Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2007-0698

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 Brantford Power 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: Paul Vlahos
Presiding Member

Bill Rupert
Member

DECISION

Brantford Power Inc. ("Brantford" or "the Company") is a distributor of electricity that operates within the City of Brantford. The Company is 100% owned by Brantford Energy Corporation, which in turn is 100% owed by the City of Brantford. The Company contracts services from the City of Brantford.

Brantford 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 Brantford 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, Brantford was to file its application and evidence by August 15, 2007 to provide sufficient time so that its new rates can be implemented May 1, 2008. Brantford's application was received by the Board on December 20, 2007.

The Board assigned the application file number EB-2007-0698 and issued a Notice of Application and Hearing dated January 9, 2008. The Board approved the intervention of the School Energy Coalition ("SEC"). SEC was active in submitting interrogatories and argument. Board staff also posed interrogatories and made submissions. Brantford's reply argument was received on June 17, 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.

The Board deals below with the following matters: expenditures on smart meters; expenditures on conventional meters; expenditures on other projects; and, working capital.

Expenditures on Smart Meters

The Company currently has a smart meter adder of $0.28 per month per metered customer included in the monthly service charge and proposed to continue this adder at the same level.

In response to Board staff interrogatory #5.2a, the Company stated that it does not intend to install any smart meters in 2008, but that it is planning to do so in 2009. Costs associated with smart metering activities are being recorded in Variance Account 1555.

Board Findings

Unlike some other distributors (for example, Lakefront and PUC Distribution), Brantford is not forecasting installation of any smart meters during the 2008 test year. For this reason, the Board finds that the Company's proposal to continue the existing $0.28 per month per metered customer is appropriate and is therefore approved.

It is unclear from the record whether the Company has included any expenditures associated with smart meters in rate base or in its revenue requirement in general. If it has, the Company is directed to remove these in preparing its Draft Rate Order. Until a further order by the Board, expenditures associated with smart meters shall be recorded in Variance Account 1555, which shall be cleared at a later time.

Expenditures on Conventional Meters

The table below shows the capital expenditures associated with installing new conventional meters for new customers or replacing expiring conventional meters.

Meter-related Capital Expenditures

	Number of Meters	**Capital Expenditures**
Residential and General Service < 50 kW meter seal expirations	2,026	$157,872
Meters for new customer connections, non-demand type meters and other-meter-related equipment	1,104	$289,589
Total	**3,130**	**$447,461**

Source: Brantford's Reply Submission, page 24, June 17, 2008

Board staff calculated that over half of the proposed installations are for new customer connections and the other half because of seal expiries. Board staff expressed concern that meters with seal-expiring dates are being replaced with conventional meters, which will in turn will be replaced soon by smart meters and will therefore be stranded. SEC shared Board Staff's concerns.

The Company submitted that it has an obligation to maintain compliance with the legal requirements of Measurement Canada.

<u>Board Findings</u>
As the Board has stated in other decisions[1], an expired meter does not necessarily require replacement of the meter; rather, the meter will be subject to further testing. The Board notes Brantford's statement that it would consider making an application to Measurement Canada for Temporary Permission to maintain in place the meters whose seals have expired pending the determination of smart meter implementation in its service area. The Board considers this to be not only a prudent approach but a necessary step for the Company to take.

Rather than including the $157,872 in capital expenditures in replacing the 2,026 expired meters with conventional meters as the Company proposed in the event that the Company does not receive Measurement Canada approval, the Board directs the Company to exclude these expenditures for the purposes of setting 2008 rates. For additional clarity, operating costs related to meter seal verification are legitimate costs and should continue to be included in 2008 rates.

The remaining $289,589 in capital expenditures for metering is accepted by the Board for setting 2008 rates.

Other Capital Expenditures
Using Exhibit 2/Tab 3/Schedule 1, pages 12, 22, and 32, the Company's response to Board staff interrogatory #3.3a, and the Company's reply submission, paragraphs 65 and 75, the table below shows the capital expenditures for 2008, with prior years since 2006, excluding expenditures for replacing expired meters in 2008.

	2006	**2007 Bridge**	**2008 Test**
Capital Expenditures excluding Smart meters and Metering	$5,297,935	$5,429,489	$4,863,642
Capital Expenditures excluding smart meters and Replacement of Expired-Seal Meters	N/A (not available)	N/A	$5,153,231

Board staff noted that the Company has provided a capital budget extending to 2013 but the Company acknowledged that it does not have an Asset Management Plan.

In its reply submission, the Company noted that while it currently does not have a formal asset management plan, it undertakes asset condition reviews as a normal business

[1] See, for example, the Board's Decision on Lakefront Utilities Inc.'s 2008 distribution rate application considered in file EB-2007-0761, pages 12-15.

practice. The Company also noted that it intends to develop a formal asset management plan for future capital spending.

Board Findings

The Board finds that the Company has reasonably substantiated its proposed capital expenditures in areas other than those commented earlier by the Board and such expenditures are therefore approved for ratemaking purposes. For additional clarity, the Board approves 2008 capital expenditures of $5,153,231 for setting 2008 rates.

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	580,929	793,192	1,176,926	1,090,412
Maintenance	2,006,136	1,521,089	1,870,016	1,884,681
Billing and Collecting	905,817	1,900,231	2,145,847	2,302,509
Community Relations	446,549	326,422	190,140	139,091
Administrative and General Expenses	3,437,561	1.984,087	2,634,367	2,783,384
Total Controllable Expenses	**7,376,992**	**6,525,021**	**8,017,296**	**8,200,077**

The issues raised by Board staff and SEC were related to the areas of: Compensation; Purchase of Services; Shared Services; and, Regulatory Costs. These concerns and the Company's responses are summarized below.

By way of general comment, SEC noted that in comparing 2006 Board-approved OM&A to 2006 actual, consideration should be given for the fact that the Company changed its overhead capitalization policy resulting in lower OM&A costs and increasing capital expenditures.

Compensation

The Company's evidence showed a proposed increase of about $700,000 or 14% in total aggregated compensation costs from 2006 actual to 2008 proposed. Board staff invited the Company to clarify certain inconsistencies in the information presented. Also, Board staff noted that there is a significant differential in the Board-approved and actual level in 2006 and invited the Company to comment on that difference and whether it is the driver for the 2008 level. SEC stated that it shared Board staff's concerns regarding inconsistencies in the Company's evidence.

SEC expressed concern that the Company is essentially treating increases in salary incurred by the service provider, the City of Brantford, as if they were increases in its own internal compensation costs. It is not clear, according to SEC, from the Services Agreement how these costs are passed on.

In its reply submission, the Company noted that the Total Aggregated Compensation Costs table was not updated to reflect final costs and that Board staff's calculations are correct.

The Company explained other differences as a result of the estimation process and the attempt to directly respond to the interrogatories.

The Company explained the difference in the 2006 Board-approved and actual amounts being the result of:

- Annual economic adjustments for 2005 and 2006;
- Outcomes of the salary re-evaluation for management and non-union staff which were implemented as at January 1, 2006; and
- Increases in staff complement.

Purchase of Services

The Company purchased $2.5 million in services in 2006 and projected purchases of $3.3 million in 2008 (approximately 40% of total controllable expenses), a 34% increase in the two-year period. Of these, the costs associated with the City's direct services are projected at $2.898 million in 2008, an increase of $778,000 or 37% since 2006. The City's direct services are for operations and maintenance, electricity engineering, metering and settlement, administration and regulatory affairs.

Board staff expressed concern that there is not enough evidence or clarity in the evidence to support the significant increases proposed by the Company.

SEC noted the Company's response to SEC's interrogatory #17a to the effect that the Company has budgeted an additional $132,000 "for repairs and maintenance to the distribution system deferred from previous years as a result of cost containment activities" and submitted that ratepayers in 2008 should not have to pay for work that should have been done in the past.

SEC noted that the Service Agreement with the City stipulates that, in addition to the direct and indirect costs, a further 10% of such costs shall be paid to the City. SEC noted that the Company characterized this mark up as an approximation for "market conditions" in the actual Service Agreement and submitted that this mark up is contrary to the Board's Affiliate Relationships Code. SEC also submitted that, in future, if the Company seeks to recover costs that are largely based on costs allocated from its affiliate, the Company should include detailed costs from its affiliate to support these costs as prescribed in the Board's Affiliate Relationships Code.

With respect to the $132,000 expense mentioned above, the Company submitted in its reply argument that it is appropriate to include this expense in 2008 when the work is performed.

With respect to the 10% mark-up, the Company argued that such remuneration represents the fair market value for the services it receives from its affiliate pursuant to the current Service Agreement. It noted that its Transfer Pricing Study under way will be completed in 2009 and that the Service Agreement stipulates compliance with the Board's Affiliate Relationships Code. In this regard, and in the context of the new section 2.3.4.3 of the updated Affiliate Relationships Code to be effective August 16, 2008, the Company will be providing in its next rebasing application detailed cost information of its affiliate in support of the Company's claimed costs.

Shared Services

The shared services charged to the Company by the City increased from $4.1 million in 2006 to $4.7 million in 2008, a 15% increase. The increase for 2008 compared to 2006 was attributed to cost increases in the areas of customer services, IT services (31%) and property management (30%).

Board staff expressed concerns with the substantial increases and the lack of justification in the Company's evidence to support such increases.

Regulatory Costs

The Company's 2008 regulatory costs are proposed at $274,093 for regulatory staffing and $115,000 for external regulatory services (legal and consulting services).

Both Board staff and SEC suggested that the external regulatory costs incurred in 2008 for mounting the 2008 cost of service application should be amortized over three years.

The Company noted in its reply submission that the costs associated with its 2008 rates application up to December 31, 2007 was $96,073 and all these costs were paid in 2007. To the end of May 2008, the costs were $68,435 and the Company anticipated that there would be further costs of approximately $26,000. The Company proposed to reflect in rates $115,000 for external regulatory costs.

The Company indicated that costs incurred to date for external services used in the 2008 rates application are $164,508 with an estimated final cost of $190,508.

The Company submitted that it has not amortized the regulatory expenses amount of $115,000 as it expects to spend similar levels during the 3rd Generation IRM process. It noted that its costs will include a smart meters application, a transfer pricing study, a study for cost allocation improvements, code compliance reviews and other preparatory work for its next rate base application.

Board Findings

While the proposed increase in controllable OM&A expenses in 2008 is only 2.3% compared to the 2007 bridge year, the increase is 25.7% from 2006 actuals. This is an excessive increase. Utilities are at risk for excessive bridge year spending levels if they rely on them as a base for test year spending.

Board staff and SEC noted in their submission that in certain OM&A expense areas the Company failed to provide sufficient information or adequate explanations to justify an overall increase of 25.7% in OM&A expenses. As well, they noted a number of discrepancies in the Company's evidence.

It is understandable that some utilities making a forward test year cost of service application for the first time would be uncertain as to the nature of and quality of the evidence that is required to support their proposals. However, as the Board has noted in other decisions[2], a proposal itself is not evidence of anything. What is needed is clear evidence that demonstrates the need for an expenditure request to be reflected in rates and a demonstration of prudence of that request.

In this case, it cannot be said that the evidence in support of the OM&A elements of the application was clear and persuasive, especially so given the relatively large increase in revenue requirement sought by the Company. The Board found the Company's evidence to be unclear and wanting in several areas, most notably in the areas that were raised as concerns by Board staff and SEC. Given that this is the Company's first attempt at a forward test year cost of service application, and because it falls within this early stage of the incentive rate mechanism plan, the Board is prepared to extend some latitude in this case with the understanding that the Company's quality of evidentiary support will improve in the future.

[2] For example, Norfolk Power Distribution Inc. Decision EB-2007-0753, May 26, 2008, pages 8-9.

Typically, past spending is a good indication of the normal pattern of OM&A expenses for a utility. By examining past spending it is possible to put a utility's proposal in a useful and informative context. That is not to say that past spending is determinative of appropriate spending levels going forward. A utility may have reasonable spending plans which are sharply increased or decreased from year-to-year. This can occur for a variety of reasons, both within and outside the control of the utility.
In this case, the Board examined the historic spending pattern of the utility and it shows that year over year spending from 2002 to 2006 increased at a considerably more modest levels than the very sharp increase in the bridge year over 2006 actual of 22.9%. In the Board's view, OM&A spending should be relatively smooth from year to year and the evidence did not adequately substantiate that such a large increase in that year, at least not to the degree that can be considered commensurate with the magnitude of the increase reported.

Accordingly the Board will approve an increase in OM&A spending of an amount equivalent to 15% over the 2006 actuals. This represents a 2008 Test Year level of Controllable Expenses of $7.504 million, a reduction of $693,303 from the proposed level of $8.201 million. This rate of increase in OM&A for 2008 over 2006 generally falls within the ranges found appropriate by the Board in other 2008 cost of service applications that were not settled and were adjudicated by the Board.

The Board-approved Controllable OM&A spending for ratemaking purposes is an envelope approach. The specific OM&A line item expenses will be managed by the Company as it sees fit. The Company will be accountable for the decisions it makes in prioritizing its spending plans within the envelope as it supports its historic spending as a basis for its proposed revenue requirement in its next rate rebasing application.

Payments in Lieu of Taxes (PILs)

Adjustments for Interest Expense

Board Staff noted that the Company will pay more interest than the Board's deemed structure permits. In its calculation of PILs, the Company added back the higher forecast interest expense and deducted the lower permitted interest expense, thereby raising taxable income and increasing the allowance for PILs in rates. Board staff noted that this treatment was not accepted for the Oshawa PUC Networks Inc. application[3]. The reason that treatment was not accepted is 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. Similarly, SEC noted that Halton Hills Hydro Inc. had proposed the same treatment and subsequently altered its

[3] Oshawa PUC EB-2007-0710 Rate Order, May 8, 2008.

calculation to address SEC's concern that Halton Hills would be over-leveraging itself, which the Board accepted[4].

In its reply submission, the Company agreed to remove the interest expense addition and deduction in finalizing the allowance for PILs.

Regulatory Assets and PILs

In calculating the 2008 PILs provision, the Company included in taxable income the forecast net decrease in its regulatory assets of $1,204,054. Board staff submitted that this treatment does not reflect the guidance provided by the Board in the 2006 EDR Handbook. In that regard, Board staff noted that, in the Board's decision on PUC Distribution Inc.[5], the Board denied increasing regulatory taxable income through the addition of movements, or recoveries, in regulatory assets.

In its reply, Brantford submitted that it is appropriate to include the higher PILs provision in the 2008 revenue requirement because of the manner in which related reductions in PILs prior to May 1, 2006 were treated. Brantford noted that there was a fundamental change in the Board's PILs true up requirements in 2006. The Company submitted that the new PILs true up regime, which became effective May 1, 2006, did not provide the necessary transitional measures relating to the reversal of PILs-related true up variances that were created pre-May 2006.

Before May 1, 2006, Brantford credited the tax savings arising from increases in regulatory assets to deferral account 1562 for future disposition. Brantford argued that because the tax savings in those earlier periods were credited to a deferral account and were not for the benefit of the Company, it would be unfair to require the Company to bear the taxes payable when those regulatory assets decline.

In Brantford's view, the appropriate treatment would be to record taxes payable attributable to reversals of pre-May 1, 2006 regulatory asset balances in account 1562. The Company noted that the Board has not permitted any additional entries to account 1562 since April 30, 2006. Therefore, the Company proposed to include the PILs provision in its 2008 revenue requirement.

Board Findings

The Board has announced its intention to review the 2008 applications of seven distributors to dispose of the balances in the PILs account 1562. This PILs variance account was used for the period 2001 through April 30, 2006. The combined proceeding would likely include a review of the evidence and methodology of the prior PILs regime

[4] Halton Hills Hydro Inc. EB-2007-0696 Decision, March 27, 2008, pages 8-9.
[5] PUC Distribution Inc. EB-2007-0723 Decision, January 8, 2008, page 4.

and should deal with the issues described by Brantford in the instant proceeding. While Brantford did not request disposition of its 1562 account in this application, the outcome of the PILs combined proceeding will be applied to all electricity distributors.

The test year PILs tax allowance or proxy to be included in rates should reflect the forecast PILs tax exposure on base distribution income in the application. This is the position advocated by distributors in other cases, where applicants have submitted that changes in deferral or regulatory asset balances should not be included in the determination of test year PILs or taxes. In its reply submission, Brantford has introduced new information that was not tested by parties during the hearing and the Board appreciates the Company's attempt to clarify its position on a complex issue.

The Board does not approve Brantford's proposed treatment of regulatory assets in its PILs calculation. The appropriate forum for the issues raised by the Company is the Board's pending proceeding on account 1562. Until that proceeding is concluded, there is no basis for the Board to deviate from the findings it has made in other cases where the same issue has been identified.[6] The Company shall remove the various amounts related to regulatory assets, including the Global Adjustment, from the computation of the test year PILs tax allowance. Brantford can track any variance that it believes to be correct, intervene in the combined PILs proceeding, and apply to the Board in a future application if its evidence can support its position.

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.

In response to Board staff's interrogatory #7.2(a), Brantford indicated that it was aware of the 0.225% reduced rate proposed by the government. The Company stated that this lower rate was not substantively enacted at the time of its application to the Board and it used the 0.285% rate. In response to interrogatory #7.1(b) related to the income tax rate, the Company stated that it will be amending the rate to the current enacted rate when it files its Draft Rate Order.

[6] For example, Enwin Utilities EB-2007-0522 Decision, pages 4-5; PUC Distribution, EB-2007-0723 Decision, page 4; Enersource Hydro Mississauga EB-2007-0706 Decision (settlement agreement page 16).

Board Findings

Brantford 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 normalized average consumption ("NAC") estimate for a given rate class 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 2008 load forecast is based on a forecast of customer growth using historical data from 2002 to 2006 and projected data for 2007 and 2008.

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. SEC shared Board staff's concerns.

In its reply submission, the Company stated that it is premature to comment on a multi-year normalization approach at this time pending the completion of its review of alternative methods to the single-year normalization used in the application.

Board Findings

The Board accepts the Company's customer forecast. The Board also accepts the Company's use of 2004 weather normalized data. 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 proposal is leveraging the value of this work. The Company has not expressed concern that its load may be overestimated.

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.

Brantford 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 16% and 14% respectively.

<u>Board Findings</u>
The Board finds Brantford's proposal reasonable and accepts it.

Line Losses
In its original application, the Company proposed a Total Loss Factor of 1.0305 for Primary Metered Customers <5000kW and 1.0409 for Secondary Metered Customers <5000kW[7]. In response to a Board staff interrogatory, Brantford revised its request for Total Loss Factor for Secondary Metered Customers <5000kW to 1.0373. Based on this revised proposed Total Loss Factor and a Supply Facilities Loss Factor of 1.0045, the Distribution Loss Factor was derived to be 1.0326. In its reply submission, the Company clarified that the correct Distribution Loss Factor based on an averaging of losses in its distribution system for the 5-year period 2002 to 2006 is 1.0373, resulting in a further revised proposed Total Loss Factor of 1.0420 for Secondary Metered Customers <5000 kW.

<u>Board Findings</u>
The Board approves the proposed Total Loss Factor of 1.0420 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 Loss Factor for Primary Metered Customers <5000kW of 1.0316.

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*

[7] There are no rate classifications with demand >5000kW

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. Brantford had proposed an overall cost of capital based on the following capitalization and cost of capital components:

Proposed 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	6.04
Common Equity	46.7	8.57
Total	100.0	

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 Brantford, 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 Findings

The Board approves the capitalization of rate base and cost of capital as proposed by the Company. The deemed capital structure of 53.3% long-term debt and 46.7% equity complies with the Board's direction to phase in a target 60:40 debt:equity ratio. The proposed cost rate for short term and rate of return on common equity are consistent with the Board's direction. The proposed cost for long term debt reflects the Company's actual cost rate and is below the Board's updated deemed long-term debt rate of 6.10%.

COST ALLOCATION AND RATE DESIGN

The Company determined its total service revenue requirement to be $18,649,709. The total revenue offsets in the amount of $1,422,329 reduce the Company's base service revenue requirement to $17,277,380 to be recovered from base rates.

Rate Classes

The Company is a host to one embedded distributor, Brant County Power, and also serves one large customer with demand greater than 5000 kW.

Board staff noted that the Company did not propose separate rate classifications for these loads; rather, they are being served within the GS>50 kW rate class.

With respect to the large customer, the Company noted that the customer is new in this size range and the Company did not want to jeopardize the timing of its application for 2008 rates by designing and implementing a new rate class. The Company proposed that it would undertake a cost allocation study to support the establishment of a large user rate class for its next rate rebasing.

With respect to the embedded distributor, Brantford clarified in response to an interrogatory that it intends to begin billing the embedded distributor in the 2008 rate year, and will do so by using the GS>50 kW rate classification. Board staff submitted that host distributors should be proposing a rate for embedded distributors, but noted that the practice of using the General Service rate is not unusual.

Board Findings

The Board accepts as reasonable the Company's proposal to defer the rate classification matter for the time of its next rebasing application. The Board notes that the issue of rates for embedded distributors is in the scope of a study currently underway at the Board (EB-2007-0031), the Rate Design study. The Board expects Brantford to keep itself informed as to potential developments through that process.

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 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 same revenue to cost ratios for its rate classes shown in column 2 in the table below. The Board's target ranges contained in the Board's Cost Allocation Report for Electricity Distributors, dated November 28, 2007 (the "Cost Allocation Report"), are shown in column 3.

Revenue to Cost Ratios (%)

	Informational Filing / Run 2 **Col 1**	**Per Application** **Col 2 (same as Col 1)**	**Board Target Range** **Col 3**
Residential	91	91	85 – 115
GS < 50 kW	83	83	80 – 120
GS > 50 kW	140	140	80 – 180
Street Lighting	37	37	70 – 120
Sentinel Lighting	10	10	70 – 120
Unmetered Scattered Load (USL)	110	110	80 – 120
Back Up/Standby	116	116	N/A

Column 2 shows that two rate classes (Street Lighting and Sentinel Lighting) remain outside the Board's target range shown in Column 3.

With respect to the Street Lighting rate class, Board staff noted that in other situations similar to Brantford's the Board has directed that the rates be increased to reach the Board's target range in two or three years.

SEC argued that the rates for the Street Lighting and Sentinel Lighting rate classes should be increased to yield revenue to cost ratios of 100% and the ratio for the GS>50kW rate class should decrease to 120% in 2008 and 100% in 2009.

In its reply submission, the Company revised its proposal. It proposed to:

- set the 2008 rates for the Street Lighting and Sentinel Lighting rate classes so that the revenue to cost ratios will move by 50% toward the bottom of the Board's target ranges;
- achieve the remainder of the shift to the bottom of the Board's target ranges in two equal increments in the years 2009 and 2010; and

- apply the additional revenues from the Street Lighting and Sentinel Lighting rate classes to the GS>50 kW rate class since it is the rate class that it is over-contributing the most.

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 Brantford'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.

The Board therefore accepts the Company's revised revenue to cost ratio proposals.

DEFERRAL AND VARIANCE ACCOUNTS

Disposition

The following table shows the deferral and variance account balances Brantford has sought to recover in its application. 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	$89,919
1525	Miscellaneous Deferred Debits	$7,898
1550	Low Voltage Variance	($217,343)
1565	CDM	($89,823)
1566	CDM - Contra	($1,450)
1571	Pre-Market Opening Energy	($333,319)
1580	RSVA - WMSC	($2,422,484)
1582	RSVA – One Time WMS	$333,033
1584	RSVA - RTNC	$615,321
1586	RSVA - RTCC	($1,071,809)
1588	RSVA - Power	$783,232
1518	RCVA - Retail	$19,363
1548	RCVA - STR	$320,252
TOTAL		**($1,967,210)**

Brantford proposed to refund the net balance to ratepayers over one year through rate riders.

Board staff noted that the Company has not provided the Continuity Statement that is necessary to confirm the balances requested for disposition.

On June 10, 2008, the Company provided this information with the explanation that its omission was inadvertent.

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.

CDM accounts

Board staff noted that, as the CDM accounts are tracking accounts for 3rd Tranche CDM activities which were expected to continue till September 2007 and the reported balances are only as of December 31, 2006, it would be premature to dispose of these balances at this time.

In its reply submission, the Company noted that the $89,823 balance consists of a debit balance of $1,450 representing the balance in the 3rd Tranche CDM spending and a credit balance of $91,273 representing the net recoveries and expenditures for Brantford's Incremental CDM program approved in the 2006 rates case. The Company noted that the Incremental CDM program ended April 30, 2007 and the actual credit balance as of April 30, 2008 is now $90,996 rather than $91,273. According to the Company, the principal reasons for the variance in the 2007 CDM spending were lower than projected uptake by customers for certain programs and lower than budgeted costs for certain other programs.

Board Findings

On the basis of the Company's explanation, the Board finds that it is not premature to dispose of the balances in this proceeding related to the incremental CDM programs.

However, the Board will not order disposition of the balances related to the 3rd Tranche CDM spending. Reporting on these expenditures is done through an annual process separate from this rate proceeding. The policy and methodology of disposing of residual 3rd Tranche spending has not been finalized and therefore ordering disposition of these balances would be premature.

Therefore, the Company is ordered to clear only the $90,996 in account 1556 associated with incremental CDM spending.

Pre-Market Opening account

Board staff raised questions whether the 2004 balances in account 1571 are correct and, by association, the balances in certain other accounts, such as account 1590.

In its response submission, the Company set out the derivation of the balance in account 1571 and submitted that it is the correct balance.

Board Findings

The Board accepts the proposed balance in account 1571 on an interim basis. However, the Board is concerned with the information provided on the record to support the requested disposition of this variance account and other regulatory accounts.

Due to this concern, the Board will approve proposed clearance of account 1571. By this Decision, the Board informs the Board's Chief Regulatory Auditor ("CRA") of this situation and suggests that an audit review may assist the Board in determining how best to finalize the amounts in this account and other impacted accounts. When the CRA has concluded a review of these accounts, and depending upon the CRA's conclusions, the Board will determine whether it is necessary to order a different final disposition.

Request for Expanding Definition of Account 1592

The Company requested that account 1592 – PILS and Variance for 2006 and subsequent years be expanded to include the impact of PILs and taxes arising from non-discretionary changes in Generally Accepted Accounting Principles ("GAAP") due to the introduction of International Financial Reporting Standards ("IFRS") or changes to the Board's Accounting Procedures Handbook ("APH").

Board staff and SEC submitted that any changes will be generic to all distributors and should be dealt with if and when they arise. In its reply submission, the Company withdrew its request.

<u>Board Findings</u>

The Board accepts the Company's withdrawal of its original proposal. This is a generic matter that would apply to all distributors. In this regard, by letter dated May 8, 2008 the Board informed stakeholders of the commencement of a consultation process to deal with the matter of transitioning to International Financial Reporting Standards.

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 four months late in filing its application and did not adhere on several occasions to the Board's directed timelines during the proceeding, 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. Given this 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, 2009.

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 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, 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 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 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 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 any objections to the claimed costs within 40 days from the date of this Decision.

6. SEC 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 18, 2008
ONTARIO ENERGY BOARD

Original Signed By

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Paul Vlahos
Presiding Member

Original Signed By

____
Bill Rupert
Member