Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2009-0260

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 Cambridge and North Dumfries Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010.

BEFORE: Gordon Kaiser
Vice-Chair and Presiding Member

DECISION

[1] This Decision concerns an application by Cambridge and North Dumfries Hydro Inc. ("CND", the "Applicant", or the "Utility") to the Ontario Energy Board on August 31, 2009 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, seeking approval for changes to the rates that CND charges for electricity distribution, effective May 1, 2010.

[2] CND owns and operates an electricity distribution system in the City of Cambridge and the Township of North Dumfries, where it serves approximately 50,000 Residential, Street Light and industrial customers.

[3] Three parties requested and were granted intervenor status: Energy Probe Research Foundation ("EP"), the School Energy Coalition ("SEC"), and the Vulnerable Energy Consumers Coalition ("VECC"). All were granted cost eligibility.

[4] Board staff and intervenors filed interrogatories which were answered by CND on November 30, 2009.

[5] The Board issued a Procedural Order on December 14, 2009 providing for supplemental interrogatories and a Settlement Conference. CND responded to supplemental interrogatories on January 13, 2010.

[6] The Settlement Conference was held on January 20, 2010 involving CND, EP, SEC, VECC and Board staff. CND filed a proposed Partial Settlement Agreement in February 10, 2010 and a revised Partial Settlement Agreement on February 17, 2010.

[7] On February 18, 2010, the Board issued a Decision on Partial Settlement, accepting the revised Partial Settlement Agreement which was included as Appendix A to the Decision on Partial Settlement.

[8] The unsettled issues are as follows:

Rate Base:

- Treatment of the Harmonized Sales Tax effective July 1, 2010; and
- Working Capital Allowance – Need for a Lead/Lag Study for CND's next Rebasing Application.

Operating Revenue:

- The 2009 and 2010 Load Forecast; and
- Treatment of Loss of Water and Sewage Billing Services Contract with City of Cambridge and Regional Municipality of Waterloo.

Operating Costs:

- Treatment of Incremental Operating Expenses Related to new CIS System and Monthly Billing.

Cost of Capital and Capital Structure:

- The percentage of CND's regulated capital structure that should be made up of short-term debt; and
- The appropriate allowed Return on Equity.

Deferral and Variance Accounts:

- Treatment of Global Adjustment Sub-account of Account 1588.

Other matters:

[9] In addition to the unsettled issues listed above, the Board in this Decision addresses other matters necessary for establishment of CND's 2010 electricity distribution rates, specifically:

- Variance Account designation for the CIS billing system costs;
- MicroFit Generator Service Classification and Rate;
- Implementation of Rates; and
- Cost Awards.

Rate Base

Treatment of the Harmonized Sales Tax effective July 1, 2010

[10] The provincial sales tax ("PST") and goods and services tax ("GST") will be harmonized effective July 1, 2010 pursuant to Bill 218, which received Royal Assent on December 15, 2009. Unlike the GST, the PST is currently included as an OM&A expense and is also included in capital expenditures. When the GST and PST are harmonized, corporations will realize a reduction in OM&A expenses and capital expenditures that has not been reflected in the current application for 2010 rates.

[11] CND stated that it has not made any adjustments to its 2010 OM&A and capital expenditure forecasts to reflect the elimination of the 8% PST costs starting on July 1, 2010.[1] In response to an interrogatory,[2] CND stated that it believes that the Harmonized Sales Tax ("HST") issue is a generic issue that would apply to all distributors and that the effects are unknown at this time. CND submitted that there will be incremental costs, some of a one-time nature but others ongoing, due to changes in ongoing accounting. Further, CND submitted that it may not be possible to track all costs and savings that may result from the tax harmonization. CND does not believe that accurate accounting can be done and therefore does not support the use of a deferral and variance account.

[1] Response to EP IR # 1
[2] Response to Board staff supplemental IR # 42

[12] As an alternative, CND submitted that a $0.10 reduction in the monthly service charge for all customers be applied universally to all electricity distributors, whether under cost of service rebasing or IRM. CND submitted that the impacts on capital expenditures are immaterial due to the general long amortization periods over which investments (and equally savings) would be recoverable.

[13] Board staff submitted that there was no basis for the proposed $0.10 reduction in the monthly service charge. Board staff also expressed concerns that this proposed reduction would not be appropriate, as it would be different, on a percentage basis, for different customers (i.e. Residential versus General Service > 50 kW or Large Use). Board staff also expressed concern that, while the Applicant has focused on increased costs due to harmonization, there will be benefits to businesses through the Input Tax Credits. Board staff also suggested that, in the long run, accounting and administration should be simplified with one set of tax rules.

[14] Board staff agreed that the HST will affect all distributors, but noted that the Board must deal with the individual applications before it. Initiating a generic proceeding or consultation to review this matter industry-wide would require additional time and resources. In the absence of accurate estimates of the HST impacts, Board staff submitted that the Board should consider establishing a deferral account to track savings for subsequent refunds to customers.

[15] EP disagreed with CND's proposal that this matter should be dealt with generically. They argued that this matter could be dealt with in 2010 Cost of Service applications. EP noted that there are other tax changes for 2010 which were settled and documented in the Partial Settlement Agreement. EP submitted that there should be a reduction to 2010 capital expenditures of $169,209 and a reduction to OM&A expenses of $43,009, both calculated as one half of annual estimates (i.e. six months from July 1 to December 31) of the forecasted PST provided by CND in response to EP interrogatory #1. With these reductions to opex and capex, EP submitted that there should be no need for a deferral account. If the Board decided to establish a deferral account, EP stated that the wording of the account should be similar to that established in the approved Settlement Agreement for Toronto Hydro.[3]

[3] EP's Submission, February 26, 2010, referencing the Settlement Agreement, pp. 4-5, in EB-2009-0139

[16] SEC submitted that there is no dispute that, with the implementation of the HST on July 1, 2010, CND's OM&A and capital expenditures will be overstated to the extent that the forecasts are based on historical expenditures which incorporate PST as an applicable embedded cost. SEC noted that leaving the PST amounts in the forecasts will mean that ratepayers will be paying the PST or its equivalent twice: first, with the amount embedded in rates and again when the HST is levied on ratepayers' bills beginning July 1, 2010.

[17] SEC submitted that estimating the PST in test year capital and OM&A costs is similar to forecasting other test year costs. To this end, SEC submitted that CND has provided forecasts and that, based on EP's submission, these seem reasonable. SEC submitted that the estimates documented in EP's submission should be adopted as reductions to test year capital and OM&A.

[18] VECC submitted that the harmonization of the GST and PST will result in utilities experiencing a reduction in capital and operating costs, which should be passed on to ratepayers. VECC disagreed with the Applicant's statement that the impact was immaterial, noting that the estimated capital impact of $196,336 was higher than the materiality threshold for capital projects. VECC submitted that the 2010 capital expenditures should be reduced by $196,336, as half of the estimated $392,671 of PST included in 2010 capital, and that a variance account should be established to track the difference between this amount and actual retail tax savings in 2010. VECC suggested similar treatment for OM&A costs, with an estimated reduction of half of $82,985 to OM&A and a variance account to track the difference between this amount (i.e., $46,493) and actual retail savings in 2010.

[19] In reply, CND submitted that the adjustments for the removal of the PST on July 1, 2010 suggested by the intervenors should be rejected. They argued that it was not known if savings will be passed on by suppliers, and that the treatment proposed by other parties ignores incremental costs associated with this new tax regime. CND repeated its position that the HST implementation is an industry-wide issue, and that the Board should initiate a generic consultation. However, CND also submitted that any industry-wide variance accounting approach should track incremental costs along with any savings arising from tax harmonization.

Board Findings

[20] The Board agrees that the HST implementation will affect all distributors, but does not accept the submission that this should be dealt with by way of a generic process as this would result in delays to applications before the Board. The Board notes that HST implementation has already been considered in at least two different ways in recent applications. In *Burlington Hydro*[4], 2010 OM&A and capital were reduced for six-month estimates of PST. In *Toronto Hydro*[5], no adjustments were made but a deferral account to track input tax credits ("ITCs") was implemented. Both approaches achieve similar results.

[21] While CND has provided estimates of the PST embedded in test year OM&A expenses and capital expenditures, and some intervenors submit that these should be used as reductions to reflect the HST implementation as of July 1, 2010, the Applicant does not support using these estimates.

[22] The Board does not accept CND's proposal of a $0.10 per month reduction in the service charge, without any variance account. The Board acknowledges the concerns raised by Board staff and agrees that there is no evidence to support the accuracy of this proposal.

[23] In the absence of agreement on the forecasted adjustments, the Board will not direct reductions to 2010 OM&A and capital expenditures, but will establish a deferral account to record incremental savings due to the implementation of the HST. CND will use deferral account 1592 PILS and Tax Variances, "Sub-account HST/OVAT Input Tax Credits" for recording this information. The Board does not consider it necessary to make allowances for minor implementation costs. The Board finds that it will not be onerous for CND to track the Input Tax Credit amounts as CND will need to file this information in GST/HST returns which will be subject to review by the tax authorities.

[24] CND will record the actual Ontario Value Added Tax Input Tax Credits claimed after June 30, 2010 on those costs and expenses that would normally be considered for inclusion in rate base or revenue requirement in a cost of service application. CND will retain copies of its GST/HST returns as part of RRR and for evidence in future rates proceedings.

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[4] *Decision and Order*, EB-2009-0259 (March 1, 2010)
[5] *Decision*, EB-2009-0139 (April 9, 2010)

Working Capital Allowance – Need for a Lead/Lag Study

[25] In its original application, CND forecasted a Working Capital Allowance ("WCA") of $18,989,476. CND has used the standard methodology of 15% of OM&A and cost of power in the calculation of the WCA. The Partial Settlement Agreement includes an updated WCA of $17,537,926. In the Partial Settlement Agreement none of the parties took issue with CND's use of the 15% WCA formula in this Application.

[26] No lead/lag study was provided, as CND relied on the common formula where WCA is set as 15% of the sum of controllable expenses plus the cost of power. CND has indicated that it does not intend to conduct a lead/lag study as part of its next cost of service rebasing application.

[27] Board staff disagreed with CND's position, noting that CND is deploying smart meters and will be implementing Time-of-Use ("TOU") pricing and monthly billing. Board staff submits that smart meters, TOU pricing and monthly billing will reduce the lag between when the utility pays the IESO and when it receives payment from its customers. Many larger customers may already receive bills on a monthly basis but this change will also affect Residential and General Service customers, a large portion of total demand. Board staff disagreed with CND's response that the move to monthly billing will not change the asset values for the cash working capital. Board staff suggested CND should either adopt the results of a Board staff-led generic lead-lag study, or conduct its own similar study for use in its next rebasing application.

[28] EP submitted that CND should be directed to undertake a lead-lag study. Noting that the 2010 Working Capital Allowance represents 16.8% of rate base. EP also submitted that the change to monthly billing will reduce the lag between when the utility incurs costs and receives the revenues from its customers, and hence will reduce working cash requirements. EP argued that CND, has a rate base over $100 million, and should not be considered a small utility. Accordingly, the costs of a lead-lag study should not be onerous and must be balanced against the potential impact on the revenue requirement.

[29] VECC made a submission similar to EP. VECC also noted that lead-lag studies conducted by other distributors have resulted in working capital allowances below the standard 15% of cost of power plus controllable expenses. VECC pointed to the *Hydro*

One Networks Decision[6], where working capital equates to under 12% in each year. VECC submitted that CND should be directed to conduct a lead-lag study, and that the costs for such a study would be more than offset by the potential benefits to customers in a rebased year and subsequent IRM period.

[30] SEC supported the submissions of EP and VECC.

[31] In reply, CND submitted that it should not be directed to undertake an individual lead-lag study. It argued that its position is supported by the Board's decisions in *Peterborough Distribution*[7], where a similar request by VECC was rejected. They also relied on the Board's recent decision in *Burlington Hydro* [8], which utility CND noted is larger than CND.

[32] CND repeated its concern about the costs of such a study. They noted that they had not factored any such costs into this Application and requested approval of a deferral account to track any costs incurred.

Board Findings

[33] The Board accepts the position of Board staff and the intervenors regarding the continued use of the 15% Working Capital Allowance. The Board agrees that Smart Meters and Time-of-Use ("TOU") pricing, and the move to monthly billing increase the concerns with existing methodology. At the same time, the Board realizes the costs of such a study.

[34] The Board, in its recent decision for *Burlington Hydro*[9], stated:

> The Board agrees with Board staff that further work on the formulaic WCA approach is warranted. The Board expects to initiate a generic proceeding / consultation on determining a new working capital methodology in advance of Burlington's next cost of service filing.

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[6] *Decision with Reasons*, EB-2009-0096 (April 9, 2010)
[7] *Decision*, EB-2008-0241 (June 1, 2009)
[8] *Decision and Order*, EB-2009-0259, (March 1, 2010), page 23
[9] *Ibid.*

Given the Board's intentions to undertake a Board staff-led generic study of working capital in the near future, the Board will not direct CND to conduct a lead/lag study for its next Cost of Service rate application. The Board will also not approve a deferral account for tracking any costs related to a lead-lag study.

Operating Revenue

The 2009 and 2010 Load Forecast

[35] CND's weather normalized load forecast was developed using a three-step process:

1. A total system-wide weather normalized energy forecast was developed using a multivariate regression model that incorporates historical load, weather, and economic data;

2. This energy forecast is adjusted by historical loss factors to derive the system-wide billed energy forecast; and

3. The system-wide billed energy forecast is allocated by rate class using a forecast of customer numbers and historical usage per customer.

[36] CND revised the purchased load forecast from 1,522,594 MWh, shown in the Application, to 1,420,552 MWh , as provided in the response to VECC IR # 14. CND noted that this model uses a trend variable to account for Conservation and Demand Management ("CDM") impacts; it also removes the negative and insignificant (and counterintuitive) population coefficient in the regression model originally used in the Application. The 2010 estimate provided in response to VECC IR # 14 reflects updated Ontario GDP forecast data as of October 2009.

[37] CND submitted that its updated model is based on more current data, results in a higher R^2, and addresses the concerns raised by Board staff and intervenors regarding the negative population coefficient, and it is also consistent with 2009 actual purchased kWh of 1,450,836 MWh.

[38] Board staff noted that most distributors are using econometric regression modeling techniques that are more sophisticated than the normalized average

consumption approach previously used by many distributors. However, Board staff submit that CND has had limited success with its regression modeling techniques.

1. Board staff is concerned that the focus of the modeling on the achievement of a high R^2.[10] Board staff stated that there are other measures of goodness of fit, and also that the suitability of a model should be both conceptually as well as technically sound;

2. Board staff also questioned the results of the CDM variable in the revised forecast, which is at odds with the price elasticity (sensitivity) of electricity consumption. Board staff also noted that there is currently no price variable in the load forecasting models;

3. They were also concerned with the impact of the CDM variable, a linear trend variable starting in January 2006, reduces purchased kWh by 190,000,000 kWh, or 11.8%, in the 2010 forecasts provided by the model estimated in response to VECC IR #14.

[39] CND prefers the forecasts from the CDM Model. Board staff prefers an alternative model where the insignificant population and spring/fall variables were omitted. Board staff believes the parameters of this model are better than the original model in the application and at least equal to the result of the CDM Model. The Non-CDM Model does not have a CDM variable, but all coefficients are significant. This model results in a 2010 system billed forecast of 1,502,332 MWh, an increase of 5.8% over CND’s revised forecast.

[40] EP supports CND’s methodology for developing its load forecast. They prefer load forecasts developed on a customer class basis, but recognized that reliable class data was not available. While supporting CND’s forecasting methodology generally, EP expressed concerns with the system load regression model (i.e. the CDM Model). In general, EP’s submission echoed the concerns expressed by Board staff regarding the CDM Model which CND is relying on for its updated forecast. EP submitted that the

[10] The R^2 (R-squared) is a statistical measure of how much of the variation in the variable being modeled (in this case, system demand) is explained by the estimated model and the explanatory variables, including income/economic activity, population, seasonal variables, etc. R^2 ranges from 0% to 100%, with a higher R^2 indicating better explanatory power and model fit. It is a common, but not the only, measure of the goodness of fit for statistical models.

Non-CDM Model produces a 2010 test year forecast of 1,541,693,000 kWh. If updated with the lower but more recent Ontario GDP forecast, the system purchase forecast would be approximately 1,533,020,000 kWh, which EP submitted is the appropriate forecast.

[41] EP also raised concerns over CND's methodology for determining the kWh-to-kW conversion for demand-billed customer classes. CND has used the class-specific average kW/kWh ratio for the period 2003 to 2008 for each demand-measured class. EP submitted that this approach ignores trends over time, whereby the kW/kWh ratio is trending up for the GS 1000-4999 kW and GS > 5000 kW classes, and trending down for the Streetlighting class. EP submitted that CND should use the 2008 ratio for each class instead of the average from 2003 to 2008.

[42] VECC expressed concerns similar to those of Board staff and EP. In VECC's submission, the reliance on R^2, without looking at other measures of variable significance and goodness of fit, was inappropriate. They argue that the Board cannot have confidence in the CDM Model. VECC also expressed concerns that the CDM trend variable and the flag values for 2010 yield a CDM adjustment of over 190,000 MWh; purchased loads would be 13.5% higher without the trend variable. As a result, VECC submitted that the CDM savings implicit in CND's 2010 load forecast are too high and hence the model does not provide reasonable results. VECC also submitted that the 2010 forecast, lower than for 2009, is counter-intuitive in light of increasing population growth and positive GDP growth of 2% forecasted for 2010.

[43] VECC provided an alternative analysis in its submission, which contrasted the average consumption per customer per class from the forecasts versus 2008 actual and 2008 weather normalized data. VECC submitted that its analysis demonstrated that the analysis shows that 2010 forecasts are too low compared to 2008 actuals, noting that average consumption in the Residential and GS < 50 kW classes was lower by 12%. VECC submitted that, even with a cumulative GDP reduction of 1.5% and further CDM, such reductions are unreasonable. VECC submitted that the 2010 forecast should be based on the 2008 actuals, for a forecasted billed consumption of 1,466,002 MWh.

[44] Board staff, VECC and EP are concerned that load forecasts cannot be compared with the 2009 actuals, stating that the 2009 actuals are not weather normalized while the forecasts are normalized. EP and VECC also noted that the 2009

actual was introduced in CND's argument and not in evidence. They argue that the Board should ignore this information.

[45] In reply, CND submitted that VECC's proposal was an updated normalized average consumption and hence based on only one year of data. While based on more recent data (2008 versus 2004), CND submitted that the NAC approach still has the issues which the Board has addressed in previous decisions. CND argued that its regression analysis approach is appropriate.

[46] CND submitted that it was not appropriate to rely on the Non-CDM Model estimated in response to Board staff IR # 9. Even if that model has better model statistics, it ignores the impacts of CND's CDM initiatives in the last three years (2006 to 2008). Analysis shows that the model over-forecasts the last three years of actuals, from 2006 to 2008, while the CDM Model more closely predicts to actuals. CND submitted that its revised proposed 2010 billed forecast of 1,384.3 GWh is a reasonable forecast and should be approved.

[47] With respect to the issue of load forecasting generally, CND submitted that this is a common element of cost of service applications for electricity distributors. CND argued that the Board should commence a generic process to review various approaches to establish what approach is acceptable.

Board Findings

[48] The load or demand forecast, both in terms of number of customers and consumption levels, underpin the capital and operating costs to be recovered in the revenue requirement, and "just and reasonable" rates to recover that revenue requirement.

[49] The Board acknowledges that load forecasting is continuing to evolve. This is a highly technical area, and the move to more sophisticated econometric techniques make it more so. The Board agrees that regression techniques can, if properly applied, provide valuable insight to the utility and the Board. Misapplied, techniques can result in significant errors and material under- or over-recovery. The impacts of errors may be magnified, as the base rates determined through a cost of service hearing will impact the IRM formula until rebased in four years.

[50] A great deal of time and effort in this Application has been spent on load forecasting, with numerous interrogatories, estimated models, and extensive submissions of all parties. There is no general consensus on the difficulties with the model used in the original Application; and no consensus on the solution.

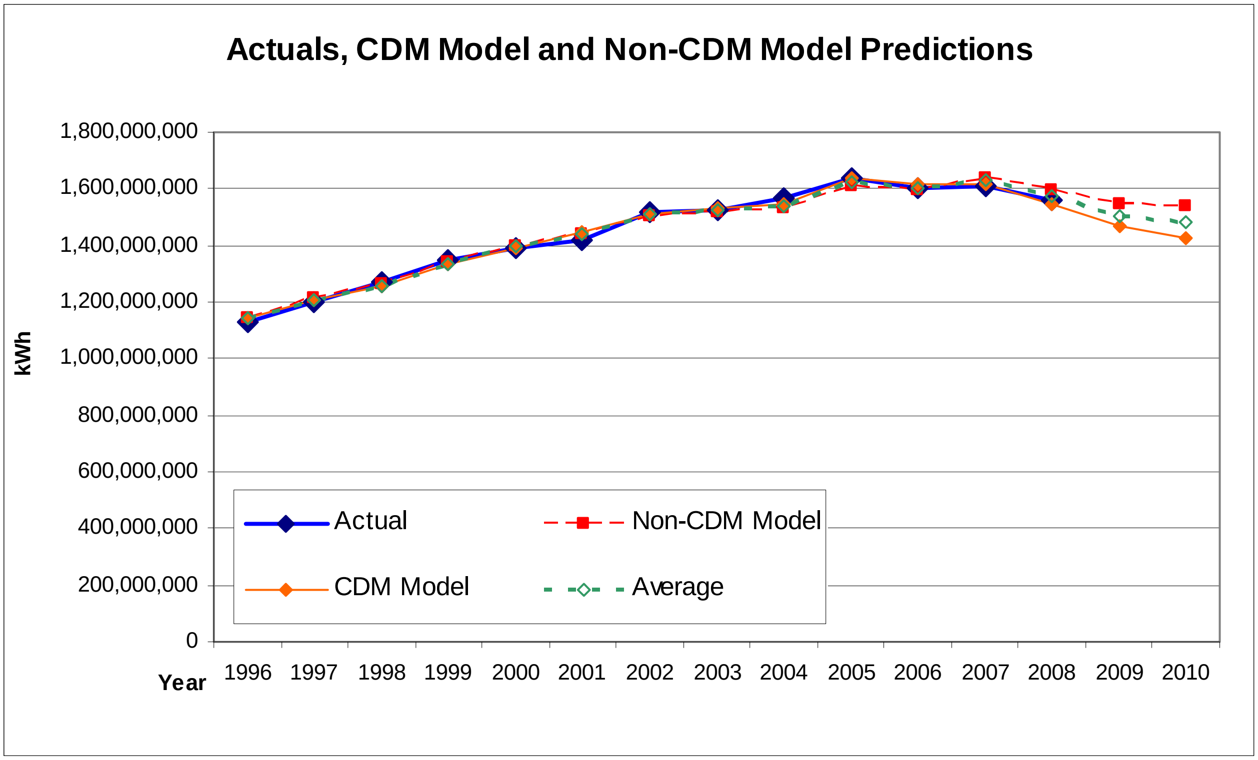
[51] The Board does not accept the updated NAC forecast as submitted by VECC. The Board has expressed its concerns over the NAC approach and views that the regression approach is preferable, particular for a medium-sized utility such as CND. The Board is also concerned that VECC's NAC approach may not appropriately reflect CDM and economic activity impacts in the forecast period.

[52] Two alternative models were filed in response to interrogatories. Both models appear to be "superior" compared to CND's model in its original Application, both in terms of goodness-of-fit and significance and reasonableness of variable coefficients. Both estimated models have their strengths and weaknesses. However, the two models provide significantly different forecasts, varying by about 8% from each other.

[53] CND notes that it has undertaken CDM activities with considerable success since 2006. These should reduce consumption over time. The Board acknowledges the concerns of the Applicant that the Non-CDM Model will not capture this reduction. At the same time, the Board shares the concerns expressed by Board staff, EP and VECC that the trend variable likely overestimates the CDM impact in the CDM Model.

[54] The CDM variable assumes a linear trend for CDM impacts that is not supported by actual data. Board staff and VECC have submitted that the CDM variable and coefficient reduces the load forecast by about 191,000 MWh or 12% of load in 2010; that equates to a reduction of over one month of consumption. This number, for one year, is also significantly higher than the cumulative Lifecycle Savings over four years (2005 to 2008) of 69,220,523 kWh, or 69,221 MWh documented in the Total Life Evaluation of its CDM Plan documented on page 12 of CND's Reply submission.

[55] The following graph shows the actuals, and predicted values from the CDM Model and the Non-CDM Model. The Board notes that the Non-CDM Model diverges in 2007 and 2008. While the CDM Model gives predicted values closer to actuals in those years, the downward trend, attributable to the CDM trend variable is apparent.



Note: Predictions for the CDM Model filed in response to VECC IR # 14 c) and EP Supplemental IR # 63. Predictions for the Non-CDM Model filed in response to Board staff IR # 9 c). Updating the forecasts for the Ontario GDP Outlook discussed in VECC IR # 14 f) would marginally lower the forecasts in 2009 and 2010 but not alter the patterns shown.

[56] The Board has also extracted the average of the forecasts from the CDM Model and the Non-CDM Model. In the Board's view, this average provides a more reasonable estimate of the load forecast. The effects of CND's CDM are modeled but the effects are not as significant. The average balances the strengths and weaknesses of what are, based on the record, two equally sound models. The Board directs CND to use a Purchased Forecast of 1,476,786,159 kWh and a Billed Forecast of 1,439,110,974 kWh.

		2010 Purchased Forecast (kWh)	2010 Billed Forecast (kWh)
Board staff	Non-CDM Model	1,541,693,000	1,502,331,904
Energy Probe	Non-CDM Model	1,533,020,000	1,493,910,199
VECC			1,466,002,000
C&ND Hydro - Original Application		1,522,593,844	1,483,750,031
C&ND Hydro - Revised	CDM Model	1,420,552,318	1,384,311,748
Average of CDM Model and Non-CDM Model		1,476,786,159	1,439,110,974

Note: Purchased and Billed Forecasts shaded reflect the October 2009 Ontario GDP Outlook, as documented in CND's Reply Submission.

[57] The Board accepts the kWh/kW conversion based on the historical average as proposed by CND. The Board does not accept EP's proposal to use only 2008 data. Data for a single point in time may be impacted by unique events and not represent long-term trends.

[58] Much of this Decision and indeed the entire proceeding has been devoted to the 2009 and 2010 load forecasts. This "war" of econometric models has become the least attractive part of the process. It has consumed considerable time and costs, all of which will be borne by the ratepayer. In the end the Board was forced to declare a truce, and essentially split the difference between the two models.

[59] It is important to consider how the process can be improved in the future. The difficulties experienced in this case are not unique to this proceeding, and have been repeated in a number of applications for other utilities. The Board recognizes that it is one thing to forecast for a province or even large cities. It is another to forecast for smaller markets, like the City of Cambridge and the Township of North Dumfries which consists of 50,000 customers. We have 80 rate regulated electricity distributors in this province and many are small in size with unique economic characteristics that pose real challenges for econometric modeling.

[60] CND's suggestion that the Board review load forecasting methodologies in a generic hearing may have some merit and should be considered. As a first step, however, the Board would urge the parties to participate in the consultation currently underway regarding revenue decoupling. That process, in part, was motivated by an

attempt to improve the efficiency of the regulatory process, which is very much a concern here.[11]

Treatment of Loss of Water and Sewage Billing Services Contract with City of Cambridge and Regional Municipality of Waterloo

[61] CND argues that the termination of the water and sewage billing agreement with its shareholders will result in a loss of Other Revenues. However, the costs of billing and collecting (envelopes, paper and printing and mailing, among others) remain. The loss of the water and sewage billing means the loss of revenues that help to recover or subsidize the cost of billing and collecting that the utility must do as part of servicing its electricity ratepayers.

In its Application, CND noted the reduction of $110,000 in Other Revenues for the fourth quarter of 2010. CND also noted that the annual expected Other Revenues lost will be four times the quarterly amount, or $440,000. However, CND argues that the costs remain. 2010 is the year that the utility is rebasing. This will set base rates that will be followed by three years of price cap adjustment, where there is no opportunity to further adjust for the lost revenues over all four quarters beginning in 2011. Given this, CND has proposed to normalize or amortize the lost revenues over the four years (the 2010 rebasing year and three subsequent years of IRM adjustments). CND's proposal is set out in the following table.

	Q1	Q2	Q3	Q4	Annual
2010				-$110,000	-$110,000
2011	-$110,000	-$110,000	-$110,000	-$110,000	-$440,000
2012	-$110,000	-$110,000	-$110,000	-$110,000	-$440,000
2013	-$110,000	-$110,000	-$110,000	-$110,000	-$440,000

Total (2010-2013)	-$1,430,000
Amortized over four years	-$357,500

[11] *Consultation on Distribution Revenue Decoupling*, EB-2010-0060 (March 22, 2010). The report of the Board's consultants, Mark Lowry and Matt Makos, *Review of Distribution Revenue Decoupling Mechanisms* (19 March 2010) states, at pg. 18:
"Decoupling true ups and SFV pricing can increase the efficiency of regulation in other ways as well. Both approaches reduce the importance of load forecasts in rate cases. This is a subject of considerable controversy in many proceedings. … The importance of regulatory economies also depends on the number of utilities that a commission regulates. For a commission with jurisdiction over dozens of utilities, regulatory cost savings can be decisive in deciding to embark upon decoupling."

[62] CND submits that this treatment is analogous to that of *Greater Sudbury Hydro*[12] where the Board accepted “normalization” of OM&A costs for a new CIS system. In that case, the OM&A costs would not occur in the 2009 test year, but would occur in subsequent years. On the presumption that no costs would apply in 2009, but there would be about $100,000 in costs for each of the subsequent years, the Board allowed ¾ of the expected OM&A expenses, or $75,000 to be recoverable in the rebased rates (and flowed through in subsequent years when rates are subject to the IRM price cap adjustment).

[63] Board staff argued that the annual impact of the lost revenues could be amortized over the period of 2010 and three years of IRM, subject to a reduced impact over time. Board staff suggested that “loss of revenues” impact be reduced by ¼ in each of the succeeding years, so that it would be zero for CND’s next rebasing expected for 2014. This reduction each year is to reflect either replacement revenues from new sources or cost savings or redeployment to other operations that the utility’s management should be expected to effect to offset the revenues from Water and Sewer Billing being lost. Board staff’s proposal is documented in the following table:

	Q1	**Q2**	**Q3**	**Q4**	**Annual**
2010				-$110,000	-$110,000
2011	-$82,500	-$82,500	-$82,500	-$82,500	-$330,000
2012	-$55,000	-$55,000	-$55,000	-$55,000	-$220,000
2013	-$27,500	-$27,500	-$27,500	-$27,500	-$110,000

Total (2010-2013)	-$770,000
Amortized over four years	-$192,500

[64] The Board staff proposal would result in a normalized reduction in Other Revenues of $192,500 per year, to be reflected in the 2010 rates and then carried forward in rates for three years of the IRM period. Board staff suggested that, with the new CIS and billing system that CND is installing in late 2010, CND has an opportunity, over the next few years, to search for and implement process and technological changes that will allow for more cost-effective billing operations, and hence lessen the cost-recovery impact of the revenue stream lost with the cessation of the water and sewer billing contracts.

[12] *Decision and Order*, EB-2008-0230 (January 19, 2010)

[65] VECC noted that there was no agreement between the parties that $440,000 represented the lost revenue offsets beyond 2010. They submitted that the estimated $440,000 in 2010 represents an allocation of shared and general costs in that year. VECC also disagreed with the proposition that all of these costs, and in particular the general overhead costs, would continue throughout the IRM period. VECC expected that, over time, there should be some reduction in costs to reflect the reduced activity by CND upon cessation of the water and sewer billing.

[66] VECC also expressed a more general concern with "normalization" of costs and reflecting costs or benefits beyond the test year in the test year revenue requirement. While acknowledging that there is a general practice of normalizing costs, VECC submitted that this practice is not standard. Specifically, VECC referred to the Board's decision with respect to London Hydro's 2009 Cost of Service application,[13] where the Board disallowed "normalization" of accelerated Capital Cost Allowance related to a new CIS system. VECC submitted that::

> "normalization" should be the exception and limited to those circumstances where not only is the circumstance unique but the costs and the benefits of the activity can be clearly documented and are separable from the distributor's other activities.[14]

[67] VECC submitted that the termination of the water and sewer billing did not satisfy these criteria. They also submitted that there were other revenue offsets, such as bank interest, which would be expected to increase as interest rates are expected to rise beyond 2010, but where the Applicant has not proposed "normalization". In summary, VECC submitted that CND's proposed "normalization" of the lost revenue offsets should be rejected.

[68] SEC also submitted that the CND proposal should be rejected. SEC stated that there was no agreement that the $440,000 represented the annual amount and that it was net of expenses. SEC also agreed with VECC's submission that there should be some reduction in costs over time so that the loss to CND Hydro would be less than $440,000 annually. SEC also submitted that this is a single known event, but that there may be other events which occur over the period of IRM that could change. SEC

[13] *Decision and Order*, EB-2008-0235, August 21, 2009
[14] VECC's Submission, February 26, 2010, pg. 10

suggested that adjustments of this nature, as proposed by CND, should only be done in exceptional circumstances.

[69] EP, in its submission, accepted the forecasted reduction in other revenues of $110,000 for the last quarter of 2010, but did not accept the “normalization” proposal of CND. EP referred to the response to EP interrogatory # 24 f), where the costs for providing these services are classified as direct (36% of total) and shared and overall general (64% of total). EP submitted that CND has not provided forecasts beyond 2010 on how it expects to reduce costs currently shared in providing billing for electricity distribution and for water and sewer billing, nor has it forecasted reductions in general costs that are no longer recovered with the termination of the water and sewer billing arrangements.

[70] EP also argued that CND had not forecasted other elements of revenue offsets such as bank interest. EP submitted that normalization should only be done in exceptional circumstances and where full forecasts of all such revenues are provided over the full period. In this Application, EP submitted that the proposed normalization should be rejected.

[71] In reply, CND submitted that its proposed normalization should be accepted. CND did argue that staff’s assumption that all revenues or costs can be eliminated was not realistic, noting the costs like postage, envelopes, stationary or supervisory staff are still required for billing for electricity. CND contends that staff’s proposal would also impose an additional productivity factor on the utility in the IRM period.

[72] CND rejected the submissions of intervenors, relying on the Board decision in *London Hydro*. CND argued that *London Hydro* related to taxes and PILs, while CND’s situation refers to the treatment of an expense and there is no difference between the treatment of an expense, as in the *Greater Sudbury Hydro* case, or the loss of other revenues.

Board Findings

[73] This is one of two items for which the Applicant is seeking the “normalization” of cost recovery not only over the 2010 test year, but also over the subsequent three-year period of IRM adjustments. The Board has general concerns about the need for such normalization as argued by Board Staff and the intervenors. The Board also addresses

this in the normalization of CIS and billing increases related to monthly billing elsewhere in this Decision. However, in specific circumstances where supported by the evidence, the Board has allowed for normalization and the Greater Sudbury Hydro decision is one example.

[74] The issue here is the recovery of operating costs related to customer billing. To date, the costs are recovered from two sources – through the distribution rates charged to electricity ratepayers and through service revenues received for water and billing services provided to municipalities through service agreements. By 2010 Q4, the service agreements for water and sewer billing cease. CND proposes to “normalize” the cost recovery shortfall over the four year period.

[75] The Board recognizes that the termination of the service agreements does not mean that all costs can be avoided. Postage, paper and envelope costs are largely unchanged, whether billing covers both electricity, and water and sewer, or is only done for electricity. However, the Board does not agree with the Applicant’s proposed normalization, which assumes that the water and sewer billing revenues are solely a subsidization of fixed costs which remain invariant. The Board considers that at least some capacity in its billing system and in its workforce, was used to provide the water and sewer billing. In other words, there were costs to provide water and sewer billing under service agreements to the municipalities that will not be necessary to provide electricity distribution services. The Board finds that such costs should not be recovered from electricity ratepayers.

[76] The Board accepts Board staff’s submission that these are operating costs. They are not fixed or “sunk” as is the case with an investment in a capital asset, like poles, wires and transformers, which can often not be readily redeployed or salvaged. The Board also agrees with Board staff that, while the utility may not be able to fully offset any under-recovery by cost reductions immediately, it should be able to do so over time.

[77] Accepting that some costs, such as for postage and envelopes, will remain, the Board accepts CND’s concerns over Board staff’s proposal. In the absence of specific evidence on the quantum of these costs, the Board will adopt a variation of the Board staff proposal, whereby $44,000 (10% of the annual amount of $440,000) represents recovery of unavoidable and invariant costs. The Board accepts Board staff’s proposal that the remainder should be reduced over the four year period, and the cumulative

adjustment to Other Revenues “normalized” for recovery in 2010 and the subsequent IRM period. The derivation of this is shown in the following table:

	Q1	Q2	Q3	Q4	Annual
2010				-$110,000	-$110,000
2011	-$85,250	-$85,250	-$85,250	-$85,250	-$341,000
2012	-$60,500	-$60,500	-$60,500	-$60,500	-$242,000
2013	-$35,750	-$35,750	-$35,750	-$35,750	-$143,000

Total (2010-2013)	-$836,000
Amortized over four years	-$209,000

The Board will thus allow a reduction to Revenue Offsets of $209,000 for determining 2010 distribution rates.

Operating Costs

Treatment of Incremental Operating Expenses Related to new CIS System and Monthly Billing

[78] The only unsettled matter with respect to Operating, Maintenance & Administrative (“OM&A”) expenses relates to an incremental amount of $42,500 related to CND’s proposal to move to monthly billing, to be coordinated with full deployment of smart meters this year and implementation of the new billing system. CND notes that the incremental costs of $42,500 for November and December 2010 would not fully recover the costs in subsequent years under IRM, when these costs will be incurred in all twelve months of each year. CND proposes that the OM&A incremental costs be “normalized” or amortized over the rebasing year and the subsequent three years of IRM, with an amount of $244,625 ($42,500 plus three years of $312,000 spread over four years).

[79] CND submits that this normalization should be done for the same reasons as for the “normalized” treatment of the “Other Revenues” lost due to the loss of the Water and Sewage Billing contract.

[80] Board staff notes that the Board has sometimes allowed for a “normalization” of costs, as CND cites from the *Greater Sudbury Hydro* decision. In this case, these are operating costs that result from a prudently incurred capital investment, for the new CIS and billing system. Board staff added:

> … That the CIS and billing system are integral to the provision of electricity distribution services is not being questioned, and hence ongoing costs for the operation of these systems are legitimate costs for which recovery should be allowed in rates. To this end, Board staff does not oppose some form of "normalization" of the costs, but does raise concerns over the incidence and support for such treatment. The difficulty, in Board staff's view, is that the test year cost of service approach sets a revenue requirement and rates to recover necessary and prudent costs of providing safe, reliable and high quality services and meeting demand, including the opportunity to earn for investors a market-based return on capital and maintain the financial viability of the firm. At the same time, the rebased rates for the basis for IRM adjustments in subsequent years, and so should reflect a "normal" level or relationship of rates, costs and demand.
>
> The Board must balance this situation of rates relating to the test year, in a pure cost of service application, and that of recognizing that these become the basis for rates in more mechanistic adjustments in subsequent years. Strict treatment of 2010 in a forward test year application would argue that no normalization is appropriate.[15]

[81] Board staff was concerned that the $312,000 estimated as incremental costs for monthly billing was not supported, given that the new CIS system is not developed and installed, and the utility does not know the costs of monthly billing. Board staff suggested two options:

- Allowance of the $42,500 incremental costs for 2010. CND Hydro could apply for a cost of service rebasing subsequently when better estimates of the costs are known; or
- An amount of $142,500 to be factored into base rates over the period of 2010 rebasing and three years of IRM. Staff noted that this amount, about half-way between the $42,500 for 2010 and $244,000 requested by CND Hydro was arbitrary, but it would allow some recovery of costs while providing an incentive for the utility to seek efficiencies.

[15] Board staff's submission, February 26, 2010, pg. 13

[82] VECC opposed the normalization of OM&A costs, given the similar arguments for rejecting normalization of revenue offset reductions. While acknowledging that CND has estimated some cost savings, they note that no reductions in bad debt expenses were forecasted, and that impacts on cash balances and interest expense are based on current low interest rates projected for 2010. VECC submitted that the Board needs to establish clearer guidelines regarding the practice of cost normalization in a test year. If the Board were to allow for cost normalization, VECC submitted that some reduction (e.g., at least 10%) should be incorporated to reflect unaccounted benefits.

[83] SEC submitted that its position on this matter was similar to that with respect to revenue offset normalization. SEC also concurred with VECC, saying that "[i]t would be unfair to ratepayers to make an adjustment for a single cost item when, even with respect to that cost item, there may be offsetting savings."[16] SEC thus opposed the proposed normalization of CIS costs.

[84] EP submitted that CND's proposal should be rejected. Noting the CND was primarily relying on the Board's Decision and Order with respect to Greater Sudbury Hydro's 2009 electricity distribution rates (Board File No. EB-2008-0230), EP submitted that CND's circumstances differed from those of Greater Sudbury Hydro. EP submitted that there were other impacts, beyond increased costs for postage, stationary and envelopes and bank charges, and submitted that cost reductions in working capital requirements and bad debt expenses could also result. However, there are no such estimates on the record.

[85] EP further submitted that CND's situation was similar to the *London Hydro* case, where the Board rejected London Hydro's proposal to normalize or amortize the Capital Cost Allowance for a new CIS system over the rebasing year and three years of IRM.[17] Finally, if the Board were to allow some form of normalization, EP submitted that the working capital allowance should be reduced from 15% to 12.5%, the latter still being higher than the 11% from the approved Settlement Agreement of Toronto Hydro in its 2010 rate application[18]; EP noted that the reduction of CND's WCA to 12.5% would more than offset CND's proposed OM&A increase.

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[16] SEC's submission, February 26, 2010, pg. 3
[17] *Decision and Order*, EB-2008-0235, (August 21, 2009)
[18] *Decision*, EB-2009-0139, (April 9, 2010)

[86] In reply, CND rejected the submissions of Board staff and intervenors. It rejected VECC's submission that the Board provide additional guidance on normalization. CND stated that it has accounted for savings associated with the move to monthly billing and reiterated its belief that its proposal is reasonable; if the Board felt that some reduction was warranted, the 10% reduction suggested by VECC would be more reasonable.

Board Findings

[87] The Board notes at the outset that CND's application is for 2010 test year distribution rates based on a cost of service methodology. This reflects forecasted demand, costs and revenues for the 2010 test year alone. Costs beyond the test year have not been tested.

[88] There is no agreement on the level of the costs, whether all savings have been accounted for, or whether there are other offsetting adjustments that should be considered. In particular, while the Board considers that the incremental costs for 2010, in the amount of $42,500, to be adequately supported and tested, the Board finds that extrapolating this for twelve months in each of the subsequent three years, when CND will have its rates adjusted through the IRM plan, is unsupported. The Board accepts the submissions of intervenors that CND may not have estimated the costs, or reflected other savings or adjustments, beyond the 2010 test year.

[89] The Board will, in the circumstances, accept the incremental cost of $42,500 for 2010, but will not allow the normalization of incremental costs for the IRM period. The Board directs CND to reflect this finding in its draft Rate Order. The Board believes that this is less arbitrary than the second Board staff proposal.

Cost of Capital and Capital Structure

[90] In its original Application, CND proposed a cost of capital treatment in accordance with the Board's cost of capital guidelines then in effect. These guidelines are documented in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors* (the "2006 Report"), issued December 20, 2006.

[91] In Exhibit 5 of its Application, CND proposed the following cost of capital:

Cost of Capital Parameter	**CND's Proposal**
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	1.33%, but to be updated in accordance with section 2.2.2 of the 2006 Board Report.
Long-Term Debt	5.20%, reflecting the weighted average of the actual rate (4.99%) on debts owed to Sun Life and 7.62% as the deemed rate relating to the promissory note due to its shareholder, the Corporation of the Township of North Dumfries. The deemed long-term debt rate would be updated in accordance with section 2.2.1 of the 2006 Board Report.
Return on Equity	8.01%, but to be updated in accordance with the methodology in Appendix B of the 2006 Board Report.
Return on Preference Shares	Not applicable
Weighted Average Cost of Capital	6.17% as proposed, but subject to change as the short-term and long-term debt rates and ROE are updated per the Board Report at the time of the Board's Decision.

[92] The Board subsequently revised and documented its guideline cost of capital methodology in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"), issued December 11, 2009, under Board File No. EB-2009-0084. The 2009 Report is a guideline, but departures from the methodology in the 2009 Report must be adequately supported. While the 2009 Report was issued subsequent to the filing of this Application, the 2009 Report does state that the revised guidelines apply to applications for rates effective in 2010 or later and determined through review of cost of service applications. Thus, the 2009 Report supersedes the guidelines documented in the 2006 Report and is applicable to CND's Application for 2010 distribution rates.

[93] In the revised Partial Settlement Agreement, under Issue 5 b), CND and the intervenors agreed that the weighted average cost of long-term debt would be 4.99%, which is the documented rate on the debt instruments held by both Sun Life and by the Corporation of the Township of North Dumfries Hydro.

[94] CND and the intervenors did not settle on the following aspects of the Cost of Capital:

- That the ROE should be determined in accordance with the methodology as documented in section 4 and Appendix B of the Board's Cost of Capital report; and

- That the short-term debt component of the deemed capital structure, set at 4%, should apply for setting the weighted average cost of capital.

[95] On February 24, 2010, the Board issued a letter documenting the updated Cost of Capital parameters to be used in determining distribution rates for 2010 cost of service applications, based on the methodologies documented in the Cost of Capital Report. These can be summarized as follows:

Cost of Capital Parameter	**Updated Value for 2010 Cost of Service Applications**
Return on Equity	9.85%
Deemed Long-term Debt Rate	5.87%
Deemed Short-term Debt Rate	2.07%

[96] CND submitted that the guidelines in the 2009 Report should apply. CND notes that the deemed capital structure was set at a common 56% long-term debt, 4% short-term debt, and 40% equity in the 2006 Report, and this approach is unchanged in the more recent 2009 Report. CND also stated that its ROE should also be established in accordance with the methodology established in the 2009 Report.

[97] Board staff submitted that CND's proposals for cost of capital comply with the guidelines documented in the 2009 Report.

[98] EP submitted that the evidence in this proceeding regarding the level of the WCA indicates that the 4% deemed level of short-term debt is not reasonable and that the incremental costs, as a result of the WCA attracting the higher long-term rate, are neither just nor reasonable. EP pointed to the Board's comments in the 2006 Report to the effect that the term of the debt should mirror the life of the assets that the debt is used to finance. EP expressed its view that the WCA, which represents about 16.8% of CND's rate base for rate-setting based on evidence in this proceeding, should attract only the deemed short-term debt rate. EP noted that the working capital allowance has been stable, ranging from $17.9 million to $19.0 million over the period from 2006 to 2009, while the deemed short term debt component for 2010 is about $4.2 million; this represents a difference of about $13.4 million. EP submitted the difference means that customers are paying in distribution rates long-term debt rates on working capital financed with short-term debt, with an estimated over-collection of $393,030. EP submitted that this is a significant proportion of the rate base (approximately 1.7%) and that it would mean that ratepayers would overpay by about $1.56 million over the four year period of rebasing and IRM rate adjustments.

[99] EP submitted that CND has actual and new debt in 2010 totaling $38,019,703, compared to a deemed long-term debt capitalization of $58,530,092. The difference is about $20.5 million; if this was added to the 4% deemed capitalization, the amount would closely correspond with the short-term working capital amount of 16.8% of rate base. Treating the notional debt as short-term would reduce the 2010 revenue requirement by $390,000, which would be carried forward in rates subject to IRM adjustments.

[100] EP submitted that the 9.75% ROE set by the Board in the 2009 Report includes an implicit 50 basis points for transactional costs and asserted that the component is only applicable in cases where a distributor releases new stock or issues new debt. EP acknowledged that this implicit component for flotation and transactional costs is long standing within Ontario and across North America. However, EP stated that the inclusion of the implicit 50 basis points for transactional costs is not appropriate for CND because there is no evidence that it will incur any transaction costs in the test year and that, to allow the recovery of the amount, would result in rates which are not just and reasonable. EP submitted that the Board does not allow recovery of costs that do not exist for capital expenditures, OM&A expenses or for debt costs, and that the Board should similarly not allow recovery of the flotation costs that CND will not incur.

[101] SEC supported EP's submission with respect to the ROE. SEC noted that the ROE is a proxy figure, designed to reward the utility investor with a rate of return on its investment that is equivalent to what the investor would earn had it invested in an enterprise with a similar risk profile in a competitive market. This ROE is included in the determination of the revenue requirement even when the utility has no actual equity. However, SEC stated that the flotation cost of 50 basis points is the estimate for the recovery of costs that the utility would have to pay to obtain equity; this flotation cost should not be allowed as there is evidence that CND will not incur these costs, as it does not go to market and issue new shares.

[102] VECC supported EP's submission. Specifically, VECC submitted that "… any costs which are not incurred by the utility, i.e., in this case flotation costs as included in the ROE through a 50 basis point adder but not incurred by the utility, should not be recovered from the ratepayer."[19] VECC also submitted that there was a "general consensus" amongst the experts at the Board's 2009 consultation in the cost of capital

[19] VECC's submission, February 26, 2010, pp. 12-13

that the spread between debt borrowing costs and the allowed ROE should be in the range of 200 to 300 basis points. As such, VECC submitted that the allowed ROE should be no more than 9.12%, or 325 basis points above the deemed long-term debt rate of 5.87.[20]

[103] In reply, CND disagreed with the submissions of intervenors. With respect to EP's proposal to reduce the allowed ROE by the 50 basis points for flotation and transaction costs, CND argued:

> EP's approach creates an entirely new, unexpected and unprecedented burden of proof that would open the floodgates to numerous arguments about all aspects of the allowable ROE – requiring utilities to hire costly consultants to justify a proposed ROE and subjecting the Board to lengthy administratively cumbersome proceedings on disputed ROE allowances. [CND] submits that the Board should reject EP's approach and affirm [CND]'s use of a 9.85% ROE pursuant to the December 2009 Report and the 2010 updates.[21]

CND noted that the Board rejected an identical submission from EP in the Board's Decision in Burlington Hydro.[22]

[104] CND disagreed with EP's argument of aligning the short-term debt capitalization to the working capital. They argue that the proposed WCA is calculated for the purposes of determining the rate base for rate-setting purposes, but does not, nor should not, correlate or act as a proxy for actual short-term debt. CND submitted that its proposed capital structure complies with Board policy as documented in the 2009 Report. CND also submitted that EP erred in assuming that all working capital is funded by short-term debt, and the Applicant responded that this is not the case in reality, and that for corporate financing purposes, firms need both a long-term (or permanent) and a short-term or cyclical component for cash working capital.

[105] In summary, CND submitted that its proposed Cost of Capital complies with Board policy, which is itself the result of extensive consultative processes. CND also submitted that the proposals of intervenors represent deviations from the Board's

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[20] *Ibid.*, pg. 13
[21] CND, Reply Submission, March 5, 2010, pg. 34, para. 95
[22] *Decision and Order*, EB-2009-0259, (March 1, 2010)

policies which should not be addressed through ad hoc procedures in applications of individual distributors.

Board Findings

Return on Equity

[106] EP argues that 50 basis points should be removed from the ROE because CND does not issue equity in the market. This is the same argument that EP made in *Burlington Hydro*[23], *Festival Hydro*[24] and four intervenors made in *Toronto Hydro*[25].

[107] The Board finds that it would be inappropriate to adjust the formula without evidence supporting such an adjustment. This evidence must address whether such an adjustment for CND is appropriate under the "stand alone" utility principle and whether the allowance is related only to specific transactional costs or whether it has broader application.

[108] In *Toronto Hydro*, the intervenors took the position that the evidence established that Toronto Hydro would not be issuing equity, and therefore the Board should deduct the 50 basis points which were included in the ROE to compensate for issuance costs. The Board, in its decision, elected not to make the adjustment to the ROE proposed by the intervenors for a number of reasons, stating:

> First, the downward adjustment of the ROE is proposed because THESL gave evidence that it did not intend to issue equity in the test year. THESL is not unique; very few of Ontario's regulated entities issue equity even indirectly and those who have would not necessarily have done so in every year. This is true for both the gas industry and the electricity industry. This situation has existed for considerable time and would have been understood throughout the evolution of the Board's approach. Since the Board started using the mechanistic approach, the Board has never differentiated the ROE awarded on the basis of whether an entity issued equity.

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[23] *Ibid.*
[24] *Decision and Order*, EB-2009-0263 (April 1, 2010)
[25] *Decision*, EB-2009-0139 (April 9, 2010)

The Board points out that the submissions of cost of capital experts since 1998, including those of Dr. Booth (who has testified for the intervenors on numerous occasions), include this component in cost of equity estimates, without qualifying it as being only applicable to entities with equity issues in the test period or based on ownership. The Board further highlights that its treatment of flotation costs with respect to municipally-owned utilities is not unique; the ROE of municipally-owned utilities in Alberta also includes flotation costs and the ROE afforded Alberta-based, municipally-owned utilities is the same as that for investor-owned utilities. Finally, as set out in the 2009 Report, there is no information to suggest that the market differentiates the cost of equity capital in the manner presented by intervenors; rather "the cost of capital depends on the use of the capital – or, more precisely, the risk associated with the use of the funds".

Second, changes to the methodology should only be undertaken with evidence that can establish the appropriateness of the adjustment with regard to the applicant utility. The onus for providing that evidence rests with the proponent of the adjustment.

…

In this case, while the intervenors have put forward evidence to establish that THESL does not intend to issue equity in the test year, they have not put any evidence forward which would address the type of concerns raised by the Board in Burlington Hydro. The experts who have provided opinions to the Board on this matter have never qualified the flotation costs as being applicable only to entities with equity issues in the test period and as a result, the Board has always awarded an ROE containing that component. The Board requires a reasonable basis to support a departure from its longstanding practice in this application. The Board also requires a reasonable basis to support the appropriateness of such an adjustment in terms of the overall methodology in the context of THESL's circumstances. No such information has been filed.

> Having found that there is no reasonable basis to support an adjustment to the method of determining the ROE, the Board will apply the method set out in the 2009 Report.[26]

[109] For the reasons set out in *Toronto Hydro*, the Board finds that the methodology for the ROE established in the 2009 Report should apply to CND without adjustment.

[110] The Board also does not accept VECC's argument that the ROE should be at most 9.12%, or 325 basis points above the deemed long-term debt rate. A review of the references cited by VECC does not support the claim that there was a "general consensus" amongst the experts of a 200 to 300 basis point spread between the long-term corporate debt and the ROE. The Board is of the view that, while there may be a distribution of the spread between the long-term debt rate and the corresponding ROE, depending on circumstances, there is not conclusive evidence, either here or in the consultative process that resulted in the 2009 Report, that it is bounded in the range suggested by VECC.

[111] The emphasis in the 2009 Report regarding the need to support an application refers particularly to long-term debt and the proper application of the Board's policy, an area which has drawn considerable attention in several cost of service applications in the past few years. With respect to adjustments to the ROE, such as that proposed by EP, the Board finds that the evidentiary burden rests with the party proposing a departure from the policy. Depending upon the circumstances this could be either the applicant or an intervenor.

Capital Structure

[112] The Board will make no adjustment to the deemed capital structure of 56% long-term debt and 4% short-term debt. The Board's uniform deemed capital structure and the general approach to setting the WCA have both been in place for considerable time. The Board is not prepared to depart from these policies on the basis of the record in this proceeding.

[113] EP has asserted that the WCA should align to short-term debt in the capital structure, but it has not provided any evidence to support this contention, theoretically or

[26] *Ibid*., pp. 13-15

practically; nor has CND had the opportunity to respond with rebuttal evidence. However, CND has submitted, in reply, that for corporate financing purposes generally and not just distributors, working capital has both long-term and short-term components. The Board finds CND's argument reasonable. In other words, the Board considers that working capital is not fully funded by short-term debt as contended by EP.

[114] However, as indicated earlier, the Board may review the formulaic approach to determine the WCA. In the context of that review it may be appropriate to examine the levels of WCA across utilities and consider whether any refinement to the deemed capital structure is warranted.

Weighted Average Cost of Capital

[115] The table below sets out the Board's findings for CND's deemed capital structure and cost of capital for the purposes of setting its 2010 revenue requirement and distribution rates:

Board-approved 2010 Capital Structure and Cost of Capital for CND

Capital Component	% of Total Capital Structure	Cost rate (%)
Long-Term Debt	56.0	4.99
Short-Term Debt	4.0	2.07
Equity	40.0	9.85
Weighted Average Cost of Capital		**6.82**

In preparing its updated revenue requirement arising from this Decision and the draft Rate Order to implement this Decision, CND should reflect these parameters.

Deferral and Variance Accounts

Treatment of Global Adjustment Sub-account of Account 1588

[116] The only outstanding issue with respect to deferral and variance ("D/V") accounts relates to the treatment of the Global Adjustment sub-account of Account 1588. This is an issue that applies to all 2010 distribution rate applications, but is being addressed in each application on a utility-specific basis. The individual circumstances of each distributor vary, including the ability to allow for a rate rider specific to the non-RPP customers of each customer class and the costs for such implementation.

[117] For CND, the Global Adjustment sub-account contains a debit balance of $2.1 million, including interest to April 30, 2010. CND has appropriately used the kWh for non-RPP customers as the allocator for the Global Adjustment sub-account. In response to Board staff supplemental IR # 53, CND provided calculations of the rate riders to dispose of the deferral and variance account balances, excluding the Global Adjustment sub-account, and separate rate riders to dispose of the Global Adjustment sub-account balance. CND explained that it did not have estimates of 2010 non-RPP customer consumption and used 2008 actuals as the billing determinant. CND noted that it does not have the capability in its systems to exclude MUSH sector (Municipalities, Universities, Schools and Hospitals) customers if a separate rate rider for disposition of the Global Adjustment sub-account balance is established. Further, CND stated that some MUSH sector customers may have voluntarily become non-RPP customers in advance of November 2009. In such cases, where these customers contributed to the Global Adjustment variance, they should also benefit from any refund or payment through the Global Adjustment rate rider.

[118] CND argued that its current billing system is not capable of handling different rate riders for customers within the same customer class.

[119] Board staff submitted that recovering the Global Adjustment sub-account balance solely from non-RPP customers more appropriately recovers the under-collection from those customers that were undercharged in the first place. Board staff took no issue with CND’s responses on the applicability and practicality of not excluding MUSH sector customers from any specific Global Adjustment rate rider.

[120] Board staff suggested that one solution would be to defer disposition of the Global Adjustment sub-account balance until 2011, when CND has documented it would have its new system in place. As part of the design of the new system, CND could ensure that the new systems could handle several rate riders and adders and also handle sub-classes, such as RPP and non-RPP customers, within each customer class. The additional capabilities could be designed into the new system at marginal incremental cost. Board staff noted that deferring the Global Adjustment balance would increase the remaining D/V credit balance to be disposed to over $11 million, over a period of two years; this would assist in mitigating rate increases over this period. Finally, Board staff submitted that CND should provide a detailed spreadsheet showing the rate rider calculations to demonstrate compliance with the Board’s findings in this Decision.

[121] In its submission, EP expressed concern about the costs that CND might incur to establish a separate rate rider for non-RPP customers, and that these costs might outweigh the benefits in the test year. However, EP noted that this sub-account might have significant balances that need to be disposed of annually, and that the costs for separate rate riders might be justified in the long run. EP submitted that the Board should direct CND to investigate the costs of establishing different rate riders within a rate class, and that the Board should initiate a consultation to consider options for dealing with disposition of the Global Adjustment balance to non-RPP customers only.

[122] VECC submitted that the use of a separate rate rider for disposing of the Global Adjustment sub-account applicable only to non-RPP customers is appropriate. However, VECC noted that CND's system is not capable of handing a separate rate rider, and there is no evidence on the record as to the costs for doing so, or whether these costs are justified by the benefits. Noting that billing systems have shorter economic lives compared to many utility assets, VECC submitted that a solution would be to have CND assess the costs and benefits of implementing separate rate riders in its new billing system under development.

[123] In reply, CND noted that the balances in the Global Adjustment sub-account will continue to increase. It requested that the Board not delay disposition of the current balances, and that the disposition be dealt with as proposed, i.e. recovered from all customers. CND indicated that, based on the Board's feedback, it would ensure that its new CIS/billing system would have the functionality for separate rate riders for non-RPP customers.

Board Findings

[124] The Board will not approve disposition of the Global Adjustment sub-account balance at this time. The balance is not immaterial, being $2.1 million . The balance may have increased through 2009, but the Board does not agree that the balance will necessarily continue to increase. The increase in 2009 for many utilities reflects certain conditions in the IESO-controlled market. These may change depending on IESO forecasts, developments in the grid and in the market, and supply/demand relationships, including the impacts of CDM activities.

[125] While the balance is not immaterial, the Board considers it inappropriate that the current balance be collected from both RPP and non-RPP customers. The Board

concurs with VECC that this balance is attributable to non-RPP customers. Collecting it equally from both RPP and non-RPP customers means that RPP customers, who have already had the Global Adjustment factored into the RPP price, could be asked to pay in the order of $1.0 million. This would amount to a subsidization of non-RPP customers by RPP customers, a situation that the Board considers unreasonable.

[126] In other applications for 2010 electricity distribution rates, distributors have noted their ability to implement a rate rider specific to non-RPP customers. It appears that the vintage of CND's existing CIS/billing system, and delays in its replacement are largely responsible for the situation in which CND finds itself. While some of the factors are beyond the utility's control, the Board has concerns about CND management's efforts to recognize and react to this situation. In the following section, the Board provides direction on the accounting of capital costs related to the new CIS system in accordance with the terms of the Partial Settlement Agreement. In light of the delays and increased costs in replacing the CIS system, the Board also directs CND to provide quarterly reporting on the costs and status of the new system until it is in place.

OTHER MATTERS

Variance account designation for CIS Billing System costs

[127] CND's new CIS and billing system is due to be in service by November of 2010. As part of the Partial Settlement Agreement approved by the Board, the capital costs for the new CIS/billing system to be reflected in 2010 distribution rates is $1.85 million, subject to an asymmetrical variance account. Should capital costs be below the $1.85 million, the shortfall will be credited back to customers when application for disposition is made; if the capital costs exceed $1.85 million, then the overrun is borne by CND's shareholders.[27]

[128] CND is directed to record the variance between the actual capital costs for the new CIS/billing system in Account 2425, Other Deferred Credits, Sub-account: Over-Recovery of Capital Expenditures. CND shall record in this account the difference between its forecasted 2010 CIS capital expenditure of $1.85 million and the actual incurred expenditure for the CIS, if the incurred amount is less than $1.85 million. No amount shall be recorded if the incurred expenditures are greater than the forecasted

[27] Section 2 d) of the Settlement Agreement, Appendix A of the Decision on Partial Settlement, February 18, 2010

$1.85 million amount. CND shall also record in this account the revenue requirement impact associated with any over-recovery of the expenditure amount (i.e., incurred expenditure less than $1.85 million). Carrying charges at the Board's prescribed interest shall be calculated using simple interest applied to the monthly opening balances in the account (exclusive of accumulated interest) and recorded in a separate sub-account of this account.

[129] CND is also directed to file quarterly reports on the implementation of the new CIS/billing system. These reports should summarize the status of the project, any delays realized or expected, updated in-service date, any issues regarding the capabilities/functionality of the new system, and provide the variance sub-account balance. These quarterly reports should be filed 45 days following the end of each quarter beginning with the end of 2010 Quarter 2 (April to June). Once the new CIS/billing service is in place, the Board will review the need for any further reporting.

[130] The Board reminds CND that the necessary accounting entries, to reflect the Partial Settlement Agreement in this proceeding on the disposition of deferral and variance accounts, should be recorded as soon as possible, and certainly no later than June 30, 2010, for RRR purposes.

MicroFIT Generator Service Classification and Rate

[131] CND's application and the revised Partial Settlement Agreement do not include any consideration of the Feed-In Tariff program established in the Green Energy and Green Economy Act, 2009. That program includes a form of generation called microFIT, which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts (kW) or less.

[132] In its February 23, 2010 Decision and Order[28], the Board approved a service classification called microFIT Generator, to be used by all licensed distributors. This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. On March 17, 2010, the Board approved a province-wide fixed service charge of $5.25 per month for all electricity distributors effective September 21, 2009. Accordingly, the Board directs CND to identify the microFIT Generator service

[28] *Decision and Order*, EB-2009-0326, (May 23, 2010)

classification on its Tariff of Rates and Charges and must include the monthly service charge of $5.25.

Implementation of Rates

[133] As provided in the Application, the new rates are effective May 1, 2010. The revised Partial Settlement Agreement approved and included as Appendix A to the February 18, 2010 Decision on Partial Settlement, together with the Board's findings outlined in this Decision, are to be reflected in CND's draft Rate Order. The Board expects CND to file detailed supporting material, including all relevant calculations showing the impact of the implementation of the Partial Settlement Agreement and this Decision on its proposed Revenue Requirement, the allocation of the approved Revenue Requirement to the classes and the determination of the final rates, including bill impacts. 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. CND should also show detailed calculations of any revisions to the rate riders or rate adders reflecting the approved Settlement Agreement.

[134] A Rate Order will be issued after the steps set out below are completed:

1. Cambridge and North Dumfries Hydro Inc. shall file with the Board, and shall also forward to the intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges and all supporting documentation reflecting the Board's findings in this Decision within 10 days of the date of this Decision.

2. Intervenors shall file any comments on the draft Rate Order with the Board and forward to Cambridge and North Dumfries Hydro Inc. within 5 days of the date on which Cambridge and North Dumfries Hydro Inc. has filed the draft Rate Order.

3. Cambridge and North Dumfries Hydro Inc. shall file with the Board, and forward to the intervenors, responses to any comments on its Draft Rate Order within 5 days of the date on which intervenors have filed their comments on the draft Rate Order.

Cost Awards

[135] The Board may grant cost awards to eligible intervenors pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. The Board will determine such cost awards in accordance with its *Practice Direction on Cost Awards*. When determining the amounts 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 maximal hourly rate set out in the Board's Cost Awards Tariff will also be applied.

[136] A cost awards decision will be issued after the following steps have been completed:

1. Intervenors found eligible for cost awards shall file with the Board, and forward to Cambridge and North Dumfries Inc., their respective cost claims within 24 days from the date of this Decision.

2. Cambridge and North Dumfries Inc. shall file with the Board and forward to intervenors any objections to the claimed costs within 31 days from the date of this Decision.

3. Intervenors shall file with the Board and forward to Cambridge and North Dumfries Inc. any responses to any objections for cost claims within 38 days of the date of this Decision.

[137] Cambridge and North Dumfries Inc. shall pay the Board's costs incidental to this proceeding.

[138] All filings to the Board must quote the file number, EB-2009-0260, 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 clearly state the sender's name, postal address and telephone number, fax number and email address. Parities must 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 parties may email documents to the address below. Those who do not have internet access are required to submit all filings on a CD or diskette in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies. All communications

should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

DATED at Toronto**,** April 20, 2010

ONTARIO ENERGY BOARD

Original Signed By

Gordon Kaiser
Vice Chair and Presiding Member