104861	10526263	2713797	1826795	844151	117743	14929	61183
			65.36%	16.85%	11.34%	5.24%	0.73%	0.09%	0.38%
	2009 Base Rev Req @ Current Rates	17518938	11450515	2952080	1987196	918271	128081	16240	66555
	Determination of 100% Dx Revenue Allocation								
#11	- Misc Revenue (2009 Rates)	1,802,790	1,083,898	375,770	221,372	80,578	37,530	866	2,776
#12	- Total Revenue (@ Current Rates)	19,321,728	12,534,413	3,327,851	2,208,568	998,849	165,611	17,106	69,331
#13	- Adjusted Total Rev 100% Cost by Class	19,517,537	9,738,232	2,879,889	3,341,815	2,300,847	1,180,749	15,669	60,337
#14	- Adjusment to Reconcile 2009 SRR	19,321,728	9,640,534	2,850,996	3,308,288	2,277,763	1,168,903	15,512	59,732
#15	- 2009 Dx Revenue for 100% R/C Ratio	17,518,938	8,556,635	2,475,226	3,086,916	2,197,186	1,131,373	14,645	56,956
#16	**Thunder Bays Base Rev Req Alloc**	100%	61.76%	16.85%	12.55%	6.11%	2.26%	0.09%	0.38%
#17	**Total Revenue by Class**	19,321,728	11,903,612	3,327,850	2,420,174	1,150,284	433,370	17,105	69,332
#18	**R/C Ratio Based on Thunder Bay Alloc**	100.00%	123.47%	116.73%	73.15%	50.50%	37.07%	110.27%	116.07%

Notes:
#1-#3 - from VECC #7 c)
#4-#6 - based on values set out in preceding rows
#7 - from VECC #7 c)
#8 - based on Row #3/Row #7
#9 - Based on Row #7/Row #3
#10 - VECC #6 b)
#11 - Based on 2009 proposed Misc. Revenues prorated using Row #6
#12 - Based on Row #10 + Row #11
#13 - For each Class calculated based on Row #12 x Row #9
#14 - Each Class' Row #13 value inceased by same proportion to yield 2009 Service Revenue Requirement
(excluding the Transformer Ownership Allowance and LV Costs)
#15 - Based on Row #14 less Row #11
#16 - Based on VECC #5 a)
#17 - Based on Row #16 * Total Base RR + Row #11
#18 - Base on Row #17/Row #14