

**Ontario Energy
Board**

**Commission de l'Énergie
de l'Ontario**



EB-2006-0501

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

**FOR 2007 AND 2008 ELECTRICITY TRANSMISSION REVENUE
REQUIREMENTS**

DECISION WITH REASONS

August 16, 2007

**Summary of the Decision with Reasons
(EB-2006-0501)**

Chapter	Application	Board Decision
2	Revenue Requirement Adjustment Mechanism for 2009 and 2010	Not approved.
3	Board's jurisdiction to provide guidance on human resource costs	Board has the authority to make findings and provide guidance on the reasonableness of compensation costs.
4	OM&A expenses	Approved. Data on asset condition to be improved.
	Compensation levels	Approved. Improved reporting required and any reductions in executive compensation to be tracked.
5	Capital expenditure budget	Approved. Data on asset condition to be improved.
	Prudence of Niagara Reinforcement Project	Approved.
6	Special treatment for designated capital projects	Not approved.
	Special treatment of Niagara Reinforcement Project	Applicant allowed to expense carrying costs.
7	Return on Equity	Not approved. Applicant to use the Distribution ROE formula.
	Capital Structure	Same as allowed for electricity distributors.
8	OEB Costs deferral account	Not approved.
	2006 Earnings Sharing Mechanism	Adjustments required to excess income calculation. Capital contribution treatment not allowed.
	2007 Revenue Deficiency Deferral Account	To be effective January 1, 2007.
9	Load forecast	Weather-normal peak load forecast approved. Report required on weather normalization and differences with the IESO forecast.
	CDM impact	Reduced by 350 MW.
10	Charge determinants	Status quo approved.
11	Implementation	Uniform Ontario Transmission Rates to be set in a further proceeding; targeted effective date of change November 1, 2007.

This summary excludes the particulars in the Settlement Proposal and does not form part of the Decision nor does it itemize all findings. It is not to be relied on for the purpose of applying or interpreting the Decision.

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Appendix 4 --- Partial Decision and Order

EB-2006-0501

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 Hydro One
Networks Inc. for an Order or Orders approving or fixing just
and reasonable rates and other charges for the transmission
of electricity commencing January 1, 2007.

BEFORE: Pamela Nowina
Vice Chair and Presiding Member

Paul Sommerville
Member

Bill Rupert
Member

DECISION WITH REASONS

August 16, 2007

1. INTRODUCTION

1.1 THE APPLICATION

Hydro One Networks Inc. (“Hydro One”, the “Company”, the “Utility” or the “Applicant”) filed an application dated September 12, 2006 (the “original Application”) with the Ontario Energy Board (the “Board”) under section 78 of the *Ontario Energy Board Act, 1998*; S.O. c.15, (Sched. B) (the “Act”), for an order or orders approving “the revenue requirement for the test years 2007 and 2008; customer rates for the transmission of electricity to be implemented on May 1, 2007; changes to the current capital structure with an increase in the return on common equity; the inclusion into rate base of certain capital costs; a revenue requirement adjustment mechanism for 2009 and 2010”; and other matters related to the fixing of just and reasonable rates for the transmission of electricity. The Board assigned file number EB-2006-0501 to the Application. Updates to certain parts of the original Application were filed on February 23, 2007 (the “updated Application”).

The transmission revenue requirement of Hydro One Networks Inc. (then known as Ontario Hydro Networks Company Inc.) was last set in proceeding RP-1998-0001 when the Board approved a Transitional Rate Order, dated March 31, 1999 and effective April 1, 1999. This revenue requirement was amended to update Hydro One’s Rate of Return on Common Equity on March 1, 2000 (EB-1999-0526). On May 26, 2000 the Board issued its decision on Hydro One’s transmission cost allocation and rate design application (RP-1999-0044).

Appendix 1 contains details regarding the procedural aspects of the Application, including a list of witnesses and a list of active parties.

1.2 THE SETTLEMENT CONFERENCE AND SETTLEMENT PROPOSAL

An Issues List was provided to parties with Procedural Order No. 2 on December 20, 2006. On March 26, 2007 a Settlement Conference was held to settle as many of the issues as possible. The Settlement Conference resulted in a Settlement Proposal which was filed with the Board on April 3, 2007. The Board considered the Settlement Proposal at a hearing held on April 10, 2007. The Board issued its Settlement Proposal Decision on April 18, 2007. The Settlement Proposal and the Settlement Proposal Decision are attached to this decision as Appendices 2 and 3 respectively.

Of the 40 issues on the Issues List, the Settlement Proposal fully settled 24 issues (the “Settled Issues”) and partially settled two issues (“Partially Settled Issues”). The parties were unable to reach agreement on the remaining 14 issues.

Fully Settled Issues

Issue 1.1	Effectiveness and Efficiency of Affiliate Service Agreements
Issue 1.2	Board directions from previous proceedings (some specifics to be addressed part of other issues, principally issues, 9.1, 3.4 and 2.2).
Issue 1.6	Economic and Business Planning Assumptions
Issue 2.3	Cost Allocation between Distribution and Transmission
Issue 2.4	Depreciation Expense
Issue 2.5	Overhead Capitalization Rate
Issue 2.6	Capital and Property Taxes
Issue 2.7	Income Taxes and Methodology
Issue 3.3	Capital and Common Asset Allocation
Issue 3.5	Lead Lag Study for Working Capital Calculation
Issue 3.6	Asset Condition Assessment
Issue 3.7	Allowance for Funds Used During Construction
Issue 5.1	External Revenues
Issue 6.1	Cost Pools and Allocation to the pools
Issue 6.2	Dual Function Lines
Issue 6.3	Wholesale Meter Pool
Issue 6.4	Directly Connected Customers and Line Connection Charges
Issue 6.5	Cost Pools and Local Loop allocation
Issue 7.2	Forecast for Charge Determinants
Issue 7.4	Continuation of the Export Transmission Tariff
Issue 8.1	Deferral and Variance Accounts (establishment and methodology)
Issue 8.2	Deferral and Variance Accounts (amounts and disposition)

- Issue 8.3 Service Levels and Performance Standards
- Issue 8.4 Demonstration of Need for Leaside/Birch Junction project

Partially Settled Issues

- Issue 3.1 Rate Base
- Issue 7.3 Charge Determinants for Network and Connection Service

Settlement Proposal Decision

The Board accepted the Settlement Proposal on April 10, 2007 save for the three issues below, which were addressed in its Settlement Proposal Decision of April 18, 2007:

- Issue 7.4 The Board modified the language for the settlement of the Export Transmission Rates issue.
- Issue 8.4 The Board did not accept the Settlement Proposal and directed Hydro One to present evidence on the need to relieve loading on the connection lines between Leaside TS and Birch Junction TS in the oral hearing.
- Issues 8.1 & 8.2 The settlement of the Ontario Energy Board Cost Account was not accepted by the Board.

This Decision with Reasons addresses the 14 non-settled issues, beginning at Chapter 2.

1.3 PARTIAL DECISION AND ORDER

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established, beginning January 1, 2007, to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account. The Partial Decision and Order is attached as Appendix 4. Further details regarding this account are found in Chapter 8 of this decision.

1.4 UNIFORM TRANSMISSION RATES

In this decision, the Board is approving the revenue requirements and charge determinants for Hydro One Transmission which will form the basis for the Hydro One Networks' portion of the Ontario Uniform Transmission Rates. The Ontario Uniform Transmission Rates and the revenue shares of each of the other transmitters in the transmission rates pool (Great Lakes Power Inc., Five Nations Energy Inc., and Canadian Niagara Power Inc.) will be established in a subsequent proceeding.

1.5 THE HEARING, SUBMISSIONS AND EXHIBITS

The hearing took place at the Board hearing room in Toronto on April 23, 24, 26 and May 7, 8, 11, 14, 15, 17, 18, 22, 28 and June 13, 2007. Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

2. PROPOSED REVENUE REQUIREMENT ADJUSTMENT MECHANISM

Hydro One's Proposal

In addition to an order from the Board approving the revenue requirement for test years 2007 and 2008, Hydro One sought approval for a Revenue Requirement Adjustment Mechanism (RRAM) to set transmission revenues for 2009 and 2010 and to replace a full cost-of-service proceeding for those years.

Hydro One described its RRAM for 2009 and 2010 as an indexed revenue requirement plan that is an extension of the 2008 rate setting process. Each of the components of the company's revenue requirement for 2009 and 2010 – operating, maintenance and administration (OM&A) expenses; depreciation; capital taxes; income taxes; and return on capital – would be recomputed prior to each year and submitted to the Board for approval. The Company submitted that its RRAM process would require a much smaller commitment of resources, time and cost than would a full cost-of-service proceeding.

The most significant aspects of the proposed RRAM are the mechanisms used to compute OM&A expenses and the capital expenditures to be included in rate base. Hydro One's approach to these items (set out in its prefiled evidence, and modified by the testimony of its witnesses) is summarized in Table 1. The table deals only with the 2009 calculations but similar calculations would be done for 2010.

Hydro One proposed that the return on capital in 2009 and 2010 would be based upon the debt-equity ratio and cost of debt approved for 2008. The allowed return on equity would be calculated using the OEB-approved return on equity (ROE) formula for 2008, updated for the then current long Canada bond yield. Depreciation expense and taxes

for 2009 and 2010 would be simple recalculations based on the updated expense, rate base, and return on capital.

Table 1: Calculation of 2009 Revenue Requirement/Rate Base Amounts Under Proposed RRAM

Expense/capital addition	Calculation of 2009 Amounts
OM&A expenses	(2008 approved OM&A) multiplied by (1 + inflation factor – productivity factor + “OM&A asset aging” adjustment factor)
Sustaining, Operations, and Shared Services capital expenditures added to rate base	(2008 approved Sustaining, Operations, and Shared Services capital expenditures) multiplied by (1 + inflation factor – productivity factor + “capital asset aging” adjustment factor)
Non-IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
“Supply mix” capital expenditures added to rate base	Forecast capital expenditures expected to be incurred in 2009 (without regard to the in-service dates of the assets) *

**The amounts added to rate base would be subject to a half-year rule.*

Hydro One submitted that the review and approval process for an adjusted revenue requirement for 2009 could commence in June 2008 and could involve at least two rounds of interrogatories and workshops with intervenors. A negotiated settlement would be presented to the Board for approval. While intervenors strongly opposed the proposal, Hydro One said it believes such a process is achievable based on the experience of the British Columbia Utilities Commission, which has used a similar approach in regulating FortisBC .

Dr. Poray of Hydro One stated that the Company was not seeking to have all the details of its proposed plan approved by the Board in this proceeding. Hydro One, he said, would be “willing to work with the intervenors to try and sort out the details, but I think Hydro One would like the assurance of having a concept approved by the Board as a

mechanism for moving forward, where the details would be subject to a review, but it would be a review which is much more streamlined than a full cost of service.”¹

During his examination-in-chief, Dr. Poray listed the specific approvals that Hydro One was requesting as part of this proceeding:

First of all, we want the Board to approve the concept behind the revenue adjustment mechanism, that is to say the mechanical adjustment mechanism that uses inflation, productivity and asset-aging adjustment factors to calculate the respective increments in OM&A and capital cost components for 2009 and 2010, starting from Board-approved values.

Secondly, we want the Board to approve the concept behind the derivation of the asset-aging factors, which is based on Board-approved information that Hydro One filed as part of the current proceeding.

Thirdly, we want the Board to approve the setting of a constant productivity factor at one percent for the 2009 and 2010 period.

Fourth, we would want the Board to approve the treatment of capital development costs as we've outlined previously.”²

Hydro One was clear that its RRAM proposal is not a comprehensive incentive regulation plan. In its pre-filed evidence, the Company noted:

It will not be realistic to design an effective comprehensive incentive regulation regime before that time [2010] for a number of reasons. Most importantly, the industry is currently going through a period of significant uncertainty. This includes structural changes for the industry as well as uncertainty related to supply mix options and timing. Stability will not be achieved until the OPA's IPSP [Ontario Power Authority's Integrated Power System Plan] is filed and approved by the OEB and until significant progress is made in implementation planning. In addition, it will be necessary to collect appropriate cost data for several years so that cost functions can be estimated as a basis for setting the cost and

¹ Tr. Vol. 6, p.36

²Tr. Vol. 5, p.107 (Dr. Poray is referring to a previous discussion recorded in Volume 5 of the transcript, pages 92 to 99, where he outlines the treatment of capital expenditures in the proposed adjustment mechanism.)

quality parameters for the incentive regulation model that is ultimately adopted as was the case in other jurisdictions³.

The principal argument made by Hydro One for its RRAM proposal is that it will streamline the approval process during two years that Hydro One expects to have a heavy workload in connection with its capital programs and asset sustainment activities.⁴ Other reasons cited by Hydro One were:

- The base year for the adjustment mechanism, 2008, will have been subject to a full cost-of-service review.
- The costs borne by customers for additional operating and capital spending on Hydro One's aging infrastructure will be limited by the pre-approved OM&A and capital adjustment mechanisms.
- The two-year RRAM period will be followed by a full cost-of-service review.
- The two-year RRAM period will allow Hydro One to align subsequent transmission and distribution rate filings.
- The RRAM will reduce the uncertainty with respect to the cost borne by transmission customers in 2009 and 2010, while providing an incentive for Hydro One to contain cost within the envelope established by the adjustment mechanism.
- The RRAM may serve as a first step towards a more comprehensive incentive regulation plan as part of Hydro One's cost-of-service filings for post-2010 rates⁵.

³Ex.A/Tab13/Sch.1/p.9

⁴Tr. Vol. 5, p. 111

⁵ Ex.A/Tab13/Sch1/pp.2-3.

Intervenor Arguments

The RRAM proposal was severely criticized by each of the five consumer groups that participated in the hearing (Association of Major Power Consumers in Ontario “AMPCO”; Consumers’ Council of Canada “CCC”; Energy Probe; Schools Energy Coalition “SEC”; and Vulnerable Energy Consumers’ Coalition “VECC”). No other intervenors dealt with the RRAM proposal in their arguments. The five consumer groups submitted that the Board should reject Hydro One’s proposal and, instead, should require Hydro One to file a full cost-of-service application in respect of 2009 and 2010.

In summary, the intervenors argued that:

- RRAM is only a concept; one that Hydro One acknowledges requires further definition and stakeholdering. The Board should not consider approving an ill-defined proposal.
- It is premature for the Board to approve any automatic revenue requirement adjustment mechanism given the significant uncertainties about the nature and extent of Hydro One’s future costs and activities. It was submitted that automatic rate adjustment mechanisms work best when a utility operates in a relatively steady-state environment, which Hydro One admits is not the case today in its transmission business. Some intervenors also submitted that a period of instability and uncertainty is precisely the time when regulatory oversight should be maintained, not relaxed.
- The proposed method of calculating revenue requirement adjustments is flawed. Intervenors raised several issues but were especially critical of the proposed use, and method of calculation, of the OM&A and capital asset aging factors. Intervenors noted that the proposed aging factors were the result of a simple calculation based on the change in spending between 2003 and 2008; no evidence was provided to link the change in spending

with asset aging. They also noted that the proposed productivity factor was developed by Hydro One and is not based on external benchmarks.

Board Findings

The Board has been supportive of regulatory mechanisms that provide greater regulatory predictability, reduce regulatory burden, and offer appropriate incentives to regulated utilities. This is clearly demonstrated by the Board's multi-year rate-setting plan for electricity distributors and its current initiative on multi-year incentive regulation for natural gas utilities.

A multi-year revenue requirement adjustment mechanism for electricity transmission may ultimately be appropriate for Hydro One; however, the Board cannot accept the RRAM proposed by Hydro One.

This proceeding is the first cost-of-service review of Hydro One's transmission revenue requirement since 2000. Hydro One pointed out on many occasions that its transmission business today is facing significant change in its spending levels and work programs. During the hearing, Hydro One stressed what it described as an unprecedented increase in capital expenditures driven by government directives and system growth. Hydro One's evidence and its witnesses also referred at length to the significant increase in spending related to Hydro One's aging asset base. The Board also heard evidence about the possible impact of the OPA's IPSP, which has not yet been filed with the Board, on Hydro One's investment plans and spending.

Given these significant changes and uncertainties, the Board does not believe that this is the time to adopt a revenue requirement adjustment mechanism for 2009 and 2010. Before setting the post-2008 revenue requirement, it will be important to examine how actual OM&A expenses and capital expenditures in 2007 and 2008 compare with Hydro One's forecasts (and to determine the reasons for any significant variations), and to test

forecasts of spending in subsequent years. That can only be accomplished through a cost-of-service proceeding.

Even if the environment were more stable, the Board would be unable to accept the proposed RRAM because it is not a fully developed plan. The Board does not see how it could approve a mechanism in concept when many of the elements of the mechanism are not clearly defined or are open to change based on future consultations. While the Board appreciates that Hydro One is willing to consult with stakeholders on various aspects of its proposal, it believes that consultation should occur prior to a proposal being submitted to the Board in a rates case.

The Board also shares the intervenors' concerns about some aspects of the proposed indexing of OM&A and certain capital expenditures, especially the use and calculation of the proposed asset aging factors. In its evidence, Hydro One stated that the residual growth in OM&A spending from 2003 to 2008 was "deemed to represent the effect of asset aging on OM&A costs."⁶ Should Hydro One choose to submit a multi-year adjustment mechanism that contains asset aging factors as part of its next transmission rates case, the Board will expect detailed evidence to establish that such factors are appropriate estimates of the increase in costs due to asset aging. The Board also expects that any productivity factors will be supported by detailed information and external comparisons.

The Board does not accept Hydro One's proposed Revenue Requirement Adjustment Mechanism for 2009 and 2010. The revenue requirement for those years should be established through a full cost-of-service proceeding. Multi-year incentive regulation for Hydro One Transmission could be implemented in subsequent years.

⁶Ex.A/Tab13/Sch1/p.14

3. JURISDICTION

The Society of Energy Professionals (the “Society”) has challenged the Board's jurisdiction to provide detailed guidance to Hydro One with respect to compensation costs negotiated as part of the collective bargaining process with its various unions. In its written submissions it stated:

It is the position of the Society that the statutory jurisdiction of the Ontario Energy Board to set rates for the transmission of electricity does not include the jurisdiction to:

1. Issue directions or orders which would in effect require Hydro One to violate the terms of a binding collective agreement with any of the unions representing Hydro One employees;
2. Issue directions or orders regarding positions Hydro One must take or objectives it must pursue in collective bargaining with unions representing Hydro One employees;
3. Issue directions or orders which in any other way would have the effect of pre-empting free and good faith collective bargaining between Hydro One and the unions representing Hydro One employees.

The Board notes that the Society did not challenge a specific decision of the Board. Rather, the Society appears to be anticipating reasons from the Board similar to those issued in Hydro One’s 2006 Distribution Rates Decision (RP-2005-0020/EB-2005-0378), the “Distribution decision”; in particular, certain paragraphs which state clearly the Board’s concerns with the Company’s labour rates and compensation costs. In its Distribution decision the Board said:

3.4.3 The Board notes that the high compensation issue for Hydro One has a considerable history before this Board, dating back to the Ontario Hydro days.

The Board has noted in this proceeding that since the de-merger of Ontario Hydro, Hydro One has taken a number of steps to control its overall compensation costs by, for example, instituting a voluntary retirement program, outsourcing, use of the PWU hiring hall, initiating various cost efficiency programs, holding the line on compensation increases for management employees and imposing a two-tiered pension structure or a pension plan that is less generous for new employees represented by the Society of Energy Professionals. These are positive steps and the Board expects the company to continue and enhance such efforts in the future and report to the Board at the next main rates case. The Board is particularly concerned about the apparently high labour rates. In this respect, the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates.

3.4.4 Even so, the comparisons between Hydro One's cash compensation with certain other utilities presented by intervenors are of concern. For example, SEC calculated that by applying Ottawa Hydro's compensation costs to Hydro One employees there would be a reduction of about \$85 million in Hydro One's cash compensation. The Board recognizes that there may be some roughness in the derivation of that figure and some differences in the profile of the two utilities. However the contrast between the compensation structures is of concern to the Board.

3.4.5 The Board will not make an adjustment to the proposed OM&A costs based on compensation levels at this time but expects the utility to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities.

In the Society's view, such directions are beyond the jurisdiction of this Board as they interfere with and have the effect of frustrating the statutorily mandated collective bargaining process at the utility.

The Society also contended that in so far as the Board appears to mandate reductions in labour rates or compensation costs, it has assumed a direct role in the negotiation process which is improper and inconsistent with the collective bargaining process. It suggests that in such circumstances, the Board has become "the ghost at the bargaining table" imposing limits on the scope of negotiation without any direct accountability to others participating in the process.

While it appears to find the Board's comments in the Distribution decision to be problematic, the Society did not seek a review of that decision, either at the Board or elsewhere. A consideration of jurisdictional issues is best undertaken when a specific action or decision by the tribunal is considered by a party to fall outside its jurisdiction. Dealing with jurisdictional issues on a speculative or theoretical basis is awkward, and not particularly useful.

If the Society regards some aspects of this Decision to be outside the Board's jurisdiction, it has a range of remedies available to it where its concerns can be addressed and adjudicated. Nonetheless, it may be helpful and appropriate to address some of the issues raised by the Society now.

The scope of the Board's jurisdiction is always subject to its own assessment in light of specific challenges, and, ultimately, when invoked by a party, to that of the Court.

The Board's jurisdiction with respect to ratemaking has been the subject of considerable recent examination by the Board itself and by the courts. While most of that commentary has concerned the process for establishing gas distribution rates, it is clear that the Legislature has endowed the Board with broad powers in the establishment of just and reasonable rates for electricity transmission as well. The Board's jurisdiction derives from the following sections of the Act:

19(1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and fact.

19(6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act.

78(1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.

78(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity and for the retailing of electricity in

order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.

78(7) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable.

78(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.

78(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and the burden of establishing that the rates are just and reasonable is on the transmitter or distributor, as the case may be.

128(1) In the event of conflict between this Act and any other general or special Act, this Act prevails.

In addition, when carrying out its responsibilities under the Act, the Board is subject to explicit objectives to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; to promote economic efficiency and cost effectiveness in the transmission of electricity; and to facilitate the maintenance of a financially viable electricity industry.

In assessing the Society's assertions it is important to note that where there is jurisdiction to regulate there is also an obligation to regulate. A regulatory body such as the Board has a positive obligation to fulfill the mandate bestowed upon it by the Legislature.

The Board has a positive obligation pursuant to section 78 to ensure that the rates governing the transmission of electricity are just and reasonable. In a decision that has been relied upon and cited numerous times, the Supreme Court of Canada has held that just and reasonable rates are those which strike an appropriate balance between

the interests of consumers on one hand, and the right of the utility to make a reasonable return on its investment, on the other.⁷

A number of intervenors argued, and Board staff observed, that the Board's method of determining just and reasonable rates does not include prohibiting the subject utility from making expenditures or incurring costs at rigidly prescribed levels. Rather, the Board approves a revenue requirement that is consistent with its findings on various cost categories, including operating costs. The courts have recognized that operating costs include compensation costs⁸, and that in the course of setting just and reasonable rates, numerous costs may be subject to challenge including those related to compensation plans⁹.

The Board's obligation to arrive at just and reasonable rates, and to protect the interests of consumers, requires it to assess the reasonableness of all cost categories for which recovery is sought. The Board has a wide discretion to allow, disallow or adjust the components of both rate base and expense¹⁰.

In the Distribution decision, the Utility's labour rates and compensation costs appeared consistently higher than those of comparable North American utilities. As a result, the Board panel deciding the Distribution case asked the Utility to identify steps it had taken or would take to reduce labour rates in the next Distribution rates case filing. The panel also required the Utility "to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities".

⁷ "Just and reasonable" rates have been defined by the courts as those which are fair to the consumer and which permit the company to earn a fair return on the capital invested: *Northwestern Utilities, Ltd. v. City of Edmonton et al.*, [1929] S.C.R. 186, cited in *Re Union Gas Ltd. v. Ontario Energy Board et al.* (1983) 1 D.L.R. (4th) 698 (Ont. H.C.J.), p. 706.

⁸ *Re Union Gas Ltd. v. Ontario Energy Board et. al.*, *ibid.*, p. 702.

⁹ *Transcanada Pipelines Ltd. v. Canada (National Energy Board)* [2004] F.C.J. No. 654. (C.A.), para. 34.

¹⁰ *Re Union Gas Ltd. v. Ontario Energy Board et al.*, *supra.*, p. 712.

That panel also required the Utility to provide further detailed information respecting the full extent of what appeared to be a disparity in comparative compensation costs. The underlying rationale for this finding was to ensure that the costs incurred by the Utility with respect to labour rates and compensation costs are reasonable, and can therefore form the basis of part of the overall revenue requirement of the Utility.

The same approach is taken for all other categories of costs that comprise a utility's revenue requirement. In making the finding that it did in the Distribution case, the Board was giving the Utility fair warning that the Board had concerns about the apparent disparity in comparative labour rates and compensation costs.

The Board did not and does not prohibit the Utility from paying to its workforce whatever it negotiates within the context of its labour relations environment. What the Board does do is limit the recovery as part of the revenue requirement to that portion of compensation cost which the Board finds to be reasonable.

In other words, the Utility is free within the negotiating environment to arrive at whatever resolution it sees fit. It has to do so, however, with knowledge that full recovery of the consequential cost may not be available to the extent that the Board considers the settlement to be unreasonable.

To do otherwise would make the ratepayers captive to whatever private arrangements are agreed to by the Utility and its unions. The Board can only meet its responsibility to protect the interests of consumers if it assesses the reasonableness of the costs which result from such settlements and provides for recovery according to a fair, transparent, and principled regulatory approach.

In its Reply submission, the Society argued that the Board has no authority to make orders which have the effect of compelling the Utility to violate labour relations agreements to which it is bound.

It is not the practice of this Board to make any such orders. The Board is expressly not bound by the terms of any contract in its establishment of just and reasonable rates pursuant to Section 78 of the Act. The Board assesses the reasonableness of the cost consequences of the utility's arrangements, and establishes the revenue requirement on the basis of that assessment. The Board's view of the reasonableness of compensation costs is just one of the factors that the parties at the bargaining table must take into account. The consequence of a Board finding that this category of cost is excessive is a possible disallowance of a portion of the amount claimed by the utility for inclusion in the revenue requirement. In that hypothetical case, the utility would decide whether to attempt to change its compensation practices or to source the additional funding from the shareholder.

Accordingly, the Board finds that it has the authority to make findings and to provide guidance with respect to the reasonableness of a utility's compensation costs for the purpose of setting just and reasonable rates for utility service.

4. OPERATIONS, MAINTENANCE AND ADMINISTRATION

This chapter contains the Board's findings on Hydro One's proposed Operations, Maintenance and Administration expenses (OM&A) as well as the level of the Company's compensation costs.

4.1 OM&A EXPENSES

Hydro One's updated evidence showed a forecast for OM&A expenses of \$394.1 million for the 2007 test year with a slight decrease to \$387.5 million in the 2008 test year. The 5.1% increase for 2007 was in addition to an increase of almost 10% in the 2006 bridge year. Table 2 shows Hydro One's forecast amounts compared with those in the preceding four years.

Table 2: OM&A Expenses 2003 – 2008

\$ millions	Historic		Bridge		Test	
	2003	2004	2005	2006	2007	2008
OM&A by category						
Sustaining	\$146.9	\$153.9	\$166.3	\$179.0	\$200.1	\$200.9
Development	2.2	5.0	6.7	8.1	8.0	8.1
Operations	36.6	49.5	38.3	42.9	45.8	46.2
Shared services and other	125.8	81.9	59.9	76.3	67.4	57.1
Taxes, other than income taxes	<u>55.4</u>	<u>68.1</u>	<u>70.5</u>	<u>68.6</u>	<u>72.8</u>	<u>75.1</u>
Total OM&A	<u>\$366.8</u>	<u>\$358.4</u>	<u>\$341.8</u>	<u>\$374.8</u>	<u>\$394.1</u>	<u>\$387.5</u>
Year over year % change						
Sustaining OM&A		4.8%	8.1%	7.6%	11.8%	0.4%
Total OM&A		-2.3%	-4.6%	9.7%	5.1%	-1.7%

This part of the hearing focused mainly on Sustaining OM&A expenditures as this category represents just over half of the OM&A total. The Sustaining OM&A budget represents spending required to maintain existing transmission lines and station facilities so they will continue to function as originally designed and meet overall system reliability, environmental and safety requirements.

One reason for intervenor interest in the Sustaining category is the fact that it has had consistent increases in expenditures from 2003 through to the test years. Sustaining spending in 2007 is forecast to be almost 12% higher than in 2006, a year in which spending rose by 7.6% over 2005 levels.

Hydro One defended its Sustaining OM&A expenditure plans on the basis of its business planning process where it uses leading measures related to the performance, condition and age of the specific assets which make up the transmission system. The information supporting Hydro One's plans include asset performance (asset failure rate) studies, asset condition assessments and asset demographics information.

The asset demographic information identified the number of assets which are expected to enter specific critical age regions, such as mid-life, where incremental maintenance requirements are necessary to ensure continued asset performance, and end-of-life where it becomes uneconomic to try to sustain the required performance levels. Hydro One emphasized that both the volume and scope of OM&A work is increasing for Hydro One's aging fleet of assets. It is the Company's position that the business planning process utilized by Hydro One has established the appropriate level of sustaining work, based on a detailed needs identification and work program prioritization¹¹.

VECC highlighted that in Hydro One's original application, Sustaining OM&A expenditures were increasing by 28% from \$155.9 million in 2006 to \$200.1 million in

¹¹ Ex.A/Tab14/Sch1

2007. In the evidence update, the Sustaining OM&A spending for 2006 was revised upwards to \$179.0 million.

Hydro One's explanation for the higher than expected spending in 2006 was that higher than anticipated failure rates were experienced that year, associated with a specific transformer design and storms. Unexpected difficulty in getting cleanup crews to the affected sites increased unanticipated expenses Hydro One testified that this higher 2006 spending does not impact on spending plans for 2007 and 2008.

VECC did not accept Hydro One's assertion that assets and performance were actually deteriorating. VECC noted that as the updated information provided by Hydro One showed that outages of 230kV circuit breakers were lower in 2006 than in any of the previous three years, and that outages of 230 kV transformers were well below 2005 levels and in line with those in 2003 and 2004.

VECC also argued that the 2006 asset condition assessment did not show a marked difference in overall condition of the transmission assets and did not substantiate the requested increase in OM&A Sustaining spending.

VECC also noted that Hydro One's evidence indicated that a significant portion of the Priority 1 ("very poor") and Priority 2 ("poor") assets will actually be replaced over the 2006-2008 period. VECC submitted that if this level of replacement proceeds, it will have a direct impact on the level of Sustaining OM&A spending needed for these assets and should reduce overall maintenance requirements. VECC also noted that in the High Level Transmission Benchmarking Study prepared by the PA Consulting Group (September 6, 2006),¹² Hydro One Networks OM&A spending was close to the average for those utilities surveyed when normalized on either a total Gross Asset Basis or a MWh transmitted basis using data from 2003-2005. Similarly, Hydro One's reliability was shown to be about average. VECC held that this evidence showed that current levels of spending were reasonably adequate.

¹²Ex.A/Tab15/Sch2

In conclusion, VECC submitted that the proposed Sustaining OM&A budgets be reduced by 6% in both test years to \$188.1 million in 2007 and \$188.8 million in 2008.

AMPCO questioned whether the evidence established that assets are aging at a specific rate, or a rate greater or lesser than in the past, or that asset aging is creating a significant deterioration in reliability. AMPCO urged the Board to direct Hydro One to provide clear evidence on asset aging at its next rate hearing.

Citing evidence which appeared to show that the 2006 outage performance was better than previously indicated, AMPCO argued that Hydro One's data did not support a claim of significant and increasing problems with asset performance.

AMPCO maintained that Canadian Electrical Association data did not indicate a significant deterioration in system performance over the period 2003 to 2006. In addition, Hydro One's evidence showed that the Company achieved first quartile system performance compared to American utilities over the five-year period from 2000 to 2005.

AMPCO also submitted that the higher proposed capital spending should reduce the need for additional sustainment OM&A spending in future years.

Based on the above, AMPCO submitted that the 2007 Sustaining budget should be reduced to \$185 million, and the 2008 budget to \$195 million. AMPCO noted that Hydro One's proposals for Development, Operations, Shared Services and Other OM&A appeared reasonable.

CCC supported the AMPCO analysis of asset aging, asset condition and asset performance. CCC was also concerned about the increased bridge year spending revealed in the update, with no reduction shown in 2007 and 2008 plans. CCC recommended Sustaining OM&A spending be reduced by \$10 million to \$190.1 million in 2007.

SEC also submitted that planned Sustaining OM&A increases were too high in the test years. SEC argued that expenditure increases should have taken place earlier, citing evidence from Hydro One's 1999 transmission rates proceeding which indicated Hydro One was already aware that blocks of assets were reaching the end of their service lives.

SEC argued a prudent company, operating in a competitive market, which foresaw an imminent need to refurbish or replace aging assets would not wait until all of those assets reached a certain age before taking action. Rather, it would seek to smooth the impact of those investments to avoid problems with cash flow in a given year.

SEC also referred to the improvement in asset failure rates and forced outages in 2006, as shown in the updated evidence. SEC focused on Exhibit L1.3 where comparisons of OM&A per line kilometre show a 12% increase from 2006 to 2007 compared to an average annual increase between 2003 and 2006 of only 7%. SEC recommended that the Sustaining OM&A budget should be frozen at the updated 2006 level of \$179 million for each of 2007 and 2008. This would mean a reduction in the OM&A budget of \$21.1 million in 2007, and \$21.9 million in 2008. SEC's rationale for the reduction is based on its view that although planned expenditures in 2007 and 2008 are needed, they are unreasonable for inclusion in 2007 and 2008 rates because they are the result of imprudently low expenditures in the historic years. It contends that the Company should have been investing in the business during a period of overearning, and should not make up for that failure during the test years. SEC also asserts that the proposed spending levels do not take into account the higher 2006 spending levels revealed in the evidence update in February. In its view, this higher spending in 2006 should result in lower spending in the test years.

The Power Workers' Union ("PWU") supported the levels of OM&A spending applied for by Hydro One on the basis that Hydro One demonstrated the need for the levels of spending through their planning methods (asset condition assessment, outage data and asset aging data). PWU argued that if the Board found that these planning

methods are reasonable, then the results should be accepted as well. PWU submitted that as more units of work are required, and wages and material costs are increasing also, the increased costs are justified. PWU also submitted that if reductions are ordered, the impact of not doing this work on service quality, reliability and safety must also be taken into account.

Board Findings

Hydro One is seeking approval of a significant increase in its Sustaining OM&A spending. The key issue is the need for planned spending in 2007 which is almost 30% higher than the \$155.9 million originally planned for 2006.

The primary concern of intervenors with respect to this increase is its magnitude when compared to spending in this area in the recent past. Hydro One's response was that the need for such increases became apparent recently, and as the result of improved analytical and planning techniques. It argues that it would not have been prudent to make larger investments in preceding years, given its understanding of the condition of its plant at that time.

It is the view of the consumer intervenors that such large program increases require strong and objective evidence of a broadly-based deterioration in system performance or a demonstrated severe and rapid deterioration of a major asset class. They argue that no such evidence has been provided by Hydro One.

Intervenors suggest that it is impossible to conclude from the evidence provided by Hydro One that its asset base is aging at any specific rate, that this rate is greater or less than it has been in the past, or that further asset aging is creating a significant deterioration in reliability. Intervenors also assert that the evidence does not support claims of significant and increasing problems with Hydro One's assets or system performance deterioration.

Hydro One answers that the use of historic data to extrapolate an appropriate spending level for the test year is unsound. It argues that transmission system reliability is a lag indicator – by the time impairments in reliability become apparent it is too late. The Company relies on an improved package of leading indicators to plan its expenditures in this category.

The Company also asserts that while the evidence shows there was a marginal decrease in the failure rate of a single asset class in 2006, the trend is that of increasing and continuing deterioration overall.

The Company also disputes the claim made by some of the intervenors that the 2003/2006 Asset Condition Assessment comparison does not show asset condition deterioration. It suggests that the comparison made by the intervenors is inappropriate, given that it is based on two materially different data bases. The Company also separates its significant increases in capital expenditures to replace assets from its OM&A budget. It argues that there is no good reason to conclude that the replacement program contemplated will have any material effect on the short-term OM&A requirements.

The Board notes that the concerns of the intervenors with respect to the proposed level of spending were heightened by Hydro One's request that the Board approve a RRAM for 2009 and 2010. Under the proposed RRAM, the approved OM&A spending for 2008 would find its way into a rate adjustment mechanism for the following years. As noted in Chapter 2, the Board has not approved Hydro One's request for the RRAM, and the revenue requirement for 2009 will be based on a cost-of-service examination.

In the OM&A section of the Application, as in a number of other sections, the Board found some of the evidentiary record to be inadequate or incomplete. For example and as noted above, the Applicant insisted that the overall trend of its assets was continued and increasing deterioration while the evidence it placed before the Board

on that point showed a marginal decrease in the failure of a single asset class in 2006. The Board has concerns about the comparatively low spending levels in the years preceding the bridge year. It would be expected that a large and capable transmission company, such as the Applicant, would have had a more reliable asset condition assessment capability than appears to have been the case until recently. The Board would expect that the Company would attempt to smooth spending on this category of expense as much as possible, given the nature of the activity, which is, by definition, incremental in nature. It is concerning that the revenue requirement would include such a steep increase from one year to the next. While the Company has provided an explanation for its request for the sharp increase sought there remains ambiguity about the real state of the asset base. The evidence presented by the Company is not always consistent with the claims advanced.

It would have been better had the Company had been able to demonstrate with more acuity the statistical and technical underpinning of its point of view. The safe and reliable operation of the system is of paramount importance to the province's economy, and the well being of its population. This Application, and many other matters currently before the Board, documents the fact that the transmitter is engaged in very significant extensions and reinforcements of the system.

In the Board's view, resolving the ambiguity of the asset reliability evidence against the applicant by reducing the proposed OM&A budget would be inappropriate and unsafe. The Board is convinced that the Company has genuinely formed the judgment, based on its engineering expertise and its enhanced analytical capability, that increases of the nature applied for are needed to maintain a robust, safe, and reliable transmission system.

Accordingly, the Board will approve the OM&A budget as applied for the years 2007 and 2008. However, the Board directs the Applicant to work with intervenors to develop the type of and format for data reflecting asset condition. In particular, the Board directs Hydro One to provide asset aging data which includes data by value

and importance of the type of asset, as suggested in AMPCO's submissions, in its next transmission rates proceeding.

It is important that an approach is found that will allow all parties to make better assessments of the state of the asset base at the time of the next revenue requirement case. This data must enable the Company to bring to its next cost of service application a reliable representation of all important parameters of the condition and reliability of the asset base and the financial implications thereof. The Applicant will report to the Board no later than six months from the date of this decision on the progress made in the development of its improved asset database. It is the Board's intention that this stakeholdered exercise be implemented in time to provide a very clear representation of the condition of the Company's plant in time for its expected cost of service application for the 2009 revenue requirement.

4.2 EMPLOYEE COMPENSATION

Several intervenors directed their arguments to the overall size and growth of Hydro One's employee compensation cost. These issues are covered in this section. Some intervenors also raised issues with respect to two narrower compensation issues. Those issues are the rate treatment of incentive pay, and the possible impact on senior management compensation of the recommendations of the Province of Ontario's Agency Review Panel. Those two smaller issues are covered at the end of this chapter in section 4.3.

Hydro One conducts both its transmission and distribution businesses within a single corporate entity, Hydro One Networks Inc. Table 3 provides summary information on combined compensation cost and headcount for Hydro One's transmission and distribution businesses for the past four years, and the proposed amounts for 2007 and 2008.

Table 3: Employee Headcount and Compensation (total Hydro One Networks)

<i>Compensation cost in \$ millions</i>	<i>Historic</i>			<i>Bridge</i>	<i>Test</i>	
	2003	2004	2005	2006	2007	2008
No. of employees at year end						
Regular	3,696	3,841	3,904	4,018	4,204	4,158
Non-regular	<u>906</u>	<u>1,032</u>	<u>1,174</u>	<u>1,283</u>	<u>1,605</u>	<u>1,645</u>
Total	4,602	4,873	5,078	5,301	5,809	5,803
Compensation cost *	\$388.1	\$404.2	\$397.9	\$459.3	\$493.0	\$508.0
* Includes base salary, overtime pay, incentive pay, benefits (other than costs for pensions and other post-employment benefits), and other compensation.						
Source: Exhibit J1.40						

A portion of Hydro One’s compensation cost is included in OM&A expenses and the balance is included in the cost of various capital projects. Hydro One did not file any information in this proceeding about the amount of total forecast corporate compensation cost for 2007 and 2008 that will be borne by the transmission business (either as OM&A expenses for 2007 and 2008 or as additions to the transmission business rate base). The Company did estimate that just under 50% of full-time equivalent employees for the test year 2008 would be allocated to the transmission business based on the split of work programs between transmission and distribution.

The Board considered compensation issues at Hydro One most recently in its hearing on 2006 rates for the company’s distribution business. Given the short interval between the release of the Board’s decision on Hydro One’s distribution rates in April 2006, and the filing of Hydro One’s transmission rates application in September 2006, it is understandable that most of the compensation issues raised by intervenors in this case would be the same as those addressed in the distribution rates case.

In the Distribution decision, the Board made the following observations (in paragraphs 3.4.3 to 3.4.5):

- in future rate cases it expects Hydro One to identify what steps the company has taken or will take to reduce labour rates;
- the contrast between the compensation structures of Hydro One and some other utilities is of concern; and
- in future rate cases it expects Hydro One to demonstrate that lower compensation costs per employee have been achieved or to have concrete initiatives in place to bring compensation costs more in line with other utilities.

Hydro One stated that its approach to compensation has to be considered in light of several environmental factors. First, over 90% of Hydro One's workforce, including its engineers, is unionized, which places significant constraints on its ability to reduce compensation cost per employee. The two largest unions are the PWU and the Society. In the event of a strike by the PWU, which represents 70% of the company's workforce, Hydro One stated that it would be unable to sustain operations. Second, like many other entities in the power sector, Hydro One has an aging workforce, with over 1,000 employees eligible to retire by the end of 2008. The Company said it was working hard to strike a balance between the need to control compensation costs, and the need to hire new workers and to retain existing staff. Third, over the next few years, Hydro One must complete a large work program involving asset sustainment and major development projects.

Despite these factors, Hydro One submitted that it has had some success with its two major unions. It listed five areas in which it believes it has made gains in negotiations with the PWU (such as eliminating incentive pay) and three areas in which it has made gains in negotiations with the Society (including a pension arrangement for new Society employees that is 25% less costly than the pensions for existing employees). The Company also intends to increase its reliance on external consultants and contractors as a way to deal with its major work programs.

Hydro One filed a benchmarking study, prepared by PA Consulting in September 2006 (the “study”¹³), which compared 21 of the Company’s business performance metrics with 13 North American utilities. It also provided specified wage rate and overtime policy comparisons for three job classifications with 13 Canadian regulated transmission or distribution companies. With regard to the specified wage rate and overtime policy comparisons, Hydro One’s rates were highest for two of the job classifications and third highest for the other.

Hydro One argued that the benchmarking study was completed under tight time constraints on a “best efforts” basis and has several shortcomings which limit its usefulness. The study itself referred to several limitations and noted that further substantial effort and investigation would be required before any conclusions can be drawn. Hydro One stated that given more time it would not necessarily have selected the 13 companies for a benchmarking study on salaries.

PWU supported the forecast compensation costs for 2007 and 2008. It submitted that given the heavily unionized and aging workforce, and Hydro One’s need to complete a major work program over the next few years, the Board should not expect any material reduction in cash compensation per employee. It also argued that the results of the benchmarking study were incomplete and inconclusive, and cautioned the Board against drawing any conclusions from the study’s labour rate comparisons.

The Society argued that compensation costs for Hydro One’s unionized employees are not high. It cited many of the same environmental factors noted by Hydro One as support for this view. It also submitted that total compensation cost per employee is not a useful measure of the Company’s efficiency. Rather, it would be better to assess Hydro One’s performance against productivity measures such as units of

¹³Hydro One was directed by the Board in the Distribution decision to prepare a high level benchmarking study for the next distribution rates case, based on a list of comparable North American companies with similar business models (transmission and/or distribution) and to report on high level comparative performance and costs information for Hydro One and the companies. The Company was directed to submit the study “on a best efforts basis” in its transmission rates application for 2007.

accomplishments per employee.

Although the Society accepts Hydro One's compensation budget, it said that if the Board continues to have concerns there are better ways for Hydro One to increase efficiency than to reduce compensation for unionized employees. It recommends that Hydro One address what the Society considers to be an unnecessarily high manager-to-employee ratio, made worse in 2006 as the result of the transfer of 155 Society-represented positions to management positions.

CCC said it continues to be concerned about the overall level of Hydro One's compensation costs. It did not, however, recommend any reduction in Hydro One's proposed revenue requirement as a result of such concerns. Instead, it urged the Board to direct the Company to work with stakeholders to propose and undertake a meaningful review of costs relative to comparators.

Energy Probe described Hydro One's overall compensation cost as clearly excessive and above market. It acknowledged that the issue requires management's attention over a number of years and said it is difficult to move towards market-based compensation every year. It argued that, as part of Hydro One's next distribution rates case, the Company should be required to provide more responsive evidence on initiatives to achieve cost per employee closer to market value.

SEC submitted that Hydro One's evidence on compensation was not responsive to the Board's direction to the Company in the last distribution rates case. It said the various negotiated gains cited by Hydro One in this application pre-dated the Board's April 2006 decision on distribution rates. It also challenged Hydro One's statement that the elimination of incentive pay for PWU-represented employees was a gain as it appears that the gain was offset by higher base pay.

Despite its concerns, SEC did not recommend any change in the forecast compensation costs except for a component of forecast management compensation. In 2006, Hydro One increased the minimum and maximum pay bands for management employees, an

action SEC said was not appropriate because management salaries “set the bar for all the Company’s pay bands.” SEC recommended that the Board disallow the portion of forecast compensation costs resulting from this change without specifying an amount, or if the amount involved is material.

SEC said the Board should reaffirm the direction given in the Distribution decision and warn Hydro One that it will risk not recovering all of its compensation costs if it fails to take reasonable steps to reduce compensation.

VECC and SEC noted that the compensation comparisons provided by Hydro One look only at base salary and short-term incentives. Both intervenors recommended that in future filings Hydro One should provide information on how its total compensation, including pension and similar benefits, compares to other companies. VECC also recommended that Hydro One should develop measures that would allow parties to judge whether the size of the Company’s management group is appropriate.

Board Findings

The Board finds itself in the same position after this hearing as it was after the hearing on Hydro One’s 2006 distribution rates – it has lingering concerns about the size and growth of overall compensation costs at Hydro One. Having said that, the Board will accept the forecast compensation costs for 2007 and 2008. The evidence on compensation costs in this proceeding, while less than optimal, is sufficient to enable the Board to make this finding. While intervenors have expressed concerns about these costs, they have not been able to challenge these amounts convincingly, nor have they provided any coherent basis upon which the costs could be reduced. The Board notes that none of the intervenors recommended any disallowances except for SEC, which advocated that due to widening pay bands, any increases in management compensation should be disallowed.

Some intervenors recommended that the Board should direct Hydro One to prepare a

more comprehensive study of its compensation costs and how they compare with the costs of comparable utilities. Hydro One indicated during the hearing that it is carrying out further work now that will be filed as part of its next distribution case.

The Board looks forward to the filing of a study which provides useful and reliable information concerning Hydro One's compensations costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America.

To that end, the Board directs Hydro One to consult with stakeholders about the type of information to be gathered and the types of utilities and other companies that should be used for comparison purposes. The Board also expects Hydro One to gather and compare data reflecting total compensation costs, not just base salaries. Detailed comparisons of compensation costs for specific job categories are of some help in understanding how Hydro One compares to others in the industry. Equally important is the size and trend of labour costs per unit of output of various sustainment, development, and corporate activities. In the study that Hydro One is now preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities. Deficiencies in the evidence which are not fully justified could be construed against the utility in its next rates case.

The PA study filed in this Application suffered from various deficiencies and shortcomings, as noted by the authors of the study, the Applicant and the intervenors. The Board expects the new study to be comprehensive and reliable, with none of the limitations of the PA study. If Hydro One cannot correct all of these deficiencies in time for the Company's 2008 Distribution rate filing, the Board expects them to be corrected in the 2009 transmission filing.

4.3 OTHER COMPENSATION ISSUES

In its decision on Hydro One's 2006 distribution rates, the Board approved the inclusion of incentive compensation payments in the revenue requirement. The Board also made the following comment:

While the Board does not consider the achievement of net income to be a factor that works only for the benefit of the shareholder, as customers benefit from a healthy utility through higher credit ratings and good service, the Board would be concerned if this factor predominated compared to the other factors determining incentive pay. The Board expects Hydro One to file appropriate evidence in its next main rates case to establish that none of the incentive compensation should be charged to the shareholder.”¹⁴

Budgeted incentive payments for Hydro One’s transmission and distribution businesses are \$6.9 million for 2007 and \$8.5 million for 2008. Hydro One did not file information that specified the portion of those amounts that relate solely to its transmission business. (As noted in section 3.2 above, Hydro One estimated that just under 50% of its full-time equivalent employees would be allocated to its transmission business.) The amount of incentive payments are linked to 14 performance measures included in the company’s balanced scorecard, one of which is the achievement of net income targets.

Although the amounts may not be significant, CCC recommended that as a matter of principle none of the forecast incentive pay for 2007 and 2008 should be recovered through transmission rates. CCC submitted that this would be consistent with the methodology the Board has applied to electricity distributors. Energy Probe accepted that incentive payment targets do benefit ratepayers but argued that 25% of the amounts should be disallowed because Hydro One failed to file evidence that none of the cost should be borne by its shareholder. VECC also recommended a 25% disallowance. SEC recommended the disallowance of an unspecified portion of the forecast payments.

CCC and VECC also recommended that Hydro One be directed to establish a deferral account to track any cost reductions in 2007 and 2008 that result from Hydro One’s implementation of the findings of the Agency Review Panel, established in January 2007. It released its Phase I report on executive compensation at Hydro One and four other provincial electricity sector institutions on June 27, 2007. At that time, the Minister

¹⁴ Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006. para. 3.4.6.

of Energy announced that he has directed each institution to implement the Panel's recommendations.

Board Findings

The Board accepts the inclusion in the revenue requirement of the forecast incentive payments.

The concern of intervenors is the inclusion of a net income target in Hydro One's balanced scorecard, which is the basis for incentive payments. The Board acknowledges that its 2006 Distribution Rate Handbook ("2006 EDR Handbook") stated that incentive payments related to benefits to shareholders would not be recoverable in the 2006 revenue requirement of a distributor. In the Board's view, our decision to allow incentive compensation costs in Hydro One's transmission revenue requirement is not in conflict with the 2006 EDR Handbook. First, net income is only one of 14 performance measures in Hydro One's balanced scorecard; there is no evidence that the net income performance measure predominates, which was the concern expressed by the Board in the Hydro One distribution decision. Indeed, Hydro One pointed out that incentive payments are contingent on meeting a range of performance measures; no payouts would occur if the net income target were met but other measures were not achieved. Second, there is no evidence that would allow the Board to make an objective determination of how much of the forecast incentive payments relate to shareholder benefits. Even if that were possible, it appears to the Board that the amount, if any, would be very small given that the total incentive payments allocated to the transmission business for the test years are not particularly significant.

Executive compensation costs in Hydro One's application obviously could not have reflected the recommendations of Agency Review Panel. The impact of the recommendations on Hydro One's executive compensation for 2007 and 2008 is unknown given that the Company's Board of Directors would only recently have started the implementation process. In addition, the effective date of any new compensation

practices at Hydro One is also unknown. Accordingly, there is no way to predict if the impact in 2007 and 2008 of the implementation of the Agency Review recommendations will be significant.

The Board would generally not require a utility to track variances in routine costs when new information about the extent of those costs in the test years becomes known only after the rates hearing is completed and the parties have submitted argument.

In this case, the Board believes an exception is warranted. In his announcement of the release of the Panel's report, the Minister of Energy noted that the government wants to ensure that compensation for top executives strikes an appropriate balance between being competitive on the one hand, and fair to ratepayers, on the other. The Board directs Hydro One to track any reduction in executive pay during 2007 and 2008 that results from implementing the Panel's recommendations and to report that amount at its next transmission rate case.

5. CAPITAL EXPENDITURES

Hydro One's updated evidence shows a significant increase in transmission capital spending. The Company has requested approval for capital expenditures of \$691.5 million in the 2007 test year and \$768.2 million in 2008, as shown in Table 4. The 2007 amount is 72% higher than bridge year levels and the 2008 amount is 11% higher than 2007. The bridge year amount of \$401.6 million was 15% higher than 2005 levels. The two main areas of this growth are the Sustaining and Development capital budgets, which comprise over 90% of the total proposed capital expenditures.

Table 4: Capital Expenditures 2003 – 2008

\$ millions	Historic			Bridge		Test	
	2003	2004	2005	2006	2007	2008	
Capital Expenditure by Category							
Sustaining	\$160.3	\$173.7	\$168.9	\$178.5	\$288.1	\$295.6	
Development	59.5	217.3	134.6	179.4	298.7	409.4	
Operations	38.9	20.7	10.2	9.4	20.1	20.4	
Shared Services & Other	28.7	20.2	35.5	34.1	84.6	42.7	
Total*	<u>\$287.4</u>	<u>\$431.9</u>	<u>\$349.2</u>	<u>\$401.4</u>	<u>\$691.5</u>	<u>\$768.1</u>	
Year over year % change							
Sustaining		8.4%	-2.8%	5.7%	61.4%	2.6%	
Development		265.2%	-38.1%	33.3%	66.5%	37.1%	
Total Capital Expenditures		50.3%	-19.1%	14.9%	72.3%	11.1%	
*Note: Totals may not add due to rounding. Source: Exhibit D1/Tab3/Sch1							

Hydro One defended its capital budgets on the basis of what it considers a comprehensive planning process that encompasses the effects of an aging asset base, the results of the asset condition assessment and monitoring of failure rates. In addition,

its process takes into account significant expansion of the transmission system to accommodate what the Utility describes as the changing electricity infrastructure needs of the province.

Intervenors generally limited their arguments to the Sustaining and Development budgets.

5.1 SUSTAINING

The Sustaining budget is growing from \$178.5 million in 2006 to \$288.1 million in 2007, an increase of 61% with a further small increase in 2008 of 2.6%.

Sustaining expenditures include the cost of investment required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. The evidence showed that these capital expenditures are largely driven by the same factors as OM&A spending, that is, asset condition assessment, asset aging records and data respecting failures and outages.

Intervenors' concerns fell largely into three categories: concerns that the asset assessment was not sufficiently robust to accurately determine the need to replace the assets; criticism that Hydro One spent insufficient funds on asset maintenance in previous years; and concerns that Hydro One would not be able to spend all the funds budgeted.

Part of Hydro One's asset analysis relied on information on asset failure rates. VECC argued that updated information on failure rates showed that outages were actually lower than those used to develop the sustaining budget. In addition, VECC argued that the 2006 asset condition assessment was not much different than the previous (2003) assessment. Overall, VECC questioned whether this information justified the large increase in sustaining capital expenditure.

SEC reiterated the arguments it made with respect to the OM&A budget, namely that Hydro One had ample information regarding the state of its asset base during the historic period to justify gradual increases in expenditures so as to avoid major increases in the test years. SEC suggested that this demonstrated that the Sustaining capital budget should be reduced, but did not suggest a specific reduction in the test years.

AMPCO's position was that the evidence on asset aging was not clear, and urged the Board to direct Hydro One to provide better evidence of asset aging at its next rate hearing. AMPCO also questioned the evidence that system performance was deteriorating. In addition, AMPCO cited Hydro One's performance compared to analogous utilities. Further, AMPCO argued that there should be significant sustainment benefits arising from the proposed large increase in development spending, which will result in the replacement or upgrading of existing components in capital projects. AMPCO submitted that the sustainment budget should be reduced to \$215 million in 2007 and \$255 million in 2008.

Hydro One responded that its capital spending plans are based on multi-year trends in asset failures, and a slight reduction in failures in 2006 would not cause it to alter its plans for single year results or for a single asset group.

Hydro One also argued that the asset condition assessment methodology for 2006 was markedly different than the 2003 study, with a larger asset base, refined techniques, improved data quality and enhanced algorithms. Hence, the results of the two assessments were not directly comparable. Hydro One maintained that the evidence it had in the earlier period, when it completed its business planning, did not justify higher expenditures in the years leading up to the test year. There was no reason to increase expenditures during that period, given that the information available at that time did not show a need to accelerate replacements or upgrades. In addition, Hydro One asserted its evidence points to increasing numbers of mid-life and end-of-life assets, largely the result of a high growth period in the 1950s and 1960s.

PWU supported the Hydro One request for Sustaining capital, citing the asset aging and performance evidence as well as raising the risk to reliability, service quality, safety and increased maintenance costs, if capital spending were to be reduced from planned levels. The PWU stated that some of the increased budget for Sustaining capital was a result of the increasing cost of material and equipment in a time of unprecedented transmission development globally.

Board Findings

The findings in this decision on OM&A expenditures are very relevant to these findings, as increases in both cases are largely based on aging assets. Hydro One is seeking approval of a sustainment capital budget that increases by an extraordinary 61% from 2006 to 2007. Intervenors are understandably concerned. Their concerns regarding asset assessment information are equally relevant to sustainment capital and OM&A.

The Board accepts that Hydro One's asset assessment methodology and information is improved over previous years. However, it still lacks clarity and robustness. While Hydro One's quantitative evidence is not compelling, the Board finds that Hydro One's qualitative evidence provides assurance that capital costs are escalating significantly. The Board accepts that the high growth period of the 1950s and 1960s likely results in a similar period of a high number of assets coming to the end of their useful life. Though the most recent failure information did show some improvement in failure trends, the Board also acknowledges Hydro One's position that plans for sustaining investment must take into account more than a one-year or short-term improvement when planning capital spending programs. In addition, the Board notes Mr. McQueen's evidence that increasing costs are also a result of escalating global demand for material and equipment. No intervenor refuted this evidence. Therefore, the Board accepts that both the number of replacements and the cost per replacement are escalating.

Intervenors asserted that Hydro One could have avoided the proposed significant increase in expenditures by recognizing the asset aging problem sooner and smoothing the expenditures over the past several years. The Board accepts that it is difficult to

smooth a capital budget over several years and that it is both imprudent to invest too soon in capital replacements and imprudent to wait until the system deteriorates to very low levels of reliability before action is taken. Hydro One must balance the immediate investment needs of the system with an eye to proactive action to prevent an unsupportable level of failure and reliability levels.

AMPCO submitted that a large capital investment program should result in lower sustaining capital expenses and suggested that the Board should take this into consideration. The Board agrees that the replacement of old equipment during a capital program should have the effect of lowering sustaining capital costs. We anticipate that there will be a lag in the effect, and expect Hydro One to provide evidence on the 2009 and 2010 sustainment capital benefits of 2007 and 2008 capital expenditures as the newer facilities come into service and replace the aging fleet. However, the Board does not accept AMPCO's rationale for its recommended reduction to OM&A expenses for the test years.

The Board approves the amounts applied for sustaining capital in 2007 and 2008 rates. As noted earlier in this decision in the OM&A chapter, the Board must have improved asset aging data for the next Hydro One cost-of-service proceeding. In approving the Sustaining capital investment plans, the Board expects Hydro One to continue to improve its asset condition assessment work and its work on the influence of asset aging on investment levels. The Board refers the reader to Chapter 3 of this decision for the Board's direction on developing this information.

5.2 DEVELOPMENT

The Development budget is growing from \$179.4 million in 2006 to 298.7 million in 2007, an increase of 66% with a further increase of 37% in 2008 to a level of \$409.4 million.

The Development Capital category covers funding for projects related to new or upgraded transmission facilities. Those facilities provide inter-area network transfer

capability provide adequate capacity to deliver electricity to local areas, connect new generation and load customers to the transmission system, and maintain the performance of Hydro One's transmission system in accordance with Delivery Point Performance Standards. Hydro One showed project detail for all projects with budgets in excess of \$3 million.

Hydro One classified the proposed Development projects on the basis of in-service date and the nature of the approval the applicant was seeking from the Board.

Category 1 included 15 projects with in-service dates in 2007 and 2008. The Applicant seeks to include the budgeted expenditures in the rate base the Board for 2007 and 2008.

Category 2 included six projects with in-service dates in 2009 and 2010. These projects do not require Board approval pursuant to section 92 (leave to construct), but will come before the Board again when the Company applies to include the costs associated with them in rate base. As these projects require significant spending in 2007 and 2008, the Applicant seeks assurance from the Board that the projects appear to be necessary, and the costs of the projects appear to be reasonable and prudent. The most significant project in this group is the Claireville/Cherrywood 500 kV circuit unbundling project.

Category 3 included seven projects that will require section 92 approvals. In the course of those proceedings the Company will present evidence establishing need and cost. However, for reasons that will be outlined below, Hydro One requested a determination by the Board of the need for the Leaside to Birch Junction project in this proceeding.

Category 4 consisted of two projects which may be part of the Integrated Power System Plan process, and which will have in-service dates beyond the test years. The evidence regarding these projects will be brought before the Board in a subsequent rate proceeding for inclusion in rate base. The Company did not seek any decisions from

the Board with respect to these projects in this proceeding, and the Decision does not comment on those projects.

Board Findings – Development Category 1 Projects

In the Board's view, Hydro One's justification for the bulk of Category 1 projects was extensive and thorough. Support for these projects from sources such as the OPA, the IESO and preliminary documents related to the IPSP is persuasive. The Board also notes the support provided by Toronto Hydro and OPG for some of these investment projects.

There were no Intervenor or Board staff concerns with any of the Category 1 projects. The Board is of the view that these projects are well documented and substantiated by the evidence presented by Hydro One. The Board approves the inclusion into rate base of the budgeted amount of these projects. The total amount projected to be included in rate base in connection with the Category 1 projects is \$256 million.

Board Findings – Development Category 2 Projects

Of the Category 2 projects, the Claireville/Cherrywood project was the most discussed. This project, which has an expected capital cost of \$107 million, involves unbundling two 500 kV lines that are now connected and operated as a "super" circuit. Currently when one of the two circuits is out of service due to a planned or forced outage, generation connected to the 500 kV system in eastern Ontario must be curtailed. If constructed, the project will result in over 3,000 MW of transfer capability between the Claireville and Cherrywood transmission stations. The project was included in the June 2006 and March 2007 editions of the IESO's Ontario Reliability Outlook ("ORO").¹⁵

¹⁵ In its final argument, the IESO said that "The inclusion of a project in the ORO ... underscores the IESO's assessment that a proposed project meets a reliability need that has been identified or confirmed by the IESO. ... To be clear, the inclusion in the ORO is not a directive for a transmitter or other entity to undertake construction, but agreement from the IESO that the proposal meets a specific need to improve reliability of the IESO-controlled grid or the load it serves."

Intervenors were generally in support of the Claireville/Cherrywood project and found the economics and rationale compelling. Toronto Hydro supports the project as it will improve supply reliability to Toronto's distribution system. OPG supports the Claireville/Cherrywood project as it is critical to the integrity of the power system, and benefits the electricity system and the operations and safety of the Darlington Nuclear station once completed. According to OPG, the project will reduce the risk of sudden generation reduction, which results in a revenue loss per event in the range of \$0.5 million to \$1 million.

Toronto Hydro also supported the Hydro One Development Capital program, making submissions for 16 specific projects cited in the Hydro One evidence, including several Category 2 projects. PWU supported the Hydro One Development capital budget proposals, citing the IPSP, OPA procurement activities and the IESO ORO reports as justification for these investment plans.

Regarding the Category 2 projects, including Claireville/Cherrywood, VECC was concerned with Hydro One's desire for assurance from the Board that "the capital program that the company is proposing is an appropriate approach, subject to coming back later to demonstrate to you that the costs have been reasonable and prudently incurred." ¹⁶ VECC submitted that the Board should not grant this assurance and that any such conclusion should be no more than an observation that the projects are reasonable.

The Board agrees with VECC. The costs of these projects will be subject to approval in a future proceeding. However, the Board does make the observation that these projects appear to be needed and, based on the limited evidence available, the Board did not identify any concerns about the proposed costs. The need for at least some portion of the Claireville/Cherrywood project appears to be non-discretionary. As Hydro One will be returning in 2008 for a 2009 test year application, the Board expects to see updates and progress reports on all these projects at that time, for final scrutiny and

¹⁶ Tr. Vol.2, p.121

consideration of approval of the inclusion of these amounts into rate base. For discretionary projects, the Board expects Hydro One to quantify the reliability and other benefits of the projects.

Board Findings – Development Category 3 Projects

In this proceeding, the Board need make only one finding regarding the Category 3 projects. This is the need determination for the Leaside TS to Birch Junction TS project. Approval of all of the elements of the other projects will be covered under Leave to Construct (section 92) applications.

The Settlement Proposal stated:

The parties agreed that the Applicant has demonstrated the need to relieve loading on the existing 115kV connection lines and Leaside and Birch Junction TSs.

The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Notwithstanding this settlement, the Board determined that the need for this project should be examined on the record. Hydro One presented witnesses to address this issue in the oral hearing and provided evidence of need supported by the IESO and Toronto Hydro. Other intervenors did not comment on the evidence respecting need but submitted that the scope of the finding that the Board makes should not be broader than that agreed to in the Settlement Proposal.

The Board agrees. The evidence clearly demonstrates the need for the project as it addresses specific reliability issues. The Board finds that the need to relieve loading on the existing lines between Leaside TS and Birch Junction TS has been demonstrated. The Board accepts that the issues on options, alternatives and costing of mitigating alternatives be deferred to a section 92 application, as agreed to by parties in the Settlement Decision.

5.3 ECONOMIC JUSTIFICATION OF THE NIAGARA REINFORCEMENT PROJECT

The Board in its July 8, 2005 Decision on the Niagara Reinforcement Project (“NRP”) (RP-2004-0476), granted leave to construct without a determination that Hydro One had proven the economic benefits of the project. As part of that decision, Hydro One was directed to demonstrate the benefits when seeking to recover the costs associated with the project. The Company provided evidence respecting the economic benefits of the project in this proceeding.

Hydro One indicated that the NRP, when operational, will increase import capability from New York by 350 MW. To assess the economic benefit of the project, Hydro One compared, for a 30-year period, the cost of acquiring additional generation capacity through the installation of a 350 MW single cycle combustion turbine unit with the NRP costs. According to Hydro One’s evidence the present value of the cost of the 350 MW combustion turbine unit is \$309 million and the present value of the cost of the NRP of \$103 million. The implied net present value is about \$200 million.

Part of the evaluation involved estimating the difference in cost between buying energy in the New York market versus producing energy in Ontario from the combustion turbine. The difference was estimated to be about \$70 million in favour of the New York purchase option. The assumptions underlying this estimation were the subject of significant cross examination concerning energy price differentials between the New York and Ontario markets.

Intervenors generally did not comment on the NRP economic justification issue in their final submissions. Only VECC raised concerns regarding Hydro One’s analysis. While VECC accepted that the NRP offers benefits that allow new generation in the Niagara Peninsula and increases access to imports, it questioned the 30-year time horizon of the analysis. VECC suggested that the Board direct Hydro One to revise its economic analysis of the project, add congestion costs to the calculation and file the revised

analysis prior to requesting any determination from the Board that all of the costs of the NRP (when in-service) be recovered from ratepayers.

Board Findings

While the Board agrees that the further analysis suggested by VECC might have been helpful, the Board finds it was reasonable to compare the transmission reinforcement to a 350 MW single cycle gas combustion turbine. The Board accepts that the need for NRP should be assessed based on the circumstances that existed at the time the project was initially conceived and the information available at that time. For this project, the relevant time period was 2004/2005. When the historical context is taken into account, the economic evaluation provided by the Company is sufficiently persuasive to allow the Board to make this finding. The Board accepts the expenditures associated with the project as prudent, and requires no further analysis from Hydro One to justify the expenditures incurred to date.

However, the Board is concerned that the economic evaluation presented by the Company had shortcomings, which should not be repeated in future applications. In preparing economic justification for similar projects, the Board expects a more complete, precise and rigorous evaluation which includes an analysis of the option of not proceeding with a project, (the “do nothing” scenario) and sharply improved efforts to quantify reliability benefits.

Hydro One is seeking extraordinary relief to recover the costs of this uncompleted project in rate base. The discussion of this aspect of the NRP and the Board’s decision on the matter can be found in Chapter 6 of this Decision.

5.4 OPERATIONS AND SHARED SERVICES

Shared Services capital spending for the test years is substantially higher than spending in 2006 and earlier years. This is mainly due to the Hydro One's Cornerstone information technology project.

Phase One of the Cornerstone project involves the replacement of the PassPort asset and work information system with an integrated Enterprise Asset Management application. The evidence showed that capital spending on this phase alone will be \$102 million in 2007, with \$57 million allocated to the transmission business.

Although there was significant cross examination on this project, intervenors did not address this issue in their final arguments. According to the Company's evidence, the net present value of the first phase of the project is a \$60 million cost over the seven years from 2008 to 2015. Hydro One asserts that the benefits of the project will follow full implementation.

Board Findings

Hydro One was able to demonstrate that the Company's information systems cannot provide the information required to efficiently manage its work and assets. Indeed, the difficulty in getting robust asset aging information in this proceeding was partially attributed to the poor information systems. The Board accepts the Operations and Shared Services capital costs for the 2007 and 2008 rate years, including funding for the Cornerstone project. The Board anticipates greater scrutiny of the cost of Cornerstone in the next transmission rate proceeding when more detailed information will be available.

5.5 CAPITAL CONTRIBUTIONS

Hydro One estimated the total cost of Cambridge Preston TS project cost to be \$21.2 million. The Company is not requiring a capital contribution from the customer based on the Company's interpretation of the Transmission System Code (TSC). The appropriate interpretation of the TSC regarding capital contributions is being considered in another Board proceeding, the Connections Procedures case (EB-2006-0189). The decision in that case will clarify the interpretation of the relevant sections of the TSC regarding capital contributions.

VECC submitted that if the EB-2006-0189 decision is not rendered in time to have it reflected in the revenue requirement for 2007 and 2008, then a deferral account should be set up to track the impact of any capital contributions, should that decision reflect an interpretation of the TSC contrary to that taken by the Company in this proceeding. Hydro One argued that a deferral account would not be necessary, but if it is determined that a capital contribution is required, a deferral account could be used to adjust rate base. Hydro One indicated that were a capital contribution required, the customer would have to pay \$17 million. The Board estimates the effect on the revenue requirement of such a capital contribution would be less than \$2 million in 2007 and 2008.

Board Findings

Since the outcome of the EB-2006-0189 proceeding is not known, the Board accepts VECC's position that a deferral account should be established. Entries in the account will be necessary only if the Board's decision in EB-2006-0189 results in the customer being required to make a capital contribution in respect of the Cambridge Preston TS project.

5.6 EARNINGS/SHARING MECHANISM

While VECC and CCC did not recommend a reduction in the proposed capital budget, they did suggest that Hydro One's capital spending plans were too ambitious and there was a risk that they may not be completed as planned. VECC also questioned Hydro One's prioritization methods. VECC suggested that underspending of the capital budget be returned to ratepayers through an earnings sharing mechanism. CCC supported this recommendation.

Hydro One submitted an earnings sharing mechanism was not necessary and cited evidence that the capital additions expected to come into service during the test years were manageable. The Company also pointed out that earnings sharing proposal would be inconsistent with a cost-of-service filing that is based on future test years.

Board Findings

Hydro One submitted evidence comparing the Company's actual capital spending to budget forecasts for the years 2003 through 2006. The results show variances of up to 20%, both positive and negative. The Board is concerned with the magnitude of the variances but has no basis to believe that the forecast budget for 2007 and 2008 will be under spent. The Board finds that an earnings sharing proposal to guard against variances to budget is unnecessary. As a result of the Board's decision to deny Hydro One's request for a 2009/2010 RRAM, the Board expects Hydro One to file a cost-of-service application for 2009 rates. At that time, the Board expects Hydro One to provide evidence on 2007 and 2008 actual capital spending compared to the Board-approved budget. Future decisions on capital budgets will be informed by Hydro One's performance to plan.

SUMMARY BOARD FINDINGS ON CAPITAL EXPENDITURES

In summary, the Board approves the capital budget for 2007 and 2008 as presented by Hydro One. This includes the budgets for all categories of the capital spending including the Operations and Shared Services categories. The Board reiterates the need for more robust data regarding some of the categories of capital expenditures, as outlined more fully in text above, which the Board expects Hydro One to file in its next transmission rates application.

6. HYDRO ONE'S REQUEST FOR SPECIAL TREATMENT FOR DESIGNATED TRANSMISSION PROJECTS

Hydro One requested special regulatory treatment for four transmission projects: the Bruce Project, a proposed new transmission line to support additional electricity generation from Bruce Power and proposed or possible wind generation projects; the Quebec Intertie, a 1,250 MVA interconnection with Hydro-Québec's transmission system; the installation of static VAR compensators in southwestern Ontario; and the Niagara Reinforcement Project ("NRP"), a new transmission line that is virtually complete. Table 5 shows actual and forecast spending on these projects.¹⁷

For each of these projects, Hydro One proposed:

- Increasing rate base as expenditures are incurred rather than waiting until the projects are in-service;¹⁸
- Commencing amortization of the project costs as funds are spent (that is, before they are in-service and are being used) and including the amortization in the revenue requirement; and
- Holding Hydro One financially harmless in respect of the designated projects in the event of abandonment for reasons outside the Company's control.

¹⁷ In its evidence, Hydro One referred to these four projects as "supply mix capital projects". It was not clear to the Board why Hydro One decided to use that description. The Minister of Energy's June 13, 2006 directive to the OPA on the supply mix goals of the Integrated Power System Plan did not mention any particular transmission projects. Two of the projects – the Quebec Intertie and the NRP – were planned and approved before the Minister issued the directive. The other two projects are being initiated before the OPA files its IPSP. In this chapter of the Decision, the Board refers to these projects as the "designated projects", not "supply mix capital projects."

¹⁸ Hydro One also requested that this adjusted rate base would be used to set the revenue requirement under the Company's proposed revenue requirement adjustment mechanism for 2009 and 2010. As noted in Chapter 2 of this Decision, the Board denied Hydro One's request for the RRAM. Therefore, this request is now moot.

The proposed approach differs from the conventional regulatory approach of capitalizing interest costs during construction, and waiting until the project is in-service to transfer the costs to rate base and to commence amortization.

Table 5: Actual and Forecast Expenditures on the Designated Projects

(\$ millions)	Historic		Bridge	Test		Total (including future years)	Expenditure Period
	2004	2005	2006	2007	2008		
Bruce Project	-	-	-	5	52	613	2007 - 2011
Quebec Intertie	-	-	1	65	48	115	2006 - 2009
Static Var Compensators	-	-	-	-	10	54	2008 - 2009
Niagara Reinforcement	1	35	61	2	0	101	2004 - ?? *
Total	1	35	62	72	110	883	

* Project is almost complete but work has been suspended.

Only three projects were designated for special treatment in Hydro One’s September 2006 application; the NRP was added when the Company amended its application in February 2007. As most intervenors noted, the NRP is fundamentally different from the other three projects in that it is substantially complete but work has been halted because of events outside of Hydro One’s control. In this chapter, the Board deals with the other three projects in section 6.1 and then separately considers the NRP in section 6.2.

6.1 BRUCE PROJECT/QUEBEC INTERTIE/STATIC VAR COMPENSATORS

Hydro One’s primary rationale for the proposed special treatment is that the designated projects require significant expenditures, must be initiated in the short term, have long lead times, are driven by Ontario’s supply mix initiatives, and are exposed to risks over which Hydro One has limited or no control or influence.

Hydro One submitted that its proposed regulatory treatment is consistent with the approach recently adopted by the Federal Energy Regulatory Commission (“FERC”) in the United States, will result in a neutral bottom line and will mitigate rate shock and, will result in ratepayers, the primary beneficiaries of the projects, bearing the risks.

FERC Policy and Precedents

To stimulate private capital investment in transmission infrastructure, the United States Congress directed FERC to establish incentive-based rate treatments to promote investment in transmission infrastructure. In 2006, FERC issued Order No. 679, which identifies the types of rate incentives that FERC will consider for federally-regulated transmission entities when justified by the specific facts and circumstances.¹⁹ The identified incentives include higher rates of return on equity for specific transmission investments; the inclusion of 100 percent of construction work in progress (“CWIP”) in rate base; and the assurance of recovery of the costs of a project that is abandoned for reasons outside the control of the utility.

In its evidence, Hydro One cited four transmission projects for which FERC approved various incentives. Table 6 summarizes those projects and the incentives granted by FERC. The American Transmission Company decision pre-dated Order No. 679. The other decisions were issued at the same time or after the issuance of Order No. 679²⁰.

¹⁹ Federal Energy Regulatory Commission, Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, July 20, 2006. In December 2006, after rehearing certain issues, FERC issued Order No. 679-A, which clarified and amended some aspects of the original order but did not change the overall framework for transmission incentives.

²⁰ After the oral hearing was completed, Staff circulated *Commonwealth Edison Company*, 119 FERC ¶ 61,238 (2007), the most recent decision on incentives for transmission projects, to all parties. The Board did not rely upon it in making its decision.

Table 6: Recent FERC Cases on Incentives for Transmission Projects

Proponent	Project	Cost (US \$ millions)	FERC Incentives
American Transmission Company²¹	Various proposed projects over 10 years	Up to \$2,800	<ul style="list-style-type: none"> ▪ 100% of CWIP in rate base ▪ Expense pre-certification costs ▪ Increased ROE
American Electric Power²²	550 miles of 765 kV lines from West Virginia to New Jersey Target completion date – 2014	\$3,000	<ul style="list-style-type: none"> ▪ 100% of CWIP in rate base ▪ Option to expense pre-commercial costs ▪ Increased ROE
Allegheny Energy²³	240 miles of 500 kV lines from Pennsylvania to northern Virginia Target completion date – 2011	\$820	<ul style="list-style-type: none"> ▪ 100% of CWIP in rate base ▪ Expense pre-commercial costs ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment
Duquesne Light²⁴	New high voltage line; increase capacity of underground 345 kV lines with advanced technology; upgrade certain 69 kV facilities to 138 kV. Target completion date – 2009 (some work already complete)	\$184	<ul style="list-style-type: none"> ▪ 100% of CWIP in rate base ▪ Expense pre-commercial cost ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment

While the FERC incentives listed in Table 6 are intended to encourage investment in transmission projects, Hydro One stated a different rationale. In response to a question from the Board Panel, Hydro One said:

What we're asking for is not an incentive in the traditional use of that word, as far as to provide some incentive to encourage a certain behaviour ... [what] we're asking for is special regulatory treatment for these projects as opposed to an incentive to do something before the fact.²⁵

²¹ *American Transmission Company LLC*, 105 FERC ¶ 61,388 (2003), and *order approving settlement*, 107 FERC ¶ 61,117 (2004).

²² *American Electric Power Service Corporation*, 116 FERC ¶ 61,059 (2006), and *order on rehearing*, 118 FERC ¶ 61,041 (2007).

²³ *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 (2006), and *order on rehearing*, 118 FERC ¶ 61,042 (2007).

²⁴ *Duquesne Light Company*, 118 FERC ¶ 61,087 (2007), rehearing pending.

²⁵ Tr., Vol. 7, p. 62

In a concurring statement appended to FERC's decision on the rehearing of the Allegheny Energy application, Commissioner Suedeen Kelly provided a framework for evaluating incentive proposals. She stated:

I deem it important to identify and assess the following six characteristics of any transmission project in order to make reasoned and consistent decisions on requests for incentives for the project: (1) the public interest benefits of the project; (2) the cost of the project in absolute terms; (3) the cost of the project in proportion to the current transmission rate base of the applicant; (4) the difficulty of completing it due to the number of jurisdictions traversed and whether they are jurisdictions the applicant regularly deals with; (5) the difficulty of relying on normal rate recovery methods due to the length of time it will take to complete; and (6) whether the applicant would otherwise be required to build the project even without an incentive.

The comments submitted in connection with Order Nos. 679 and 679-A, and the experience gained in working on individual incentive cases over the past year lead me to conclude that these particular characteristics are most relevant to deciding whether to award incentives.²⁶

A witness for Hydro One said Commissioner Kelly's six criteria "are important characteristics and I believe they're consistent with the criteria that Hydro One has put forward, in terms of assessing the supply mix projects."²⁷

Mindful of the fact that there is no government directive in place comparable to that which resulted in FERC Order No. 679, the Board found Commissioner Kelly's framework and criteria of assistance when it considered whether the special regulatory treatment sought by the Applicant for the designated projects was necessary or warranted. While certain of the criteria have reduced significance (for example, the traversing of jurisdictional boundaries poses different problems in the United States than in Ontario²⁸) others, such as the costs of designated projects in proportion to rate base

²⁶ *Allegheny Energy, Inc.*, 118 FERC ¶ 61,042 (2007), Kelly concurring statement, p. 1.

²⁷ Tr., Vol. 6, p. 147

²⁸ PWU noted, the lion's share of the cost of the Quebec Intertie project will be borne by Hydro-Québec, a fact which may increase the risks associated with that project because it might be dependent on decisions made in Quebec and so beyond the control of Hydro One. Other intervenors, such as CCC, submitted that Hydro One faced no appreciable or substantial jurisdictional risks.

and whether normal rate recovery methods can be relied upon, are of equal significance and importance here.

Many of the intervenors made reference to the criteria in their closing submissions. While none of the intervenors challenged the public interest benefits or the absolute cost of the designated projects, several of the intervenors observed that the aggregate costs of the projects relative to the Applicant's rate base did not present significant risk. Energy Probe noted that, in aggregate, the cost of the projects (including NRP) is less than one-seventh of Hydro One's current rate base, and would be only about 12.8% of Hydro One's forecasted 2008 rate base. PWU made a similar observation. In Energy Probe's view, costs of that magnitude should not create any special risks for the utility, assuming vigilant management. Energy Probe argued that the aggregate costs of the designated projects are comparable to rate base additions in recent years, when no rate changes occurred.

The other criterion which elicited significant comment from the intervenors was whether conventional rate recovery methods were adequate, given the costs of the designated projects and the time period over which the costs would be advanced. It was Hydro One's position that the designated projects are extraordinary in many respects when compared to those normally undertaken by a transmission company, and so merit special rather than conventional regulatory treatment.

VECC submitted the evidence established that the investment community does not perceive an impending risk that would necessitate special treatment. VECC added that regulators in Ontario have considerable experience in dealing with such matters and have traditionally allowed recovery of costs under conventional methods provided the utility has acted responsibly.

CCC submitted that there is no reason to deviate from conventional regulatory approaches and to compensate Hydro One now for risks that have not, and may not,

materialize. CCC characterized the proposal by Hydro One to recover a return on expenditures as they are incurred (and to allow for amortization to also be recovered) as a significant departure from the accepted regulatory treatment for capital projects. CCC also pointed out that the bond rating agencies have either maintained positive ratings or improved ratings for Hydro One, without any reference to a need for extraordinary treatment for these projects.

Energy Probe addressed each project separately, and concluded that conventional regulatory treatment was appropriate for all three of the designated projects.

AMPCO submitted that there is no evidence to suggest that, in the absence of special treatment, Hydro One will be left with abandoned or stranded assets from undertaking these projects. AMPCO pointed out that Hydro One may always seek relief from the Board should such an event occur.

Both CCC and VECC were of the view that Hydro One's proposal was solely directed to risk management. VECC observed that the underlying rationale of the FERC initiatives was to provide an incentive to private U.S. transmission owners to make investments, a rationale not present in this case.

The PWU similarly noted that the request for special treatment of the designated projects is not an incentive in the traditional use of the term, as Hydro One is committed to undertake the projects in any case. However, the PWU also submitted that the request is one of fairness in that Hydro One should be protected from any financial harm for reasons outside its control.

Impact on Ratepayers

Hydro One's application states that approval of special regulatory treatment for the designated projects would lower and smooth customer rate impacts, and have a positive impact on the Company's credit ratings and borrowing costs, to the benefit of current customers.

Hydro One also suggested its proposal would result in a neutral financial effect. That conclusion is based on qualitative information obtained in a seminar presented by the National Association of Regulatory Utility Commissioners; Hydro One confirmed that no quantitative analysis had been completed to confirm that the proposed approach would result in a neutral financial effect. In response to an interrogatory, Hydro One advised that it had not estimated the impact of the proposal on its credit rating or borrowing costs; however, in response to another interrogatory, Hydro One stated that the Company may be slightly better off financially under the proposal.

VECC estimated a substantial favourable effect on Hydro One's income by 2010, based on the differential between a pre-tax return on equity and AFUDC. VECC submitted that while Hydro One's intent may not have been to be financially advantaged, the result is that it will derive a substantial financial advantage from the proposed treatment. SEC provided estimated impacts over the long term in noting the proposal is, in essence, an interest free loan to Hydro One from ratepayers that will be paid back over 45 years.

Hydro One also argued that a primary benefit of the proposed special treatment is to avoid rate shock for consumers. VECC, in its argument, notes that Hydro One has done no specific analysis of the rate impact of its proposal. VECC provided its own analysis of total bill impact based on conventional rate making practice. VECC submits that the result (less than 0.3% increase in 2012) does not constitute rate shock.

Energy Probe said that the designated projects are each small, relative to Hydro One's overall rate base, and as the projects have unique in-service dates scattered fairly evenly over future years, the overall rate impact under a conventional ratemaking approach is already smooth.

Board Findings

AMPCO, CCC, Energy Probe, SEC, and VECC argued that the proposed special regulatory treatment for the designated projects should be rejected by the Board. PWU

was the only intervenor to support Hydro One's proposal. In summary, the arguments against the proposal were:

- There is no reason why Hydro One should be compensated now for risks that may not materialize.
- The proposal is a significant departure from conventional regulatory treatment for capital projects. The Board should permit departures only under very exceptional circumstances and Hydro One has failed to establish that such exceptional circumstances exist. To allow Hydro One the relief it is seeking would set a precedent that may prompt other Ontario utilities to seek similar relief. Before setting such a precedent, the Board must be satisfied that conventional regulatory treatment is inadequate to meet needs such as those associated with the designated projects.
- If construction is delayed or if there are abandonment issues, Hydro One would be free to come to the Board for relief.
- Hydro One has not established that it is now subject to an increased risk with respect to the recovery of the costs associated with these projects.
- Hydro One has not established the need for "incentives" to undertake or complete those projects.
- FERC precedents arise out of a different regulatory regime and are not applicable in the Ontario context.
- The benefits to ratepayers as articulated by Hydro One have been overstated.

The Board shares these concerns and finds that a departure from conventional regulatory treatment has not been justified.

There is no evidence in this case that any regulator other than FERC has approved a package of special regulatory treatments like those advocated by Hydro One. FERC regulatory initiatives can be important guidance in some cases and the Board will continue to monitor FERC's actions to incent new transmission. However, the Board is not convinced that FERC's approach to incentives for transmission investments justifies the special treatment that Hydro One has requested. The cost of the designated projects, while large in absolute terms, is not particularly significant in relation to Hydro One's rate base, and there is no evidence that Hydro One will have difficulty financing the projects under conventional regulatory treatment.

The Board is not persuaded that ratepayers would benefit from the proposed special regulatory treatment. Specifically, the Board does not accept Hydro One's argument that the treatment would result in revenue neutrality and rate smoothing. The evidence from Hydro One on this point was in conflict and lacked substance.

The Board acknowledges Hydro One's concerns about the magnitude of its capital expansion program. At the same time, based on the evidence from the credit rating agencies, the Board is not convinced that Hydro One will be unable to finance the capital program under the conventional approach.

The Board is of the view that conventional regulatory treatment for the three designated projects provides the appropriate balance between the interests of ratepayers and utilities. The Board agrees with the consensus position of the intervenors that the mitigation of losses that have not, and might not, occur is unnecessary and not appropriate. There is nothing in the record that would justify the burdening of ratepayers with such losses. In addition, Hydro One is reminded that it can come forward with applications for relief, if a special circumstance arises which puts it clearly at risk. The Board has promptly responded to such requests from other applicants in the past. There is no reason to expect that the Board would not deal fairly and promptly with Hydro One on these projects should significant issues arise in the future.

Hydro One's request for special regulatory treatment for these designated projects is denied. In reaching this decision, the Board is not ruling out providing incentives for future projects where there is a compelling case.

6.2 NIAGARA REINFORCEMENT PROJECT

Hydro One was granted approval by the Board in July 2005 to construct the NRP and construction began shortly thereafter. As the result of a land claim by aboriginal peoples and the occupation of a portion of the lands necessary for the completion of the last two kilometers of the project, the project has been frustrated, pending a multi-lateral resolution of the underlying land claim issues.

CCC, SEC and VECC supported some form of relief regarding the NRP, while AMPCO and Energy Probe were of the view that the project should be accorded conventional ratemaking treatment.

SEC submitted that Hydro One should be allowed to expense, rather than capitalize, the AFUDC associated with the project. CCC suggested that Hydro One should be allowed to expense AFUDC for NRP for 2007 and 2008 only. VECC submitted that the Board could consider allowing AFUDC associated with the NRP to be expensed as opposed to capitalized – effective January 1, 2007. If Hydro One required additional relief prior to the project being completed and in-service, then a specific application should be brought before the Board seeking the same.

The common rationale was that, as a result of factors beyond its control, Hydro One has been prevented from placing the asset in service. All but a very short span of the project has been completed, and the overwhelming majority of the funds needed to complete and make serviceable the reinforcement have been expended. The respective positions of these intervenors reflect their assessment that this is an exceptional circumstance requiring a special regulatory response.

PWU also supported relief on the NRP and advised that the Board should focus on the substantive issues underlying the request for special treatment rather than the question of whether or not the NRP fits into the category of the other three designated projects.

Energy Probe took the position that the appropriate course is to disallow recovery of any NRP costs from ratepayers until the project is in service. Once in service, ratepayers should have to pay all costs, except those incurred from the time the Province bought the land in Caledonia until the project is placed in service.

AMPCO was of the view that as Hydro One had asked that the NRP be considered a supply mix project, it should receive the same treatment as the other designated projects.

Board Findings

The Board's role is to make decisions that are in the public interest and to determine an appropriate balance between the interests of the regulated utility and consumers. The Board agrees that special regulatory treatment is appropriate for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One.

In determining the special relief, it is important to take into consideration all aspects of this project.

Hydro One brought an application to the Board in 2004, requesting approval to proceed with this project. Hydro One's decision to initiate the NRP was not the result of OPA planning. In that 2004 application, Hydro One did not provide what the Board considered to be a sound economic rationale for the NRP. As such, the Board decided that Hydro One would be required to provide an acceptable economic justification in the future before the project costs could be recovered from ratepayers.

Hydro One has now spent \$97 million on this project and the Board has received the required updated economic rationale in this application. It is not known if the project will eventually be completed, if it will come into service with a different route and additional costs, or if it must be abandoned and written off. The Board is of the view that it would not be in the public interest to shift the entire financial burden of an asset that is not in service to consumers as requested by Hydro One.

However, Hydro One faces carrying costs for these expenditures and the Board agrees with VECC and CCC that a compromise is appropriate. As CCC, VECC and SEC suggested, the Board has decided to allow Hydro One to expense – rather than capitalize – the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date. While CCC and SEC suggested it should be limited to the test years, the Board agrees with VECC in that it should be effective January 1, 2007, with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved. If Hydro One requires additional relief prior to the project being completed and in-service, it is free to bring an application seeking such further relief.

7. HYDRO ONE TRANSMISSION ROE AND CAPITAL STRUCTURE

Return on Equity (ROE)

Hydro One Transmission's revenue requirement for the year 2000, the last time the Board conducted a cost-of-service review of the transmission business, was based on a return on common equity ("ROE") of 9.88%. The Company is requesting an increase to 10% in 2007 and 10.25% in 2008.

Hydro One provided evidence in support of its request through Ms. Kathleen McShane of Foster Associates, who initially argued that an ROE of 10.5% in both 2007 and 2008 was appropriate for Hydro One Transmission. In updates of February 23, 2007 and March 1, 2007, Ms. McShane revised her recommendation on the basis that prevailing market conditions warranted lower ROEs of 10.0% in 2007 and 10.25% in 2008.

Ms. McShane's study made use of the equity risk premium, discounted cash flow and comparable earnings tests. Ms. McShane took the position that her recommendation was demonstrably reasonable in light of returns allowed for Hydro One Transmission's U.S. peers (range of 10.5%-12.5%), with whom she submits Hydro One would have to compete for capital to finance close to \$2 billion in transmission-related capital expenditures in the 2006-2008 timeframe, and potentially similar levels for the several subsequent years.

CCC and VECC provided evidence through Dr. Laurence Booth of the University of Toronto, who took the position that a fair ROE for Hydro One Transmission would be approximately 7.50%, including a 50 basis point cushion. Dr. Booth submitted that most of Hydro One Transmission's risk comes from its rate design and the amount of debt

financing, not its underlying business risk. Dr. Booth saw underlying business risk to be minimal for Hydro One and most regulated utilities in Canada.

The *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* of December 20, 2006 (the "Cost of Capital Report") incorporates an ROE methodology that, when applied to Hydro One Transmission, produces ROEs considerably lower than the levels proposed by Hydro One and somewhat higher than the level proposed by Dr. Booth. Based on an answer to an undertaking provided by Hydro One, application of the Board's distribution formula to Hydro One Transmission would produce an ROE of 8.53% in 2007 and 8.64% in 2008.

Capital Structure

Hydro One Transmission has a current deemed capital structure of 60% debt, 4% preference equity, and 36% common equity. It is requesting Board approval for a more favourable deemed capital structure of 56% debt, 4% preference equity and 40% common equity.

Hydro One provided evidence in support of its proposed capital structure, again by Ms. McShane, who argued that Hydro One's proposed capital structure was justified in light of its need to maintain an 'A' bond rating. Ms. McShane stated that this bond rating was critical in light of Hydro One's need to access debt markets to finance extraordinary capital expenditures, the more limited market for BBB debt, and the lesser ability of BBB-rated companies to access the long-term (30-year) debt market.

CCC and VECC provided evidence by Dr. Booth on this matter, who recommended that the Board should reduce Hydro One Transmission's allowed common equity ratio to 34%, with a 66% debt ratio. Dr. Booth noted that his recommended common equity ratio was 1% higher than that imposed on the Alberta transmission companies regulated by the Alberta EUB. During his examination-in-chief, Dr. Booth stated that he viewed transmission assets as the lowest risk regulatory assets in Canada, mainly because

transmission is a natural monopoly and an essential component in the distribution of electricity. Dr. Booth also noted that Hydro One had the highest bond rating of any regulated utility in Canada. The Board notes that while Hydro One owns over 97% of the transmission system in Ontario, it is not, strictly speaking, a “monopoly”.

The Cost of Capital Report incorporates a capital structure policy for distributors of 60% debt and 40% equity. This is in line with Hydro One Transmission’s presently approved deemed capital structure.

Transmission versus Distribution Risk Differentials

In the course of this proceeding, Board staff retained Professors Fred Lazar and Eli Prisman of York University to undertake a study of whether or not there is a determinable risk differential between Hydro One’s distribution and transmission businesses that would justify differences in the allowed capital structures and cost of capital for the respective businesses.

Professors Lazar and Prisman concluded that “at this time, the results are too mixed, and most often statistically insignificant to reach any conclusion other than to award the same ROEs for both the Transmission and Distribution segments of Hydro One.”

Ms. McShane took a similar view noting that the difference in the level of risk between Hydro One Transmission and Distribution is not material enough to distinguish between the two in terms of either recommended capital structure or return on equity.

Dr. Booth expressed the view that Hydro One Transmission is of lower risk than Hydro One Distribution. During his cross-examination, Dr. Booth stated that he would be amenable to the use of the Board’s distribution rate of return mechanism to set Hydro One Transmission’s ROE, but only on the basis that the Board adjust for Hydro One Transmission’s lower risk through a lower common equity ratio.

Cost of Debt and Preference Shares

Hydro One provided its derivation of the forecast yields for each of the debt issues anticipated for 2007 and 2008, which were based on forecast Government of Canada yields for 5, 10 and 30 year debt with a Hydro One spread applied to them.

Although Ms. McShane updated her evidence on February 23, 2007 and March 1, 2007, and concluded that prevailing market conditions justified a lowering of her ROE recommendation, Hydro One did not update its debt and preference share costs to reflect the changes in market conditions that had occurred since its evidence had been filed in September 2006.

During cross examination, Hydro One acknowledged that it had not updated these costs and had issued new 30-year debt in March of this year. The Company acknowledged that there would be a difference between the cost of that new debt compared to the cost of debt assumed in the evidence. Specifically, the coupon rate of the 30-year debt assumed in the evidence was 5.53%, but the new debt had been issued at a coupon rate of 4.89%.

Hydro One explained that the reason it had not updated these costs while updating its ROE estimate was that the impact of any such update would be far more significant on the ROE than it would be on the cost of debt, as the cost of debt is based on a full portfolio of outstanding bond issues that incorporate placements going back a number of years. Also, Hydro One stated that it viewed the cost of debt as but one of a bundle of assumptions embedded in its Application, and it did not propose to revisit the full suite of its planning assumptions as the revision of some may have been more favourable to one stakeholder, while the revision of others may have been more favourable to another.

Treatment of Designated Projects – Impact on Capital Structure/ROE

Ms. McShane’s initial evidence on ROE was submitted with the presumption that three designated capital projects would receive the special treatment applied for. The NRP was not initially included among these projects or as part of her assumptions.

Hydro One subsequently updated its evidence to include the NRP in its request for special treatment of the designated projects; however Ms. McShane’s evidence update did not make any reference to this apparent reduction in Hydro One’s risk profile.

During cross-examination Ms. McShane was asked about the impact on her recommendations if Hydro One’s request for the special designated project treatment was denied. She stated that the ROE calculation would have to be adjusted upward by 25 to 35 basis points, or alternatively that a two-and-a-half to three percentage points increment in the equity ratio would be necessary. Ms. McShane noted that her preference was for an adjustment to the equity ratio.

The Board’s consideration of the proposed treatment of the designated projects, including the NRP, is dealt with in Chapter 6 in this Decision.

Board Findings

Hydro One asserted that its proposed increase in ROE is necessary to enable it to access capital markets effectively, and to borrow the very large sums needed to fund the expansion and reinforcement of the transmission system at interest rates that are as low as possible.

Access to these markets, and the costs of borrowing, are often seen to be dependent on the opinions expressed by various bond rating organizations. One of the key factors used by these agencies to assess the credit-worthiness of a borrower is the adequacy of its ROE in light of the business risk associated with the borrower. If the ROE is seen

to be low given an entity's business risk, the cost of borrowing will rise to account for it. If the disparity is too great between the ROE and the inherent business risk, funds may not be available at all.

In this way, the Company's proposal for an increased return on equity, and an increase in the equity portion of its deemed capital structure, is bound up in many of the other proposals forming part of this rates proceeding.

It is also true that the comparative risk faced by the transmission business of the Company was an overarching theme of this Application. The Company sought to limit or eliminate the regulatory risks it is facing. Hydro One was concerned that the Company would not be granted recovery for expenditures prudently incurred. This is seen in the proposals for the designated projects, and in the assurances requested for portions of the capital projects budget, and in the Company's RRAM proposal.

To consider the Company's proposal, it is necessary to consider the riskiness of its operating environment, the perception of that environment by market analysts, and the appropriateness of the Board's methodology in establishing the appropriate ROE and capital structure.

As the operator of the vast majority of the transmission system in the province, the Company is uniquely capable, and uniquely positioned, to make a wide range of informed decisions respecting system growth and reinforcement. The ratepayer is entitled to expect that the Company makes careful, engineering-based plans, founded on its best judgement as to what the system needs.

Where line connection enhancements are made, the TSC provides a formulaic approach directed to assessing the prudence of a project, and the extent to which those directly benefited by the project are required to contribute capital. This serves to limit the exposure of the transmitter to risk. Although the same formulaic methods do not exist to assess prudence and cost recovery for large capital projects, Hydro One has

ample opportunity to address these issues in Leave to Construct applications and rate cases.

A utility which has followed reasonable engineering and financial practice, and has applied the TSC appropriately, is unlikely to be denied recovery of prudently incurred costs. Similarly a utility which is confronted with unusual circumstances is unlikely to be denied relief when events out of the utility's control occur. Indeed, the response of the Board and the intervenors to the Company's dilemma respecting the NRP is evidence of a regulatory approach in the province that is flexible and responsive. This positive regulatory environment is noted in one of the bond rating agency reports.

The Board recognizes that some of the projects the Company becomes involved in are very large, both in terms of their related costs, and their potential impact on the effectiveness of the overall provision of electricity to the province's residents and businesses. It is understandable that the Company has concerns respecting its ability to recover the very large sums that it commits to such projects; however, the Board cannot discern any significant risk for the Company that it will be unable to recover prudently incurred costs.

Under the concept of just and reasonable rates, the Company has a reasonable and enforceable expectation that its prudently incurred costs will be recovered in a timely fashion. This includes an expectation that in considering the prudence of expenditures, the Board will assess the Company's judgement in light of the circumstances prevailing at the time the expenditure is made, and without the distraction of hindsight. The Company's prudence should be adjudicated on the basis of what it knew or ought to have known at the time the expenditure was made, not on the basis of subsequent events or conditions, which may have the effect of making the expenditure appear to be unwise.

There is always a risk that if the Company fails to use good judgement in formulating its plans, or otherwise incurs costs imprudently, it will not be authorized to recover such

costs. That is a risk that the Company must bear on its own. No responsible regulator can protect a utility from imprudence, poor judgement or laxity. Nor, to be fair, does Hydro One appear to be asking for protection from these.

The evidence respecting the observations of the bond rating services suggests that they are much more confident than the Applicant in the regulatory regime governing the company's operations. This was particularly evident in the examples cited during the cross-examination of Ms. McShane by counsel for CCC.

One analytical tool useful in determining the appropriate ROE and deemed capital structure lies in assessing the extent to which the transmission business can be considered to be more or less risky than the distribution business. The Board's recent consideration of cost of capital in the Cost of Capital Report is of assistance in determining an appropriate ROE and capital structure for the applicant's transmission business.

The Board has examined the fundamentals of its ROE methodology on a number of occasions in the recent past. The Cost of Capital Report is only the most recent example. In each case, the Board's use of its current methodology has been confirmed.

The Cost of Capital Report was generated to inform the Board with respect to the appropriate ROE and capital structure for the local distribution companies, including Hydro One in its operation of a substantial distribution network. It follows that a consideration of the relative risks as between the transmission business and the distribution business should inform a consideration of the appropriate ROE and deemed capital structure for the transmission business.

Importantly, most of the experts providing evidence in this case were unable to conclude that there was any material difference in the level of risk between the distribution and the transmission undertakings. Dr. Booth alone suggested that transmission was less risky, and therefore should be subject to a lower overall ROE.

With respect, Dr. Booth's view seemed to be analytical, and not data based. He referred to the approach taken by the Alberta Board in the case of Altalink, a comparator that was not demonstrated to be apt.

It is the Board's view that there really is no convincing quantitative evidence before us which suggests that transmission is more or less risky than distribution. It is true that distribution has greater and more immediate exposure to the possibility of bad debts. On the other hand, in absolute terms, the transmission system involves very large capital projects of significant complexity, which can be subject to delay in completion, and consequential delay in expected revenues. On balance, the Board concludes that the evidence before us does not provide a basis upon which we can make a finding that there is any meaningful difference in risk as between distribution and transmission.

The Company is in a unique position compared to other utilities in the province. It alone among all of the utilities in Ontario operates a major transmission business and an equally large distribution business. If the Company believes that there is a significant risk differential between its two business segments, it should have been able to present much more convincing evidence respecting the relative risks. The fact that it did not is telling.

It follows that the ROE for the transmission arm of the company should not enjoy a different ROE than that governing its distribution business.

Accordingly, the Board finds that the ROE formula for electricity distributors, as documented in the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism, shall be applied to Hydro One Transmission. The Board has determined that Hydro One's ROE shall be derived based on an application of the Board's formula as of January 1, 2007, using December 2006 *Consensus Forecasts* and Bank of Canada data. This should result in an ROE of 8.35% for both 2007 and 2008.

The Board notes that all of the consumer intervenor groups were receptive to the use of the Board's distribution formula for setting ROE, although most also argued that Dr. Booth's lower recommended common equity ratio should be applied in establishing Hydro One Transmission's capital structure. However, as has been discussed, the Board has not been presented with any convincing quantitative evidence in this proceeding which suggests that transmission is more or less risky than distribution. Accordingly, the Board will also apply the distribution capital structure to Hydro One Transmission.

The Board has further determined that Hydro One's debt costs will not be updated. The Board notes the comments of some intervenors that the Board should require Hydro One to update its forecast debt costs, as is done for the regulated natural gas utilities. The Board notes that in recent gas proceedings where this has been done, it has usually arisen out of rates agreed to by the respective parties and included in the Settlement Agreements. In the absence of such a settlement on this issue in this proceeding, the relative magnitude of the amounts involved, and the uncertainties surrounding changes in interest rates and Hydro One's financing plans, the Board is not convinced that the cost of debt should be updated and will use the rates contained in Hydro One's application for the purpose of rate-setting.

8. DEFERRAL ACCOUNTS

8.1 ONTARIO ENERGY BOARD COST ACCOUNT

Hydro One has used this deferral account to capture the excess of OEB cost assessments during the past several years over the amount included in Hydro One's last approved revenue requirement. The account also includes capitalized interest. Hydro One requested Board approval of the balance of the account and its disposition over four years.

The account was established by Hydro One in 2004. The amount charged to the account in that year, \$4.6 million, apparently included amounts dating from 2000.²⁹ The account balance was \$4.8 million at the end of 2005, \$7.1 million at the end of 2006, and \$7.9 million at April 30, 2007.

The balance of the account and its disposition were settled issues in the Settlement Proposal but the settlement was not accepted by the Board.³⁰ In its Settlement Decision, the Board instructed Hydro One to provide additional evidence to establish why the Company should recover such costs, given that it did not have a Board-approved deferral account at the time the costs were being incurred.

Hydro One provided a copy of a December 2004 letter to Board staff indicating the Company's intention to implement deferral accounts and practices for tracking OEB costs, similar to those approved by the Board for use by electricity distributors. Hydro One also stated that since 2004 it has consistently included the account in its quarterly reporting, pursuant to the Board's Recordkeeping and Reporting Requirements.

²⁹ Tr. Vol. 7, p. 178, lines 11 to 15.

³⁰ EB-2006-0501, Settlement Proposal Decision, April 18, 2007, p. 6.

There is no evidence that the Board's staff acknowledged Hydro One's December 2004 letter or that the Board otherwise approved the deferral account.

Hydro One's position is that OEB costs affect its transmission and distribution businesses in an equivalent manner and it is appropriate for both businesses to maintain a deferral account for these costs. With respect to the lack of approval, Hydro One stated that "the failure to establish an official deferral account was an oversight arising out of a misunderstanding between the OEB Staff and the Applicant. Under those circumstances, Hydro One now asks that an official deferral account be established."³¹

Board Findings

The Board cannot accept that the balance in this account should be recovered from ratepayers. Although, as Hydro One suggests, there might have been a misunderstanding, the fact remains that the account has not been approved by the Board.

The Board might have considered approving recovery of the account had the balance resulted from an extraordinary variation in expenses and if the balance were large enough that non-recovery might be a financial burden on the company. In the Board's view, that is not the case here. At least six years have passed since the Board last examined Hydro One's transmission revenue requirement. Over that period, the revenues and expenses of the transmission business have varied, sometimes significantly, from the amounts approved in the last rates case. In a business with annual revenues in excess of \$1.2 billion, it does not seem particularly noteworthy that the cumulative variance in a single expense line over that time is \$7.9 million (including capitalized interest). The swing in transmission revenues in any year due to weather and other factors has been many times larger than that.

³¹ Hydro One Reply Submission, June 13, 2007, p. 57.

As noted in the following section, an earnings sharing mechanism was in place in 2006. Although the Board disallows recovery of the OEB cost deferral account balance, it will permit Hydro One to deduct the growth in the account in 2006 (\$2.3 million) from 2006 earnings in calculating excess earnings.

8.2 2006 EARNINGS SHARING MECHANISM

Calculation of Excess Earnings

The earnings sharing mechanism (ESM) was established by the Board in its February 21, 2006 decision on EB-2005-0501. In that decision, the Board determined that excess earnings of Hydro One's transmission business from January 1, 2006 until new transmission rates are implemented should be shared equally by ratepayers and the Company. Earnings for 2006 were to be determined from actual results as shown in Hydro One's 2006 audited transmission business financial statements. In its Partial Decision and Order dated March 30, 2007, the Board approved a 2007 Revenue Difference Deferral Account, which had the effect of terminating the ESM as at December 31, 2006.

In its pre-filed evidence, as updated April 20, 2007, Hydro One calculated total excess after-tax earnings for 2006 of \$37.5 million, 50% (\$18.7 million) of which would be for the account of ratepayers. In calculating that amount, Hydro One decided to exclude two 2006 income statement credits aggregating \$30.2 million, after tax:

- A tax benefit of \$16.4 million that was recognized in the first quarter of 2006. According to the 2006 audited financial statements of Hydro One's transmission business, the benefit related to a "recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized."

- A \$21.6 million recovery in 2006, recorded as a reduction of OM&A expense, of property taxes for the years 1999 to 2005 inclusive. The after-tax impact of this item was \$13.8 million.

In its final argument, Hydro One indicated it would increase its calculation of excess earnings as a result of reallocating expenses from its transmission business to its distribution business. This adjustment was made after discussion in the hearing about how to apply the requirements of the Board's February 21, 2006 decision that established the ESM.³² In its reply argument, Hydro One noted that this reallocation would increase excess pre-tax earnings by \$9.5 million (\$6 million after tax).

Hydro One submitted that it is appropriate to exclude the two items from income because they resulted from the resolution in 2006 of issues that arose in prior years. In support of its position, Hydro One cited a 2004 Board decision on an Enbridge Gas Distribution earnings sharing mechanism,³³ in which the Board directed Enbridge to exclude from its calculation of excess earnings the write-off in 2004 of a non-recoverable receivable (the balance in a deferral account established in an earlier period). The decision stated: "Earnings determinations should be unfettered by differing accounting treatments and related reporting inclusions and exclusions."

Intervenors disagreed with the exclusion of the two items from the calculation of 2006 excess earnings. They submitted that it is clear from the Board's decision on EB-2005-0501 that the excess earnings should be calculated from the unadjusted 2006 audited financial statements. Hydro One submitted that the intervenors who oppose Hydro One's adjustments are reversing the position they took when they supported the exclusion of expenses from Enbridge's earnings sharing mechanism in 2004. SEC argued, however, that the Board's intent in the 2004 Enbridge Gas Distribution decision

³² In its decision on EB-2006-0501, the Board ordered Hydro One "to report revenue changes for the 2006 rate year resulting from the Board's decision on cost allocation in RP-2005-0020/EB-2005-0378. The [cost allocation] report will be reviewed with the objective of crediting the resultant cost allocation adjustment to transmission customers in the 2007 rate application." (p. 6)

³³ RP-2003-0203/EB-2004-0468, Decision With Reasons, November 24, 2004.

was simply “to avoid the absurd result whereby an amount previously adjudged to be non-recoverable from ratepayers would become partially recoverable as a result of the earnings sharing mechanism”.³⁴

Proposal to Treat Excess Earnings as a Capital Contribution

Hydro One proposed that the pre-tax amount of the ratepayers’ share of the 2006 excess earnings be treated as a capital contribution (that is, the amount would be treated as a reduction of rate base) to be applied against two capital projects that under development.³⁵ Ratepayers would receive the benefit of the excess earnings through reduced charges in the future for both depreciation and return on capital.

The capital contribution treatment was proposed by Hydro One when the Board first established the ESM in February 2006. The Board did not accept the treatment at that time but indicated that Hydro One could bring the matter forward at the time of disposition of the account balance.

Hydro One cited some U.S. cases as precedents for the capital contribution treatment. In response to concerns that its capital contribution proposal creates intergenerational equity issues (by stretching out the return of the excess earnings to ratepayers over several decades), Hydro One suggested it could credit the excess earnings against capital projects with much shorter useful lives, such as the Cornerstone IT project.

Intervenors were opposed to the capital contribution approach. They objected to ratepayers, who overpaid for transmission service in 2006, receiving the benefits over a protracted period starting in 2009 when the two capital projects are to be in service. AMPCO also argued that capital contribution mechanisms are designed to protect ratepayers who will not benefit from projects requested by specific customers. In

³⁴ SEC Final Argument, p. 44.

³⁵ The projects are the Southern Georgian Bay Reinforcement and the Hurontario Switching Station. The aggregate estimated cost of the projects is \$135 million. Both developments are expected to be in service in 2009.

AMPCO's view, such mechanisms are inappropriate for returning overearnings to ratepayers.

The intervenors argued that excess earnings should be returned to ratepayers over a much shorter period, either over two years (2007 and 2008) or over four years (the period over which other Hydro One deferral accounts are cleared). CCC, SEC, and VECC supported netting the balance against the RDDA balance (see section 8.3 below) and including the net amount in the revenue requirement over either two or four years.

Board Findings

The Board does not agree with the proposal to exclude the two income items from the calculation of 2006 excess earnings. The Board finds that the EB-2005-0501 decision which established the ESM is clear that the 2006 audited income statement (called the Statement of Operations by Hydro One) is the basis for the calculation. There is nothing in that decision that suggests Hydro One was to have discretion to exclude any income or expense. The section on page 10 of that decision entitled, "By what mechanics should excess earnings be established?" sets out a mechanical approach to the calculation that does not provide for adjustments for "prior period" or "non-recurring" items. In fact, that section states: "The following items will be sourced from the audited financial statements (Transmission): Net Income (actual, not normalized for weather) – from Statement of Operations."

Although the two items in question result from resolution of issues that arose in prior periods, neither item apparently qualified as a prior period adjustment under generally accepted accounting principles; had they so qualified, they would have been omitted from the 2006 audited income statement and included in restated prior period financial statements.

The Board does not agree with Hydro One that the 2004 Enbridge Gas Distribution decision is a relevant precedent. The decision that established the Hydro One ESM is

so clear on how the calculation is to be done that there is no need to seek guidance from any other source. In addition, as noted by SEC, the 2004 Enbridge decision concerned the write-off of a regulatory balance that apparently had been determined to be uncollectible from ratepayers, so it would make little sense to require ratepayers to absorb some of that amount through an ESM.

The Board will require Hydro One to recalculate the amount of excess 2006 earnings without exclusion of the two income items. As noted in section 8.1 on the OEB cost account, the Board will also permit Hydro One to deduct the growth in that account in 2006 in determining excess earnings.

The Board does not accept the capital contribution approach proposed by Hydro One. In the Board's view, it is important that overearnings be returned to customers as soon as possible; the capital contribution approach results in an inappropriately long "refund" period. That is true even if the excess earnings were to be credited against a capital project with a shorter life than a transmission station. The Board finds that the balance in the ESM account should reduce Hydro One's revenue requirement at the first available opportunity, which is the revenue requirement for the years 2007 and 2008.

8.3 2007 REVENUE DIFFERENCE DEFERRAL ACCOUNT

This account was approved by the Board in a March 30, 2007 Partial Decision and Order. It is intended to capture the difference (positive or negative) between (a) revenue determined using the rates resulting from this proceeding, and (b) revenue determined using currently approved transmission rates. The revenue difference is to be calculated for the period from the effective date of Hydro One's new revenue requirement to the date on which new uniform transmission rates are implemented. The Board did not make a decision on either the effective date or the implementation date in its March 30, 2007 Partial Decision and Order. The Board also did not decide whether the revenue amounts should be based on actual or forecast load.

During the hearing, Hydro One witnesses presented the Company's proposal on the calculation of the balance in the Revenue Difference Deferral Account ("RDDA") and the manner in which new rates should be implemented (Exhibit L7.1). Hydro One proposed that:

- The new revenue requirement resulting from this proceeding should be effective January 1, 2007;
- New uniform transmission rates should be implemented November 1, 2007; and
- The RDDA balance for the 10 months to October 31, 2007 should be calculated based on forecast load, not actual load.

Hydro One set out two options for making the rate change. The first option, and Hydro One's preference, is to implement a single rate change on November 1, 2007 to collect the approved 2007-2008 revenue requirement for the next 14 months and the balance in the RDDA. The second option would be to have two rate changes – one on November 1, 2007 and a second on January 1, 2008.

Three intervenors (CCC, SEC, and VECC) argued that the effective date of the new revenue requirement should depend on whether it is higher or lower than the revenue Hydro One would earn at current rates. If the new approved revenue requirement is lower, all three supported an effective date of January 1, 2007. If the new requirement is higher, all three advocated a later effective date. CCC and VECC supported May 1, 2007, the date Hydro One requested in its initial application. SEC submitted that a higher revenue requirement should only become effective when new uniform transmission rates are implemented. The intervenors acknowledged the asymmetrical nature of their recommendations but submitted that the result would be fair given that Hydro One filed its application less than four months before the beginning of 2007. SEC explained its position this way:

SEC understands that at first blush that position may seem contradictory or even unfair to the Company. However, it is the applicant that controls the timing of rate applications. Accordingly, the Applicant should be at risk of not recovering its revenue deficiency in the event it does not file in time to have its rates in place at the beginning of the test year. It is not acceptable, however, for the Applicant to risk the ratepayers' money by filing in such a way as to ensure that a portion of a rate reduction is not paid to ratepayers as a result of the timing of the application.³⁶

With respect to the calculation of the balance in the RDDA, AMPCO supported using actual load while CCC supported using forecast load. Both intervenors supported the first rate implementation option, a single rate change on November 1, 2007. VECC argued that Hydro One should be directed to come forward with a detailed implementation plan once the 2007-2008 revenue requirement is approved.

In reply, Hydro One stated that a January 1, 2007 effective date is simple to implement. It submitted that it was not possible for the Company to file an application any earlier than September 2006. It also said that the intervenors' request for different effective dates depending on the amount of the new revenue requirement was not fair and balanced.

Board Findings

This is the first application by Hydro One Transmission in many years and there is no well established practice for determining the effective date of a new revenue requirement for this business.

The Board acknowledges the intervenor comments that there was no prospect of new transmission rates being implemented on January 1, 2007 given that the application was filed in mid-September 2006. The Board notes that the pooled uniform rates used for electricity transmission in Ontario necessarily will result in a longer period between the application date and the implementation of new rates than is the case in gas and

³⁶ SEC Final Argument, p. 39.

electricity distribution. For this reason, the Board is not as concerned as some of the intervenors about the relatively short period between the timing of Hydro One's application and its request for a January 1, 2007 effective date.

The Board has determined that Hydro One's new revenue requirement should be effective January 1, 2007. This approach aligns the start date of the new revenue requirement with the beginning of the 2007 test year for which Hydro One filed considerable evidence and analysis. A later date would effectively result in three different revenue calculations for the 2006-2007 period (2006 – revenue based on current rates, adjusted for the ESM; 2007 up to effective date – revenue based on current rates; 2007 after effective date – revenue base on new rates).

The Board is also not supportive of selecting an effective date that is always to the disadvantage of the Applicant, which is what several intervenors advocated (that is, an early date if the revenue requirement falls but a later date if the revenue requirement is increasing). The Board agrees with Hydro One that this would not be fair and balanced.

The Board accepts the use of forecast load to calculate the RDDA balance since that is consistent with the way new rates will determined. The Board also agrees with the first option to rate implementation (a single rate change targeted for November 1), which is a relatively simple approach.

9. LOAD FORECAST

Rates for each of Hydro One’s three transmission charge pools – network, line connection, and transformation – are based on a customer’s coincident or non-coincident peak load. Thus, a peak load forecast is required to translate the Board-approved revenue requirement for 2007 and 2008 into rates. Customer rates per kW of load are directly affected by the forecast used to derive the rates.

Table 7 shows Hydro One’s forecast of average 12-month peak load for the test years for Ontario as a whole and for Hydro One’s individual charge pools. Hydro One’s estimates of the impact of embedded generation and conservation and demand management (CDM) are also shown.

Table 7: Hydro One Load Forecast

<i>12-month average peak load in MW</i>	ONTARIO DEMAND	HYDRO ONE CHARGE POOL		
		Network	Connection	Transformation
2007				
Forecast before embedded generation and CDM	22,507	22,023	20,892	17,962
Impact of embedded generation	(140)	(140)	(10)	(10)
Impact of CDM	<u>(1,085)</u>	<u>(1,055)</u>	<u>(1,007)</u>	<u>(866)</u>
Net forecast load	<u>21,282</u>	<u>20,828</u>	<u>19,875</u>	<u>17,086</u>
2008				
Forecast before embedded generation and CDM	22,730	22,241	21,099	18,140
Impact of embedded generation	(165)	(165)	(10)	(10)
Impact of CDM	<u>(1,239)</u>	<u>(1,203)</u>	<u>(1,150)</u>	<u>(988)</u>
Net forecast load	<u>21,326</u>	<u>20,873</u>	<u>19,939</u>	<u>17,142</u>
Source: Pre-filed evidence, Exhibit A, Tab 14, Schedule 3, page 19.				

Forecast peak load, before the impact of embedded generation and CDM, is based on several methods (econometric models, end-use models, customer surveys, hourly load shape analysis) and is “weather-normal”, that is, the forecast assumes typical weather conditions based on data from the past 31 years.

In the hearing and in final argument, intervenors focussed on two load forecasting issues. The first related to the accuracy of Hydro One’s peak load forecast and the weather normalization methodology used by the Company. The second issue concerned the amount by which weather-normalized peak load should be reduced in respect of CDM activities. None of the intervenors challenged Hydro One’s adjustment for embedded generation or the economic assumptions underlying the forecast, such as forecasts of GDP, housing starts, and population growth.

9.1 WEATHER-CORRECTED FORECAST DEMAND

AMPCO noted that Hydro One’s weather-corrected peak load has been less than actual peak load for each of the last eight years. On average, the actual peak exceeded the weather-adjusted peak by 438 MW per year over that period. AMPCO argued that either the process is flawed or the definition of normal weather is no longer applicable. AMPCO also noted that monthly maximum peak demand in each of the first five months of 2007, as shown in IESO publications, exceeded Hydro One’s forecast.

Hydro One disagreed with the conclusion drawn by AMPCO from the eight years of data. The Company stated that weather is fundamentally unpredictable and past data shows that there can be years of consistent positive or negative differences between forecast and actual load. The Company stated that over the 20 years from 1982 to 2001 the average difference between actual and weather-adjusted monthly peak demand was just 17 MW, which Hydro One says supports its contention that its methodology is sound and unbiased.

Hydro One stated that its weather normalization methodology is consistent with the industry standard and is the most commonly used approach by electricity transmitters and distributors.

AMPCO and VECC commented on the differences between the weather-normal forecast of monthly peak demand published by the IESO and Hydro One's forecast. Forecast demand for each of the 18 months from January 2007 through June 2008 is substantially higher in the IESO forecast. Hydro One indicated that the two forecasts are based on different assumptions, approaches, and definitions that arise from the different purposes of the respective forecasts. In their arguments, AMPCO and VECC disagreed with some of the examples of differences cited by Hydro One.

AMPCO recommended that the Board direct Hydro One to set its charge determinants using the IESO's weather-normal maximum hourly demand forecast. VECC submitted that the unexplained difference between the IESO and Hydro One weather-normal forecasts is growing. However, VECC did not recommend that the Board order Hydro One to use the IESO's forecast.

Board Findings

The Board does not have sufficient evidence to agree with AMPCO's assertion that Hydro One's weather-normalized forecasts have shown a "clear and growing bias" and that the weather-normalization methodology is flawed. The Board acknowledges that Hydro One's weather-normalization method has been applied consistently over the years and is similar to the methods used by most North American utilities. The Board accepts Hydro One's weather-normal peak load forecast for 2007 and 2008 (before the effects of CDM). The Board is, however, convinced that the weather-normalization issue needs further study given the well-publicized concerns about global climate change and the apparently increased occurrence of so-called "extreme weather events" in recent years.

The Board also does not have sufficient evidence to accept AMPCO's recommendation that Hydro One use the IESO weather-normal forecast to set its rates for 2007 and 2008. The IESO forecast was not examined in the hearing in any detail, and the Board has limited understanding of the assumptions and definitions that underpin that forecast. On the surface at least, the two forecasts appear to be directed at essentially the same thing, namely weather-normalized monthly peak load. The IESO's forecasts are publicly available and apparently widely-used by electricity sector participants. Thus the Board concludes that it needs to have a much better understanding of the similarities and differences between the widely-available IESO forecast and the forecast used to set transmission rates, before it can direct the Company to adopt the IESO forecast methodology in place of its own.

Given the concerns set out in the two preceding paragraphs, the Board directs Hydro One to prepare, and to submit to the Board prior to the Company's next transmission rates case, a study of evolving weather-normalization practices of utilities and other relevant entities. The study should include a recommendation, with supporting rationale, for either retaining the current methodology or making modifications. As noted by Hydro One's counsel in final argument, the Board's current three-year business plan includes an initiative to review weather normalization methodologies. That project, which has not yet been fully defined, is intended to deal specifically with the practices of gas distributors. As such, it is not a substitute for the study that the Board is directing Hydro One to undertake.

The Board also directs Hydro One to submit a detailed comparison of its forecasting methodology and assumptions with those used by the IESO in its monthly peak load forecasts before its next rates case. That report should, to the extent possible, identify the reasons for significant differences in the two forecasts in recent years.

9.2 CDM FORECAST

Considerable hearing time was devoted to the question of how much Hydro One should reduce its estimated peak load to recognize the results of CDM activities across

Ontario. Intervenors from consumer groups submitted that Hydro One has overstated the impact of CDM for 2007 and 2008 and, therefore, the Company's peak load forecast after CDM is too low.

As shown in Table 7 above, the impact of Hydro One's proposed CDM adjustment is significant. The 12-month average peak load for each of Hydro One's charge categories is lower by approximately 5% in 2007 and 2008 due to the estimated impact of CDM. According to Hydro One, transmission rates would have to increase by 1% for every 300 MW decrease in peak load.

Hydro One's approach to the 2007 and 2008 CDM adjustment can be summarized as follows:

- The Company's peak load forecast (before embedded generation and CDM) is intended to capture the impact of natural conservation efforts that individuals and businesses undertake. According to the OPA, natural conservation "occurs when Ontarians invest in conservation on their own initiative and when the efficiency of the overall stock of equipment and appliances increases as older, less efficient stock is replaced by more efficient products mandated by Ontario's building and appliance standards."³⁷
- Hydro One assumes that the government's 2007 CDM target of a reduction in peak load of 1,350 MW will be achieved. For 2008, a peak load reduction of 1,550 MW is assumed. The reductions in Table 7 are lower than these amounts reflecting the fact that Table 7 shows 12-month average peak loads, not peak load in any single month.
- Hydro One points to its success in forecasting CDM-related load reductions in 2006 as support for its forecast of the impacts in 2007 and

³⁷ Chief Energy Conservation Officer's 2006 Annual Report, p. 26.

2008. In its 2006 forecast, Hydro One reduced peak load by 675 MW for CDM. Information from the OPA suggests that program-driven CDM reductions in 2006 (i.e.. reductions not due to naturally occurring CDM) reached 635 MW by summer 2006, six per cent below Hydro One's estimate.³⁸

AMPCO, CCC, SEC, and VECC took issue with several aspects of Hydro One's CDM adjustment.

First, CCC submitted that the 2007 reduction of 1,350 MW is solely based on a provincial target, one that is acknowledged by the OPA to be aggressive.

Second, several intervenors argued that Hydro One has in effect "double counted" load reductions due to natural conservation: once through its normal forecasting process and then a second time by using the full 2007 CDM target of 1,350 MW.

Third, those intervenors also argued that it is inappropriate to reduce a weather-normalized peak load forecast for demand response programs that by their nature are triggered, or become fully effective, only during periods of extreme weather.

The intervenors representing consumer groups, recommended various reductions in Hydro One's CDM adjustment. CCC recommended a reduction from 1,350 MW to 650 MW for 2007 comprised of 400 MW for the double counting of natural conservation and 250 MW for overstated results of demand response programs.

SEC argued for a 400 MW reduction for each of 2007 and 2008.

³⁸ The 2006 Annual Report from Ontario's Chief Energy Conservation Officer reported, at page 26, that "preliminary analysis suggests that Ontarians have reduced peak demand by 963 megawatts by summer 2006. These savings include 328 megawatts of naturally occurring conservation ..." The difference in the two numbers, 635 MW, presumably is the amount of the reduction due to various CDM programs.

VECC recommended a 600 MW reduction for 2007 and a 650 MW reduction for 2008. AMPCO did not recommend a specific reduction of the CDM adjustment because its concerns about all load forecasting issues were reflected in its suggestion (referred to in section 9.1) that the Board order Hydro One to use the IESO monthly forecast.

PWU supported Hydro One's CDM adjustment. It stated that the Board should exercise caution in relying on estimates of 2006 CDM-related load reductions published by the OPA. It also argued that any adjustments are premature because the OPA is in the process of developing evaluation, measurement and verification standards for CDM programs.

Board Findings

The Board acknowledges that forecasting the impact of CDM on peak loads is not a simple task at this time. The impact and effectiveness of particular CDM programs is sometimes elusive, and hard to define with precision. Having said that, the Board is not satisfied that Hydro One's proposed CDM adjustments are appropriate. While we do not object to Hydro One starting its analysis with the provincial target of 1,350 MW for 2007, we agree with intervenors that Hydro One has double counted the impact of natural conservation. It is clear from the evidence that the OPA intends to count natural conservation in determining if the 2007 target of 1,350 MW has been met.³⁹ Hydro One testified that its forecast, before the CDM adjustment, already factors in natural conservation. Therefore, the Board fails to understand how Hydro One can rationalize not reducing the 1,350 MW target for estimated natural conservation.

The Board also agrees with the consumer group intervenors with respect to the impact of demand response programs. Hydro One's base forecast is weather-normal, which means that extreme weather events are excluded. It would seem logical to reduce the

³⁹ This is particularly clear from OPA comments submitted by AMPCO on May 24, 2007 in response to Undertaking K10.3.

impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

The Board finds that Hydro One should reduce the expected impact of CDM on total Ontario peak demand by 350 MW. This adjustment is intended to address both the natural conservation and demand response issues discussed above. The Board acknowledges that this reduction is probably at the low end of an acceptable range given that it is only marginally above the 328 MW of natural conservation for 2006 referred to in the Chief Energy Conservation Officer's 2006 annual report. The Board finds there is sufficient data to support a reduction of 350 MW but also finds there is not enough reliable data to support a larger reduction as advocated by some intervenors.

The Board directs Hydro One to recalculate the average monthly forecast peak load for each charge determinant category for 2007 and 2008 based on Ontario peak load reductions of 1,000 MW in 2007 and 1,200 MW in 2008.

CDM adjustments were also addressed in Hydro One's last distribution rates case. The Decision in that case stated: "The Board was dissatisfied with the clarity and precision of the determination of the forecast CDM and expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications⁴⁰." The Board recognizes that Hydro One's transmission application was filed not long after those comments were made. It would be unfair to expect Hydro One to have rectified all of the issues identified in the distribution case. The Board does expect, however, that the CDM adjustments to the load forecast included in Hydro One's next transmission filing will be based on a much more rigorous analysis, including, where possible, load impacts attributable to specific programs.

⁴⁰ Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006, para. 2.3.9.

10. CHARGE DETERMINANTS

Hydro One proposed to continue with the status quo charge determinants for its Network, Line Connection, and Transformation Connection services. The connection-related charge determinants were settled leaving only the Network determinants as an issue. AMPCO was the only intervenor with a particular interest in changing the Network charge determinants. It submitted evidence and presented a witness panel.

The current Network charge determinant, which was approved by the Board in 2000,⁴¹ is the higher of (i) a customer's demand in kW in the hour during a month that overall system demand is at its peak (coincident peak), and (ii) 85% of the customer's peak demand during the period 7:00 am to 7:00 pm on weekdays that are not holidays (non-coincident peak). The current charge for Network service is \$2.83 per kW per month.

Before it filed its application, Hydro One consulted with stakeholders about rate design options and possible changes to charge determinants. Its application described two alternatives for the Network charge determinant that it said received the most consideration. Those were coincident peak only (that is, elimination of the 85% of non-coincident peak aspect of the calculation), and coincident demand in the hours when the system peak exceeds 90% of the monthly system peak demand. Hydro One concluded that the status quo was superior to the alternatives when judged against the following criteria – cost causality, electricity market benefits, revenue stability/security, cost shifting, alignment with precedents, and implementation issues.

Provided its revenue requirement is protected in some fashion, Hydro One should be financially neutral regardless of the charge determinant selected. But changing charge

⁴¹ Decision With Reasons, RP-1999-0044, May 26, 2000.

determinants could shift, possibly by material amounts, transmission charges incurred by individual customers or customer groups.

AMPCO's Proposal

In its evidence, AMPCO proposed that the Network charge determinant should be a customer's peak demand during the hour when system peak demand occurs in the five months of January, February, June, July and August. This method was referred as a "five-coincident-peak" approach (5-CP). AMPCO indicated that a similar method is used by transmission owners in the PJM Interconnection in the United States, where some of AMPCO's members operate manufacturing facilities.

In its final argument, AMPCO modified its proposal to some extent and recommended that the Board direct Hydro One to do three things:

- Eliminate the second element of the current Network charge determinant (85% of non-coincident peak demand, referred to by AMPCO as the "85% ratchet").
- Work with the IESO, OPA and stakeholders to define those peak demand months of the year that are of concern to system planners, operators, and Hydro One in terms of system reliability, adequacy of supply, and the need for future peaking supply. AMPCO proposed there would be just five or six such months.
- Develop an appropriate non-ratcheted charge determinant based on the identified peak months.

In its evidence, AMPCO proposed a "balancing account" for Hydro One to mitigate the risk of revenue instability due to elimination of the "85% ratchet." Its witnesses stated

that AMPCO had not yet developed the details of how to calculate the revenue differences to be included in the account.

AMPCO's rationale for changing the Network charge determinant is that the current design "is incorrect in principle and constitutes a barrier to demand response and the efficient use of the transmission system."⁴² It submitted that the 85% ratchet is inconsistent with practices in other jurisdictions. In AMPCO's view, the "ratchet" reduces (by 85%) a transmission customer's incentive to control its demand during system peak hours. AMPCO submitted few large power consumers can shift all of their consumption away from the peak weekday hours from 7:00 am to 7:00 pm. Even if such consumers shifted load away from the individual peak hour, they will only receive a 15% reduction in their network transmission charges. AMPCO also suggested that it is inappropriate to charge consumers for Network service every month of the year when total demand in many months is not material from a system planning and operational standpoint.

AMPCO asserted that its approach would increase demand response during peak periods, which would be consistent with Ontario government policy, and would reduce electricity costs for all consumers.

Opposition to AMPCO's Proposal

AMPCO's proposal was opposed by Hydro One and all intervenors who commented on the issue (CCC, EDA, IESO, SEC, Toronto Hydro-Electric System, and VECC). The intervenors submitted several criticisms of AMPCO's proposal; some of the significant criticisms are summarized below.

Intervenors argued that AMPCO presented no evidence that its proposal would avoid or defer capital spending on the transmission system. VECC noted that much of the anticipated capital expenditures on the transmission system in the near term, such as

⁴² AMPCO Final Argument, p. 27.

the Bruce to Milton line, are driven by new generation projects or local area load constraints, not system-wide capacity issues.

EDA noted that in the decision which set the current charge determinants (RP-1999-0044) the Board stated:

A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future. (paragraph 3.4.27)

EDA submitted that AMPCO did not provide any evidence that Hydro One's system is capacity constrained now. EDA argued that the Board's finding in RP-1999-0044 remains sound. Hydro One confirmed that the transmission system is generally not capacity constrained.

EDA suggested that the AMPCO proposal would benefit only those transmission customers with the ability to shift consumption away from the peak hours. Toronto Hydro pointed out that it and other local distribution companies (LDCs) have little or no ability to shift their demand away from the peak because LDCs have little control over when their customers consume power. They would, therefore, pay a larger share of Hydro One's Network charges.

AMPCO provided little evidence that its 5-CP method would lead even its own members to shift their demand significantly. From the evidence, it appears that only steel companies have the operational flexibility to shift a significant amount of load off peak.

AMPCO provided no evidence that its proposal would lower commodity costs for the benefit of all electricity consumers even if it is assumed that it would result in significant load shifting by large industrial and commercial consumers. VECC noted Hydro One submitted data for 2005 showing that high-priced hours in the IESO-administered

electricity market were poorly correlated with transmission system peak hours. If this relationship cannot be established, the “benefits” associated with the AMPCO proposal become elusive.

AMPCO filed a 2003 Navigant Consulting study, *A Blueprint for Demand Response in Ontario*, as support for its views on the commodity price impact of its proposal. VECC submitted that the study’s conclusions on the value of demand response did not support AMPCO’s premise, in part because Navigant Consulting estimated the impact of demand response for many more hours than would be relevant under AMPCO’s 5-CP proposal. A further concern was that the study was prepared several years ago when there were few organized demand response programs in Ontario. AMPCO acknowledged that a more current study would be helpful and that “it may be that a lot of the commodity savings that Navigant talked about have been mined.”⁴³

EDA submitted that AMPCO’s proposal is more complex than the status quo and noted that it is unclear how the proposed “balancing account” would work. The IESO, which is responsible for billing transmission charges for all transmitters, indicated that AMPCO’s 5-CP proposal would take a minimum of six months and cost \$150,000 to make the required information system changes.

During the hearing, Board staff noted that days defined as holidays by the IESO (which calculates Network transmission charges) differ from the days defined as holidays by the Board for purposes of its Regulated Price Plan. The IESO suggested that the best approach would be to have Board staff work with the IESO to implement a consistent holiday schedule.

Board Findings

The Board finds that Hydro One should continue to charge for its Network service using its current charge determinant. It does not accept AMPCO’s recommendation that the

⁴³ Tr. Vol. 10, p. 142.

Board should order Hydro One to work with the IESO, OPA and other stakeholders to design a new method.

AMPCO's 5-CP proposal was not well defined and, as became evident during cross examination of its witnesses, it appeared the proposal was really more of a concept than a workable alternative to the status quo. More fundamentally, the Board is not convinced that AMPCO has made a compelling case either that the current Network charge determinant has significant defects or that its 5-CP proposal is superior.

In reaching these conclusions, the Board is not saying that it is impossible to improve on the current methodology, nor is it saying that it is not open to considering changes in the future. As the Board knows from RP-1999-0044, the proceeding in which the current approach to the Network service charge determinants was approved, designing transmission rate structures requires considerable evidence and the involvement of a wide range of stakeholders. Parties that advocate changes in how customers should pay for transmission service need to submit a strong case for change, with detailed evidence and analyses showing why the status quo has undesirable effects and is inappropriate. In the Board's view, AMPCO did not put forward that case in this proceeding.

With respect to achieving a consistent definition of "holiday," the Board agrees with the IESO that the issue need not be resolved in this proceeding. It is more appropriate for Board staff to work with the IESO to implement a consistent holiday schedule.

11. IMPLEMENTATION AND COST AWARDS

Hydro One applied for a transmission revenue requirement of \$1,240 million for the 2007 test year and \$1,277 million for the 2008 test year. The Board made a number of findings that will affect these amounts.

During the course of the oral hearing, Hydro One provided two options for transmission rate implementation.

Option 1, is a proposal for a single uniform transmission rate change on November 1, 2007, covering a 14 month period, including:

- An RDDA amount consisting of: [Approved 2007 Revenue Requirement x 10 month forecast volume/ forecast annual volume] **less** [2000 Rates x 10 month volume], (*revenue share adjustment is not mentioned*).
- 2007 approved revenue requirement for 2 months in 2007 (Nov. and Dec.)
- 2008 approved revenue requirement for 12 months in 2008.

Option 2, is a proposal for two rate changes, one on November 1, 2007 and one on January 1, 2008.

As noted in Chapter 8, the Board finds that a single rate change (Option 1) should be implemented by Hydro One.

Therefore the Board directs the Company to file with the Board and all intervenors of record, a draft exhibit outlining the final revenue requirements and charge determinants to reflect the Board's findings in this decision. The Company should file this exhibit within 10 days of the issuance of this decision. In addition, an exhibit should be filed

which includes the calculation of the uniform transmission rates, charge determinants and revenue shares resulting from this decision. This exhibit will be used in the uniform transmission rates proceeding to establish the Ontario Uniform Transmission Rates.

Hydro One should provide a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits. Intervenors shall have 10 calendar days to respond to the Company's exhibit. The Company should respond as soon as possible to any comments by intervenors.

Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding. On June 26, 2007, Procedural Order No. 5 was issued directing those intervenors to file their cost claims with the Board by July 10, 2007. Hydro One was to reply to those claims by July 23, 2007 and any intervenor reply to Hydro One's submissions was to be submitted by August 1, 2007.

The following eligible intervenors requested recovery of their costs and filed cost statements: Energy Probe, VECC, CCC, SEC, Electricity Distributors Association ("EDA"), and AMPCO.

Hydro One did not comment on the cost claims submitted by the eligible intervenors.

The Board wishes to commend all intervenors for coordinating their cross-examination, which resulted in efficiencies with no perceived compromise in effectiveness. The Board awards all eligible parties (Energy Probe, VECC, EDA, CCC, AMPCO and SEC) 100 percent of their reasonably incurred costs. The precise amounts will be confirmed after a review by the Board's Cost Assessment Officer to ensure that the rates or fees claimed and disbursements do not exceed the Board's guidelines contained in the Practice Directions. Hydro One shall pay the amounts of the intervenor cost awards immediately upon receipt of the Board's cost orders.

Hydro One shall also pay the Board's costs upon receipt of the Board's invoice.

DATED at Toronto August 16, 2007.

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

Original signed by

Paul Sommerville
Member

Original signed by

Bill Rupert
Member

APPENDIX 1

**HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES**

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

**PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES**

August 16, 2007

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On October 17, 2006, the Board issued a Letter of Direction and Notice of Application to Hydro One Networks Inc.

The Board issued Procedural Order No.1 on November 30, 2006, establishing the procedural schedule for a number of early events prior to the oral hearing. These events included an Issues Conference on December 7, 2006, and an Issues Day on December 14, 2006;

On Issues Day, the Board heard submissions from the SEC, CCC, VECC, PWU and AMPCO.

The Board issued Procedural Order No. 2 on December 20, 2006, which included the Board's decision on the contested issues identified on Issues Day. The Issues List for the proceeding was attached to Procedural Order No. 2. The Board also directed that notice be given to all transmitters and their customers, informing them that this proceeding would deal with the issue of charge determinants. Procedural Order No. 2 also included Schedule 1, consisting of excerpts of certain findings and observations from the Distribution decision (RP-2005-0020/EB-2005-0378). A number of hearing event dates were also amended:

- Written interrogatories to the Applicant by Board staff due on December 21, 2006 and by the intervenors due on January 11, 2007;
- Written interrogatory responses from the Applicant due by January 29, 2007;
- Intervenor evidence filed by February 14, 2007; interrogatories on this evidence by February 23, 2007 and responses due on March 2, 2007;
- Applicant evidence update on February 23, 2007 with a related technical conference on the update on March 6, 2007;

- A Settlement Conference was set for March 26, 2007 and the Settlement Proposal Hearing set for April 10, 2007;
- The oral hearing set to begin on April 19, 2007.

The Board issued Procedural Order No.3 on March 2, 2007, amending the start date for the oral hearing to April 23, 2007.

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. The Board issued Procedural Order No. 4 on March 12, 2007 inviting intervenors to make submissions on this request.

On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account.

The Settlement Conference was held on March 26, 2007 and on April 3, 2007 the Settlement Proposal was filed with the Board and was the subject of the Settlement Proposal hearing held on April 10, 2007. The Board issued its Settlement Decision on April 18, 2007.

The oral hearing began on April 23, 2007 and concluded on June 13, 2007.

Procedural Order No. 5 was issued on June 26, 2007 regarding submission of cost claims by eligible intervenors.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Donna Campbell Jennifer Lea
	Harold Thiessen Nabih Mikhail Chris Cincar Wade Frost Martin Davies
Hydro One Networks Inc.	Don Rogers Joe Toneguzzo
Society of Energy Professionals	Richard Long Sonia Pylyshyn
IESO	David Short
Consumers Council of Canada	Robert Warren Julie Girvan
Ontario Power Generation	Tony Petrella
Association of Major Power Consumers of Ontario	Mark Rodger Wayne Clark
Energy Probe	David MacIntosh Tom Adams
School Energy Coalition	John De Vellis
Vulnerable Energy Consumer's Coalition	Michael Buonaguro Bill Harper
Power Workers Union	Richard Stephenson

WITNESSES

There were 20 witnesses who testified at the oral hearing.

The following Company employees appeared as witnesses at the oral hearing:

Frank Jacob	Manager, Program Integration and Regulatory Filing
Mike Penstone	Director, System Investment
George Carleton	Director, Supply Chain Services, Finance
Andy Stenning	Director, Station Maintenance

Naren Pattani	Manager, Transmission System Development
Nairn McQueen	Vice President, Engineering and Construction Services
Paul Tremblay	Director, Network Operating, Grid Operations
Judy McKellar	Director, Human Resources
Sandy Struthers	Chief Information Officer
Greg Van Dusen	Director, Business Integration
Ian Innis	Director, Corporate Planning and Regulatory Finance
William Paolucci	Assistant Treasurer, Treasury Division
Andy Poray	Director, Regulatory Policy and Support
Stanley But	Manager, Economics and Load Forecasting
Henry Andre	Manager, Regulatory Affairs, Corporate Regulatory Affairs

In addition, the Company called the following witness:

Kathleen McShane	President and Senior Consultant, Foster Associates Inc.
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Witnesses called by intervenors:

For AMPCO:

Wayne Clark	Consultant, SanZoe Consulting, Inc.
Darren MacDonald	Director of Energy, Gerdau Ameristeel
Gary Saleba	President and CEO, EES Consulting

For VECC/CCC:

Dr. Laurence D. Booth	CIT Chair, Structured Finance, Rotman School of Management, University of Toronto
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In addition, evidence was filed by York University professors Dr. Fred Lazar and Dr. Eli Prisman on behalf of Board staff. Drs. Lazar and Prisman did not appear as witnesses in the oral hearing.

APPENDIX 2

**HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES**

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT PROPOSAL

August 16, 2007

**Hydro One Networks Inc.
Test Year 2007/2008 Transmission Rates
EB-2006-0501**

SETTLEMENT PROPOSAL

Preamble:

This settlement proposal is filed with the Ontario Energy Board (“the Board”) in connection with the application by Hydro One Networks for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented in 2007.

Further to the Board’s Procedural Order No. 2 dated December 20, 2006, a settlement conference was held on March 26 and 27, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (“Rules”) and the Board’s Settlement Conference Guidelines (“Guidelines”).

Hydro One Networks and the following intervenors (“the parties”) participated in the settlement conference:

- Association of Major Power Consumers in Ontario (“AMPCO”)
- Consumers Council of Canada (“CCC”)
- Electrical Distributors Association (EDA)
- Energy Probe Research Foundation (“Energy Probe”)
- Independent Electricity System Operator (“IESO”)
- Ontario Power Generation (“OPG”)
- Power Workers’ Union (“PWU”)
- School Energy Coalition (“SEC”)
- Society of Energy Professionals (SEP)
- Vulnerable Energy Consumers Coalition (“VECC”)

Ontario Energy Board staff also participated in the settlement conference but are not party to this settlement proposal.

Outlined below are the positions of the parties following the settlement conference. The settlement proposal follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

Settled: If the settlement proposal is accepted by the Board, the parties will not adduce any oral evidence during the hearing as the applicant and the intervenors who take any position on the issue agree to the proposed settlement.

Partially Settled: If the settlement proposal is accepted by the Board, the parties will only adduce evidence on portions of the issues as the applicant and the intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue.

Not Settled: The applicant and the intervenors who take a position on the issue will adduce evidence at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the settlement proposal:

Settled: Issue completely resolved. Parties will not adduce evidence at the hearing.	Partially Settled: Issue partially resolved. Parties will adduce evidence at hearing on certain portions of the issue.	Not Settled: Issue not resolved. Evidence to be adduced on entirety of issue.
# issues settled: 24	# issues partially settled: 2	# issues not settled: 14

The positions taken by the various parties on each of the settled or partially settled issues are identified throughout the settlement proposal.

The settlement proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence filed to date. The parties to the settlement proposal agree that the evidence filed to date in respect of each settled or partially settled issue supports the proposed settlement. In addition, the parties agree that the evidence filed in support of each settled or partially settled issue contains sufficient detail, rationale and quality information to allow the Board to make findings in keeping with the settlement or partial settlement reached.

The settlement of issues 8.1 and 8.2 are proposed as a package. The balance of the issues in the settlement proposal are not proposed to the Board as a package settlement. As such, the parties acknowledge that the Board may accept settlement on any individual issue, or combination of them.

1. ADMINISTRATION (Exhibit A)

- 1.1 Are the Affiliate Service Agreements still cost effective and efficient in delivering services? Have any changes occurred in these arrangements since the 2006 distribution rates proceeding (RP-2005-0020/EB-2005-0378)? (A1/T8/S2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

A-8-2 Affiliate Service Agreements

J-1-1, J-1-2, J-1-3, J-5-1, J-5-2, J-5-3, J-5-4, J-5-5, J-5-6, J-9-36, J-9-37, J-9-38

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 1.2 Has Hydro One addressed all relevant Board directions from previous proceedings? (A/T17/S1)

Settled. The parties accept the Applicant's position on this issue, as it was agreed that the following matters, for which agreement could not be reached, would be addressed in the context of other issues. The particulars are outlined below.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

d) Intervenors raised a concern relating to the justification for the Niagara Reinforcement Project

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 3.4. However, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project.

e.) Intervenors, except the SEP, raised a concern regarding whether the Company has complied with the following directives, relating to compensation issues, given by the Board in its Decision with Reasons dated April 12, 2006 in EB-2005-0378: "the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates." [para. 3.4.4]; and, "The Board expects Hydro One to file appropriate evidence in the next main rates case to establish that none of the incentive compensation should be charged to the shareholder." [para. 3.4.7]

The parties, except the SEP, agreed this concern would be dealt with as part of the Board's consideration of issue 2.2.

Evidence:

Exhibit A-17-1, Table 1 (entitled Board Directives from Proceeding RP-1998-0001) identifies the reference exhibit which contains Hydro Ones response to the related directives.

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP (with the exception that the SEP requested to be excluded from comments in 1.2e), VECC

Parties taking no position: EDA, IESO, OPG,

1.3 Is the proposal to establish a revenue requirement beyond the 2007 and 2008 test years without a separate cost of service approval appropriate?

Not settled. The parties were unable to reach agreement on this issue.

1.4 Is the proposed methodology to establish the future revenue requirement beyond 2007 and 2008 appropriate?

Not settled. The parties were unable to reach agreement on this issue.

- 1.5 Is the proposal to include capital spending as incurred in Rate Base for 2009-2010 appropriate? (A1/T13/S1)

Not settled. The parties were unable to resolve this issue.

- 1.6 Are Hydro One's Economic and Business Planning Assumptions for 2007 and 2008 appropriate?

Settled. Intervenors had no concerns with respect to Hydro One's economic and business planning assumptions for 2007 and 2008, except for the assumed interest rates regarding cost of capital. The parties agreed that business and economic planning assumptions utilized by Hydro One for 2007 and 2008 are appropriate.

The parties agreed that concerns regarding Hydro One's interest rates assumptions as they affect cost of capital would be addressed under issue 4.2.

Evidence:

A-9-1 Hydro One Transmission Financial Statements for the Year Ended 2005

A-10-1 Hydro One Inc. – Historic Year Annual Reports

A-10-2 Hydro One Inc. – Budget Year Quarterly Reports

A-14-1 Planning Process

A-14-2 Economic Indicators

A-14-4 Project and Program Approval and Control

J-1-15, J-1-16, J-1-17, J-5-26, J-10-1, J-10-2, J-10-3, J-10-4

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

2. COST OF SERVICE (Exhibit C)

- 2.1 Are the overall levels of the 2007 and 2008 Operation, Maintenance and Administration Budgets appropriate? (C1/T1/S1)

Not settled. The parties were unable to reach agreement on this issue.

- 2.2 Is the 2007 and 2008 budget for Human Resources related costs (wages, salaries, benefits, incentive payments and pension costs) including employee levels, appropriate? (C1/T3/S1&2)

Not settled. The parties were unable to reach agreement on this issue.

- 2.3 Is the proposed level of corporate O&M costs allocated to the transmission business for 2007 and 2008 appropriate and in line with the O&M cost allocation approved by the Board in Hydro One's 2006 distribution proceeding (RP-2005-0020/EB-2005-0378)? (C1/T5/S1&2)

Settled. The parties accept the Applicant's position on this issue.

The methodology for allocation of costs, for purposes of setting 2007 and 2008 rates, has been accepted, subject to impacts of Hydro One's Human Resource related costs which is an unsettled issue (Issue #2.2).

Evidence:

C1-5-1 Common Corporate Cost Allocation and Cost Allocation Methodology

J-1-29, J-1-42, J-1-43, J-1-44, J-1-45, J-1-46, J-1-47, J-1-48, J-1-49, J-1-99, J-5-65, J-5-66, J-5-67, J-5-68, J-5-69, J-9-36, J-9-37, J-10-8

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 2.4 Is Hydro One's depreciation expense appropriate for 2007 and 2008 and in line with the depreciation methodology approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T6/S1&2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-6-1 Depreciation and Amortization Expenses

C1-6-2 Depreciation Rate Review

C2-5-1 Depreciation and Amortization Expenses

J-1-50, J-5-70, J-9-54

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 2.5 Is Hydro One's proposed transmission overhead capitalization rate appropriate? (C1/T5/S2)

Settled. The parties accept the Applicant's proposed overhead capitalization rate.

Evidence:

C1-5-2 Overhead Capitalization Rate

J-1-51, J-1-52, J-1-53 (overlap with issue 3.3), J-1-54, J-1-77ii, J-5-71

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 2.6 Are the amounts proposed to be included in 2007 and 2008 revenue requirements for capital and property taxes appropriate? (C2/T4/S1)

Settled. The parties accept the Applicant's position on this issue.

Note the Capital Tax amount for 2006 is currently under review and will be revised subject to finalization of results and audit review. Audited Transmission Financial statements will be filed when available during the hearing. Hydro One commits to filing an update of 2006 capital taxes using the audited 2006 financial statements.

Evidence:

C2-4-1 Capital Taxes

C1-2-6 Property Taxes

J-1-55, J-1-56, J-1-57, J-1-58, J-5-72, J-7-23

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.7 Is the amount proposed to be included in 2007 and 2008 revenue requirements for income taxes, including the methodology, appropriate? (C1/T7/S1)

Settled. The parties accept the Applicant's position on this issue.

Additional information was provided during the Settlement process. It was agreed that the 2007 Federal and Provincial Budgets will not have a material impact on HONI's revenue requirement in 2007. Any impacts arising from those budgets will be captured in the proposed Tax Rate Changes Variance Account.

Evidence:

C1-7-1 Payments in Lieu of Corporate Income Taxes

C2-6-1 Calculation of Utility Income Taxes

J-1-59, J-1-60, J-1-62

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3. RATE BASE (Exhibit D)

3.1 Are the amounts proposed for the 2007 and 2008 Rate Base appropriate? (D1/T1/S1)

Partially Settled. The parties have agreed that the proposed amounts for the 2007 and 2008 rate base are appropriate, except for the amounts proposed for capital expenditures in 2007 and 2008 to be dealt with under issue 3.2. Rate base will be modified to reflect any subsequent changes to capital expenditures in 2007 and 2008 resulting from the resolution of issue 3.2.

During the Settlement Conference, additional information was provided that deals with \$7.3M of OEFC owned assets in Hydro One's rate base¹.

Evidence:

D1-1-1 Rate Base

D1-1-3 Level and Appropriateness of Transmission Assets

D2-1-1 Statement of Utility Rate Base

J-1-58, J-1-63, J-1-64, J-1-65, J-5-73

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.2 Are the amounts proposed for Capital Expenditures in 2007 and 2008 appropriate? (D1/T3/S1&3)

¹ Hydro One made payment for these assets as part of the settlement for the acquisition of assets from Ontario Hydro.

Due to jurisdictional issues and due to the fact that underlying land permits did not allow assignment without federal governmental consent, assets owned by Ontario Hydro on Reserves did not pass to HONI under the transfer orders. Instead, these were held by OEFC, as the continuation of Ontario Hydro, in trust for HONI. Pursuant to an Indemnity and Trust Agreement between OEFC and HONI, it is clear that OEFC is merely holding these assets in trust for HONI as the beneficial owner. HONI has all of the operational responsibility for the assets and has indemnified OEFC completely and comprehensively from any and all liabilities and responsibilities arising from the assets, or the underlying permits.

Not settled. The parties were unable to reach agreement on this issue.

- 3.3 Is Hydro One's corporate asset allocation for the transmission business in line with the common capital and common asset allocation approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T5/S3) (D1/T3/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-5-3 Common Asset Allocation

J-1-53 (overlap with issue 2.5), J-1-99, J-5-91

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 3.4 Is the proposed inclusion of "Supply Mix" Capital Project expenditures in 2007 and 2008 Rate Base as they are incurred, appropriate? (D1/T1/S4)

Not settled. The parties were unable to reach agreement on this issue.

In addition, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project (from issue 1.2).

- 3.5 Is the submitted Lead Lag study appropriate for the development of the Working Capital component of the Rate Base? (D1/T1/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

D1-1-5 Working Capital and Lead/Lag Study

J-1-63, J-1-104, J-5-94, J-7-28

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 3.6 Does the Asset Condition Assessment adequately address the current condition of the transmission system assets and the determination of capital needs of the system in the future? (D1/T2/S1)

Settled. The parties accept the adequacy of the Applicant's Asset Condition Assessment but without prejudice to their position on capital spending levels.

Evidence:

D1-2-1 Asset Condition Study

J-1-105, J-1-106, J-3-4, J-5-29, J-5-31, J-5-34, J-5-77, J-5-95, J-5-96, J-5-97, J-5-98, J-6-2

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

- 3.7 Is the method that Hydro One has used to calculate AFUDC appropriate? (D1/T4/S1)

Settled. Hydro One has agreed that the AFUDC will be calculated using the rate approved by the Board for distribution companies, to be effective January 1, 2007.

Evidence:

D1-4-1 Allowance for Funds Used During Construction

J-1-68, J-1-69

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

4. **COST OF CAPITAL/CAPITAL STRUCTURE (Exhibit B)**

- 4.1 What is the appropriate Capital Structure for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were unable to reach agreement on this issue.

- 4.2 What is the appropriate Return on Equity (ROE) for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were not able to reach agreement on this issue.

- 4.3 Are Hydro One's proposed costs for its debt and preference share components of its capital structure appropriate? (B1/T2/S1)

Not settled. The parties were not able to reach agreement on this issue.

- 4.4 Should the Capital Structure, Capital Costs and Rate of Return on Equity vary between Hydro One's distribution and transmission businesses? (B1/T3/S1)

Not settled. The parties were unable to reach agreement on this issue.

5. **REVENUE REQUIREMENT (Exhibit E)**

- 5.1 Is the proposed amount for 2007 and 2008 External Revenues, including the methodology used to cost and price these services, appropriate? (E3/T1/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

E3-1-1 External Revenues

J-5-104, J-5-105, J-7-41, J-7-42, J-7-43

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6. COST ALLOCATION (Exhibit G)

6.1 Are Hydro One's proposed cost pools appropriate and have the costs assigned to these pools been allocated appropriately? (G1/T1-6)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G1-4-1 Transformation Connection Pool

G1-5-1 Wholesale Meter Pool

G1-6-1 Cost Data for Low Voltage Switchgear Compensation

G2-5-1 Detailed Revenue Requirement by Rate Pool

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-4, J-1-136, J-1-138, J-5-106, J-5-107, J-5-108, J-5-109, J-5-110, J-5-111, J-5-112, J-5-113, J-5-114, J-5-115, J-5-123, J-8-4

AMPCO Evidence, Testimony of Gary S. Saleba, Pg. 11 Line 16-18

J-13-1 (Pg.2 under the heading "Hydro One Cost Allocation")

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.2 Is the proposed cost allocation treatment of "dual function" lines appropriate? (G2/T2/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G2-2-1 Allocation Factors for Dual Function Lines

G2-4-1 Asset Value by Functional Category

G2-4-2 Total Depreciation by Functional Category

G2-4-3 Return on Capital and Income Taxes by Functional Category

G2-4-4 OM&A Costs by Functional Category

J-5-107, J-5-108, J-5-109, J-5-111, J-5-114, J-5-115,

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.3 Is it appropriate to create a Wholesale Meter pool and was the establishment of this pool done appropriately? (G1/T5/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-5-1 Wholesale Meter Pool

G2-5-1 Detailed Revenue Requirement by Rate Pool

J-5-107, J-5-111

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.4 Should the customers directly connected to Network Stations that do not pay Line Connection Charges pay them and if so, what mechanism should be used? (G1/T3/S1)

Settled. The parties agreed to resolve this issue and agree that the status quo is appropriate for this case. Hydro One has undertaken to conduct an internal study on connection facilities terminating in Network Stations and associated connection charges to be submitted as part of the next transmission rate application.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-137

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.5 To what cost pools should “Local Loops” be allocated? (G1/T3/S1)

Settled. The parties accept the Applicant’s position on this issue.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-138, J-5-115

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

7. **RATE DESIGN and CHARGE DETERMINANTS (Exhibit H)**

7.1 Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected? (A1/T14/S2&3) (H1/T2/S1)

Not settled. The parties were unable to reach agreement on this issue.

7.2 Have the proposed charge determinants been forecast appropriately for each of the transmission revenue pools? (G1/T1/S1) (H1/T3/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

H1-3-1 Charge Determinants

H1-4-1 Rates for Wholesale Meter Service

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

7.3 Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate? (H1/T3/S1)

Partially settled. The parties were able to agree that the current charge determinants for Connection service are appropriate. The parties were unable to reach agreement on whether the current charge determinants for Network service are appropriate.

Evidence:

H1-3-1 Charge Determinants

J-5-122

Supporting Parties: AMPCO, CCC, EDA; Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: OPG

7.4 Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed? (H1/T5/S1, 2 & 3)

Settled. The parties were able to reach agreement on this issue.

After identifying alternatives as directed by the Board, Hydro One assumed that the status quo of \$1.00/MWh would continue, for the purposes of its application.

The parties have agreed that the status quo ETS tariff of \$1/MWh should be maintained for the time being, but that the IESO should now be identified as the entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.

Evidence:

H1-5-1 Rates for Export Transmission Service

H1-5-2 Review of Export Tariffs in Other Jurisdictions

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-144, J-1-145, J-1-146, J-1-147, J-1-148, J-5-106, J-5-125, J-5-126

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, SEC, SEP, VECC

Parties taking no position: EDA, PWU ("not opposed")

8. OTHER ISSUES

- 8.1 Is the proposal for the establishment and methodology of Hydro One's 2007 and 2008 Deferral and Variance Accounts appropriate? (F1/T3/S1)

Settled. The parties have agreed, as part of a package, to resolve this issue together with issue 8.2 as follows:

- i) The amount of the Deferred Export Transmission Service Credit is \$54.5M (Update).
- ii) The Ontario Energy Board Cost Account will not be altered to reflect load growth.
- iii) The Market Ready Cost Account will be reduced by 10%, even though it has already been reduced to reflect the OEB Distribution decision. This value after a 10% reduction is \$16.7M as at April 30, 2007.

Note: The 10% reduction to principal was calculated effective December 2004 (consistent with the date of adjustments arising from the Distribution market ready decision). This amount is then interest improved to arrive at the value of \$16.7M as at April 30, 2007.

- iv) Interest on all variance accounts will be that approved by the Board for distribution companies, to be effective January 1, 2007.
- v) All variance accounts will be cleared over four years in order to facilitate rate smoothing.

In addition, as it relates to new accounts, the parties agree that the following requested new variance accounts should be approved:

1. OEB Cost Assessment Differential
2. Tax Rate Changes
3. Transmission System Code Changes
4. Pension Cost Differential

The parties further agree to await the Board's decision on the 2007 Revenue Deficiency Deferral Account presently under reserve.

As the recent federal and provincial budgets have not been formally passed into law, any tax impacts of those budgets will be recorded in the new Tax Rate Changes Account, once formalized.

Evidence:

F1-1-1 Regulatory Assets

F1-1-2 Variances Resulting From Board Decisions

F1-2-1 Planned Disposition of Regulatory Assets

F1-3-1 Variance Account Requested

F2-1-1 Regulatory Assets

F2-1-2 Schedule of Annual Recoveries

J-1-149, J-1-150, J-1-151, J-1-152, J-1-153, J-1-154, J-1-155, J-5-19, J-5-127, J-5-128, J-5-129

Supporting Parties: AMPCO, CCC, Energy Probe, IESO (v), SEC, SEP, VECC

Parties taking no position: EDA, IESO [(i) to (iv) and new accounts], OPG, PWU ("not opposed")

8.2 Is the proposal for the amounts and disposition of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate? (F1/T1/S1)

Settled. The parties have resolved this issue as a package with issue 8.1, outlined above.

Evidence: see issue 8.1 above.

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

8.3 Has Hydro One delivered an adequate level of service and other performance compared with other jurisdictions and other relevant performance standards? (A1/T15/S1, 2&3)

Settled. The parties accept the Applicant's position on this issue. The parties have agreed that the issue related to customer delivery point performance

standards would be addressed as part of proceeding RP-1999-0057/EB-2002-0424.

Evidence:

A-15-1 Transmission Business Performance

A-15-2 Transmission Benchmarking

A-15-3 Customer Delivery Point Performance Standards

J-1-33, J-1-35, J-1-36, J-1-38, J-1-156, J-1-157, J-1-158, J-1-159, J-1-160,
J-1-161, J-1-162, J-1-163, J-1-164, J-1-166, J-2-6, J-3-1, J-3-4, J-3-5, J-5-130,
J-5-131, J-5-132, J-5-133, J-5-134, J-5-135, J-5-136, J-5-137, J-6-3, J-6-4, J-7-7,
J-8-5

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

- 8.4 Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the city of Toronto project? (D2/T2/S3)

Settled. The parties were able to reach agreement on this issue. The parties agreed that the applicant has demonstrated the need to relieve loading on the existing 115kV connection lines between and Leaside and Birch Junction TSs.

The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Evidence:

D2-2-3 Justification for Programs or Projects in excess of \$3 Million (#D18 Leaside x Birch Junction Transmission Reinforcement)

J-1-167, J-5-138

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

9. RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue implications regarding the Hydro One Transmission earnings/sharing mechanism (EB-2005-0501) established by the Board?

Not settled. The parties were unable to reach agreement on this issue.

Also, the parties agreed that the following concerns would be dealt with as part of the Board's consideration of issue 9.1 rather than issue 1.2.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

9.2 Are the bill impacts as a result of this application for various customer groups reasonable? (A1/T2/S1)

Not settled. The parties agreed that this issue could not be resolved at this time.

APPENDIX 3

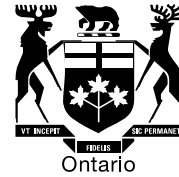
**HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES**

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT DECISION

August 16, 2007



EB-2006-0501

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 Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

SETTLEMENT PROPOSAL DECISION

Hydro One Networks Inc. (“Hydro One” or the “Company”) filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998*, S.O. 1998, c.15, Schedule B. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

On April 3, 2007, Hydro One Networks Inc. filed a Settlement Proposal that was developed and agreed to by Hydro One and ten intervenors in this proceeding. The Settlement Proposal indicates that the parties reached full settlement on 24 issues and partial settlements on two issues. There was no settlement on fourteen issues.

Hydro One presented the proposal to the Board at a settlement hearing on April 10, 2007 (together with some additional clarifying statements on settled Issues 1.2 and 6.5). Board staff made submissions on two settled issues – 8.1 and 8.2,

which relate to deferral and variance accounts – and recommended that those issues be removed from the proposal.

On April 10, 2007, the Board accepted the Settlement Proposal¹ except for issues 7.4, 8.1, 8.2 and 8.4. The Board's decision on these issues is below.

Issue 7.4 – Export Transmission Service Tariff

Issue: “Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed?”

The settlement proposal stated that the status quo of \$1.00/MWh would continue. It also went on to describe agreement on the role that the IESO would take in negotiating acceptable reciprocal arrangements with neighbouring jurisdictions, studying the appropriate ETS tariff and making its report available to the Board. At the settlement hearing, the Board asked the parties to consider whether or not the issue could be settled by simply agreeing to the status quo and removing the additional discussion in the proposal on future actions by the Independent Electricity System Operator (IESO)².

After consulting with the settling parties, on April 11, 2007, Hydro One filed with the Board modified settlement language for this issue. Although the settlement continues to refer to possible future action by the IESO, the language makes clear that the Board is not approving the future actions of the IESO and that any change to the ETS charge must be made through a Board rates process. The settlement language is now in a form satisfactory to the Board. The Board accepts the modified settlement proposal for this issue.

Issue 8.4 – Leaside TS to Birch Junction TS Reinforcement

Issue: “Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the City of Toronto project?”

¹ Transcript, April 10, 2007, page 91.

² Transcript, April 10, 2007, page 36.

The settlement proposal agreed that the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS had been demonstrated and was accepted. The proposal also stated agreement that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board. In the oral hearing of the settlement proposal, the Board indicated that it could not accept the proposed settlement on this issue because it would mean the need for this project would not be examined on the record.³ The Board asked Hydro One to consider two options for addressing the need for this project: moving the issue from this rates case to the Section 92 leave to construct proceeding for the project, or by having a Hydro One witness panel address the need issue as part of this rate hearing.

On April 11, 2007, Hydro One informed the Board that it will present evidence on the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS at this hearing. The Board accepts the remainder of the settlement on this issue, being the deferral of issues on options, alternative and costing of mitigating alternatives to a section 92 application.

Issues 8.1 and 8.2 – Deferral and Variance Accounts

Issue 8.1, “Is the proposal for the establishment and methodology of Hydro One’s 2007 and 2008 Deferral and Variance Accounts appropriate?”

Issue 8.2, “Is the proposal for the amounts and disposition of Hydro One’s existing Deferral and Variance Accounts (Regulatory Assets) appropriate?”

At the settlement hearing, Board staff made submissions on general policy issues with respect to deferral and variance accounts being established through settlement agreements. Staff also expressed some particular concerns on the specific accounts referred to in the proposed settlement of Issue 8.1. The Board

³ Transcript, April 10, 2007, page 80.

indicated it would consider the issues further in light of the submissions by Board staff.

Policy Issues

Board staff submitted that there are “policy dimensions to creating the variance and deferral accounts that Staff believes should be addressed on a more comprehensive basis than is permitted by the settlement process.”⁴ Staff noted that its concerns extended to the disposition of account balances as well as the creation of accounts. Staff advocated that Issues 8.1 and 8.2 not be accepted by the Board as settled issues; rather, the issues should be explored in the hearing. In addition, Board staff submitted that “for policy reasons perhaps it is now the time for the Board to consider whether or not the creation of such accounts should in fact be part of a settlement proposal.”⁵

Hydro One, VECC and CCC indicated that in other rates cases the Board has accepted many settlement agreements that have dealt with deferral and variance accounts. Hydro One submitted that if the Board wishes to establish a policy that these accounts should not be considered in settlement agreements, it should seek input from larger group than just the parties in this particular rates case.

Specific Deferral and Variance Accounts

Three existing deferral accounts are covered by Issues 8.1 and 8.2. Board staff submitted that the Board should not accept the settlement because the Board should explicitly address whether the accounts were authorized, the prudence of the expenditures included in the accounts, and the disposition of the accounts.⁶ Staff observed that Hydro One did not seek, and was not given, permission by

⁴ Transcript, April 10, 2007, pp. 57 and 58.

⁵ Transcript, April 10, 2007, page 48.

⁶ Transcript, April 10, 2007, page 63.

the Board to establish one of the accounts, the Ontario Energy Board Cost Account.

None of the parties to the settlement proposal object to Hydro One establishing the following four new variance accounts: OEB Cost Assessment Differential; Tax Rate Changes; Transmission System Code Changes; and, Pension Cost Differential. Board staff submitted that the Board should reject the settlement on these accounts and, instead, should consider whether the accounts meet criteria used in the past by the Board when granting deferral and variance accounts for electricity distributors.

The settlement proposal for Issue 8.1 refers to a possible fifth new account and states: "The parties further agree to await the Board's decision on the 2007 Revenue Deficiency Deferral account presently under reserve." The Board understands that this language was included in error and is unnecessary given that the Board has already authorized that account in Procedural Order No. 4 issued on March 12, 2007.

Board Findings

With respect to the general policy issues raised by Board staff, the Board does not believe that this rates case is the right forum to address those issues. The Board agrees with Hydro One that if this issue is to be addressed the Board should seek input from a wider group, including parties active in the natural gas sector.

Deferral and variance accounts are used extensively by the OEB in both natural gas and electricity rates cases. The OEB may want to review its regulatory agenda to determine if it should initiate a public policy process to examine the issues associated with the use of these accounts.

The Board will accept the settlement proposal for existing deferral accounts, including the four-year period over which the balances will be cleared, except that the Board will not accept the settlement in respect of the Ontario Energy Board Cost Account. As Board staff noted, Hydro One never applied to the Board to establish that account. If Hydro One continues to believe that the balance in that account should be recovered through future rates, then the Board expects Hydro One to provide evidence in this hearing as to why it would be appropriate for the company to recover such costs given that it did not apply to the Board for a deferral account at the time the costs were being incurred.

The Board also accepts the settlement proposal to establish four new variance accounts. Hydro One and the other parties to the settlement should be aware that the Board is providing no assurance that any amounts in those accounts in the future will be included in rates, nor does the approval of the establishment of these accounts indicate any acceptance by the Board of the types of expenditures being recorded in the accounts.

DATED at Toronto, April 18, 2007.

ONTARIO ENERGY BOARD

Signed on Behalf of the Panel

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

APPENDIX 4

**HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES**

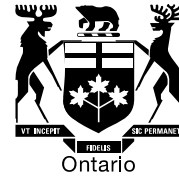
DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

PARTIAL DECISION AND ORDER

Issued
March 30, 2007

August 16, 2007



EB-2006-0501

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 Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

PARTIAL DECISION AND ORDER

Hydro One Networks Inc. ("Hydro One" or the "Company") filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998, S.O. 1998, c.15, Schedule B*. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

By letter dated February 14, 2007 and in the February 23, 2007 update to its application, Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007.

On March 12, 2007 the Board issued Procedural Order #4 requesting that Hydro One make further submissions addressing the following issues:

- The need for the revenue deficiency deferral account;
- Why the issue of the account must be dealt with on an expedited basis;

- What will be booked into the account, and the accounting entries that are proposed to be made;
- The date upon which Hydro One proposes to start booking entries into the account; and
- What, if any, consequences follow if the account is not established at all, or is not established prior to March 31, 2007 as requested.

The procedural order also invited intervenors to respond to Hydro One's submissions and then provided for Hydro One's subsequent reply submissions.

Hydro One Submissions:

Hydro One, in its March 13, 2007 submissions, stated that the EB-2005-0501 transmission earnings sharing mechanism (ESM) was intended to end once new transmission rates were implemented. The establishment of the 2007 revenue deficiency deferral account (RDDA) beginning January 1, 2007, would replace and end the ESM.

Hydro One claimed that the proposed RDDA was more transparent than the ESM, and would be easier to justify and implement for a portion of a year (as un-audited financial results would be used.) In contrast, the part-year RDDA calculations would be based upon approved data consistent with Hydro One Transmission 2007 rate filing. A rates decision in late 2007 would lead to regulatory lag and uncertainty regarding Hydro One in financial markets. An RDDA was also consistent with the Great Lakes Power Limited (GLPL) deferral account (EB-2005-0241) granted in 2005. A decision by March 31, 2007 was requested due to first quarter financial reporting requirements to external investors.

Under the proposed plan, Hydro One submitted that no amounts would be recorded for the ESM in 2007; however, on a monthly basis, the deficiency between the proposed revenue 2007 requirement (per the Hydro One Transmission rate filing) and revenue calculated using current approved rates (by applying a weather normal monthly load forecast consistent with the 2007

load forecast) would be reflected in the deferral account. Monthly carrying costs would be applied to this entry using the short-term interest rate included in the 2007 revenue requirement. Disposition of the account would be subject to future OEB review and approval. Entries would be booked immediately upon receiving a favourable decision from the OEB reflecting the commencement date of January 1, 2007.

Intervenors' Submissions:

Four intervenors responded to the Hydro One submission. The Vulnerable Energy Consumers Coalition (VECC) and Schools Energy Coalition (SEC) argued against granting the account. The Association of Major Power Consumers (AMPCO) and the Power Workers Union (PWU) were supportive of the request.

VECC argued that approval of this account was retroactive ratemaking and should not be approved by the Board. The GLPL case should not be considered as a precedent in this application as the deferral account granted to GLPL was only one aspect of a comprehensive settlement agreement. In addition, the GLPL account only applied to deficiencies starting on April 1, 2005, not January 1. VECC also argued that if the account was granted, no interest should be collected in the account.

SEC argued that the Board does not have the authority to revisit rates. SEC noted that in the EB-2005-0501 ESM decision, the Board stated that it was reluctant to have existing rates declared interim and if the Board had meant the mechanism to last only until January 1, 2007, it would have said so. SEC indicated that it would be unfair to ratepayers to allow Hydro One to revisit rates during a period where it anticipates a revenue deficiency but not do so during a period of over-earning. SEC also mentioned the fact that the GLPL deferral account was part of a comprehensive settlement agreement. SEC also noted that recent decisions of the Board have refused to implement rates retroactively on basis that the applicant had not demonstrated that the delay in arriving at just

and reasonable rates by the beginning of the test year was not due to factors within the applicant's control, citing the January 2, 2007 Erie Thames Powerlines Corporation rate order.

AMPCO did not object to the establishment of the RDDA as this action would reassure investors that regulatory risk is minimal. AMPCO stressed that this approval should not pre-empt the Board's hearing process or be misconstrued as prior approval of Hydro One's revenue requirement. AMPCO submitted that any revenue deficiency calculation should be based on actual, non-weather corrected revenue under current rates and that the RDDA should be based only on continuance of program expenditures at the level Hydro One executed in 2006 and not on the increased levels being requested for 2007.

The PWU also supported the approval of the RDDA citing the need for utilities to have sufficient financial certainty so that they can carry out existing and new transmission work programs. The PWU also agreed with Hydro One that the RDDA was consistent with the GLPL decision and stated that the extended application of ESM for 2007 was inappropriate.

Hydro One Reply Submissions:

In its March 21, 2007 reply, Hydro One indicated that it was not requesting prior approval of its proposed 2007 programs or revenue requirements. Hydro One also submitted that SEC's assertions regarding "retroactive rate increases" are not supported as the OEB is not retroactively setting rates and that it is not revisiting rates for a period during which final rates were in place. Hydro One also noted that the settlement agreement in the GLPL case was the basis for the final order issued November 14, 2005, while the deferral account was granted much earlier on March 22, 2005.

Hydro One also stated that it believes that by requiring the use of audited financial statements for the ESM calculations, the Board intended full year application of the ESM, not part year application.

Hydro One submitted that AMPCO's suggestions that the revenue deficiency be calculated on the basis of non-weather corrected actual 2007 revenue and to use 2006 actual program costs is inconsistent with typical regulatory practice and the GLPL decision. Hydro One also pointed out that the GLPL decision included carrying costs in the approved deferral account.

Findings

It often happens that rate proceedings occur within timeframes that do not coincide with the conventional rate period. This can occur for a variety of reasons. In such situations an issue arises as to when the rates approved by the Board will become effective. Determining the effective date for rates is an important aspect of the Board's jurisdiction, and it can have significance for Applicants and ratepayers.

It is clear that such a situation will arise this year with respect to the revenue requirement for Hydro One. It is likely that the final determination of its revenue requirement for 2007 will not be made until the latter half of 2007.

Deferral accounts, such as the one applied for by Hydro One in this proceeding, are accounting devices intended to allow an entity to capture and record in an identifiable location an aspect of operations, the final quantum and disposition of which is dependent on some future unknown event.

In the case of the deferral account applied for by Hydro One, the unknown future event is the Board's final determination of the 2007 revenue requirement, the effective date governing that revenue requirement, and the terms and conditions

imposed by the Board on the disposition, if any, of the amounts recorded in the deferral account.

Parties commenting on Hydro One's request for the Revenue Deficiency Deferral Account have raised issues respecting rate retroactivity, and have attempted to define with great particularity the terms and conditions that should govern the creation of the account, if the Board sees fit to approve its creation.

In the Board's view, the time to make these arguments is in the course of the revenue requirement proceeding per se, and, if necessary, at the time Hydro One seeks to have the amounts recorded in the account disposed of, so as to effect its revenue requirement or the resulting rates derived from it. Parties will be free to make whatever submissions they see fit as to the appropriateness of any disposition option.

At this stage, the Board is simply concerned with ensuring that the account meets the objective of administrative and accounting utility.

Accordingly, the Board approves the creation of a deferral account, effective January 1, 2007, to be referred to as the Revenue Difference Deferral Account. This account will record the sufficiency or deficiency arising from the difference between the 2006 Transmission rates, that is, rates that are currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding. Parties will note that the Board has made the deferral account symmetrical to account for the possibility that the new revenue requirement as found by the Board may be lower than that which underpinned the 2006 rates.

In its materials, the Applicant referenced the Earnings Sharing Mechanism (ESM), which was instituted by a previous Board panel. In the Board's view, the creation of the deferral account as approved by the Board in this proceeding has the effect of terminating the ESM as of December 31, 2006. That is so because the Revenue Difference Deferral Account now accommodates the tracking of

sufficiency as well as deficiency and this fact makes the continuation of the ESM unnecessary. If the new revenue requirement is higher than that underpinning the 2006 rates, the account will represent a credit to the utility to the extent of the difference. On the other hand, if the new revenue requirement is lower than that upon which the 2006 rates are based, the entire amount reflected in the account will be to the credit of ratepayers.

The final balance in the account will reflect a series of decisions made by the Board in its determination of the revenue requirement for 2007.

The Board's approval of the creation of this deferral account should not be construed in any degree as predictive of the quantum of, the terms of or the timing of the disposition, if any, of the contents of this account.

THE BOARD THEREFORE ORDERS THAT:

1. Hydro One shall establish a deferral account in which to record the differences in revenue between 2006 Transmission rates currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding, beginning January 1, 2007. Hydro One is directed to prepare and submit a draft accounting order to the Board reflecting this order.

DATED at Toronto, March 30, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary