Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2007-0742

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 Guelph Hydro Electric Systems Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity for the 2008 rate year.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

DECISION

July 31, 2008

Guelph Hydro Electric Systems Inc. ("Guelph" or "the Company") is a distributor of electricity that serves the City of Guelph and the Village of Rockwood. The Company is 100% owned by Guelph Hydro Inc., which in turn is 100% owned by the City of Guelph.

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

On May 4, 2007, as part of the plan, the Board indicated that Guelph would be one of the electricity distributors to have its rates rebased in 2008. Accordingly, the Company filed a cost of service application based on 2008 as the forward test year. In accordance with the Board's plan, Guelph was to file its application and evidence by August 15, 2007 to provide sufficient time so that its new rates could be implemented May 1, 2008. Guelph's application was received by the Board on February 26, 2008.

The Board assigned the application file number EB-2007-0742 and issued a Notice of Application and Hearing dated March 13, 2008. The Board approved the intervention of the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC"). SEC and VECC were active in submitting interrogatories and argument. Board staff also posed interrogatories and made submissions. Guelph's reply argument was filed on July 3, 2008.

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

RATE BASE

For a distributor, rate base consists of net fixed assets (gross fixed assets minus accumulated depreciation and any contributed capital) plus an allowance for cash working capital. Net fixed assets are determined as the average of the beginning and the end year values, and reflect capital additions for the test year. The Board's guidelines stipulate a level of cash working capital equal to 15% of the sum of OM&A

controllable expenses and the cost of power. The cost of power consists of the commodity cost of power and transmission charges.

Below the Board deals with the following matters: Smart Meters; In-Service Dates; Lease and Sale of Building; and, Working Capital:

Smart Meters

The Company currently has a smart meter adder of $0.27 per month per metered customer included in the monthly service charge. In its original proposal, Guelph included capital expenditures of $2,765.452 in 2008 for the installation of smart meters. Guelph had also proposed to refund to customers monies collected in account 1555 through the rate adder.

In light of the comments by Board staff and intervenors to the effect that the Company is not one of the thirteen named utilities to undertake expenditures in installing smart meters, and the fact that it is unclear why the Company proposed to refund the seed money collected through the smart meter rate adder, the Company revised its proposals in its reply submission. The Company now requests that the Board increase the smart meter adder to $1.00, consistent with certain Board decisions for other distributors. Consequently, the Company would remove the amount of $2,765,452 in capital expenditures, $178,117 for related amortization expenses, the amount of $193,500 in Controllable OM&A expenses, and the PILs impact for setting 2008 rates, and it would not refund at this time to customers any amounts collected through the smart meter rate adder.

Board Findings

The Board accepts the Company's revised proposal as reasonable. The Company shall reflect the impacts of its revised proposal on its revenue requirement in its Draft Rate Order.

In-Service Dates

Board staff questioned the appropriateness of including in 2008 rate base capital expenditures associated with the new Rockwood Distribution Substation when the in-service date appears to be in the spring of 2009.

VECC noted that the Company appears to include capital additions to plant on a “cash basis” which results in no construction work in progress and capital spending being treated as “in-service” even when the associated projects are not. VECC argued that this is counter to conventional regulatory practice whereby rate base represents assets that are in-service and are used and useful. VECC stated that it is unable to determine the impact of the Company’s premature inclusion of capital spending in rate base for 2008. It appeared to VECC that, at a minimum, the following adjustments are required:

- The $933,903 in spending on the Rockwood Substation and related feeders.
- A portion of the planned spending on Wholesale Meter Points ($590,000).
- A portion of the planned spending on Expansions and Connections ($1,926,000).

VECC submitted that the Board should direct the Company to identify on a best effort basis the 2008 capital spending on projects that are not expected to be in-service as of year-end and exclude such spending from the determination of the 2008 rate base. VECC also submitted that the Board should direct the Company to correct its methodology with respect to rate base determination for future filings with the Board.

VECC also noted the following anomaly in the application and interrogatory responses that needs to be either corrected or explained by the Company. In response to Board staff interrogatory #3.1, the Company stated that a value of $105,998,804 was used for rate base in the calculation of rates. However, in Exhibit 7, Tab 1, Schedule 2 (page 1), the value used in establishing return on rate base appears to be $106,012,735.

In its reply submission, the Company stated that the Rockwood substation was planned to be constructed and “substantially completed” in 2008 and ”minor work” may be required in 2009 to energize it and thus it would be inappropriate to deny the recovery of any return on this significant asset for three or more years on account of the minor work.

The Company did not respond to VECC’s other submissions.

Board Findings

The Board’s conventional practice is that the rate base for a test year shall only include capital expenditures for projects that will be placed in service during the test year. Otherwise, expenditures for projects made in the test year with in-service dates beyond the test year attract an allowance for funds during construction, or AFUDC.

Therefore, the capital expenditure of $933,903 associated with the Rockwood Substation and related feeders, is to be excluded from determining rate base for the 2008 test year.

The evidence is unclear as to whether any portion of the planned spending on Wholesale Meter Points ($590,000) and on Expansions and Connections ($1,926,000) relate to in-service dates beyond the 2008 test year. With its filing of the Draft Rate Order, the Company is to remove any such portions. The Company shall provide sufficient information to enable verification of any adjustments.

With respect to the “anomalies” identified by VECC in reported rate base amounts, the Company shall ensure that its proposed rates in the Draft Rate Order reflect a revenue requirement that is underpinned by total capitalization being equal to rate base.

Lease and Sale of Building

Prior to June 2006, the Company operated out of facilities at Dawson road and Southgate centre. In June 2006, after the completion of Phase II of Southgate centre, all of Guelph’s facilities were consolidated into the Southgate office. Since then, the Dawson Road property was vacated and declared as surplus. The Company confirmed that the book value of the Dawson road property is still included in the 2008 rate base[1]. The Company also stated that the Dawson road property is currently being leased with revenues used to cover the operating, maintenance and amortization/depreciation expenses. Lease revenues are reflected as revenue offsets in the determination of the revenue requirement on which distribution rates are based.

Board staff stated that it is unclear whether the lease revenues also recover the cost of capital and associated taxes/PILs related to the Dawson Road property. If not, these costs are being borne by rate payers even though the facility is no longer “used and useful” for providing electricity distribution services.

In reply, the Company confirmed that the lease payments being collected do not recover the cost of capital and associated PILs. The Company stated that the property was sold on June 30, 2008 at a gross sale price of $1 million, with the net gain still to be determined. As a mitigation measure for ratepayers, the Company proposed to apply

[1] Response to Board staff interrogatory 3.3 b

one-half of the net gain generated from the sale of the property against its revenue requirement over three years.

Board Findings

It is clear that the property did not serve any operational purpose for the utility in 2008 and it is now sold. As such, it should not form part of rate base for 2008. Therefore the costs of its inclusion and the lease revenues should be removed from determining the Company's revenue requirement. Consistent with Board policy and practice[2], the net gains from the sale are to be equally shared between the shareholder and ratepayers. The amount owed to ratepayers shall be in a form of a rate rider from the effective date of the new rates to the end of the 2008 rate year (April 30, 2009). The Company shall reflect these findings in its Draft Rate Order.

Asset Management

Board staff noted that the Company does not have a formal documented asset management policy. Rather, it prioritizes sustaining expenditures based on condition assessments of various assets, annual equipment inspections, trouble reports, and reliability data. Further, major capacity additions may be planned 2 to 3 years in advance, but most work requires less than 12 months to implement.

VECC noted that the Company stated that it considers and reviews performance-related asset information annually such as data on reliability, asset age and condition, system load, forecast growth in residential and commercial connections and system configuration in order to determine investment needs and to prioritize each capital project. However VECC further noted that, despite this statement when VECC requested a schedule that set out the capital projects considered during the planning process and their relative priorities, the Company responded that it did not have one. Similarly, when requested by Board staff to provide its Asset Management Plan or Asset Condition Assessment, the Company responded that it does not have a formal asset management plan. VECC stated that the Company's capital planning process is not as rigorous as the Company's evidence suggests.

[2] For example, EBRO 341 (Consumers' Gas) June 30, 1976, EBRO 465 (Consumers' Gas) March 1, 1991, RP-2002-0133 (Enbridge Gas) November 7, 2003, RP-2003-0048 (Enbridge Gas) August 13, 2003, RP-2002-0147/EB-2002-0446 (NRG), RP-2002-0130 (Union Gas) May 8, 2003, EB-2005-0211/EB-2006-0081, Decision and Order, January 30, 2006. The Report of the Board on the 2006 Electricity Distribution Rate Handbook in RP-2004-0188, May 11, 2005 also established a general 50:50 sharing of the net proceeds of sales, with the exception of affiliated transactions.

In reply, the Company stated that it intends to develop a more formalized and documented process to reflect its operating practices in determining its capital expenditure program for its next rate rebasing application.

Board Findings

The Board expects the Company's capital expenditures proposal in its next rates rebasing application to reflect a more formalized and documented process, as the Company has stated it intends to develop.

Working Capital

Elsewhere in this Decision the Board makes adjustments to the proposed controllable OM&A expenses. Therefore, the cash working capital will need to be recalculated to reflect these adjustments.

In Chapter 2 of the Board's filing requirements for distributors, the Board suggests that when filing, the cost of power will be that available from the most recent Board-approved Regulated Price Plan ("RPP"). In the Board's view, there are benefits and no cost for the electricity distribution sector and for the Board to have one common cost of commodity power forecast. As long as the Board is required to produce a cost of power forecast in its responsibility to set RPP prices, and to the extent that the Board's forecast covers a period which can subsume, in whole or in large part, the test period for setting distribution rates, it makes good sense to utilize that forecast. Applying individual efforts by each distributor can lead to inconsistencies among distributors, can be expensive and is unnecessary. The Navigant forecast used by the Board to set RPP prices for May 1, 2008 onward covers most of the Company's test year filing. The Board prefers that the use of Navigant's forecast prices should be used in this case and it so finds. The Board directs the Company to reflect in its re-calculation of cash working capital an all-in supply cost of $0.0545/kWh derived from the Board's Price Report issued April 11, 2008.

OPERATING COSTS

Operating costs include OM&A expenses, depreciation and amortization expenses, payments in lieu of taxes ("PILs"), and any transformer allowance payments to customers. PILs taxes are proxies for capital and income taxes that, otherwise, would have to be paid if the distributor was not owned by a municipality or the Ontario government.

The final PILs tax allowance for ratemaking purposes is determined after the Board makes its findings on other relevant parts of the Company's application.

Operating costs also include interest charges on the Company's debt. These are dealt with in the cost of capital section of the Decision.

The Board deals below with the following issues: Controllable OM&A expenses; and, PILs.

Controllable OM&A Expenses

The table below shows the components of the proposed controllable OM&A expenses for 2008 and compares them with previous years.

Controllable OM&A Expenses ($)

	2006 Board-Approved	2006 Actual	2007 Bridge Year	2008 Test Year
Operations	1,117,605	781,808	1,037,615	1,223,322
Maintenance	1,517,143	1,594,353	1,498,775	1,433,534
Billing and Collecting	1,622,591	1,824,541	1,936,943	2,346,230
Community Relations	29,591	102,544	107,500	101,500
Administrative and General Expenses	4,507,329	4,375,397	5,206,226	4,855,752
Total Controllable Expenses	**8,794,259**	**8,678,643**	**9,787,059**	**9,960,338**

The issues raised by Board staff, SEC and VECC were related to the areas of: Regulatory Costs; Employee Costs, and Conservation and Demand Management spending ("CDM"). The concerns and the Company's responses are summarized below.

Regulatory Costs

The Company proposed $338,448 for ongoing regulatory costs of which $168,448 represents one-time regulatory costs associated with the 2008 rates application. Board staff and intervenors argued that the one-time $168,448 regulatory costs should be amortized over three years.

The Company argued that the $168,448 amount should be considered as part of the ongoing regulatory costs of operating the utility. The one-time costs associated with the 2008 rates case will be replaced by other regulatory costs, such as IRM rate applications, smart meter rate applications, cost allocation study improvement, and code compliance reviews. Alternatively, the Company should be authorized to track in a deferral account any additional regulatory costs that are not reflected in rates.

Employee Costs

Board staff and intervenors noted that there is a significant increase (14.6%) in labour costs in the 2008 test year compared to 2006, driven by an increase of 36% in non-unionized/student salary and wages, a 50% increase in incentive payments, and a 34% increase in employee benefits. VECC also raised the issue of training costs, and particularly training costs associated with communication training. In VECC's view these are one-time costs and should therefore be excluded from 2008 expenditures.

The Company responded that the increases in benefit costs were due to both an increased usage as well as a larger than usual claim in 2007. The Company also attributed the cost increase in 2008 to a maturing employee population and the escalation in overall health sector costs. As to the training costs, the Company argued there will rarely be no training costs in a given year.

Conservation and Demand Management ("CDM")

SEC raised questions as to why certain 2006 CDM expenditures should continue into 2008 and be included as part of OM&A since CDM activities are funded by the Ontario Power Authority ("OPA").

The Company responded that it supports a number of CDM activities by providing advice and education on such CDM activities as new lighting, use of capacitors, cogeneration opportunities and the use of solar energy as part of its ongoing business activities and that these costs are not funded through the OPA.

<u>Board Findings - CDM</u>

The Company's evidence did not identify the specific amount denoted to CDM activities. What is discernible from the evidence is that within account 5630 (Outside Services Employed) there is an undisclosed amount within the 2008 total budget amount of $347,500 for consulting fees related to the administration of the CDM program.

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* EB-2008-0037 state:

> "Funding through distribution rates will therefore continue to be available for programs designed to address local CDM opportunities or other programs for which no OPA funding is available. Where funding for a particular program is not available from the OPA at the time of application, distributors may apply to the Board for funding through distribution rates. If funding from the OPA subsequently becomes available for a program which was approved through distribution rates, the Board expects the distributor to apply to the OPA for program funding to replace the distribution rate funding. This expectation applies equally where OPA funding for a distribution rate-funded program becomes available prior to the end of the term of a CDM plan." (p.3)

The Company has not applied for CDM funding pursuant to the above guidelines, which contain specific filing and other requirements. Guelph has not provided evidence as to whether it has actually approached the OPA to determine if these costs are recoverable through its funding mechanism.

With respect to the latter, the Board notes that the EDA and the OPA have recently agreed to establish an LDC Community Initiatives Fund designed to provide LDCs with funding for community initiatives to promote electricity conservation awareness and to enhance or promote their standard programs. This additional OPA funding is available in the year's 2008, 2009, and 2010.

In the circumstances, the Board does not approve for purposes of setting 2008 distribution rates, the consulting costs for the Company's CDM programs that are proposed to be funded through distribution rates. Instead, the Board will permit the Company to track these expenditures in account 1508 – Other Regulatory Assets, under sub-account Consulting Costs for CDM Programs, and seek disposition at a later time. At that time, the Company will need to satisfy the Board that the requirements in the Board's guidelines in recovering any amounts from distribution rates have been met, including evidence that the Company could not recover its expenditures from existing or new OPA funding.

In its Draft Rate Order, the Company shall identify the amount included in account 5630 (Outside Services) related to the consulting costs for the Company's CDM programs and remove this amount from its 2008 OM&A budget amount.

Board Findings – Regulatory Expenses

The Company's budget for its own internal regulatory costs is proposed at $170,000, which the Board accepts. The Company argues that the $168,448 in one-time costs incurred for mounting its 2008 rates case will be replaced by other regulatory costs for other regulatory activities. The Board does not accept that the other regulatory activities identified by the Company justify an annual expense of $168,448 for non rebasing years, in addition to the $170,000 in internal regulatory costs.

As in certain other decisions dealing with cost of service applications[3], the Board directs the Company to amortize the $168,448 one-time costs over three years. One-third of this amount is $56,149. To allow for the time value of money, the Board will allow instead an expense of $60,000 to be reflected in 2008 rates. On the expectation that the 2008 approved revenue requirement will remain in place for three years, the Company will have recovered the full amount by the time it re-bases.

On the evidence adduced, the Board accepts that the Company will face some external regulatory expenses for dealing with ongoing regulatory matters. Based on the Company's proposed overall budget, and the Board's findings above, such expenses would amount to $108,448 ($168,448-$60,000) if no adjustment is made. The Board considers this amount to be excessive. The Board will instead allow for ratemaking purposes an additional amount of $50,000.

In the result, in addition to the $170,000 budget for internal regulatory costs, the Board allows a total of $110,000 ($60,000 +$50,000) to reflect amortization of the expenses incurred for mounting the 2008 rates case ($60,000) and for other external expenses ($50,000) for the rate years until next rebasing.

The Board does not accept the Company's proposal for a variance account. Deferral or variance accounts are reserved for situations where the risks of over or under recovery are greater than what is at risk here. Proliferation of variance accounts for these types of expenses would render the principle of a forward test year meaningless.

[3] For example; Oshawa PUC Inc. EB-2007-0710, and Hydro 2000 Inc. EB-2007-0704

Board Findings – General OM&A

Earlier in this Decision, the Board accepted the Company's proposal to remove $193,500 from Controllable OM&A associated with Smart Meters and the Board reduced regulatory expenses by $58,448. Later in this Decision, the Board finds that the Company's OM&A is overstated by $108,000 on account of pension costs. Therefore, the 2008 controllable expenses figure that the Board needs to assess is $9,600,390. This amount will likely be further reduced to reflect the removal of consulting fees for CDM activities in account 5630 (Outside Services Employed). In view of these adjustments, the resultant Controllable OM&A expenses increase in 2008 over 2006 actuals generally falls within the ranges found appropriate by the Board in other 2008 cost of service applications that were adjudicated by the Board and the Board will not make any further reductions.

Payments in Lieu of Taxes (PILs)

Adjustments for Interest Expense

In response to a Board staff interrogatory, it was revealed that the Company's proposed revenue requirement reflects an interest adjustment in the PILs calculations. In its calculation of PILs, the Company added back a net amount representing the difference between deemed and forecast actual interest expense, thereby raising taxable income and increasing the allowance for PILs in rates.

Board staff noted that this treatment was not accepted in the Decision and Order in the Oshawa PUC Networks Inc. application on the grounds that the pre-tax income used as the starting point for the regulatory tax calculation is after deduction of deemed interest. Thus, there is no need for the adjustment proposed by the Company.

In its reply submission, the Company stated that the add-back to taxable income has been made to reflect the fact that Guelph will have a lower interest deduction and hence a higher taxable income and PILs liability when it files its actual tax returns for 2008.

Board Findings

The Board has found in other proceedings that the addition and deduction of interest expense in the PILs calculations is not necessary[4]. Since pre-tax income, after the deduction of deemed interest, is used as the starting point for the regulatory tax calculation, there is no need for the adjustment proposed by the Company.

Guelph's approach would recover more interest through the deemed structure, and in addition, more PILs by using a lower forecast interest amount. The regulatory approach to the application needs to be internally consistent, and thus the Board denies the net interest adjustment for purposes of calculating regulatory PILs taxes to be recovered from ratepayers.

Change in balance sheet liabilities for future post-employment benefits

Guelph's evidence has shown the changes in reserves, or liabilities, for future post-employment benefits as part of the calculation of the income tax PILs allowance. The Company provided an analysis of the changes in the reserves in its reply submission. From 2003 to 2004, the accrued liability increased by 7.66%. It increased by 6.58% in 2005, by 5.65% in 2006 and by 5.54% in 2007. Guelph's $8,707,467 forecast of its 2008 reserve is based on the use of the simple average increase (6.36%) of four years (2004-2007).
Guelph has also shown in its audited financial statements that its ending 2007 balance was $8,169,000 and the ending 2006 balance was $7,757,000. The net difference between these two amounts is $412,000. The Company used an estimate of $8,187,000 for 2007 in its PILs evidence.

The difference between the 2008 reserve amount of $8,707,467 and the original 2007 amount of $8,187,000 is $520,467. Guelph applied to recover this difference in its PILs tax allowance. The difference between the net amount of $412,000 and $520,467 is $108,467. Using the final number for 2007 of $8,169,000, the differences increase to $538,467 and $126,467 respectively.

The Company stated that it undertook an actuarial valuation of its post-retirement costs for the years 2005 to 2007.

---

[4] Halton Hills, EB-2007-0696; PUC Distribution, EB-2007-0931, EB-2007-0723; Oshawa PUC, EB-2007-0710 Rate Order; Lakefront, EB-2007-0761 Rate Order.

Board Findings

Future post-employment benefits are based in part on actuarial assumptions and calculations. Many of the underlying assumptions are also made by management of the Company. This forecast expense is an accounting estimate, and, as such, is subject to change based on many factors. From year to year the change is caused by estimates of the future liabilities and by the amounts actually paid to people who are entitled to current period benefits.

Given that Guelph undertook an actuarial valuation for 2007 suggests that the 5.54% factor shown for 2007 is more reliable factor than the average four-year factor of 6.36% used by the Company to forecast its 2008 liability for post-employment benefits. In addition, the factors have shown a downward trend which does not appear to have been reflected in the assumptions for 2008.

The Board finds that the increase in the actual 2007 liability over 2006 of $412,000 is an acceptable forecast for 2008. Guelph shall change the reserves in its 2008 PILs calculations to reflect only an increase of $412,000 over its actual 2007 balance of $8,169,000.

The increased post-employment benefit costs of $520,467, as reflected in the change in reserves shown above, would also have been included in the forecast 2008 compensation costs in the OM&A section of the application. Therefore, the Company's 2008 OM&A budget is overstated by $108,000 on this account.

Change in Tax Legislation

On December 13, 2007 the Ontario government issued an Economic Outlook and Fiscal Review. The document included corporate tax measures to reduce income tax on small businesses and to modify aspects of the capital tax calculations. The legislation, Bill 44, received Royal Assent on May 14, 2008. The effective date for the decrease in the capital tax rate from 0.285% to 0.225% was changed retroactively to January 1, 2007.

The Company used the previous rate of 0.285% in its evidence. In its reply submission, the Company stated that it will use the new capital tax rate of 0.225% when it files its Draft Rate Order.

Board Findings

Guelph shall reflect in its Draft Rate Order the new combined income tax rate for 2008 of 33.5%; the Ontario capital tax exemption amount of $15 million and the new rate of 0.225%; and, the new applicable CCA class rates.

LOAD FORECAST

The Company's load forecast was developed using a weather-normalized average consumption ("NAC") estimate for the weather-sensitive rate classes multiplied by a customer count forecast for that rate class. The NAC value is based on 2004 consumption data that was generated by Hydro One using Hydro One's weather normalization model for the cost allocation initiative previously undertaken by the Board. The Company's forecast for customer growth was based on historical data from 2002 to 2006 and projected data for 2007 and 2008. For rate classes that are not weather-sensitive (Street Lighting, Sentinel Lighting and Unmetered Scattered Load) the Company used the average annual growth rate in energy for the years 2004-2006 to project 2007 and 2008 loads.

Board staff observed that the Company's methodology utilized only a single year of weather-normalized historical load to determine the future load. Board staff noted that this assumed that no CDM improvements had occurred over the past few years and that none were expected in the immediate future, and might therefore result in an overestimation of load. VECC shared Board staff's concerns but stated that it was not clear if a better alternative exists at this time. VECC also observed that based on an interrogatory response, the Company appears to have revised its customer count for 2008.

In its reply submission, the Company stated its willingness to consider other multi-year weather-normalization methodologies provided these had broad acceptance. The Company submitted that it had not been able to identify any material change in customer usage patterns. With respect to VECC's comment regarding a revised customer forecast, the Company noted that the customer count estimates for 2007 increased for two rate classes, but decreased in one rate class but the net impact to the overall load is only eight one hundredths of one percent (0.08%).

Board Findings

The Board notes that the Company's forecasting methodology is similar to that used by other distributors, which was accepted by the Board. The Board has noted Board staff's concerns, but the process to obtain this data was an intensive effort for all parties involved and the Company's proposal is leveraging the value of this work. The Company has not expressed concern that its load may be overestimated. In fact, the Board notes that the Company's attempts to produce weather-normalized usage values by customer class for 2004 through 2007 using the IESO's province-wide weather normalization factors produced results that were not materially different. The Board also accepts that the impact on load from the updated customer count estimate for 2007 is immaterial.

The Board therefore accepts the Company's original customer and load forecast for purposes of setting 2008 rates.

OTHER MATTERS

In this section, the Board deals with the following issues: Retail Transmission Service Rates; and, Line Losses.

Retail Transmission Service ("RTS") Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order, setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their RTS rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities.

Guelph proposed to reduce its rates for Retail Transmission Rate – Network Service ("RTR-N") and Retail Transmission Rate – Line and Transformation Connection Service ("RTR-C") by 21% and 6% respectively.

Board staff submitted that the Company's adjustment methodology fails to take into account the fact that it has tended to have a shortfall in the Network variance account (account 1584) and a sizable surplus in the Connection variance account (account 1586).

In response, the Company revised its proposals and requested that the RTR-N and RTR-C be reduced by 20% and 7% respectively instead of its original proposal.

Board Findings

The Board finds Guelph's revised proposal reasonable and accepts it.

Line Losses

In its application, the Company proposed a Total Loss Factor ("TLF") of 1.0452 for Secondary Metered Customers <5000kW and 1.0347 for Primary Metered Customers <5000kW. For Customers >5000kW, the Company proposed a TLF of 1.0060 for Primary Metered Customers and 1.0161 for Secondary Metered Customers. The TLF of 1.0452 for Secondary Metered Customers <5000kW is based on a Distribution Loss Factor ("DLF") of 1.0389 and a Supply Facility Loss Factor ("SFLF") of 1.0060. The DLF is based on an average of actual DLFs for the partial year 2002 plus four year period 2003 to 2006.

The Company is a partially embedded distributor whereby the portion of its distribution system that services loads within the Village of Rockwood is embedded within the service territory of Hydro One's distribution system and the portion that services loads within the City of Guelph is directly connected to the transmission system. The Village of Rockwood represents approximately 4% of the Company's total system load, while the City of Guelph represents approximately 96%. The SFLF of 1.0060 includes losses incurred in the Hydro One distribution system.

Board staff submitted that in the determination of the DLF, the losses for 2002 are not based on a full 12 months, and, in addition, seem anomalous to the other years (2003 to

2006) used in the determination of the average DLF. Both Board staff and VECC submitted that a four year average should be used. In its reply submission, the Company responded that the calculation should be based on a five year average consistent with the industry and its previous filing and that the purpose of using an average in a calculation is to smooth out anomalous results.

Board Findings

The Board is of the opinion that given the circumstances of this case, a DLF based on a four year average would be more appropriate. Based on a four year average DLF of 1.0342, the Board approves a TLF of 1.0404 for Secondary Metered Customers <5000kW. Reflecting a ratio of 0.99 between the primary and secondary factors in the Company's original application, the Board approves a TLF for Primary Metered Customers <5000kW of 1.0300.

CAPITALIZATION / COST OF CAPITAL

The Board's guidelines for capitalization and cost of capital components are set out in its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 (the "Board Report"). The Board Report sets out the formulas and policy guidelines to be used to determine capitalization of rate base, the return on equity and the deemed costs of long term and short term debt and sets out the process by which these figures will be updated.
The Board announced updated cost of capital parameters on March 7, 2008. In setting the ROE for the establishment of 2008 rates, the Board has used the Consensus Forecasts and published Bank of Canada data for January 2008, in accordance with the Board's guidelines. In fixing new rates and charges for Guelph, the Board has applied the policies described in the Board Report. Based on the final 2007 data published by *Consensus Forecasts* and the Bank of Canada, the Board has established the ROE to be 8.57%.

The Board Report also established that the short-term debt rate should be updated using the methodology in section 2.2.2 of the Board Report. The Board has set the short-term debt rate at 4.47% using data from *Consensus Forecasts* and the Bank of Canada for January 2008.

The Board Report also established that the deemed long-term debt rate should be updated using the methodology in Appendix A of the Board Report. The deemed long-term debt rate acts as a proxy for or ceiling on the allowed debt rate for new, affiliated or variable rate debt, and may be applicable for establishing the embedded cost of debt in the test year period depending on the nature of the distributor's debt financing. The Board has set the deemed long-term debt rate at 6.10% based on data from Consensus Forecasts and TSX Inc. for January 2008.

Board staff submitted that the Company's evidence is not clear and therefore Board staff is unable to comment on whether the Company's proposals are consistent with the Board's policy guidelines.

Board staff noted that the 2008 test year capital structure shown by the Company in its evidence uses an "actual" structure of 50.5% common equity and 49.5% long-term debt, with no short-term debt. When asked to provide its deemed capital structure, the Company referred Board staff back to the same information. In Board staff's submission, the deemed capital structure used for setting the Company's 2008 revenue requirement and distribution rates to be consistent with Board policy should be composed of 46.7% equity and 53.3% debt, the latter composed of 49.3% long-term debt and 4.0% short-term debt and that the cost rate for the short-term debt should be 4.47%.

Board staff noted that the Company has proposed a long-term debt rate of 6.25%. Its debt, in 2008, is forecasted to consist of two instruments:

- A long-term loan due to the City of Guelph with a principal of $30 million at a rate of 6.25%; and
- A demand note due to Guelph Hydro Inc. with a principal of $12.6 million and a proposed rate of 6.25%.

Board staff noted that Section 2.2.1 of the Board Report states that for all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate and that when setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for a change. With respect to the $30 million loan due to the City of Guelph, Board staff noted the following documentation in Notes to Guelph Hydro's Audited Financial Statements ("AFS") for 2006 and 2007:

> "Notes payable are due to the City of Guelph and bear interest at 7.25% for the period from January 1, 2006 to April 30, 2006 and 6.25% for the period from May 1, 2006 to December 31, 2006. These were the maximum recoverable interest rates allowed to local distribution companies by the OEB in 2006.
>
> There are no principal repayment terms or specified maturity date for the notes payable. In December 2006, the Company repaid $7,690 [thousands] of principal back to the City of Guelph."

And

> "Notes payable are due to the City of Guelph and bear interest at an OEB approved rate of 6.25% for the period January 1, 2007 to December 31, 2007.
>
> The principal repayment terms or specified maturity date for the notes payable is no later than eighteen (18) months from the date of demand in writing by the City of Guelph."

Board staff submitted that the Company has not provided any evidence on the actual term of the demand note due to the City of Guelph. Board staff also noted that the demand note of $12.6 million to the parent company has not previously been reviewed by the Board.

Board staff submitted that, based on the evidence on the record, the existing debt consists of demand notes. Based on Board policy, the Company's existing debt would attract the updated deemed debt rate of 6.10% for setting 2008 rates.
In its reply submission, the Company confirmed that it requests 49.3% long-term debt, 4% short-tern debt, and 46.7% equity as the deemed capital structure. The Company stated that it had used a cost rate of 5.14% for short-term debt and 8.86% for equity when it filed its evidence with the anticipation that these cost rates would be updated in accordance with the Board's guidelines.

The Company reiterated that the Company and the City of Guelph consider the two debt instruments to be long-term promissory notes and that the Board Report provides the following:

> "The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt."

The Company argued that, since the interest rate was approved by the Board in the 2006 EDR decision, the rate of 6.25% should remain in place for the Company's long – term debt.

Board Findings

The Board approves the capitalization of rate base and cost of capital as clarified by the Company. The deemed capital structure of 49.3% long-term debt, 4% short-term debt and 46.7% equity complies with the Board's direction to phase in a target 60:40 debt:equity ratio. The Company clarified that the cost rates for short term and equity need to updated as per the Board's guidelines. The only issue then is what should be the cost of long-term debt for purposes of setting rates.

The cost rate associated with the $12.6 million demand note has not previously been reviewed by the Board. It is a demand note, with an affiliate, and the Board's policy in this regard is from Section 2.2.1 of the Board Report. That section states that "for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate." The updated rate is 6.10%.

With respect to the $30 million affiliate debt, it is clear from the Company's 2006 and 2007 audited financial statements that the interest rates payable to the City on that date mirrored the cost levels approved by the Board. It is also clear from the above financial statements that there is no specified maturity date. This would also make this debt a demand note. The fact that there is an 18-month notice required for repayment does not make it a long-term debt instrument as the Company believes. The Company's argument that since the Board had approved a 6.25% cost rate in 2006 distribution rates renders in effect this cost rate fixed in perpetuity is not reasonable given the demand nature of the debt. The Board also deems a cost rate of 6.10% for this debt.

In the result, the Board approves the following capitalization and cost of capital for purposes of setting 2008 distribution rates.

Approved 2008 Capital Structure and Cost of Capital

Capital Component	% of Total Capital Structure	Cost (%)
Short-Term Debt	4.0	4.47
Long-Term Debt	49.3	6.10
Common Equity	46.7	8.57
Total	100.0	

COST ALLOCATION AND RATE DESIGN

Revenue to Costs Ratios

The results of a cost allocation study are presented in the form of revenue to cost ratios. The Company filed results of a cost allocation study in the Informational Filing EB-2007-0001, somewhat modified, as shown in Column 1 in the table below, based on its 2006 approved revenue requirement and rates. In its current application, the Company proposed the revenue to cost ratios for its rate classes shown in column 2 in the table below. The Board's target ranges contained in the Report of the Board *Application of Cost Allocation for Electricity Distributors November 28, 2007* (the "Cost Allocation Report"), are shown in column 3.

Revenue to Cost Ratios (%)

	Col 1 **Modified Informational Filing / Run 2**	**Col 2** **Per Application**	**Col 3** **Board Target Range**
Residential	93	93	85 – 115
GS < 50 kW	137	119	80 – 120
GS 50 - 999 kW	131	126	80 – 180
GS 1000 - 4999 kW	83	97	80 - 180
Large Use	65	85	85 - 115
Street Lighting	11	42	70 – 120
Sentinel Lighting	75	71	70 – 120
Unmetered Scattered Load (USL)	61	81	80 – 120

Column 2 shows that only the Street Lighting class remains outside the Board's target range shown in Column 3.

Board staff and VECC noted that in the Sentinel Lighting class the ratio is directionally moving away from 100%.

SEC submitted that there will be a significant cross-subsidization with the GS<50kW and the GS>50 kW classes over contributing and that the Company should immediately move the ratios to 100%.

In response to Board staff's request for the Company to clarify the data it had presented, the Company submitted a revised table that reflected a number of corrections in the data in Column 1. The revised table is shown below.

Amended Revenue to Cost Ratios (%)

	Col 1 **Modified Informational Filing / Run 2**	**Col 2** **Per Application**	**Col 3** **Board Target Range**
Residential	92	93	85 – 115
GS < 50 kW	137	119	80 – 120
GS 50 - 999 kW	127	127	80 – 180
GS 1000 - 4999 kW	97	97	80 - 180
Large Use	71	85	85 - 115
Street Lighting	18	42	70 – 120
Sentinel Lighting	60	71	70 – 120
Unmetered Scattered Load (USL)	69	81	80 – 120

Board Findings

As the Board has noted in the Cost Allocation Report, cost causality is a fundamental principle in setting rates. However, observed limitations in data affect the ability or desirability of moving immediately to a revenue to cost framework around 100%. The

Board's target ranges are a compromise until such time as data is refined and experience is gained.

In other decisions, the Board has adopted the general principle that, where the proposed ratio for a given class (Column 2) is above the Board's target range (Column 3), there should be a move of 50% toward the top of the range from what was reported in its Informational Filing (Column 1). None of Guelph's classes are in this situation. Where the revenue to cost ratios in the Informational Filing (Column 1) are below the Board's ranges (Column 3), the rates for 2008 shall be set so that the ratios for these classes shall move by 50% toward the bottom of the Board's target ranges. Only the Street Lighting class (at 42%) is in this situation. The Board directs the Company to raise rates for the Street Lighting class to achieve a revenue to cost ratio of 44% for 2008. The Board expects the Company to reach the 70% Board target range by 2010 in equal increments.
The additional revenue from the Street Lighting class shall be allocated in such a manner as to reduce the revenue to cost ratios for the GS<50 kW and the GS 50-999 kW classes in proportion to their revenues.

Fixed Charges

The Company proposed to maintain the monthly fixed customer charges for each class at their current levels, with the exception of the GS<50 kW class which would increase from $11.11 to $12.26 to comply with the Board's guideline regarding fixed charges.

SEC submitted that the proposed fixed charge is too low. VECC on the other hand supported the Company's proposed charge.

<u>Board Findings</u>

The Board accepts the Company's proposals. The proposed fixed charge for the GS<50 kW rate class is consistent with the Report of the Board on the application of Cost Allocation for Electricity Distributors.

Transformer Ownership Allowance

Guelph proposed to change the monthly transformer ownership allowance from $0.60 per kW to $0.72. Guelph proposed to offer the allowance only to the GS 50 – 999 kW class. The allowance is based on the cost allocation study results filed with the response to Board staff interrogatory #10.3, Appendix F.

Staff submitted that Guelph's cost allocation and the resulting transformer ownership allowance is valid for the existing situation. However, Board staff stated that, in reviewing the Conditions of Service, it was unclear whether the Conditions contain a specific requirement that any customer with demand higher than 1000 kW will provide its own transformer, or whether customers in the two larger classes would have the option of receiving transformer service from the Company.

In response, the Company noted that Table 1 in Section 5 in the Conditions of Service define the type of transformer available for General Service, whereas Table 2 defines the maximum size of transformer available from the Company, implying that anything larger would require customer ownership. The Company intends to clarify this matter by updating its Conditions of Service in its next rebasing application to define which rate classes will be provided transformers by the Company.

Board Findings

The Board accepts the Company's proposals regarding availability of transformer service and the ownership allowance rate. The Company need not wait for the next rate rebasing application to provide the clarification in its Conditions of Service. The Company should revise its Conditions of Service now and submit them as part of its Draft Rate Order.

Harmonization of Rates

The Company proposed to harmonize the rates of the former Guelph Hydro Systems Inc. and Wellington Electrical Distribution Company.

Board staff stated that it has reviewed the calculated bill impacts and has no concerns regarding the Company's proposal.

Board Findings

The Board approves the Company's harmonization proposal. In so finding, the Board has noted that neither Board staff nor any intervenor raised any issues with the Company's proposal and the rate impacts of the proposal.

DEFERRAL AND VARIANCE ACCOUNTS

Disposition

The following table shows the deferral and variance account balances Guelph is seeking to recover in its application[5]. The balances are as of December 31, 2006 plus interest to April 30, 2008. (The balances in parentheses denote credit to customers)

Deferral and Variance Accounts Proposed for Disposition

ACCOUNT #	ACCOUNT NAME	BALANCE REQUESTED FOR DISPOSITION
1508	Other Regulatory Assets	$748,747
1525	Miscellaneous Deferred Debits	$7,084
1550	Low Voltage Variance	$10,316
1570	Transition Costs	$19,234
1571	Pre-Market Opening Energy	$4,635
1580	RSVA - WMSC	($759,297)
1582	RSVA – One Time WMS	$92,221
1584	RSVA - RTNC	$201,496
1586	RSVA - RTCC	($964,418)
1588	RSVA - Power	$2,615,966
1518	RCVA - Retail	($11,840)
1548	RCVA - STR	($32,796)
TOTAL		**$1,931,288**

Guelph proposed to collect these amounts from ratepayers over three years through rate riders.

[5] The Company initially sought disposition of the balance in the 1555 Smart Meter account. Earlier in this Decision, the Board accepted the Company's revised proposal not to dispose of this account at this time.

As a result of the Board's findings below, the only accounts to be disposed are 1508, 1525 and 1550. The total balance to be recovered is $766,147. This amount will be cleared as proposed by the Company but over the period starting with the effective date of this decision and ending April 30, 2010.

RSVA and RCVA accounts

Under section 78 (6.1) of the *Ontario Energy Board Act, 1998*, the Board is obligated to review each quarter the balance in Account 1588, RSVA – Power. The Board recently announced that it intends to launch an initiative on a review and disposition process. The Board also indicated that it is considering extending this initiative to include all the RSVA accounts. The Board, therefore, does not approve clearance of these accounts at this time.

The Board's announced review noted above may also include RCVA accounts. For that reason, the Board finds that it would be appropriate to await the outcome of this initiative and therefore will not order disposition of the Company's RCVA accounts in this proceeding.

The Board also notes that Board staff identified discrepancies in Guelph's evidence in the reported balances in accounts 1580, 1582 and 1586 and that the Company acknowledged that there were inadvertent omissions and incorrect statements made by the Company in its evidence. The Board expects that the Company will provide the correct balances at the time of application for disposition.

Account 1570 (Transition Costs) and Account 1571 (Pre-Market Opening Energy)

Board staff and VECC raised questions as to the reasons why the 2006 EDR Board-approved amounts for regulatory asset recovery to Account 1590 resulted in a residual balance in these two accounts.

In its reply submission, the Company acknowledged that there are no balances to be disposed of in these accounts.

Board Findings

The Board accepts the removal of any residual balances in the 1570 and 1571 accounts.

There have been numerous omissions and errors in the Company's original application as well as insufficient information to confirm the accuracy of the information presented, particularly related to accounting matters. In this regard, the Board expects the Company to be more diligent and attentive when filing material with the Board.

Continuation of Deferral and Variance Accounts

Guelph requested approval for the continuation of existing deferral and variance accounts.

Board staff noted that the Board has already approved and defined, through the Accounting Procedures Handbook ("APH") and associated letters, the period and functionality of deferral and variance accounts in the electricity distribution sector. Therefore, it is not necessary for Guelph to request permission to continue using open deferral and variance accounts as per the APH.

Board Findings

The Board agrees with Board staff's submissions. No distributor-specific approvals are required for existing accounts that are named in the APH or in other Board communications.

SHARED SAVINGS MECHANISM ("SSM") AND LOST REVENUE ADJUSTMENT MECHANISM ("LRAM")

In its original application, Guelph requested approval to recover an LRAM amount of $71,676 and an SSM amount of $47,360. Guelph proposed that the recovery be through a combined rate rider over three years, to apply to the Residential and Unmetered Scattered Load rate classes. As a result of interrogatories, the Company revised the LRAM amount to $80,869 and the SSM amount to $23,348.

Neither Board staff nor intervenors objected to the Company's proposals.

Board Findings

The Board finds that the Company has satisfied the Board's filing and disposition requirements for SSM and LRAM amounts. The Board approves an LRAM amount of $80,868.60 and an SSM amount of $23,348.09. These amounts will be cleared as proposed by the Company but over the period starting with the effective date of this decision and ending April 30, 2010.

IMPLEMENTATION MATTERS

The Board has made numerous findings throughout this Decision. These are to be appropriately reflected in a Draft Rate Order prepared by the Company.

The Board issued an Interim Rates Order on April 21, 2008 declaring rates interim as of May 1, 2008. However, the Company was more than six months late in filing its application and did not adhere on to the Board's directed timelines in responding to interrogatories, resulting in further delays. Given the time that is typically required to settle matters before the final Rate Order can be issued, the Board has determined that the effective date of the new rates shall be September 1, 2008. The current rates therefore shall continue to be effective until August 31, 2008. For additional clarity, the revenue deficiency arising from this Decision from May 1, 2008 to August 31, 2008, is not recoverable from customers. This decision is consistent with other Board decisions[6] where the applicants were substantially late in filing their applications from the August 15, 2007 date. Given the above effective date, the rate riders in connection with the disposal of the balances in the deferral/variance accounts shall be calculated in such manner so that they will reflect full recovery of the balances from September 1, 2008 to April 30, 2010.

The September 1, 2008 effective date is predicated on the Company complying with the timelines set out at the end of this Decision and its Draft Rate Order properly reflects the Board's findings. Should these not be reasonably adhered to, the effective date may be further delayed.

In filing its Draft Rate Order, it is the Board's expectation that the Company will not use a calculation of a revised revenue deficiency to reconcile the new distribution rates with

[6] For example, Brantford Power Inc. EB-2007-0698, Lakefront Utilities Inc. EB-2007-0761, Chapleau Public Utilities Corporation EB-2007-0755

the Board's findings in this Decision. Rather, the Board expects the Company to file detailed supporting material, including all relevant calculations showing the impact of this Decision on the Company's proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. The Draft Rate Order shall also include customer rate impacts and detailed calculations of the revised variance account rate riders.

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

1. The Company shall file with the Board, and shall also forward to SEC and VECC, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 14 days of the date of this Decision.

2. SEC and VECC may file with the Board and forward to the Company any responses to the Company's Draft Rate Order within 20 days of the date of this Decision.

3. The Company shall file with the Board and forward to SEC and VECC responses to any comments on its Draft Rate Order within 26 days of the date of this Decision.

A cost awards decision will be issued after the steps set out below are completed.

4. SEC and VECC shall file with the Board and forward to the Company their respective cost claims within 26 days from the date of this Decision.

5. The Company may file with the Board and forward to SEC and VECC any objections to the claimed costs within 40 days from the date of this Decision.

6. SEC and VECC may file with the Board and forward to the Company any responses to any objections for cost claims within 47 days of the date of this Decision.

The Company shall pay the Board's costs of, and incidental to, this proceeding upon receipt of the Board's invoice.

DATED at Toronto, July 31, 2008
ONTARIO ENERGY BOARD

Original signed by

Gordon Kaiser
Presiding Member

Original signed by

Paul Vlahos
Member