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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

January 5, 2010

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli

EB-2008-0272 – Hydro One Networks' 2009-2010 Electricity Transmission Revenue Requirements – Notice of Motion

Please find attached Hydro One Networks' Notice of Motion, returnable on a date to be fixed by the Board, served and filed in accordance with the Board Rules of Practice and Procedure.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors (electronic)

EB-2008-0272

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

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. under section 78 of the *Ontario Energy Board Act, 1998* seeking changes to the uniform provincial transmission rates;

AND IN THE MATTER OF a request for a review by Hydro One Networks Inc. pursuant to Rule 42 of the Rule of Practice and Procedure of the Ontario Energy Board.

NOTICE OF MOTION

Hydro One Networks Inc. ("HON") will make a motion to the Ontario Energy Board ("the Board") at is offices at 2300 Yonge Street, Toronto, on a date and time to be fixed by the Board.

The Motion is for:

1. A review and variance of the Board's decision of December 16, 2009 in EB-2008-0272 ("the decision") which ordered, in part, that HON calculate its 2010 transmission revenue requirement using a return on equity of 8.39%.

2. An order for an oral motion on the merits of this request;

3. An order varying the return on equity to be used by HON to calculate its 2010 transmission revenue requirement from 8.39% to 9.75% in accordance with Report of the Board on the Cost of Capital for Ontario's Regulated Utilities – EB-2009-0084;

4. An order varying the short term debt rate to be used by HON to calculate 2010 transmission revenue requirement from .55% to 1.93% in accordance with the

Report of the Board on the Cost of Capital for Ontario's Regulated Utilities – EB-2009-0084;

5. An order providing for interim rates effective January 1, 2010 pending resolution of the issues raised in this motion; and

6. Such further and other relief as counsel may advise and this Honourable Board may permit.

The Grounds for the motion are:

1. There are grounds which raise a question as to the correctness of the Board's decision, including:
    a. There has been a change in circumstances. Since HON initially filed its application for approval of 2009 and 2010 transmission rates, the Board issued a new report which modified the formula for determining the cost of capital for Ontario's regulated utilities;
    b. By letter of November 5, 2009, the Board directed HON to file draft transmission rates utilizing a return on equity of 8.39% and a short term debt rate of .55% in accordance with the Board's report on cost of capital in place at the time (EB-2006-0087/0088).
    c. On December 11, 2009, the Board issued its Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084 ("the Report") which, in part, refined the existing return on equity formula and the mechanism to derive the applicable short term debt rate
    d. The Report indicated that the refined formula and methodology for determining short term debt rates will come into effect for the setting of rates beginning in 2010.
    e. On December 16, 2009, the decision was released which required HON to utilize the previous formula to determine its ROE, contrary to the Report of December 11, 2009.

f. The Board’s decision of December 16, 2009 and the Report of December 11, 2009 are inconsistent in that the former directs that HON use an ROE of 8.39% to calculate its revenue requirement for 2010 transmission rates and the latter indicates that the new formula ought to apply yielding an ROE of 9.75%.

g. The Board’s decision of December 16, 2009 and the Report of December 11, 2009 are inconsistent in that the former directs that HON use a short term debt rate of .55% to calculate its revenue requirement for 2010 transmission rates and the latter indicates that the new methodology ought to apply yielding a short term debt rate of 1.93%;

h. HON’s transmission rates for 2010 were based on a full cost of service application. There is no good reason not to follow the refined ROE formula as set out in the Report.

i. It is an error in law for the Board to direct HON to utilize the previous formulas when the Board has previously directed that the refined formula is to be used when setting 2010 rates in a cost of service application.

2. Rules 1.03, 2.01, 8, 42, 43, 44 and 45 of the Board’s Rules of Practice and Procedure.

3. The Board’s powers, under Rule 43, to review all or part of any order or decision and to vary, cancel or suspend that order.

4. Such further and other ground as counsel may advise and this Board may permit.

The Documentary Support for this motion is:

1. The evidence filed in EB-2008-0272 (previously filed and not attached to this Notice of Motion).

2. The letter from the Board to HON dated November 5, 2009 re EB-2008-0272.

3. The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009.

4. The decision of the Board in EB-2008-0272 dated December 16, 2009.

5. The letter from HON to the Board dated December 21, 2009 filing draft rates and revenue requirement utilizing refined ROE of 9.75% and short term debt rate of 1.93% re EB-2008-0272.

6. The letter from the Board to HON dated December 22, 2009 re EB-2008-0272 directing HON to file draft rates and revenue requirement using the previous ROE of 8.39% and previous short term debt rate of .55%.

7. The letter from HON to the Board dated January 5, 2010 filing drafting rates and revenue requirement in accordance with the Board's direction of December 22, 2009.

8. Such further and other documents as counsel may advise and this Board may permit.

January 5, 2010

Rogers Partners LLP
181 University Avenue
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Tel: 416-594-4500
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D.H. Rogers, Q.C.
Counsel for the moving party, Hydro One Networks Inc.

EVIDENCE FILED IN EB-2008-0272

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Ontario

BY E-MAIL

November 5, 2009

Ms Anne-Marie Reilly
Regulatory Co-ordinator
Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto ON M5G 2P5

Dear Ms. Reilly,

RE: Hydro One Networks Inc. Transmission Revenue Requirement Supplemental Evidence EB-2008-0272

Cost of Capital Parameter Updates for Hydro One Networks' 2010 Transmission Revenue Requirement Application

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Short-Term debt rate for use in the Hydro One Network Inc.'s 2010 Transmission Revenue Requirement application.

On December 20, 2006, following the consultative process conducted under Board Files EB-2006-0087/0088, the Board issued the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"). The Board Report documents the methodologies and formulae used to determine the Cost of Capital parameters: the Return on Equity ("ROE") and the deemed Long-Term and Short-Term debt rates (collectively, the "Cost of Capital parameters").

The methodologies documented in the Board Report stated that the updated parameters will be derived from *Consensus Forecasts* and Bank of Canada/Statistics Canada three (3) months ahead of the implementation date for the proposed rates. Therefore, the September 2009 data will be used to establish the Cost of Capital parameters used for setting new distribution rates to be effective January 1, 2010.

The Board has applied the methodologies as documented in the Board Report to update the Cost of Capital parameters, in accordance with the Board's Decision in Hydro One Network's 2009 Transmission Cost of Service application (EB-2008-0272). In that Decision, the Board panel stated, at page 52:

> For 2010, the Board agrees with Hydro One that September 2009 data should be used to update the cost of capital parameters. The 2010 year is a separate test year in Hydro One's application; it is not part of an IRM period. It is therefore appropriate to update the cost of short-term debt and return on equity. The Board will issue a letter to Hydro One setting out Hydro One's 2010 cost of capital parameters in due course. The Board expects that this will be treated as a mechanistic update.

In view of the fact that Hydro One Network's weighted average cost of debt relies on its embedded or actual cost of debt, the deemed long-term debt rate is not being updated at this time.

The Board has determined the values for the updated Cost of Capital parameters, shown in the following table:

Parameter	**Value for 2010 Hydro One Networks Inc. Transmission Revenue Requirement Application (assuming January 1, 2010 implementation date for rate changes)**
Return on Equity	8.39%
Long-Term Debt Rate	N/A
Short-Term Debt Rate	0.55%

These values will be used in the Board decisions regarding approval of rates for Hydro One Networks Inc.'s transmission rate application, assuming a January 1, 2010 effective date. A summary of the calculation of the ROE is provided in Appendix A.

All queries on the cost of capital parameters should be directed to the Board's Market Operations hotline, at 416-440-7604 or market.operations@oeb.gov.on.ca .

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Attachment

c. Mr. D.H. Rogers, counsel,
Intervenors on Record

Appendix A

Summary of Return on Equity Calculation
For Hydro One Network's 2010 Transmission Revenue Requirement Application, assuming rates are effective January 1, 2010

Step		
1	Ten Year Government of Canada Bond Yield – end of December 2009 (*Consensus Forecasts*, September 14, 2009)	3.5%
	Ten Year Government of Canada Bond Yield – end of September 2010 (*Consensus Forecasts*, September 14, 2009)	3.9%
	Average of three- and twelve-month forecasts	3.7%
2	Add the average spread between 30-year and 10-year Government of Canada bonds for all business days in September 2009 as posted by the Bank of Canada	0.524%
3	Equals the forecasted yield on Long-term Government of Canada Bonds	4.224%

Per the mathematical formula documented in Appendix B of the Board Report:

4.	Updated ROE calculated as: 9.35% + (0.75 X (4.224% - 5.50%))	8.393%
5.	Maximum allowed ROE (rounded to two decimal places)	8.39%

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

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Executive Summary

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital. The Board also confirms other key principles with respect to its cost of capital policy.

The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind. In light of the information and supporting empirical analysis provided in consultation with stakeholders, the following refinements to the Board's policies with regard to the cost of capital are set out in this report.

1. <u>Need to Reset and Refine Existing Return on Equity Formula:</u> The Board will continue to use a formula-based equity risk premium approach. Also, the Board is of the view that the Long Canada Bond Forecast (the "LCBF") continues to be an appropriate base upon which to begin the return on equity calculation. However, in order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital, the Board has determined that its current formula-based return on equity approach needs to be reset and refined.

- Reset the Formula: The formula needs to be reset to address the difference between the allowed return on equity arising from the application of the formula and the return on equity for a low-risk proxy group that cannot be reconciled based on differences in risk alone. Based on the equity risk premium recommendations derived from multiple approaches that were provided by all participants in this consultation, the Board has determined that an initial equity risk premium of 550 basis points is appropriate for the purposes of deriving the initial return on equity to be embedded in the Board's reset and refined return on equity formula. This includes an implicit 50 basis points for transactional costs. Consequently, assuming a forecast long term government of Canada bond yield of 4.25%, the initial return on equity to be embedded in the Board's reset and refined return on equity formula will be 9.75% (i.e., 4.25% + 550 basis points = 9.75%).

- Refine the Formula: The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. First, the Board views the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5. Second, based on the analysis provided by participants to the consultation, the Board concludes that there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the return on equity formula. The Board has determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield and that the utility bond spread reflected will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

2. Refine Long-term Debt Guidelines and Approach to Determine Rate: The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely

supported the continuation of the Board's existing policies and practices. However, in the report the Board formalizes certain approaches to reflect recent determinations regarding long-term debt costs. Further, the deemed long-term debt rate will be estimated including the A-rated utility bond index yield consistent with refinement to the return on equity formula.

3. Refine Approach to Determine Deemed Short-term Debt Rate: The determination of the cost of short-term debt also was not a primary focus of the consultation. However, to better reflect utility short-term debt costs, the Board has determined that the spread over the Bankers' Acceptance rate used to derive the deemed short-term debt rate should be based on real market quotes for issuing spreads over Bankers' Acceptance rates for the cost of short-term debt.

The Board will apply the methods set out in this report annually to derive the values for the return on equity and the deemed long-term and short-term debt rates for use in cost of service applications. If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process. Also, the Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated return on equity continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2014.

The remainder of this Report sets out in greater detail the Board's policy as summarized above, as well as the considerations underlying the different elements of the Board's approach.

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1 Introduction

The Ontario Energy Board (the "Board") adopted a formula-based approach using the Equity Risk Premium ("ERP") method for determining the fair rate of return on common equity for Ontario natural gas utilities in March, 1997. Application of the approach was extended to the electric utilities when the Board's regulatory oversight expanded to include the electricity sector in 1999. The Board's current approach for determining the cost of capital is set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated December 20, 2006 (the "December 20, 2006 Report").

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process, detailed below, began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

This report sets out the Board's updated approach to cost of capital and the methods that the Board will use to annually update the cost of capital parameters for all rate-regulated utilities. Specifically, this report refines the Board's policies regarding the cost of capital in the following five ways: (i) resetting and refining the return on equity ("ROE") formula; (ii) refining long-term debt guidelines and the approach to determining the deemed long-term debt rate; (iii) refining the approach to determining the deemed short-term debt rate; and (iv) setting out an annual review process to be used by the Board in conjunction with each application of the methodology to ensure that the results meet the Fair Return Standard ("FRS"); and (v) developing a framework within which to conduct a periodic review of the Board's cost of capital policies.

Organization of this Report

This report is organized as follows: The consultative process is detailed in Chapter 2. Important principles in the regulation of cost of capital are discussed in Chapter 3. The Board's policy for and analysis of cost of capital are outlined in Chapter 4. Certain implementation considerations are identified in Chapter 5, and the annual update process and provision for periodic review of the cost of capital policies are addressed in Chapter 6. A summary of the formula-based ROE guidelines in effect in the 2009 rate year is provided in Appendix A. The new methods that the Board will use to annually update the cost of capital parameters as set out in this report are contained in the Appendices.

2 Consultative Process

On February 24, 2009, the Board issued a letter which set out its determination on the values for the ROE and the deemed long-term and short-term debt rates for use in the 2009 rate year cost of service applications. These cost of capital parameter values were calculated based on the methodologies and formulae set out in the December 20, 2006 Report. In that letter, the Board advised participants that it would be initiating a review of its current policy regarding the cost of capital.

2.1 Overview

Initial Consultation

On March 16, 2009, the Board initiated a consultation process to help it to determine whether current economic and financial market conditions warrant an adjustment to any of the cost of capital parameter values (i.e., the ROE, long-term debt rate, and/or short-term debt rate) set out in the Board's February 24, 2009 letter. The consultation was initiated, in part, by (i) the fact that the difference between the cost of equity and the cost of long-term debt values determined by the Board for the 2009 Cost of Service Applications was only 39 basis points (8.01% and 7.62%), versus a difference of 247 basis points in 2008; and (ii) concern that the Board did not have a sufficiently robust approach within which to exercise its discretion to adjust any or all of the values produced by the application of the methodology. The Board indicated that the objective of the consultation was to test whether the values produced, and the relationships among them, are reasonable in the current economic and financial market conditions, and to allow the Board to determine if, when and how to make any appropriate adjustments to any of the values.

Cost of Capital Review

In light of stakeholders' comments, the Board determined not to vary the 2009 parameter values for 2009 rates. In its June 18, 2009 letter setting out this determination, the Board explained that it was not persuaded that there was a sufficient basis to do so, in a timely manner. Nevertheless, the Board determined that further examination of its policy regarding the cost of capital was warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required. Therefore, the Board advised that it would proceed with a review of its policy regarding the cost of capital. The Board indicated that any changes to the policy made as a result of this review would apply to the setting of rates for the 2010 rate year.

The Board set an issues list to form the basis of its review which took into account the stakeholder comments received in response to the Board's March 16, 2009 letter and other information that the Board considered relevant (the "Issues List"). This Issues List was posted to the Board's web site on July 30, 2009. Appended to the Issues List were: a summary of stakeholder options in response to the Board's March 16, 2009 letter; and a list of references to documents germane to the consultation.

The Issues List

In the cover letter to the Issues List, the Board affirmed its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. The Board also set the scope for the consultation as follows. First, that the consultation would deal only with the means by which the Board determines the cost of capital. The actual effect, if any, on specific utilities' revenue requirements as a result of any updated policies arising from this consultation and the determination of just and reasonable rates would not be addressed in this process, but in future rate proceedings. Second, that historically, the Board has found the ERP approach to be pragmatic and efficient given the Ontario market structure and the number of utilities that the Board regulates. The Board concluded that an ERP approach remains the most appropriate in the current circumstances. However, the Board decided to review the application and the derivation of the current ERP approach to determine if it is sufficiently robust to guide the

Board's discretion in applying the FRS. And third, the Board stated that the application of the FRS would be central to the consultation.

The Board identified three areas where further information was needed:

- Potential adjustment to the established cost of capital methodology (i.e., based on the ERP approach) to adapt to changes in financial market and economic conditions;
- Determination of reasonableness of the results based on a formulaic approach for setting cost of capital parameter values; and
- Board discretion to adjust those results, if appropriate.

The Board received written comments from stakeholders identifying their views and positions on the listed issues and held a Stakeholder Conference to provide a forum for discussion of the substantive matters contained in the Board's Issues List.

The Stakeholder Conference

The Stakeholder Conference was held over a three day period, September 21, 22 and October 6, 2009.

The Board identified the objectives of the stakeholder conference as follows:

- To allow participants and their respective experts to clarify and elaborate on their written comments;
- To provide participants with an opportunity to explore in some depth the rationale and merits of alternatives supported by other participants and their respective experts; and
- To help the Board gain, through the presentations and an interactive exchange with participants and their respective experts, a clearer understanding of the positions of participants and of significant issues and areas of concern.

At the start of the Stakeholder Conference, a Capital Markets Panel provided participants with a comprehensive overview of capital markets conditions. The Panel was comprised of practicing capital markets individuals, representing investor, equity analyst, and bond market perspectives. Representatives from Sun Life Financial, TD Securities Inc., Scotia Capital, and Macquarie Capital Markets participated on the Capital Markets Panel. Panel members addressed matters such as:

- What the capital markets have been through, where they are today, and set out key indicators or variables that are of interest prospectively;
- Overall availability of capital and the cost of that capital (both debt and equity);
- Access to bank credit/debt/equity, the absolute cost of debt, spread, term availability, and covenants;
- Spreads that have been and are being observed and under what conditions; and
- Activity that has been and/or is evident in the market in terms of funds flow into the market and between asset classes.

Following the Capital Markets Panel discussion, the following individuals provided presentations to participants and the Board at the Stakeholder Conference:

- Dr Laurence D. Booth, Professor, University of Toronto (consultant for the Building Owners and Managers Association of the Greater Toronto Area, the Consumers Council of Canada, Canadian Manufacturers and Exporters, Industrial Gas Users Association, London Property Management Association, and the Vulnerable Energy Consumer's Coalition);
- Mr. Donald A. Carmichael, Independent Consultant (consultant for Enbridge, Fortis Ontario Inc., and Toronto Hydro-Electric System Limited);
- Mr. James M. Coyne, Senior Vice President, Concentric Energy Advisors (consultant for Enbridge, Hydro One Networks, Inc. and the Coalition of Large Distributors [Enersource Hydro Missisauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.]);

- Mr. John Dalton, Power Advisory LLC (consultant for Great Lakes Power Transmission);
- Ms Kathleen McShane, President, Foster Associates (consultant for Electricity Distributors Association);
- Dr Lawrence P. Schwartz, Consulting Economist (consultant for Energy Probe Research Foundation); and
- Dr. James Vander Weide, Research Professor of Finance and Economics, Duke University, The Fuqua School of Business (consultant for Union Gas).

Subsequent to the Stakeholder Conference and in light of the presentations made by participants and discussions at the conference, the Board received final written comments from participants. The Board indicated in its October 5, 2009 letter to participants that following the receipt of final written comments, it would review all of the materials, including Stakeholder Conference transcripts and all of the written comments in making its determination, and that the Board aimed to issue its report in December.

2.2 Approach to Developing Regulatory Policy

In their final comments to the Board, several participants expressed concern regarding the potential scope of outcomes arising from this consultation. In a joint submission, the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters describe their understanding that the consultation was intended to have a limited scope, and pointed to several statements made by the Board regarding the scope of the consultation. In summary, the submission states: "[i]n these circumstances, we suggest that the possible outcomes of this consultation are limited to a Board report which evaluates whether any of the information presented during the course of the consultative is sufficient to call into question the continued appropriateness of any element of the Board's current cost of capital methodology."[1] The School Energy Coalition filed a similar submission, stating: "[t]he primary purpose of this part of the consultation, as

[1] Final Comments on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters. October 30, 2009. p. 3.

noted by the Board in a number of communications, and reiterated at the stakeholder conference, is to help understand whether the current approach to cost of capital has sufficient robustness to be relied on by the Board in all circumstances."[2]

Although the Board appreciates the perspectives of these participants about their expectations, it does not agree that the scope of the consultation was limited in the fashion that they suggest. The Issues List set out a comprehensive set of issues that set the scope for this consultation. Amongst the issues are the following: How should the Board establish the initial ROE for the purpose of resetting the methodology? Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?[3]

In response to a letter it received on August 13, 2009 from Mr. Robert Warren, sent on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition and the London Property Management Association, the Board again invited participants to provide any information they felt appropriate in responding to the questions on the Issues List:

> Stakeholders are asked to provide in their written comments answers to the questions identified in the Board's Issues List. To help the Board in its review, the Board invites stakeholders to include in their written comments some analytical support and detailed information to identify their views and support their positions in response to the Board's questions.[4]

It is the Board's view, therefore, that the policies determined by the Board in this report are within the scope of the consultation. The Board has benefitted from the materials and submissions received from the participants. This information contributes to the substantive foundation upon which the Board will base its policies. The Board does not believe that the

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[2] Final Comments on behalf of the School Energy Coalition, p. 2.
[3] Ontario Energy Board. Letter to Participants re: Consultation on Cost of Capital – Issues List, Attachment B: Issues for Discussion at Stakeholder Conference. July 30, 2009. Questions 10 and 13.
[4] Ontario Energy Board. Letter to Mr. Robert B. Warren re: Consultation on Cost of Capital (Board File No.: EB-2009-0084). August 20, 2009.

extensive body of information before it would be materially improved by a hearing process, as was suggested by some participants.

Courts have long recognized that duties of procedural fairness such as the requirement of a hearing apply to adjudicative decisions and decisions affecting specific rights, interests and privileges. Where a board is engaged, as here, in the development of a policy guideline, courts have held that it falls to the board to decide on the method of consultation to be employed - as long as the legislative requirements, if any, are met. There also is abundant precedent for this approach within the Board's practice, and it is neither unusual nor improper to develop a guideline through a consultative process.[5]

The final "product" of this process, of course, is a Board policy. This was not a hearing process, and it does not - indeed cannot - set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy).

[5] The Board's current methodology for setting electricity rates through the incentive regulation mechanism, for example, was established through a consultative/guideline process.

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3 Context, Background and the Role of the Board

In competitive markets, the outputs of the goods and services of the economy and the prices for these outputs are determined in the market place, in accordance with consumers' preferences and incomes, as well as producers' minimization of cost for a given output. In such a market, the outcome is the efficient allocation of resources, including capital, and social welfare is maximized.

However, in some situations, markets fail to achieve such efficient outcomes. Market failure refers to situations in which the conditions required to achieve the market-efficient outcome are not present. Common examples of market failure are the existence of significant externalities, the exercise of market power by a small number of producers or buyers, natural monopolies, and information asymmetry between producers and their customers.

Electric transmission and distribution companies and natural gas distribution utilities are natural monopolies and are subject to rate regulation in Ontario by the Ontario Energy Board. In this context, the purpose of rate regulation, among other things, is to create or emulate an efficient market solution that cannot otherwise be achieved due to the presence of one or more market failures. As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

3.1 Fair Return Standard

On July 30, 2009 the Board issued a letter and its Issues List for the then planned stakeholder consultation. In that letter, the Board communicated its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. There are a number of key messages in this statement.

First, as set out by the Federal Court of Appeal, the cost of capital to a utility "is equivalent to the aggregate return on investment investors require in order to keep their capital invested in the utility and to invest new capital in the utility."[6]

Second, the Federal Court of Appeal also stated:

> … even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [Board] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.[7]

Thirdly, the Board is of the view that the process to determine the cost of capital aligns the private interest of the utility and its shareholders with the public interest, and notes that the Federal Court of Appeal said:

> … in the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain its existing ones…This will harm not only its shareholders, but also the customers it will no longer be able to service. The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service.[8]

The determination of a utility's cost of capital must meet the FRS. The FRS is a legal concept, and has been articulated in three seminal court determinations as set out below:

1. In *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* et. al. 262 U.S. 679 (1923), the FRS is expressed to include concepts of comparability, financial soundness and adequacy:

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[6] TransCanada PipeLines Limited v. National Energy Board et al. [2004] F.C.A 149. Para. 6.
[7] Ibid. Para. 12.
[8] Ibid. Para. 13.

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

2. In *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186, the FRS concept was described as follows:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, which will be net to the company, as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

3. In *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944), the Court expresses that "balance" is achieved in the ratemaking process, and outlines three elements of a fair return:

> The rate-making process under the act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests…the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The FRS was further articulated by the National Energy Board in its RH-2-2004 Phase II Decision as:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[9]

In its letter of July 30, 2009, the Board noted that the National Energy Board's articulation of the FRS is consistent with the principled approach described on page 2 of the Compendium to the Board's March 1997 *Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities* (the "1997 Draft Guidelines") and the policies set out in the Board's December 20, 2006 Report.

The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[10] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.

Informed by the comments made by stakeholders in the context of this consultation and the relevant jurisprudence, the Board offers the following observations about the application of the FRS.

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[9] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17

[10] *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837*, at p. 848.

First, the Board notes that the FRS expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective.

Second, the Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced."[11] Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs."[12] The Federal Court of Appeal also stated that:

> It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deterring the recovery of its cost of capital.[13]

Third, all three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to comparability test is not sufficient to meet the FRS.

Fourth, a cost of capital determination made by a regulator that meets the FRS does not result in economic rent being earned by a utility; that is, it does not represent a reward or payment in excess of the opportunity cost required to attract capital for the purpose of

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[11] National Energy Board. Reasons for Decision. Trans Quebec & Maritimes Pipelines Inc. RH-1-2008. March 19, 2009. p. 6.
[12] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 35-36.
[13] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 43.

investing in utility works for the public interest. Further, the Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for. The Board notes that while cost of capital and profit are often used interchangeably from a managerial or operational perspective, the concepts are not interchangeable from a regulatory perspective.

Fifth, there was considerable discussion in the consultation about utility bond ratings. The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.

Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. As the Coalition of Large Distributors commented:

> [t]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, ‘The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable’.[14]

[14] Final Comments of the Coalition of Large Distributors. October 26, 2009. pp. 5-6.

The Role of the Comparable Investment Standard

Continued investment in network utilities does not, in itself, demonstrate that the FRS has been met by a regulator's cost of capital determination, and in particular, whether the determination of the equity cost of capital meets the requirements of the FRS. This is a particular challenge – how does the regulator determine when investment capital is <u>not</u> allocated to a rate regulated enterprise? These decisions are typically made within the utility/corporate capital budgeting process and rarely, if ever, broadly communicated to stakeholders. The Board notes that acquisition and divestiture activities of regulated utilities are not definitive in this regard, one way or the other, and notes that there are many reasons why investors are willing to acquire or desirous of selling utility assets, notwithstanding their view of whether an allowed ROE meets the FRS.

The primary tool available to the regulator to rectify this lack of transparency is the comparable investment standard. By establishing a cost of capital, and an ROE in particular, that is comparable to the return available from the application of invested capital to other enterprises of like risk, the regulator removes a significant barrier that impedes the flow of capital into or out of, a rate regulated entity. The net result is that the regulator is able, as accurately as possible, to determine the opportunity cost of capital for monies invested in utility works, with the ultimate objective being to facilitate efficient investment in the sector.

There are a number of specific issues relating to the comparable investment standard that the Board considers are relevant in the context of this cost of capital policy.

First, "like" does not mean the "same". The comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities. It does not require that those entities be "the same".

Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[15] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS. Further, the Board notes that in the consultation session on October 6, 2009, Dr. Booth stated that it is "absolutely possible" to form a sample from a risky universe that is low risk and compare it to the universe or the population of Canadian utilities.[16] All participants agreed.

The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators.[17] The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.

The PWU commented that the position taken by Dr. Booth on the question of the comparability of US utility returns is not based on an appropriate empirical foundation.[18] The PWU further commented that:

> On the other hand, it is the view of the PWU that the analysis produced by Concentric, as summarized in one of their charts presented at the conference, represents a far more comprehensive analysis of the key characteristics of distribution utilities in Ontario vs. a North American

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[15] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 25.
[16] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. Comments of Dr. Booth at p. 60. Lines 24-26.
[17] Written Comments of Union Gas Limited. October 30, 2009. p. 14.
[18] Final Comments of the Power Workers' Union. October 30, 2009. p. 3.

> proxy group. Differences and similarities were thoroughly considered before arriving at the conclusions that based on a careful selection of like companies, a proxy group which includes US distribution utilities adheres to the Comparable Investment Standard. Moreover, Concentric was better suited to complete such as an analysis, having recognized expertise in the risks faced by both Ontario and US electricity distributors.[19]

Dr. Vander Weide indicated that since Canadian utility bonds tend to have more covenants than US utility bonds, they would receive a slightly higher credit rating. The PWU observed that it the slight variance in ratings can be attributed to specific features of debt instruments, rather than fundamental differences in the underlying business or regulatory risks faced by the utilities. This observation was also made by Ms. Zvarich of Sun Life Financial, who presented evidence that Canadian utility bonds generally have more restrictive covenants than U.S. utility bonds.[20]

The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.

Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.

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[19] Final Comments of the Power Workers' Union. October 30, 2009. p. 6.
[20] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 21, 2009. Comments of Ms. Zvarich at pp. 24 -25.

3.2 The Cost of Capital in Theory and Practice

The Cost of Capital

The Ontario Energy Board has been engaged in the rate regulation of utilities for many years. Over this extended period, the Board notes that there continues to be any of a number of misconceptions about the cost of capital concept, particularly what the cost of capital is and why it is an important consideration.

The Board is of the view that the following points articulated by Dr. Bill Cannon in his presentation at CAMPUT's 2009 Energy Regulation Conference on July 3, 2009, are principally relevant to defining and understanding the cost of capital concept.

> At its simplest, the cost of capital is the minimum expected rate of return necessary to attract capital to an investment. The rate of return includes the income received during the time the investment is held plus any capital gain or loss, realized or accruing during this period, all as a percentage of the initial investment outlay.
>
> The cost of capital can be viewed from both: (a) a company or utility perspective; and (b) from the investor's or capital provider's perspective. From the company's perspective, the cost of capital is the minimum rate of return the company must promise to achieve for investors on its debt and equity securities in order to preserve their market values and, thereby, retain the allegiance of these investors.
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> [There is interest] in the cost of capital…because all utilities – private or public – at some time… must raise financial capital to pay for investments, and both fairness and practical considerations dictate that the private and/or government investors who provide these capital funds must be adequately compensated. Raising capital is a competitive process. Private investors are under no obligation to buy a particular utility's securities, and government-owned utilities must compete with other government spending priorities. A utility will be able to secure new capital and replace maturing securities only if investors believe that they will be adequately rewarded for providing new capital funds. That required reward, in turn, must compensate the investors for a least two things: (1) for postponing the consumption of the goods and services that they might otherwise have enjoyed had they not made the investment; and (2) for exposing their funds to the risk that they may not

> get all their money back or not get it back as promptly as they anticipated. The reward demanded by investors is therefore a necessary cost of doing business from the utility's point of view, just as much as the cost of labour or fuel.
>
> From the viewpoint of investors as a group, however, the cost of capital can be defined more clearly and operationalized as "the expected rate of return prevailing in the capital markets on alternative investments of equivalent risk and attractiveness." There are four concepts embedded in this operational definition:
>
> First, it is *forward-looking*. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return.[21]
>
> Second, it reflects the *opportunity cost* of investment. Investors have the opportunity to invest in a wide range of investments, so the expected rate of return from a given utility-company investment must be sufficient to compensate investors for the returns they might otherwise have received on foregone investments.
>
> Third, it is *market-determined*. This market price - expressed as the expected return per dollar of invested capital - serves to balance the supply of, and demand for, capital for the firm.
>
> And, fourth, it reflects the *risk* of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the *use* of the capital – or, more precisely, the risk associated with the use of the funds – and not on the *source* of the funds.

In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no

[21] The word "expected" is used in the statistical sense (i.e., the probability-weighted rate of return). It does not refer to a "hoped for" or "most likely" rate of return.

compelling reason to adopt different methods of determining the cost of capital based on ownership.

The Equity Risk Premium Approach

As previously indicated, the Board has determined that the ERP approach remains the most appropriate approach in the current circumstances. The ERP approach is one of four main approaches that are traditionally used by experts during regulatory cost of capital reviews to establish a fair ROE: (1) the comparable earnings approach; (2) discounted cash flow approach; (3) the capital asset pricing model; and (4) ERP approach. These methods are all used in varying degrees to formulate and/or test an opinion regarding a fair return to investors.[22] The Board's current formulaic approach is a modified Capital Asset Pricing Model methodology and ERP approach.

Each of these four main approaches has well documented strengths and weaknesses. Notwithstanding the known weaknesses of these differing approaches, the Board agrees with Ms. McShane when she states: "each of the various types of tests brings a different perspective to the estimation of a fair return. No single test is, by itself, sufficient to ensure that all three requirements of the fair return standard are met."[23]

Through the consultative process which began in February 2009 and has culminated in this report, the Board has been informed by a number of ex-post analytical approaches, including analysis of experienced ERPs on investments in Canadian utility stocks. The Board observes from these analyses that the ROE produced by various approaches can be expressed as an absolute ROE number or as an ERP over a risk-free rate. Also, the Board agrees that expressing the ROE in terms of a premium above the long-term Canada bond yield does not mean that the initial ROE needs to be estimated by using a single test or a number of tests that might be defined as ERP tests.

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[22] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.

[23] McShane, K., Foster Associates, Inc. Written comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.

A Formulaic Approach

The Board has used a formula-based methodology to determine the rate of ROE since 1998. The advantages identified in the 1997 Draft Guidelines remain appropriate today and include:

- Simplification of the hearing process;
- Is relatively free from conflicting interpretation and is readily understood by all participants;
- Reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets; and
- Is capable of producing a rate of return that approximates the result which would have been produced through the traditional process.[24]

The Board also notes that a formula-based approach:

- Is transparent, resulting in predictable and consistent outcomes, and meets the needs of stakeholders broadly, particularly those in the capital market; and
- Is a practical necessity in Ontario, given the large number of rate regulated entities.

The Board also acknowledges that a formula-based ROE methodology and mechanical approaches in general, have a number of disadvantages, as identified in the 1997 Draft Guidelines:

- Establishing the initial parameters of the generic formula will have a profound influence on the potential success or failure of the process. Over time, these parameters and adjustment factors will have a cumulative or compounding effect on the

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[24] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 7.

results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations;

- The present formulaic ROE generally relies predominantly on the ERP method to the exclusion of other methods;

- Adjustment for the impact of timing differences for utilities with different year-ends is a challenge; and

- The Board's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace may be restricted. [25]

Notwithstanding these concerns, the Board is of the view that it is appropriate to continue to use a formulaic approach to determine the equity cost of capital and that the overall advantages of the approach outweigh potential disadvantages.

An Empirical Foundation

The essential elements of a formulaic approach must be empirically derived – the initial ROE, implied ERP and the adjustment factor are determined by the Board based on empirical analysis. It is essential that sufficient empirical analysis be provided periodically to ensure that assumed relationships are not misspecified. This includes the construction and application of a framework to evaluate the degree of comparability between rate regulated natural gas distribution and electricity distribution and transmission utilities in Canada and the United States.

To be clear, the approach to be used by the Board in setting the essential elements of a formula-based rate of ROE (i.e., base ROE, formula terms and adjustment factors) will be based on "economic theory and empirically derived from objective, data-based analysis."[26] As such, it is not sufficient for a formulaic approach for determining ROE to produce a

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[25] Ibid. p. 7.
[26] Ontario Energy Board. Report of the Board on 3rd Generation Incentive Regulation. July 14, 2008. p. 19

numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE it must generate a result that meets the FRS, as determined by the Board using its experience and informed judgment.

This principle is supported by the *Hope* decision, which states: "Under the statutory standard of 'just and reasonable' it is the result reached not the method which is controlling…"[27]

[27] Federal Power Commission v. Hope Natural Gas 320 U.S. 591 (1944). p. 602

4 The Board's Approach

4.1 Summary of Key Principles

As discussed previously, the Board confirms the following key principles with respect to its cost of capital policy. The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind.

1. **Fair Return Standard.** All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others. It is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE; it must generate a number that meets the FRS, as determined by the Board using its experience and informed judgment.

2. **The overall ROE must be determined solely on the basis of a company's cost of equity capital**. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. The opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that the impact of any resulting toll increase is an irrelevant consideration in that determination.

3. **Efficient amount of investment.** As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

4. **Predictability, transparency, and stability**. The approach adopted by the Board to determine the opportunity cost of capital should result in an environment where outcomes are predictable and consistent so that investors, utilities and consumers are better able to plan and make decisions.

5. **Systematic and empirically-based approach**. The methodology used by the Board to determine the cost of debt and equity capital should be a systematic approach that relies on economic theory and is empirically derived from objective, data-based analysis. For example, in establishing comparability, it is possible to build a low-risk sub-set from a higher risk universe using an empirically based approach.

6. **Minimize the time and cost of administering the framework.** Costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available. This objective could be met through a simple process that reflects the concerns of interested participants and reduces the formal process requirements.

4.2 Return on Equity

4.2.1 Need to Reset and Refine Existing ROE Formula

In order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital**, the Board has determined that its current formula-based ROE approach needs to be reset and refined**. As previously indicated, **the Board will continue to use a formula-based ERP approach**. However, informed by the discussion at the consultation and the written comments of participants generated by the consultation, as well as its own analysis, the Board has concluded that the formula needs to be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low-risk proxy group that cannot be reconciled based on differences in risk alone. The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity.

The Board's current approach to estimating the cost of equity has been in effect for 12 years. The Board notes that in the 1997 Draft Guidelines, the Board stated that "it is persuaded that there exists a non-linear relationship between interest rates and the ERP." [28] The existing formula approximates this relationship using a linear specification. The Board is of the view that it is unreasonable to conclude that the current formula correctly specifies this relationship, based on the passage of time, changes in financial and economic circumstances generally, and the empirical analyses provided by participants to the consultation and the discussion at the consultation itself. However, the Board is of the view that its current formulaic approach for determining the equity cost of capital should be reset and refined, not otherwise abandoned or subject to wholesale change.

The events that unfolded earlier this year that triggered this review effectively illustrated that the Board's approach needs to be refined to reduce the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. The Board concludes that the current approach could be more robust and better guide the Board's discretion in applying the FRS. The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

The view expressed by some participants in the consultation that the Board must wait to be provided with evidence from a regulated utility in Ontario of financial hardship due to the current allowed ROE before its adapts its policies to better reflect market realities is not consistent with the Board's approach.

The Board is of the view that resetting and refining the current formula-based ERP approach maintains the transparency, predictability and stability associated with the current

[28] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 31.

approach, and avoids sudden changes in regulatory policy to address potentially transitory capital market conditions. [29]

The Board has been informed by the numerous approaches used by various participants to the consultation to determine whether the formula continues to produce results that meet the FRS. The sum of the elements supporting the Board's decision to reset and refine its formulaic ROE is independent of the recent financial crisis and whether or not the crisis has abated.

4.2.2 The Initial Set Up

Use of Multiple Tests

The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate"[30].

This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates.

Participants argued from a number of different perspectives that a variety of methods should be used to develop the ERP:

- "The Board should not limit itself to one specific method of calculating an ERP; rather it should consider the results produced by multiple approaches in order to

[29] Written Comments of the Industrial Gas Users Association, October 30, 2009, p. 2.
[30] Ibid. p. 20.

generate a range of reasonable results from which it may select an appropriate ERP. This process requires the exercise of informed judgment"[31].

- "The Board established the initial risk premium for the Formula, in its decision for Consumers Gas in EBRO 495, by considering an array of risk premium estimates put forward by experts and selecting a risk premium within the range of results presented. The risk premiums put forth by experts were either the result of directly measuring the historical relationship between bond yields and equity returns; or alternatively, by deriving an implied risk-premium, by backing-out forward looking bond yields from ROE estimates produced by using other methodologies, i.e., DCF, CAPM, or Comparable earnings.

  Multiple approaches for determining ROE provide greater assurance that the end result will be just and reasonable, as conditions that may bias results could be detected or mitigated by considering alternative results."[32]

- "The Board should consider comparable utilities' rates of return and a minimum spread to long-term debt rates, as well as resetting the reference rate".[33]

- "The Board should establish the initial ROE by looking at the best available evidence on the utilities' required return. This evidence should include results of various cost of capital methodologies…The Board would be remiss to predetermine a single methodology for establishing the initial allowed ROE without reviewing alternative methods for determining cost of equity." [34]

- "We propose that the Board, in reviewing cost of capital, would hear the evidence of the various experts with their different views of the ERP result, but would also look at

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[31] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors, September 8, 2009. September 8, 2009. p. 59.
[32] Ibid. p. 47.
[33] Written Comments of the Power Workers' Union. September 8, 2009. p. 6.
[34] Dr. J. H. Vander Weide. Written Comments on behalf of Union Gas. pp. 7-8.

other ways in which the market directly speaks about returns…they (the examples provided) and many other examples – are ways in which the market communicates the returns for investment comparable to utility investments. These sources are therefore useful in testing whether the results of various ERP or other market studies of cost of capital are realistic." [35]

- "If the utility is not a stand-alone entity and/or does not have traded shares, then the Board has no alternative but to look at total rates of return earned by investors in a relevant sample of companies." [36]

- "Expressing the ROE in terms of a premium above…long-term Canada bond yield… does not mean that the initial ROE need be estimated solely using a test or tests that might be defined as ERP tests." [37]

  "No single model is powerful enough to produce 'the number' that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured." [38]

- "…use of multiple tests. The tests all measure different factors that should be considered in setting a fair return on equity that is consistent with the comparable investment standard, the financial integrity standard and the capital attraction standard. The OEB should not rely on a single method or test." [39]

The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long

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[35] Written Comments of the School Energy Coalition. September 2009. pp. 2-3.
[36] Written Comments of Energy Probe Research Foundation. September 8, 2009. p. 14.
[37] McShane, K., Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.
[38] Ibid. p. 23.
[39] Written Comments of Ontario Power Generation Inc. September 8, 2009. p. 3.

Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.

Setting the Initial Equity Risk Premium

The Board is of the view that the initial ERP should be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low risk proxy group that cannot be reconciled based on differences in risk alone.

Therefore, based on the ERP recommendations provided by all participants in this consultation the **Board has determined that an initial ERP of 550 basis points** is appropriate for the purposes of deriving the initial ROE to be embedded in the Board's reset and refined ROE formula. This includes an implicit 50 basis points for transactional costs.

Consequently, **assuming a forecast long term government of Canada bond yield of 4.25%, the initial ROE to be embedded in the Board's reset and refined ROE formula will be 9.75%** (i.e., 4.25% + 550 basis points = 9.75%).

The Board has assessed the various empirical tests and recommendations submitted by participants and translated each of the recommended approaches as an ERP assuming a forecast long term government of Canada bond yield of 4.25%, where appropriate, as summarized in Table 1.

The empirical tests of each of the participants to the consultation are also described below. Although the Board maintains its view that each of the tests has empirical strengths and weaknesses, the diversity of approaches tabled and discussed in the consultation was helpful. As a result, the Board has given each test weight in the process to establish the initial ERP to be embedded in the Board's formula.

Table 1: Summary of Participant Recommendations

Direct/Indirect Equity Risk Premium	Low	Medium	High
Dr. L.D. Booth			
CAPM (Adjusted Using CoC Formula to Reflect 4.25% GOC, 0.75 Adj)	3.31%	3.31%	3.31%
Average Dr. L.D. Booth	**3.31%**	**3.31%**	**3.31%**
Concentric Energy Advisors			
DCF Analysis for Low-Risk Proxy Group (US Gas, Elec, Cdn)	6.03%	6.78%	7.83%
CAPM Analysis for Low-Risk Proxy Groups (US Gas, US Elec, Cdn)	4.58%	4.72%	4.86%
ERP Econometric Model (Average Gas and Electric)	6.35%	6.35%	6.35%
Average Concentric Energy Advisors	**5.65%**	**5.95%**	**6.35%**
J. Dalton - Power Advisory LLC			
ERP Econometric Model #1 and ERP Econometric Model #2	6.05%	6.45%	6.85%
Average J. Dalton - Power Advisory	**6.05%**	**6.45%**	**6.85%**
K. McShane - Foster Associates			
New Formula for Calculating Allowed ROE (NEB Initial Formula Metrics)	6.38%	6.38%	6.38%
Illustrative method	5.75%	5.75%	5.75%
Average: K. McShane	**6.07%**	**6.07%**	**6.07%**
Dr. J.H. Vander Weide			
Experienced Equity Risk Premium	4.30%	5.50%	6.60%
2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Gas	6.16%	6.16%	6.16%
2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Gas	5.61%	5.61%	5.61%
2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Electric	6.26%	6.26%	6.26%
2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Electric	5.71%	5.71%	5.71%
Forecast $E(R_e)$ = DCF Expected Return - LT Treasury Yield			
Gas	6.19%	6.19%	6.19%
Electric	6.21%	6.21%	6.21%
Regression - Ex-ante ERP (Above) with YTM LT Treasury Yields			
Gas (Modified to use Canadian LT GOC bond)	6.97%	6.97%	6.97%
Electric (Modified to use Canadian LT GOC bond)	7.33%	7.33%	7.33%
DCF Analysis for Value Line Utility Companies			
Gas	7.81%	7.81%	7.81%
Electric	8.71%	8.71%	8.71%
Average: Dr. J.H.Vander Weide	**6.48%**	**6.59%**	**6.69%**
Average ERP All Submissions	**5.51%**	**5.67%**	**5.85%**

Analyses of Dr. J. H. Vander Weide

Dr. Vander Weide performed a number of empirical analyses. The average experienced ERP on an investment in Canadian utility stocks from data on returns earned by investors in Canadian utility stocks compared to interest rates on long-term Canada bonds was approximately 5.50 percent, as set out below:

Comparable Group	Period of Study	Average Stock Return	Average Bond Yield	Risk Premium
S&P/TSX Utilities	1956 - 2008	11.84%	7.54%	4.3%
BMO CM Utilities Stock Data Set	1983 - 2008	14.31%	7.66%	6.6%
Average				**5.5%**

Source: Written comments of Dr. J.H. Vander Weide. Page 14.

He also provided information on recent allowed ROEs for U.S. utilities which demonstrated implicit ERPs:

	Natural Gas Distribution		Electric Utilities	
	2008	**2006 - 2008**	**2008**	**2006 - 2008**
Average U.S. ROE Awarded (%)	10.4	10.3	10.5	10.4
Spread to OEB September 2009 Long Bond Estimate of 4.25%	6.15	6.05	6.25	6.15
Spread to Average Long-Term Canada Bond Yield in 2008 of 4.06%	6.34	NA	6.44	NA
Spread to Average Long-Term Canada Bond Yield in 2006 to 2008 of 4.21%	NA	6.09	NA	6.19
Spread to Average Long-Term U.S. Treasury Bill Yield in 2008 of 4.24%	6.16	NA	6.26	NA
Spread to Average Long-Term U.S. Treasury Bill Yield in 2006 to 2008 of 4.69%	NA	5.61	NA	5.71

Sources: Government of Canada Bond Yields: Bank of Canada; U.S. Long-Term Treasury Bill Yields: U.S. Department of Treasury

Further, forecast expected required returns by investors were calculated by Dr. Vander Weide by deducting the long-term Treasury bond yield from the DCF expected return (Exhibit 5, Dr. Vander Weide) over the period September 1999 to February 2009. This calculation produced an average ERP of 621 basis points for electric utilities and an average expected ERP of 619 basis points for natural gas utilities (Exhibit 6, Dr. Vander Weide) over the period June 1998 to February 2009.

However, regressing the relationship between the *ex ante* risk premium and the yield to maturity on long-term U.S. Treasury bond produced an ERP equation of:

- ERP = 12.10 – 1.123 x I_B for Electric Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 7.33% and an ROE of 11.58%; and

- ERP = 10.26 – 0.773 x I_B for Natural Gas Distribution Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 6.97% and an ROE of 11.22%.

Finally, Dr. Vander Weide conducted a DCF Analysis for Value Line Natural Gas Companies that resulted in an estimated ROE of 11.5% (Exhibit 9, Dr. Vander Weide) or an ERP of approximately 7.81%, using the average February 2009 long-term composite Treasury bond yield of 3.69%. His DCF Analysis for Value Line Electric Companies (Exhibit 8, Dr. Vander Weide) resulted in an estimated ROE of 12.4% or an ERP of approximately 8.71%, assuming the same long-term composite Treasury bond yield.

Analysis of Kathy McShane of Foster Associates Inc.

Ms. McShane proposed a new formula for calculating the allowed ROE: ROE_{New} = Initial ROE + 50% (Change in Forecast GOC Bond Yield) + 50% (Change in Corporate Bond Yield Spread), which reflects the analysis provided in her comments.

Ms. McShane also demonstrated that using her recommended approach for 2009, based on the NEB formula contained in RH-2-94 Decision, the ROE would have been 10.73%[40], equal to an ERP of 638 basis points and assuming a forecast GOC yield of 4.35% for 2009.

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[40] McShane, K., Foster Associates Inc. Written Comments on behalf of the Electricity Distributors Association. Schedule 4.

For illustrative purposes in her analysis, she linked a forecast long-term Canada bond yield of 4.5% and a corporate bond yield spread of 175 basis points to an ROE of 10%. Implied in this ROE is an ERP of 550 basis points.

Analysis of Power Advisory LLC

Power Advisory evaluated a range of different model specifications in an effort to come up with a formula that will yield more reasonable results than the existing formula under a range of different credit and financial market conditions.[41] Two models performed the best in terms of standard econometric considerations (i.e., goodness of fit, highly significant parameter values, and plausible statistical relationships)[42]:

1. ROE = 7.008% + (US Corp BAA Bond Yield with 6 month lag x 0.5356); and
2. ROE = 7.451% + (US Gov 30 Year Bond yield with 6 month lag x 0.5122) + (VIX index value with 6 month lag x 0.0077).

Using current values for these variables produces ROE estimates of 10.5% to 11.3%. Using Canadian values in these models results in ROE estimates of 10.3% to 11.1%. The implied ERP using the results of the models run using a forecast long-term government of Canada bond yield of 4.25% is 605 basis points to 685 basis points.

Analysis of Concentric Energy Advisors

Concentric's overall recommended ROE for natural gas distribution utilities, assuming a 40% deemed equity capital structure is 10.5% and for electric transmission and distribution utilities is 10.3%, also assuming 40% deemed equity. The implied ERP assuming a 4.25% forecast GOC bond yield is 625 basis points and 605 basis points, for natural gas and electric transmission and distribution, respectively. These recommendations are supported by multiple analytical approaches; each calculated using data for a specific proxy group for

[41] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 16.
[42] Ibid. p. 17.

the natural gas and electric transmission and distribution utilities established by Concentric.[43]

The results of Concentric's DCF analysis are presented in the table below[44].

Proxy Group	Low	Mean	High
U.S. Natural Gas Distribution Utilities	9.70%	10.44%	11.57%
U.S. Electric Distribution Utilities	10.08%	10.96%	12.09%
Canadian Utilities	9.97%	10.60%	11.47%
Average	9.92%	10.67%	11.71%
Implied ERP at 4.25% forecast LT GOC Yield	5.67%	6.42%	7.46%
Implied ERP Including 50 basis points Flotation Costs	**6.17%**	**6.92%**	**7.96%**

The results of Concentric's CAPM analysis are presented in the table below. The results reflect a Market Risk Premium of 586 basis points, which is supported by material provided in Appendix F (page F-10) and Exhibit Concentric-06 of their written comments.

Proxy Group	Low	Mean	High
U.S. Natural Gas Distribution Utilities	9.05%	9.18%	9.32%
U.S. Electric Distribution Utilities	8.54%	8.68%	8.82%
Canadian Utilities	7.80%	7.95%	8.10%
Average	8.46%	8.61%	8.75%
Implied ERP at 4.25% forecast LT GOC Yield	4.21%	4.36%	4.50%
Implied ERP Including 50 basis points Flotation Costs	**4.71%**	**4.86%**	**5.00%**

The results of Concentric's ERP analysis are presented in the table below and are explained in detail in Appendix F of their written comments.

[43] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. Appendix C.
[44] Ibid. p. F-6.

Concentric's ERP regression formula is as follows: ROE = Constant = U.S. Gov 30-year Bond • x_1 + Moody's Utility A-rated Spread • x_2 + % Generation • x_3 + Natural Gas Dummy Variable • x_4.[45]

	U.S. Natural Gas Distribution Proxy Group	**U.S. Electric Distribution Proxy Group**
Constant	7.634	7.634
U.S. Government 30-year Bond Yield	0.428 x 4.18	0.428 x 4.18
Moody's Utility A-rate Spread (July 2009)	0.310 x 1.56	0.310 x 1.56
% Generation	0.008 x 0.00	0.008 x 49.76
Natural Gas Dummy (Electric = 0,Gas = 1)	0.384 x 1.00	0.384 x 0.00
Authorized ROE	10.29%	10.30%
Implied ERP at 4.25% forecast LT GOC Yield	6.04%	6.05%
Implied ERP Including 50 basis points Flotation Costs	**6.54%**	**6.55%**

The tables below summarize Concentric's recommended ROEs prior to any adjustment for changes in leverage:[46]

U.S. Electric T & D Utilities	**Low**	**Mean**	**High**
DCF	10.08%	10.96%	12.09%
CAPM	8.54%	8.68%	8.82%
Average	9.31%	9.82%	10.46%
Differential between Vertically Integrated and T&D Utilities	(0.40%)	(0.40%)	(0.40%)
Return before Leverage and Flotation Cost Adjustments	8.91%	9.43%	10.06%
Flotation Cost Adjustment 0.50%	0.50%	0.50%	0.50%
Benchmark T&D ROE	9.41%	9.93%	10.56%
Benchmark T&D Equity Ratio	46.32%	46.32%	46.32%
Implied ERP using 4.25% forecast LT GOC Yield	5.16%	5.68%	6.31%

U.S. Natural Gas Distribution Utilities	**Low**	**Mean**	**High**
DCF	9.70%	10.44%	11.57%
CAPM	9.05%	9.18%	9.32%
Return before Leverage and Flotation Cost Adjustments	9.37%	9.81%	10.45%
Flotation Cost Adjustment 0.50%	0.50%	0.50%	0.50%
Benchmark Natural Gas Distribution ROE	9.87%	10.31%	10.95%
Benchmark Natural Gas Distribution Equity Ratio	44.47%	44.47%	44.47%
Implied ERP using 4.25% forecast LT GOC Yield	5.62%	6.06%	6.70%

Adjusting for leverage that is higher than the benchmark equity ratio, i.e., deemed equity of 40%, the recommended ROEs increase to 10.5% for natural gas distribution and 10.3% for electric transmission and distribution, representing implied ERPs of 625 basis points and 605 basis points, respectively.

[45] Ibid. p. F-14.
[46] Ibid. p. F-16.

Analysis of Dr. Booth

Dr. Booth recommended a fair ROE of 7.75%. This number is based on the following key assumptions.[47]

First, a market risk premium of 5.0%. However, Dr. Booth noted that many of his peers believe it to be 6.0%. Second, beta is estimated to be 0.5. Dr. Booth indicated that he “is not using the current beta coefficient”[48]; i.e., the beta of 0.5 used to derive the recommended ERP of 325 (assuming a 4.50% long-term government of Canada bond yield) is not supported by Dr. Booth’s recent beta estimates, where beta is less than 0.5. Thirdly, Dr. Booth also noted that the range of fair return cost of equity estimates could vary by 0.50%. His unadjusted estimate of a fair return was 7.00% and he noted that the estimates of his colleagues would be 7.50%. He therefore added 0.25% to his estimate to “split this difference”, resulting in his ROE recommendation of 7.25%. Finally, Dr. Booth added 0.50% for issuance costs, bringing his fair recommended return to 7.75%.

The Board notes that in the course of the consultation, Dr. Booth indicated that he would be prepared to recommend “fixing ROE at 8.5% or 8.75% over the business cycle, for say, a five-year period.”[49] Dr. Booth did not support this estimated ROE with empirical analysis, and as such, there is no principled basis upon which the Board can rely on Dr. Booth’s recommendation of 8.5% or 8.75%.

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[47] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer’s Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters, the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 40.

[48] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 100. Lines 12 and 13.

[49] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 98. Lines 10 – 12.

4.2.3 The Formula-based Return on Equity

4.2.3.1 Long Canada Bond Forecast

The Board is of the view that the LCBF continues to be an appropriate base upon which to begin the ROE calculation. In particular, the Board is of the view that the sensitivity of the allowed ROE to changes in government of Canada bond yields arising from monetary and fiscal conditions that do not reflect changes in utility cost of equity will be addressed, in part, by the use of multiple methods to determine the initial ERP or ROE in the formula. The Board also agrees with Ms. McShane's comment that the LCBF provides an important forecast component to the formula[50] and with the Industrial Gas Users Association's comment that "there is an intrinsic logic to using the same parameter to adjust ROE as was used to set the ROE in the first place."[51]

4.2.3.2 Long Canada Bond Forecast Adjustment Factor

In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF for the current test year and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE.[52] In that same document, however, the Board noted that there was a significant difference of opinion concerning the relationship between interest rates and the ERP and that ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1.[53] Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."[54]

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[50] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 22, 2009. Ms. McShane's presentation, pp. 161-162;
[51] Final Written Comments of the Industrial Gas Users Association. October 30, 2009. p. 10.
[52] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997. p. 31.
[53] Ibid.
[54] Ibid. p. 32.

The Board views **the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5**. The Board notes that four participants in this consultation empirically tested the relationship between government bond yields and ROE:

- Dr. Vander Weide determined that when the yield to maturity on long-term government bonds increases by 100 basis points, the allowed ERP tends to decrease by approximately 55 basis points, and when the yield to maturity on long-term government bonds decreases by 100 basis points, the allowed ERP tends to increase by approximately 55 basis points.[55]

- Kathy McShane of Foster Associates, Inc. submitted that a regression analysis used to estimate the relationship between government bond yields and the utility cost of equity indicates that the ROEs increased (decreased) by approximately 50 basis points for every one percentage point increase (decrease) in long-term government bond yields.[56]

- Concentric Energy Advisors also conducted a regression analysis in which the litigated ROEs of U.S. LDC utility returns demonstrated an elasticity factor to government bond yields of 0.45. This implies that the risk premium should have actually increased by approximately 0.55 for each percentage point drop in the government bond yield (as opposed to the 0.25 implied by the current formula).[57]

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[55] Dr. J.H. Vander Weide. Written Comments on behalf of Union Gas. September 8, 2009. p. 21.
[56] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 26.
[57] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 41-42.

- John Dalton of Power Advisory also used a regression analysis to determine that the ERP changes by less than 50% of the change in the long-term government bond rate.[58]

The Industrial Gas Users Association also stated that it sees some merit in further consideration of adjusting downwards to 0.5 the coefficient for application of changes in long Canada bond yields to ROE.

4.2.3.3 Additional Term – Changes in Utility Bond Spread

The Board is of the view that the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity is addressed, in part, by using multiple methods to determine the initial ERP and ROE in its formulaic ROE approach and by reducing the LCBF adjustment factor to 0.5 from 0.75. The Board also is of the view, however, that **the specification of the relationship between interest rates and the ERP in the formula would be improved by the addition of a further term to the formula**.

In particular, the Board is of the view that there is a relationship between corporate bond yields and the equity return, and the Board agrees with Dr. Booth, who stated, with respect to corporate bond spreads, that "this is not to say that spreads have no information about required risk premium."[59] The Board notes that three participants to the consultation conducted empirical analysis to specify the relationship between corporate bond yields and the equity return:

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[58] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. April 17, 2009. p. 15.

[59] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 29.

- Concentric demonstrated by using a regression analysis that there is a statistically significant relationship between ROE and corporate bond yields and specified that the sensitivity of allowed returns to corporate bond yields is about 0.45 to 0.55[60]. Concentric also demonstrated empirically that Treasury bonds have been more volatile than corporate bonds since January 1997.

- Kathy McShane of Foster Associates tested the relationship between corporate bond yields and the utility cost of equity. She determined the cost of equity using two approaches: first, by using approved returns on equity for utilities not governed by formulas as a proxy for the utility cost of equity, and second, by relying on a time series of utility costs of equity developed by using the discounted cash flow approach against which yields on utility bonds can be compared[61]. By using regression analysis, Ms. McShane determined that allowed ROEs have increased (decreased) by approximately 45 basis points for every one percentage point increase (decrease) in the A rated utility bond yield. Similarly, the DCF cost of equity increased (decreased) by approximately 55 basis points for every one percentage point increase (decrease) in long-term A rated utility bond yields.[62]

- John Dalton from Power Advisory LLC conducted an econometric analysis, which established that the relationship between ROE and U.S. corporate BAA bond yields with a six month lag is approximately 0.53.[63]

Based on the analysis provided by participants to the consultation, the Board concludes that **there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the ROE formula**. The Board notes that the presence of a corporate bond yield variable in its

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[60] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 53–55.
[61] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 25.
[62] Ibid. p. 26.
[63] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 17.

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has** accordingly **determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

4.3 Capital structure

The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. [66] The Board's current policy is as follows:

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[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

- The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. [67] Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.

- For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk. [68]

4.4 Debt Rates

4.4.1 Long-term debt

The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policies and practices.

While the Board agrees with this approach, it is important to note that the determination of the cost of long-term debt has typically received significant interest in the processes to establish electricity distribution and, to a lesser extent, electricity transmission rates. In contrast to the difficulty establishing the utility cost of equity that arises from a lack of transparency, the issues associated with the determination of a utility's long-term debt cost arise from different factors, including the relatively short period of time since the corporatization of electricity distribution and transmission utilities, the relatively short history of rate regulation by the Board, and the presence of significant amounts of affiliate debt.

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[67] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. p. 5
[68] Ontario Energy Board. Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March, 1997. p. 30

Natural gas distributors

The Board has a long history of determining the cost of long-term debt for natural gas distributors. Based on this experience and in the absence of any material comments in the consultation suggesting otherwise, the Board is of the view that **the current policy of using the weighted cost of embedded debt should continue**. Consistent with the current practice, in a forward test year rate application the onus is on the applicant utility to forecast the amount and cost of new long-term debt. These values are then factored into the estimated cost of existing long-term debt for the purpose of setting regulated natural gas distribution rates. Debt instruments and debt rates are subject to a prudence review in an application for rates. However, it is the Board's policy that the total estimated cost of debt should be a close proxy for the actual long-term debt cost incurred by the natural gas utility in the rate year.

OPG's prescribed rate-regulated baseload generation

Consistent with the Board's practice in OPG's 2008 Cost of Service application, considered under Board file number EB-2007-0905, the Board is of the view that **OPG's cost of long-term debt should be set in a manner similar to that adopted for natural gas distributors**.

Electricity transmitters

Consistent with the Board's current practice as set out in various Decisions and Orders arising from rate applications by electricity transmitters, the Board is of the view that **an electricity transmitter's cost of long-term debt should be set in a manner similar to that adopted for natural gas distributors**.

Electricity distributors

In the 2000 Electricity Distribution Rate Handbook, the Board adopted deemed long-term debt rates and deemed capital structures that varied based on the size of utility rate base.

The deemed long-term debt rates applied regardless of a utility's actual cost of debt and actual capitalization. This deemed approach reflected the ongoing corporatization of the sector and the fact that many electricity distribution utilities had no debt.

The *2006 Electricity Distribution Rate Handbook*, issued by the Board on May 11, 2005, documented an evolution of the treatment of long-term debt for electricity distributors. While the size-related capital structure and (updated) deemed debt rates were retained, the handbook outlined that long-term debt costs could also reflect the cost of embedded debt. The cost of affiliate debt was also capped by the deemed debt rate at the time of issuance.

In April of 2006, Board Staff undertook research, commissioned expert advice and consulted with stakeholders on the methods for setting the cost of capital and 2^{nd} Generation Incentive Rate Making. These consultative activities culminated in the December 20, 2006 Report. In that report, the Board provided additional guidance on the treatment of long-term debt, and emphasized that while there should be increased reliance on actual or embedded debt costs, the need for a deemed debt rate that would continue to apply (either in itself or as a ceiling on affiliate debt) was recognized.

In distribution utility rate applications heard by the Board since the issuance of the December 20, 2006 Report, the Board has made determinations on the treatment of long-term debt that not only reflect the 2006 guidelines, but are based on the record before it in each application. The Board has also been informed by the findings made in relation to completed applications. **The Board is of the view that it is appropriate for this cost of capital policy to reflect the current practices of the Board with respect to determining the cost of long-term debt based on recent Board decisions**.

The following guidelines on the treatment of long-term debt are intended to provide more certainty for applicants and all participants in general. **The Board wishes to emphasize that the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors**. The Board recognizes that there is still a need for the deemed long-term debt rate, however its usage should become more limited in application. The Board wishes to reiterate that the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long-term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the test year to support the reasonableness of the respective debt rates and terms.

The following guidelines are relevant with respect to the determination of the amount and cost of long-term debt for electricity distribution utilities.

The Board will primarily rely on the embedded or actual cost for existing long-term debt instruments. The Board is of the view that electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates.

In general, the Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt. The electricity distribution utility also bears the burden of establishing the need for and prudence of the amount and cost of long-term debt, both embedded and new.

Third-party debt with a fixed rate will normally be afforded the actual or forecasted rate, which is presumed to be a "market rate". However, the Board recognizes a deemed long-term debt rate continues to be required and this rate will be determined and published by the Board. **The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances**. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate <u>at the time of issuance</u> will be used as a ceiling on the rate allowed for that debt.

- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.

- The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

- For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt.

- A Board panel will determine the debt treatment, including the rate allowed based on the record before it and considering the Board's policy (these Guidelines) and practice. The onus will be on the utility to establish the need for and prudence of its actual and forecasted debt, including the cost of such debt.

Deemed Long-term Debt Formula for Electricity Distributors

While the Board is of the view that greater reliance should be placed on embedded debt, including forecasts of the amount and cost of new debt expected to be incurred during the test year, the Board recognizes that there is a continuing need for a deemed long-term debt rate.

While there were no specific suggestions for how the deemed long-term debt rate should be calculated, **the Board sees merit in modifying the formula in a manner consistent with the changes adopted for the ROE adjustment formula**.

Specifically, the Board considers that **the deemed long-term debt rate for the test year should be an estimate based on the long (30-year) Government of Canada bond yield forecast plus the average spread between an A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for all business days in the month three (3) months in advance of the (proposed) effective date for the rate changes**. This change is only in the source of the data, in the following ways:

- The 30-year A-rated Canadian utility bond yield data from Bloomberg will replace the BBB/A-rated Canadian Corporate bond yield series that was obtained from PC Bond, an affiliate of TSX.[69]

- The monthly average of business daily data will be used, instead of the weekly data used previously.

The changes are due to the data availability, and to transparency and cost. Both Bloomberg and PC Bond corporate bond series are proprietary and available on subscription bases. Using the same A-rated Canadian utility bond yield series from Bloomberg will reduce costs and work and increase transparency of the calculations. The Board does not consider the changes in methodology will have any material impact on the calculated deemed long-term debt rate. The Board also notes that this methodology was supported by LPMA and BOMA in their final written comments.[70]

Appendix C provides a detailed description of the methodology for calculating the deemed long-term debt rate.

4.4.2 Short-term debt

Natural gas distributors

For rate regulated natural gas distributors, short-term debt is used for an unfunded portion to true-up the deemed capitalization to the utility's actual capitalization. As the variance between actual and deemed capital structures is generally small, the unfunded portion is typically a small fraction of total capitalization for rate-setting purposes.

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[69] The PC Bond data was, prior to mid-2007, produced by Scotia Capital Inc., and publicly available from Statistics Canada and the Bank of Canada.

[70] Written Comments of the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. October 30, 2009, p. 32

In a Cost of Service application, the applicant natural gas distributor forecasts the cost of short-term debt for the test year, and this is subject to review. The Board notes that no participant questioned the Board's policy and practice for natural gas distributors, and **has determined that it is appropriate to continue with this approach.** With the development of a new deemed short-term debt rate for use in the electricity transmission and distribution sector, the Board notes that it and other participants may take into consideration the deemed short-term debt rate, as discussed below and documented in Appendix D.

OPG's prescribed rate-regulated baseload generation

Consistent with the Board's practice in OPG's 2008 Cost of Service application (EB-2007-0905), **the Board is of the view that OPG's cost of short-term debt should be set in a manner similar to that adopted for natural gas distributors.**

Electricity transmitters and distributors

Prior to the issuance of 2008 rates, short-term debt was not factored into electricity distribution and transmission rate-setting. In the December 20, 2006 Report, the Board adopted a deemed short-term debt rate that would apply to a deemed 4% of the capital structure. The formula for the deemed short-term debt rate was established as the average 3-month Bankers' Acceptance rate plus a 25 basis point spread, determined three months in advance of the effective date for rates. The short-term debt rate, and deemed 4% component of the capital structure was introduced in Cost of Service applications for 2008 distribution rates.

In the consultation, certain electricity distributors commented that they are unable to borrow at rates as predicted by the current deemed short-term debt formula. [71,72] These electricity

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[71] Written Comments of FortisOntario Inc. September 10, 2009. p. 8, bullet at bottom of page. FortisOntario Inc. indicates that a high-grade utility would be Bankers' Acceptance + 175 basis points, for smaller operating company entities, it would be Bankers' Acceptance + 250-275 basis points

distributors have documented that the cost of short-term debt is much higher and depends on market conditions and on the rating of a distributor. The concern was not with using the Bankers' Acceptance rate, but primarily with the spread over Bankers' Acceptances. The suggestion was that the Board should obtain estimates of the spread from major Canadian banks, and add this to the average Bankers' Acceptance rate as calculated for rate-setting. To lessen the burden, it was suggested that this spread be calculated annually in January of the year, and used as needed. The Board could obtain quotes from banks more frequently if market conditions warranted it.

The Board is of the view that this approach to establishing the deemed short-term debt rate has merit. **The Board thus will adopt the following approach to determining the deemed short-term debt rate:**

- In mid-January of each year, the Board will contact major Canadian banks to obtain estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers' Acceptance rate. The selection of R1-low is to reflect the fact that most distributors currently going to market would fall in that category; only Toronto Hydro Electric Systems Limited and Hydro One Networks Inc. would be R1-Mid or R1-High. Up to six quotes will be obtained. Ideally, the high and low estimates will be discarded to reduce the influence of outliers, and the average spread will be calculated. In the event that less than four quotes are obtained, the average spread will be calculated without discarding high and low estimates. The identity of the banks providing quotes will be protected.

- For the month three months in advance of the effective date for rates, the average 3-month Bankers' Acceptance rate should be calculated based on data for all business days in the month. To this will be added the average spread calculated above, giving the deemed short-term debt rate for rate-setting purposes.

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[72] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009, p.144, l. 20 to p. 146, l. 22. Also, p. 148, l. 19 to p. 149, l. 15.

Full documentation on the deemed short-term debt rate methodology is provided in Appendix D.

In its final comments, LPMA/BOMA submitted that the current formula should be retained, but the spread increased from 25 basis points to 50 basis points, on the basis of recent economic history.[73] The Board has determined that distributors and other participants provided sufficient documentation that the spread over bankers' acceptance rates with which they can borrow short-term debt is much higher than the 25 basis points currently used, or even the 50 basis points proposed by LPMA/BOMA. Further, LPMA/BOMA's proposal could possibly need review in the future. The Board is of the view that its adopted approach, while entailing some more work by the Board to obtain the spread quotes from the banks each year, is more flexible and will provide more reasonable estimates of the cost of short-term debt in each year.

[73] Written Comments of the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. October 30, 2009. p, 31.

4.5 Summary

The key elements of the Board's cost of capital policy are summarized in the following table.

Table 2: Components of the Board's Cost of Capital Policy

Capital structure	• 60% debt (56% long-term and 4% short-term) and 40% equity for electricity distributors. • Gas distributors, electricity transmitters and OPG will continue with approved capital structures.
Short-term debt rate	• Once a year, in January, obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates for the cost of short-term debt. • The short term rate will be calculated as the average Bankers' Acceptance for the month 3 months in advance of the effective date for the rates, plus the spread for the year calculated above.
Long-term debt rate	• The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield). • Third-party embedded/actual debt with fixed rates, terms and maturity will get the actual rate. • Affiliate embedded/actual debt with fixed rates, terms and maturity will get the lower of actual and deemed debt rate at time of issuance. • Utility provides forecasts of new debt for a forward test year, where possible. New third-party debt will be accepted at the negotiated market rate. If a forecasted new rate is not available (i.e., due to timing), the deemed long-term debt rate may apply. • For new affiliated debt, the deemed long-term debt rate will be a ceiling on the allowed rate. The onus will be on the utility to demonstrate that the applied for rate and terms are prudent and comparable to a market-based agreement and rate on arms-length commercial terms. • Variable-rate debt will be treated like new affiliated debt. • Renegotiated or renewed debt will be considered new debt. • Where a utility has no actual debt, the deemed long-term debt rate shall apply.
Common equity return	• Refined formula-based ROE will be calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year). This includes an implicit 50 basis points for transactional costs. • The ROE (and the short-term and long-term debt rates) will be based on data for the month 3 months in advance of the effective date for rates. • Reset formula for 2010: The base ROE in the refined formula will be calculated for 2010 as Long Canada Bond Forecast rate plus an ERP of 550 basis points, and reflects multiple, empirically supported, estimates provided in consultation which led to this report.

5 Implementation

5.1 Transition to Recommended Cost of Capital

The policy set out in Chapter 4 of this report will come into effect for the setting of rates, beginning in 2010, by way of a cost of service application.

The Board's "Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications" and the Board's "Filing Requirements for Transmission and Distribution Applications" are sufficient for the purposes of implementing the policies set out in this report. Those requirements include information to be filed in support of a utility's proposed cost of capital in a cost of service application. There is no need for additional filing requirements. The onus is on an applicant to adequately support its proposed cost of capital, including the treatment of and appropriate rates for debt instruments. The Board notes that this is being done in cost of service applications. However, the Board wishes to point out the increased emphasis that it is placing on applicants to support their existing and forecasted debt, and the treatment of these in accordance with the guidelines, or to support any proposed different treatment.

5.1.1 Continued Migration to Common Capital Structure

The Board will continue to include an adjustment to rates in 2010, as applicable, as outlined in its December 20, 2006 Report, in order to transition electricity distributors to the single deemed capital structure of 60% debt and 40% equity.

With 2010 rates, most electricity distributors will have completed the transition to the deemed capital structure of 60% debt (56% long-term and 4% short-term) and 40% equity. However, some distributors have not completed the transition. The Board will deal with the transition to the common deemed capital structure for these distributors when they file applications for rates.

5.2 Impact on Other Board Policies

5.2.1 Prescribed Interest Rates

The deemed short-term debt rate and the prescribed interest rate for deferral and variance accounts use closely related methodologies. Distributors commented that changes to the deemed short-term debt rate should be reflected in the prescribed interest rate. Further, there was acknowledgement that any new formula for the prescribed interest rate for deferral and variance accounts, used to calculate carrying charges on balances, would apply to both credit and debit balances. The Board agrees. While the policy in this report does not cover the prescribed interest rates, the Board intends to initiate a review of its approach to calculating the prescribed interest rate to align it with the approaches set out in this report.

6 Annual Update Process and Periodic Review

6.1 Annual Update Process

The Board will apply the methods set out in this report annually to derive the values for the ROE and the deemed long-term and short-term debt rates for use in cost of service applications.

If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the FRS is met, the Board may then use its discretion to begin a consultative process to determine whether circumstances warrant an adjustment to the formulaic approach, in general, or to any of the cost of capital parameter values specifically. The Board also may, at its discretion and based on the circumstances at the time, use the previous year's formula-generated values on an interim basis until its final determination is made following the consultative process.

Stakeholders proposed a variety of tests and approaches that could be used to supplement the Board's annual review of the cost of capital parameters. The Board is of the view that any tests or approaches used to assess the reasonableness of the cost of capital parameters should be consistent with the formulaic ROE adjustment mechanism adopted. Accordingly, the Board will not attempt to annually derive the ROE using CAPM, DCF or other cost of capital methodologies to assess the reasonableness of the formula-generated ROE. The Board notes that participants are free to perform such calculations and ask the Board to review the formula when they feel it is appropriate.

For the purposes of assessing the reasonableness of results on an annual basis, the Board will examine the values produced by the Board's cost of capital methodology, and the relationships between them, in the context of the economic and financial conditions of the day. Further and consistent with the 1997 Draft Guidelines, the Board will review its approach as conditions arise that may call into question its validity. Further, parties may ask the Board to review its cost of capital policies when they feel it is appropriate or the

Board may do so on its own initiative. In either case it will be the Board's decision as to the time for a review. Finally, the Board may request the presentation of other tests or require some weighting for other tests should the Board want to assure itself that its approach does not lead to perverse results and is directionally in line with other market indicators. [74]

6.2 Periodic Review

The Board has determined that it will periodically review its formulaic ROE adjustment mechanism. The use of any formulaic approach to approximate a change in the ROE is bound to be imperfect and any such imperfection may, over time, result in cumulative or compounding effects such that the application of it may not continue to meet the FRS.

The Board notes that the time period for a review suggested by stakeholders varied from 3-5 years, with Energy Probe suggesting that "4-5 years is probably too short."[75]
The Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated ROE continues to meet the FRS and the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2014 and any changes to the policy made as a result of that review would apply to the setting of rates for the 2015 rate year.

At the time of the review, the Board will provide guidance to stakeholders through, for example, an issues list similar to that issued on July 30, 2009, and the relevant period over which to estimate the risk-free rate. This latter approach will promote the use of a common basis to derive cost of capital estimates, increasing their direct comparability.

The periodic review will not necessarily result in a resetting of the base ROE or refining of the adjustment factors and/or terms of the formula. The Board will seek the views of

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[74] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.
[75] Written Comments of Energy Probe Research Foundation, September 8, 2009, p. 12.

stakeholders on the need to reset the ROE and the need to revise the formula. If the Board is satisfied that its approach remains appropriate, the base ROE and the formula will remain unchanged and the review will conclude.

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Appendix A: Summary on the Formula-Based Return on Equity Guidelines in Effect in the 2009 Rate Year

The Board's existing formula-based approach using the equity risk premium ("ERP") method for determining the fair rate of return for natural rate regulated natural gas utilities is set out in its 1997 *Draft Guidelines on a Formula-Based Return on Common Equity.* The 1997 *Draft Guidelines* were first applied in the EBRO 495 proceeding which set fiscal 1998 rates for the Consumers' Gas Company Ltd. The Board's December 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* reaffirmed the continued use of this approach for electricity distribution utilities subject to a number of minor modifications, as described below.

Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Natural Gas Utilities:

The 1997 Draft Guidelines, have two phases: an initial setup and an ongoing adjustment mechanism.

<u>Initial Set-Up</u>

Step 1: Establish the forecast of the long Government of Canada yield for the test year

The forecast yield of long-term Government of Canada bonds is established for the test year by taking the average of the 3 and 12 months forward 10-year Government of Canada bond yield forecasts, as stated in the most recent issue of Consensus Forecasts, and adding the average of the actual observed spreads between 10 and 30-year Government of Canada bond yields, for each business day in the month corresponding to the most recent Consensus Forecast issue.

Step 2: Establish implied risk premium

A utility's test year ROE will consist of the projected yield for 30-year long Canada bonds plus an appropriate premium to account for the utility's risk relative to long Canada bonds. The primary methodological approach to be used in evaluating the appropriate risk premium should be the ERP test.

The ERP test is designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the ROE approach is therefore usually computed as the sum of the test-period forecast for the government yield and the utility-specific risk premium the analyst has estimated based on historical ROE evidence and forward-looking considerations.

The Adjustment Mechanism

Once the initial ROE has been set for each of the utilities, a procedure must be put in place to automatically adjust the allowed ROE for each utility to account for changes in long Canada yield expectations. The timing of the adjustment mechanism process for each utility will be consistent with its fiscal year-end.

Step 1: Establish the forecast long Canada rates

The formula-based ERP approach annually adjusts a utility's allowed ROE based on changes in forecast long-term Government of Canada bond yields. Each year the process outlined in Step 1 of the initial setup phase will be repeated and an updated, consensus-based forecast of 30-year long-Canada bond yields will be obtained. The current test year rate forecast will then be compared to the previous test year forecast.

Step 2: Apply adjustment factor

The difference between the forecast long Canada rate calculated in Step 1 and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment will then be added to the utility's previous test year ROE and the sum should be rounded to two decimal points.

Term of the Rate of Return Formula

The rate of return formula should be reviewed as conditions arise that may call into question its validity. Parties may ask the Board to review the formula when they feel it is appropriate or the Board may do so on its own initiative. In either case it is the Board's decision as to the time for a review.

The Board may request the presentation of other tests or require some weighting for other tests in the formula should the Board want to assure itself that the ERP formula approach does not lead to perverse results and is directionally in line with other market indicators.

December 20, 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*:

Since 1999, the cost of capital for electricity distributors has been governed by the Board's Decision with Reasons in proceeding RP-1999-0034. This decision established a size-related capital structure for distributors and set the return on equity at 9.88%.[76] In the December 20, 2006 Report, the Board determined that the current approach to setting ROE would be maintained. The ROE will continue to be determined based on the Long Canada

[76] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2009. p. 3.

Bond Forecast plus an ERP. The approach is a modified Capital Asset Pricing Model method and includes an implicit 50 basis points for transaction costs. At that time, the Board also adopted deemed equity of 40% for all distribution utilities.

In the December 20, 2006 Report, the Board clarified the starting point to be used for each annual update and determined that it is appropriate to use the ROE calculated at that time as the starting point. This figure was 9.35%, as per the Board's determination in Hydro One Network Inc.'s RP-1998-0001 Decision. The Board indicated that it will use 9.35% as the starting point for the update. As a result of the December 20, 2006 Report, the ROE for any period would be:

ROE_t = 9.35% = 0.75 x ($LCBF_t$ – 5.50%)

Where:

- The ROE is set three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes the ROE will be based on January data.

- The Long Canada Bond Forecast ($LCBF_t$) for any Period is the average of the 3-month and 12-month forecasts of the 10-year Government of Canada bond yield as published in Consensus *Forecasts* at time t *plus* the average of the actual observed spreads between 10 and 30-year Government of Canada bond yields, for each business day during the month corresponding to the *Consensus Forecasts* at time t.

Appendix B: Method to Update ROE

With the release of this report, the Board is resetting and refining its formulaic approach for determining a utility's Return on Equity ("ROE") applicable to the prospective test year. The formula has been reset to address the difference between the allowed ROE arising from the application of the formula and the rate of ROE for a low risk proxy group that cannot be reconciled based on differences in risk alone. The formula has been refined to reduce the sensitivity of the approach to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in utility cost of equity.

The formula as set out in this report includes (a) a term to reflect the change in the Long Canada Bond forecast ("LCBF") and (b) a term to reflect the change in the spread between A-rated Utility bond yields over the Long Canada Bond yield.

The adjustment factor for the LCBF term is set at 0.5. The adjustment factor for the A-rated Utility bond term is set at 0.5. The methodology for calculating the Long Canada Bond forecast is the same as that set out in the Board's December 20, 2006 Report.

The base for the ROE adjustment formula is set at 9.75%. The corresponding base LCBF is 4.25% and the spread in 30-year A-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield is 1.415%.

While there is a change in the base numbers and the adjustment formula, the general approach for calculating the updated ROE is the same as that set out in the Board's December 20, 2006 Report.

The ROE for the prospective test year (ROE_t) will be calculated by the following adjustment formula:

$$ROE_t = BaseROE + 0.5 \times (LCBF_t - BaseLCBF) + 0.5 \times (UtilBondSpread_t - BaseUtilBondSpread)$$

Where:

- $LCBF_t$ is the Long Canada Bond Forecast for the test year, and is calculated as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \left[\frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I} \right]$$

  Where

  - ${}_{10}CBF_{3,t}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in Consensus Forecasts three (3) months in advance of the implementation date for rates;

- $_{10}CBF_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in Consensus Forecasts three (3) months in advance of the implementation date for rates;
- $_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39056**];
- $_{10}CB_{i,t}$ is the benchmark bond yield rate for the 10-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39055**]; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

- $UtilBondSpread_t$ is the average spread of 30-year A-rated Canadian Utility bond yields over 30-year Government of Canada bond yields over all business days in the month three (3) months in advance of the implementation date for rates, and is calculated as

$$UtilBondSpread_t = \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$$

Where:

- $_{30}UtilBonds_{i,t}$ is the average 30-year A-Rated Canadian Utility bond yield rate, from Bloomberg L.P., for business day i of the month that is three (3) months in advance of the implementation date for rates [**Series C29530Y**];
- $_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39056**]; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

As noted above, based on September 2009 data, the base ROE is set at 9.75% and the corresponding *BaseLCBF* is 4.25% and *BaseUtilBondSpread* is 1.415%. Thus the ROE adjustment formula is specified as:

$$ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (UtilBondSpread_t - 1.415\%)$$

The ROE for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated ROE. This means is that *Consensus Forecasts* published in the month of January, and Bank of Canada and Bloomberg L.P. data for all business days during the month of January will be used to calculate the updated ROE.

The necessary data are available shortly after the end of the month, and thus poses no undue delays for rate-setting.

The use of the ROE will be in accordance with the policy described in section 4.2 of this report.

Appendix C: Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread of A-rated Corporate Utility bond yields over the actual Long Canada Bond yield to determine the updated deemed long-term ("LT") debt rate.

This approach is consistent with the methodology adopted in the December 20, 2006 Report, to represent a fair market rate for a long-term debt instrument in the test period. The only change is the source of the corporate bond yields, which is now the A-rated Corporate Utility bond index yield obtainable from Bloomberg L.P.

Consistent with the approach used in prior guidelines, the *2006 Electricity Distribution Rate Handbook* and the December 20, 2006 Report, the ROE and the deemed long-term debt rates are based on the same forecast of the risk-free rate. For certainty, the Long Canada Bond Forecast ($LCBF_t$) used in the ROE formula will be used in the calculation of the deemed LT rate.

The deemed LT debt rate ($LTDR_t$) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$$

Where:

- $LCBF_t$ is the Long Canada Bond Forecast for the prospective test year, as defined in Appendix B for the calculation of the ROE;
- ${}_{30}UtilBonds_{i,t}$ is the average 30-year A-Rated Canadian Utility bond yield rate, from Bloomberg L.P., for business day *i* of the month that is three (3) months in advance of the implementation date for rates **[Series C29530Y]**;
- ${}_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day *i* of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada **[Cansim Series V39056]**; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated deemed LT debt rate.

The use of the deemed LT debt rate will be in accordance with the policy described in section 4.4.1 of this report and based on the evidentiary record in the particular application.

Appendix D: Method to Update the Deemed Short-term Debt Rate

The Board will use a new methodology to estimate the deemed short-term (“ST”) debt rate, consisting of the average 3-month Bankers’ Acceptance rate as published by the Bank of Canada plus a forecasted average spread of short-term debt issuances over 3-month Bankers’ Acceptance rates for R1-low Canadian utilities.

This is a change over the previous methodology, specifically in the spread above the Bankers’ Acceptance rate which previously was fixed at 25 basis points. The new methodology will use spread forecasts obtained from Canadian prime banks to better reflect the short-term rates that utilities can obtain short-term financing for.

The calculation of the deemed ST debt rate will be done through a two-step process.

1. *Annual calculation of the average spread over 3-month Bankers’ Acceptance Rates*

Once a year, in January, the average spread of short-term debt issuances over 3-month Bankers’ Acceptance rates will be obtained by Board staff contacting major Canadian banks. Up to six quotes will be obtained to calculate the average spread to be used during the calendar year. Ideally, the high and low estimates will be discarded to reduce the influence of outliers, and the average spread will be calculated. In the event that less than four quotes are obtained, the average spread will be calculated without discarding high and low estimates.

If market conditions materially change, the Board could decide that the average spread may need to be updated at some point other than January.

2. *Calculation of the Deemed Short-Term Debt Rate*

The deemed short-term debt rate ($STDR_t$) for the prospective test year will be calculated as:

$$STDR_t = \frac{\sum_i BA_i}{I} + AnnSpread_t$$

Where:

- BA_i is the 3-month Bankers’ Acceptance Rate for day i in the selected month, as published by Statistics Canada and the Bank of Canada [**Cansim Series V39071**];

- I is the number of business days for which published Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates; and
- $AnnSpread_t$ is the average annual spread in short-term debt issuances for an R1-low utility over 3-month Bankers' Acceptance rates for the test year *t*, calculated in step 1 above.

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated deemed ST debt rate.

The use of the deemed ST debt rate will be in accordance with the policy described in section 4.4.2 of this report.

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

Ontario

EB-2008-0272

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

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. under section 78 of the *Ontario Energy Board Act, 1998*, seeking changes to the uniform provincial transmission rates.

BEFORE: Cynthia Chaplin
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

DECEMBER 16, 2009.

1. INTRODUCTION

1.1 BACKGROUND

On September 30, 2008, Hydro One Networks Inc. (“Hydro One") filed an application with the Ontario Energy Board (the “Board”) under section 78 of *Ontario Energy Board Act, 1998* (the “Act”). The application sought approval for changes to the uniform provincial transmission rates that Hydro One charges for electricity transmission to be effective and implemented on July 1, 2009. The Board assigned the application file number EB-2008-0272.

The Board issued its Decision with Reasons on May 28, 2008. In its decision the Board did not approve four of the Network Capital Projects (labeled in the application as D7, D8, D9 and D10). However, the Board indicated that it would leave this part of the application open to provide Hydro One with the opportunity to file supplemental evidence on the projects.

On September 4, 2009 Hydro One filed supplementary evidence with the Board on projects D7 and D8, both of which have planned in-service dates in 2010. Hydro One advised that projects D9 and D10 would not be in-service in 2010, and therefore were not included in the supplementary material. Approval of projects D7 and D8 would increase the previously approved capital program by $82.7 million to a total of $936.5 million in 2009 and by $62.0 million to a total of $1,057.6 million in 2010. The resulting impact on the 2010 revenue requirement was estimated to be $7.1 million.

1.2 PROCEDURAL MATTERS

On September 18, 2009 the Board issued Procedural Order No.6 providing for interrogatories and requesting that parties advise the Board if they intended to submit evidence and if they preferred a written or oral hearing. No party indicated it intended to provide evidence and no party expressed a preference for an oral hearing. The Board proceeded by way of a written hearing.

Board Staff and intervenors filed submissions in October and Hydro One filed its reply submission on November 2, 2009.

2. THE APPLICATION

Project D7 involves the installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS. The planned in-service date is November 2010, and the estimated cost is $109 million.

Project D8 involves the installation of series capacitors at Nobel Switching Station. The planned in-service date is December 2010 and the estimated cost is $47 million for the project.

In its original application Hydro One had indicated that projects D7 and D8 were required to relieve congestion on the North-South Interface in order to access available northern generation and to enable incorporation of additional committed and planned renewable generation in northern Ontario. The OPA had recommended that Hydro One proceed with the projects on May 20, 2008. Its recommendation was based on its forecast of 900 MW of new generation resources coming into service in Northern Ontario by 2013. The new resources included 500MW of hydroelectric generation that had been the subject of a Ministerial Directive issued to the OPA on December 20, 2007. The supplemental application included further information and explanation in support of the projects.

Hydro One provided tables which set out summaries of the comparative costs for the project and the alternatives. These are reproduced below:

Project D7

Alternative	Cost	Capacity Added on Flow South Interface	In service date
Do nothing	0	0	N/A
Install Mechanically Switched Capacitor Banks	Lower Costs than D7	Not Viable per ORTAC	2010
Install Series Capacitor on Porcupine TS to Hanmer TS 500kV Circuit	Lower Costs than D7	None	2010
New parallel Single Circuit 500kV line from Pinard TS to Hanmer TS	About $1B	300 MW	2015
Project D7	$109 M	160 MW	2010

Project D8

Alternative	Cost	Capacity Added on Flow South Interface	In service date
Do nothing	0	0	N/A
Build a New 500kV Switching Station	Approx same Cost as D8	About 100MW	Beyond 2010
Build a New Single Circuit 500kV Line to the GTA	About $1B	1500MW	2015
Project D8	$47m	340MW	2010

Hydro One identified two particular areas where there has been change since May 2009 when the original decision was issued.

First, Hydro One provided the OPA's updated forecasts of committed and other near-term generation projects. The forecasted capacity has risen from 380 MW to 762 MW. Hydro One submitted that the additional resources further support the need to increase the capability of the North-South tie.

Second, Hydro One maintained that the enactment of the *Green Energy and Green Economy Act* (the "GEA") establishes a new regulatory environment that fundamentally alters the manner in which infrastructure projects will be planned for and the manner in which transmission and distribution companies will seek approval from the Board for those projects. It also noted that the launch of the Feed in Tariff ("FIT") program has increased the expectation for renewable generation development across the Province including Northern Ontario.

4. POSITIONS OF THE PARTIES

4.1 PARTIES OPPOSED

Board staff submitted that Hydro One is required to provide an economic evaluation, including a quantitative justification where projects are discretionary, arguing that while the connection of generation projects are mandated and do not require further justification, this characterization does not necessarily extend to transmission projects to accommodate the connection of that generation. Board staff argued that any reinforcements to reduce congestion or alleviate bottled energy must be supported by quantitative evaluation. It further argued that the onus rests on Hydro One to comply with the Board's filing requirements for transmission projects, and that if this is not done the Board could appropriately deny recovery of costs.

The Association of Major Power Consumers of Ontario ("AMPCO") concurred with Board staff's submission that the two projects are not generation connection facilities and do not fall within the immediate scope of the directives from the Minister and government objectives with respect to the connection of renewable generation, and hence ought to be justified in a manner similar to other category 2 projects.

AMPCO also expressed concern with in-service dates. It argued that, just as transmission facilities that are not in place when needed strand generation assets, the converse is also true, that transmission assets that are put in place before they are used and useful are also stranded assets.

AMPCO further argued that the reliability consideration for customers north of New Liskeard is not new and a resolution is not urgent until 2014.

The School Energy Coalition (“SEC”) submitted that projects D7 and D8 should not be viewed as non-discretionary, that Hydro One did not file a cost benefit analysis as requested, and therefore there is inadequate supporting evidence to approve the projects.

The Vulnerable Energy Consumers Coalition (“VECC”) argued that the incremental capacity provided by the projects is not all required in 2010 and that the only rationale for proceeding with project D7 at this time appears to be concerns about the reliability of supply to customers north of New Liskeard. In VECC’s view the projects are discretionary and, therefore, an economic justification is required since there are alternatives, e.g. congestion already exists on the North-south interface and is managed by the IESO through constrained dispatch. VECC submitted that a broad interpretation of what is non-discretionary will severely limit the Board’s role and obligation to ensure that investments in the transmission system and the resulting rates are prudent.

VECC submitted that the OPA’s recommendation to include costs for mitigation of the impact of delays to transmission projects, by targeting for the projects to come into service in advance of when generation projects would require the capacity, is inappropriate. If therefore the Board decided to provide recovery of the costs it should be by way of a deferral/variance account to protect customers in the event that the OPA’s concerns are proved out and the facilities are not completed in 2010.

The Consumer Council of Canada (“CCC”) and the Canadian Manufacturers & Exporters (“CME”) agreed with the analyses of Board staff and VECC, and submitted that there should not be an adjustment to 2010 rates.

4.2 PARTIES IN SUPPORT

Energy Probe accepted that Hydro One has demonstrated the technical necessity of the projects. It agreed with Board staff that the filing guidelines require comparative economic analysis of the identified alternative and that Hydro One has not provided the same level of detailed cost benefit analysis that it provided in the Bruce to Milton leave to construct application. However, Energy Probe noted that according to the evidence the only other viable alternative to the proposed projects is a new 500 kV transmission line at an estimated cost of $1 billion compared to the estimated $150 million for the proposed projects. It submitted that given the order of magnitude difference and that the transmission line could not be built in time, a more comprehensive cost benefit analysis would not likely yield a different result. Strict compliance would seem to be unnecessary according to Energy Probe.

Ontario Power Generation ("OPG") supported Hydro One's Northeast Transmission Reinforcement Project, including the subject projects, because it is necessary for the effective transmission of generation from OPG's Lower Mattagami River project, which will provide an additional 450 MW of generation, coming on line in 2013.

The Power Workers' Union ("PWU") noted that updates from the OPA indicate increases in generation resources, and that even though some in-service dates have changed, the OPA identifies that the subject projects are still required in the near term. The GEA and the FIT program also support the need to increase the capability of the North-South interface. PWU argued that the Board should balance its expectation of what it understands to be "sufficient evidence" in this matter with its commitment to streamline the process and reject calls for further analysis, which might ultimately provide the Board with little help in making its determination of the two projects.

4.3 THE APPLICANT'S REPLY

Hydro One responded that the need for the reinforcement of the North-South tie is even greater today than in May 2008 when the OPA recommended that the company proceed with the installation of reinforcement to the transmission system between Timmins and Barrie. Whereas approximately 900 MW was expected to come into service in the 2008 to 2013 timeframe, the increase in planned generation is now approximately 1300 MW.

Hydro One pointed to the passage of the GEA to encourage the delivery of infrastructure, and changes to section 96(2) of the OEB Act to promote the use of renewable energy sources and submitted that the evidence provided is a precursor of what Hydro One will be providing in support of rate applications in support of GEA initiatives. Hydro One submitted that Board staff and intervenors are interpreting the Minimum Filing Requirements too narrowly, and have failed to acknowledge the Board's new objective.

Hydro One clarified that the need for project D7 does not arise to improve reliability to customers North of New Liskeard, but rather to meet reliability requirements and hence the project is non-discretionary. Hydro One is seeking approval for the projects to facilitate the connection and utilization of renewable generation in accordance with the Minister's directive to procure northern hydroelectric generation and also to meet the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") requirements.

Hydro One noted that it does not understand Board staff's distinction between Connection Projects being non-discretionary and System Reinforcement Projects being discretionary. It is not practical to connect resources that can not be utilized, and in fact the Board's new objective includes the "use" and not merely the connection of renewable resources. Hydro One argued that the Board staff position implies that transmission reinforcements to enable the connection facilities are discretionary, a proposition with which Hydro One disagreed.

Hydro One argued that past applications, where it has provided more detail, were discretionary or partially discretionary, or were in the context of a section 92 application, not a rate application. It further submitted that the FIT program is on a non take-or-pay basis, which means that capacity constraints on the system must be removed if FIT proponents are to be able to sell their power into the grid. In Hydro One's view, the suggestion by Board staff and some intervenors that even non-discretionary projects should undergo an economic evaluation is inconsistent with the Filing Guidelines.

Hydro One submitted that little if any value would be added to the Board's review by including quantified comparisons of NPV in this case.

Hydro One referred to the support from Energy Probe regarding the order of magnitude difference in costs for a 500 kV transmission line over Projects D7 and D8 and that a more comprehensive cost benefit analysis would not yield a different outcome than the qualitative analysis presented in Hydro One's evidence. In response to Board staff's request for a loss of load probability study, Hydro One noted that project D7 is not intended to improve reliability, but rather to ensure that reliability standards are met, and therefore an economic evaluation is not required to justify this non-discretionary project.

5. BOARD FINDINGS

There are two substantial issues that are in dispute regarding the subject projects of the supplemental filing.

1. Whether Hydro One has provided adequate economic analysis in support of the projects and;
2. Whether the projects are required in the test year.

The Board's decision to allow for supplemental evidence on certain Network capital projects has provided Hydro One with an opportunity to file evidence framed within the regulatory construct created by the GEA. The filing of supplemental evidence also afforded Hydro One the opportunity to provide a more focused and comprehensive evidentiary basis for the specific projects. The compiling of supporting information that was originally filed as either pre-filed evidence, responses to interrogatories or in undertakings filed by Hydro One in the main hearing, has resulted in a more cogent rationale for the projects.

The new regulatory construct created by the GEA includes an obligation of the Board to, where applicable, promote the use of generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

Hydro One argues that the Board's new objective pertaining to the promotion of renewable energy has not been acknowledged by Board Staff and those intervenors who submit that the Board's Minimum Filing Requirements have not been met. It further argues that the proposed projects are required in the time frame stipulated to ensure that they are in place and available to enable the cited generation facilities and also potential FIT program projects being contracted for by the OPA in the area.

Board Staff, AMPCO, VECC and SEC claim that, according to the Minimum Filing Guidelines, the projects are not connection facilities and therefore, by definition, are discretionary projects requiring full supporting economic analysis. Board staff provided examples of the evaluations done for other projects, including a financial analysis of the congestion relief associated with the project D5, and alleviation of bottled energy for the Bruce-Milton project. These claims are disputed by Hydro One on the grounds that the projects are necessitated by Ministerial Directives and therefore they are non-discretionary. Hydro One claims that the type of analysis suggested by Board Staff and VECC would be of little value if any to the Board in making the determinations that are required in this case.

In the Board's view, the claims and counter claims of the parties regarding the characterisation of the projects as discretionary or non-discretionary are not determinative of the matter in this particular case. Irrespective of the manner in which the filing guidelines shape the application, the Board must decide whether or not the economic analysis provided in support of the projects demonstrates that the spending that is subject to Board review and approval is prudent.

On December 20, 2007 the Minister of Energy exercised the statutory power of Ministerial direction pursuant to section 25.32 of the Electricity Act, 1998. The Directive entailed the OPA making reasonable efforts to complete negotiations and execute financial energy supply agreements with OPG for the projects known as Lac Seul, Upper Mattagami, Healy Falls, Lower Mattagami and Hound Chute.

The evidence is clear that the Ministerial Directive to the OPA to procure renewable generation at these specific locations gave rise to the transmission system enhancements proposed by Hydro One. It is clear to the Board that the Ministerial Directive is intended to facilitate a policy initiative of the Government of Ontario and therefore these projects are to be considered in the context of the Board's new objective regarding the promotion of renewable energy sources.

The Board's obligation to promote renewable energy sources is a determinative factor in the establishment of the parameters of the economic analysis it will rely on to test the prudency of the applicant's proposals. The generation facilities will exist at prescribed locations as a result of Minister's Directive. Due to the site specificity of the renewable energy generation facilities in this application, analysis of congestion relief would essentially be an examination of the economics of the generation facility location. The Board does not intend to examine the economics of the project sites contained in the Minister's Directive. The Board does not require economic analysis of the generation locations to test the applicant's proposal to enable the generation against other alternatives that could also enable the generation.

In this application the Minister's Directives drive site specific generation projects and in turn affects discrete elements of the transmission system. Hydro One claims that the generation facilities necessitate a transmission system enhancement to render them fully operable and that the projects put forward are the most suitable of the project alternatives from both an economic and timeliness perspective.

The Board's role in this matter is to review the applicant's proposal to respond to the Minister's Directive to determine if it is the most efficient response available to it. Hydro One provided information on three alternatives to its proposed solution. They were all discounted due to ineffectiveness, cost, timeliness or a combination thereof. The Board would have been assisted by a more detailed cost comparison of the transmission line alternative but given the stark differential of nearly a seven-to-one ratio with respect to the proposed project, the Board accepts the evidence at face value. The Board accepts Hydro One's proposal as the most cost effective and timely alternative presented.

VECC and AMPCO have challenged the need for the project in the time frame proposed. Both challenge the time frames of the generation facilities being on-line and point to Hydro One's evidence as being illustrative of the projects being brought into rate base prematurely.

Hydro One counters that in addition to the projects being necessitated by the generation facilities that result from the Minister's Directive the transmission enhancements will also enable the procurement of renewable energy by the OPA through the FIT program. Hydro One also submits that the planning for completion dates for projects of this nature i.e. that are intended to enable procured renewable energy, should be done so in order to ensure projects are ready when needed.

The Board agrees that in these circumstances it is appropriate to complete the projects on the proposed timeline in order to facilitate the implementation of the FIT program in the affected area.

In conclusion, the projects are approved and Hydro One's 2010 revenue requirement will be adjusted accordingly and increased by $7.1 million.

6. IMPLEMENTATION MATTERS AND COST AWARDS

6.1 IMPLEMENTATION

New transmission rates were implemented effective July 1, 2009 in accordance with the Decision of May 28, 2008 and a rate order issued in June 2009. The present Ontario Transmission Rate Schedule is:

Service Rate	Monthly Rate ($/kW)
Network	2.66
Line Connection	0.70
Transformation Connection	1.57

The Revenue Allocators at present are shown in the following table:

Transmitter	Network	Line	Transformation
Uniform transmission Rates $/kW-Month	2.66	0.70	1.57
Five Nations Inc.	0.00438	0.00438	0.00438
Canadian Niagara Power Ltd.	0.00390	0.00390	0.00390
Great Lakes Power Ltd.	0.02944	0.02944	0.02944
Hydro One Networks Inc.	0.96228	0.96228	0.96228
Total	1.00000	1.00000	1.00000

In accordance with its May 28, 2009 Decision, the Board issued a letter to Hydro One on November 5, 2009 setting out the Board's determination of Hydro One's return on equity and cost of short-term debt for 2010. The return on equity was set at 8.39% and the short-term debt rate was set at 0.55%.These values shall be used in the derivation of Hydro One's revenue requirement.

The Board directs Hydro One to file with the Board and all intervenors:

a) A draft exhibit showing the final revenue requirement to reflect the Board's finding in this Decision and the cost of capital parameter values contained in the Board's letter of November 5, 2009.
b) An exhibit showing the calculation of the uniform transmission rates and revenue shares reflecting the revenue requirement from above.
c) A draft UTR reflecting these inputs.

6.2 COST AWARDS

Intervenors that were considered eligible for cost awards in the original case and that participated in the examination of the supplementary application shall submit their claims on or before December 31, 2009. The cost claims must conform to the Board's practice Direction on Cost Awards.

Hydro One should review the cost claims. Objections must be filed with the Board and one copy must be served on the party against whose claim the objection is made, by January 8, 2010.

The party whose cost claim was objected to will have until Friday January15, 2010 to respond. Again, a copy of the submission must be filed with the Board and one copy is to be served on Hydro One.

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

DATED at Toronto, December 16 2009.

ONTARIO ENERGY BOARD

Original signed by

Cynthia Chaplin
Presiding Member

Original signed by

Paul Vlahos
Member

Original signed by

Ken Quesnelle
Member

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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

December 21, 2009

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli

EB-2008-0272 – Hydro One Networks' 2009-2010 Electricity Transmission Revenue Requirements – Final Draft Revenue Requirements & Charge Determinants in Accordance with Decision for the 2010 Test Year

The OEB in its Decision with Reasons dated December 16, 2009, directed the Company to file with the Board and all intervenors:

a) A draft exhibit showing the final revenue requirement to reflect the Board's finding in this Decision and the cost of capital parameter values contained in the Board's letter of November 5, 2009.

b) An exhibit showing the calculation of the uniform transmission rates and revenue shares reflecting the revenue requirement from above.

c) A draft UTR reflecting these inputs.

Hydro One has provided exhibits outlining the final revenue requirement as well as the calculation of the 2010 UTR's, charge determinants and revenue shares resulting from the Board's findings in this decision with respect to the approval of Projects D7 and D8 and the cost of capital parameters based on the formula applicable for the 2010 test year per the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) released on December 11, 2009.

Attached please find the requested exhibits, as well as documentation providing a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits.

In summary, Hydro One has:

- Added the capital expenditures in 2009 and 2010 to reflect the Board's approval of Development projects D7 and D8. As these two projects are forecast to come into service in 2010, the 2010 Revenue Requirement has been adjusted upward by $7.1 million.
- Applied the cost of capital parameters based on the formula applicable for the 2010 test year per the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) released on December 11, 2009.
- Updated the average cost of embedded debt for 2010 by incorporating the actual principal amount and cost rate for debt issued in 2009 and retaining the forecast principal amounts and cost rates for debt forecast to be issued in 2010.
- Increased its Low Voltage Switchgear Credit Due to the change in the transformation pool revenue requirement for 2010.
- Lowered the 2010 Wholesale Meter Rate.

The impact on the 2010 revenue requirement of adjusting for the 2010 cost of capital parameters and for actual 2009 long-term debt issues is provided in the table below:

Item	2010 Hydro One Proposed	2010 New Parameters	Change	Revenue Requirement Impact (million)
Long-Term Debt (%)	5.80	5.73	(0.07)	($4.1)
Short-Term Debt (%)	4.75	1.93	(2.82)	($8.6)
Return on Equity (%)	9.35	9.75	0.40	$18.0
Total				$5.3

If you have any questions regarding this submission please contact Anne-Marie Reilly at 416 345-6482.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors (electronic)

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EB-2008-0272 BOARD DECISION WITH REASONS
FINAL 2010 REVENUE REQUIREMENT AND CHARGE DETERMINANTS

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Final 2010 Revenue Requirement Summary

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
OM&A	Exhibit 1.1	449.7	(23.5)	426.2
Depreciation	Exhibit 1.2	281.5	(0.2)	281.3
Capital Tax	Exhibit 1.5	6.0	(0.0)	6.0
Return on Debt	Exhibit 1.4	269.7	(13.3)	256.4
Return on Equity	Exhibit 1.4	286.1	11.7	297.8
Income Tax	Exhibit 1.6	48.0	5.6	53.6
Base Revenue Requirement		**1,341.0**	**(19.8)**	**1,321.3**
Deduct: External Revenue	Exhibit 1.7 & Note 1	18.0	-	18.0
Revenue Requirement less external revenues		**1,323.0**	**(19.8)**	**1,303.3**
Deduct: Export Revenue Credit	Note 1	(12.0)	-	(12.0)
Deduct: Other Cost Charges	Exhibit 1.8	(13.0)	(7.3)	(20.3)
Add: Low Voltage Switch Gear		11.5	(0.3)	11.2
Rates Revenue Requirement		**1,309.5**	**(27.3)**	**1,282.2**

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

OM&A Details

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
OM&A	*See supporting details below*	449.7	(23.5)	426.2

OEB Decision Impact Supporting Details

	Reference	
Sustainment OM&A adjustment	OEB Decision pg. 21	(15.0)
Development OM&A adjustment	OEB Decision pg. 23	(3.2)
Compensation adjustment	OEB Decision pg. 31	(4.0)
Property Tax adjustment	OEB Decision pg. 33	(1.3)
		(23.5)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Rate Base and Depreciation Details

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Rate Base	*See supporting details below*	7,650.5	(14.5)	7,636.0
Depreciation	*See supporting details below*	281.5	(0.2)	281.3

OEB Decision Impact Supporting Details	Reference	2010 Detailed Computation	2010 Rate Base Impact	2010 Depreciation Impact
Working Capital Adjustment				
Rate Base Details	Pre-filed Evidence Exh			
Utility plant (average)	D1-1-1			
Gross plant at cost		11,780.2		
Less: Accumulated depreciation		(4,179.7)		
Net utility plant		7,600.5		
Working capital				
Cash working capital		11.2		
Materials & supplies inventory		38.7		
Total working capital		50.0		
Total Rate Base		7,650.5		
Working capital as % of OM&A	(a)	11.1%		
OM&A Reduction	Exhibit 1.1 (b)	(23.5)		
Working capital reduction	(c) = (a) x (b)	(2.6)	(2.6)	
Rate Base Adjustment				
Development Capital (removal of projects)				
D9 - 100MVar Shunt Caps at Algoma	Prefiled Evidence	9.7		
D10 - 2 75MVAR Shunt Caps at Mississagi	D1-3-3	10.3		
D28 - Glendale TS - increase capacity		3.2		
D29 - Dunnville TS - increase capacity		0.8		
		24.0		
Associated Depreciation	*Note 1*	0.2		(0.2)
Development Capital Adjustment	*Note 2*	23.8	(11.9)	
Reduction to proposed			(14.5)	(0.2)

Note 1: Assumed 50 year service life and half year depreciation
Note 2: The 2010 net adjustment would be a half year impact on 2010 rate base

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Expenditure Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**Cumulative Updates 2009**	**Cumulative Updates 2010**	**OEB Approved 2009**	**Draft Rate Order 2010**
Capital expenditures	*See supporting details below*	944.0	1,074.1	(7.5)	(16.5)	**936.5**	**1,057.6**

OEB Decision Impact Supporting Details

Development Capital (removal or projects) *Note 1*			
D9 - 100MVar Shunt Caps at Algoma	Pre-filed Evidence	4.6	5.1
D10 - 2 75MVAR Shunt Caps at Mississagi	Exh D1-3-3	2.9	7.4
D28 - Glendale TS - increase capacity	*Note 2*	-	3.2
D29 - Dunnville TS - increase capacity	*Note 2*	-	0.8
		7.5	16.5

Note 1: 4 Development projects were removed from the revenue requirement calculation based on the OEB Decision.
Note 2: Net of capital contributions

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Structure and Return on Capital Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
Return on Rate Base				
Rate Base	Exhibit 1.2	$ 7,650.5	$ (14.5)	$ 7,636.0
Capital Structure:				
Third-Party long-term debt	OEB Decision pg. 54	56.0%	(1.8%)	54.2%
Deemed long-term debt	OEB Decision pg. 54	0.0%	1.8%	1.8%
Short-term debt		4.0%	0.0%	4.0%
Common equity		40.0%	0.0%	40.0%
Capital Structure:				
Third-Party long-term debt		4,284.0	(146.4)	4,137.6
Deemed long-term debt		0.3	138.3	138.5
Short-term debt		306.0	(0.6)	305.4
Common equity		3,060.2	(5.8)	3,054.4
		$ 7,650.5	**$ (14.5)**	**$ 7,636.0**
Allowed Return:				
Third-Party long-term debt	Exhibit 1.4.1	5.80%	(0.08%)	5.73%
Deemed long-term debt	Exhibit 1.4.1	7.29%	(1.56%)	5.73%
Short-term debt	*Note 1*	4.75%	(2.82%)	1.93%
Common equity	*Note 2*	9.35%	0.40%	9.75%
Return on Capital:				
Third-Party long-term debt	Prefiled Evidence	248.5	(11.6)	236.9
Deemed long-term debt	B2-1-1	0.0	7.9	7.9
Short-term debt		14.5	(8.6)	5.9
AFUDC return on Niagara Reinforcement Project	see below	6.6	(1.0)	5.7
Total return on debt		**$ 269.7**	**$ (13.3)**	**$ 256.4**
Common equity		**$ 286.1**	**$ 11.7**	**$ 297.8**
AFUDC return on Niagara Reinforcement Project				
CWIP		99.1		99.1
AFUDC Rate	*Note 3*	6.7%		5.73%
		6.6		5.7

Note 1: Used BA + R1-mid Spread per December 11, 2009 Cost of Capital Report
Note 2: Used December 11, 2009 Cost of Capital Report Method to Update ROE
Note 3: Used embedded cost of debt return for NRP

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2010) Updated for 2008 and 2009 Actuals
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/09 ($Millions)	Total Amount Outstanding at 12/31/10 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-10	278.4	3.6	274.8	98.70	7.34%	278.4	0.0	128.5	9.4	
2	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
5	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
6	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
7	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
8	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
9	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
10	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
11	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
12	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
13	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
14	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
15	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
16	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
17	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
18	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
19	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
20	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.74	4.95%	180.0	180.0	180.0	8.9	
21	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
22	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	0.0	50.8	2.0	
23	13-Jan-09	3.890%	19-Nov-10	65.0	(0.4)	65.4	100.67	3.51%	65.0	0.0	55.0	1.9	
24	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
25	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
26	16-Jul-09	5.490%	16-Jul-40	210.0	1.1	209.0	99.50	5.52%	210.0	210.0	210.0	11.6	
27	19-Nov-09	3.132%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
28	15-Mar-10	6.870%	15-Mar-40	170.4	0.9	169.6	99.50	6.91%	0.0	170.4	131.1	9.1	
29	15-Jun-10	6.170%	15-Jun-20	170.4	0.9	169.6	99.50	6.24%	0.0	170.4	91.8	5.7	
30	15-Sep-10	5.480%	15-Sep-15	170.4	0.9	169.6	99.50	5.60%	0.0	170.4	52.4	2.9	
31		**Subtotal**							4031.5	4139.3	4137.6	234.1	
32		Treasury OM&A costs										2.0	
33		Other financing-related fees										0.8	
34		**Total**							4031.5	4139.3	4137.6	236.9	5.7259%

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Capital Tax Summary

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Capital Taxes	*See supporting details below*	6.0	6.0	(0.0)

Capital Tax Supporting Details

($ millions)	**Reference**	
Net Taxable Capital as filed	Pre-filed Evidence Exh C2/T4/S1	7,985.8
Capital Tax rate		0.075%
Capital Tax as filed		6.0
2010 in-service additions	Exhibit 1.2	24.0
Associated depreciation	Exhibit 1.2	(0.2)
Total net taxable capital adjustments		23.8
Revised Taxable Capital		7,962.0
Revised Capital Taxes		6.0

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Income Tax Summary

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Income Taxes	*See supporting details below*	48.0	53.6	5.6

Income Tax Supporting Details

Rate Base	Exhibit 1.2	a	$ 7,650.5	$ 7,636.0	
Common Equity Capital Structure		b	40.0%	40.0%	
Return on Equity	Exhibit 1.4	c	9.35%	9.75%	
Return on Equity		d = a x b x c	286.1	297.8	
Regulatory Income Tax		e = l	48.0	53.6	
Regulatory Net Income (before tax)		f = d + e	334.1	351.4	17.3
Timing Differences *(Note 1)*		g	(182.9)	(182.7)	0.2
Taxable Income		h = f + g	151.2	168.7	17.5
Tax Rate	Prefiled Evidence	i	32.0%	32.0%	
Income Tax	C2-6-1	j = h x i	48.4	54.0	
less: Income Tax Credits		k	(0.4)	(0.4)	
Regulatory Income Tax		l = j + k	48.0	53.6	5.6

Note 1. Book to Tax Timing Differences are detailed in EB-2008-0272 C2-6-1. The adjustment above to timing differences reflect the change between capital cost allowance and depreciation as a result of the change in rate base as directed in section 6.5 of the OEB decision.

Timing difference adjustments	
less: lower depreciation related to development project adjustment	(0.2)
add: lower CCA claim related to development project adjustment	0.5
Net timing difference adjustment	0.2

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

External Revenue Details

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
External Revenue	Pre-filed Evidence Exh E3/T1/S1 & Note 1	18.0	-	18.0

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Deferral Account Recovery Details

($ millions)	**Supporting Reference**		**Draft Rate Order 2010**
Requested Deferral Account Recovery	*Note 1*		
Tax Changes Account	Pre-filed		(9.3)
OEB Costs Account	Evidence Exh		(2.8)
Pension Account	F1/T1/S1		(0.1)
Total Requested Deferral Account Recovery			**(12.2)**
Add:			
Existing Deferral Account Recovery			
MRP costs	EB-2006-0501		4.1
Export revenue	Board Order		(12.2)
Total Existing Deferral Account Recovery			**(8.1)**
Total Deferral Account Recovery			**(20.3)**

Note 1: 2010 amount is for 12 months

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

2010 Revenue Requirement Continuity Schedule

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Deferral Account 2010**	**Update Low Voltage Switch Gear 2010**	**Update OM&A 2010**	**Disallowed Projects 2010**	**Update Short Term Debt 2010**	**Update Long Term Debt 2010**	**Update Return On Equity 2010**	**Draft Rate Order 2010**
OM&A	Exhibit 1.1	449.7	-	-	(23.5)	-	-	-	-	426.2
Depreciation	Exhibit 1.2	281.5	-	-	-	(0.2)	-	-	-	281.3
Capital Tax	Exhibit 1.5	6.0	-	-	-	(0.0)	-	-	-	6.0
Return on Debt	Exhibit 1.4	269.7	-	-	-	(0.6)	(8.6)	(4.1)	-	256.4
Return on Equity	Exhibit 1.4	286.1	-	-	-	(0.5)	-	-	12.2	297.8
Income Tax	Exhibit 1.6	48.0	-	-	-	(0.1)	-	-	5.7	53.6
Base Revenue Requirement		**1,341.0**	**-**	**-**	**(23.5)**	**(1.5)**	**(8.6)**	**(4.1)**	**18.0**	**1,321.3**
Deduct: External Revenue	Exhibit 1.7 & Note 1	18.0	-	-	-	-	-	-	-	18.0
Revenue Requirement less external revenues		**1,323.0**	**-**	**-**	**(23.5)**	**(1.5)**	**(8.6)**	**(4.1)**	**18.0**	**1,303.3**
Deduct: Export Revenue Credit	Note 1	(12.0)	-	-	-	-	-	-		(12.0)
Deduct: Other Cost Charges	Exhibit 1.8	(13.0)	(7.3)	-	-	-	-	-		(20.3)
Add: Low Voltage Switch Gear		11.5	-	(0.3)	-	-	-	-		11.2
Rates Revenue Requirement		**1,309.5**	**(7.3)**	**(0.3)**	**(23.5)**	**(1.5)**	**(8.6)**	**(4.1)**	**18.0**	**1,282.2**

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Final 2010 Revenue Requirement by Rate Pool

	Supporting Exhibit	2010 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.0*	198.8	38.3	113.2	350.3	0.8	351.1
Other Taxes (Grants-in-Lieu)	*1.0*	45.7	11.6	17.8	75.1	0.0	75.1
Depreciation of Fixed Assets	*1.0*	160.4	37.7	76.4	274.5	0.1	274.6
Capitalized Depreciation	*1.0*	(7.8)	(2.0)	(3.2)	(13.0)	(0.0)	(13.0)
Asset Removal Costs	*1.0*	10.8	2.8	4.4	17.9	0.0	17.9
OPEB Amortization	*Note 1*	0.0	0.0	0.0	0.0	0.0	0.0
Other Amortization	*1.0*	1.1	0.3	0.4	1.7	0.0	1.7
Return on Debt	*1.0*	155.8	39.5	61.0	256.3	0.1	256.4
Return on Equity	*1.0*	180.9	45.9	70.9	297.7	0.1	297.8
Income Tax	*1.0*	32.6	8.3	12.8	53.6	0.0	53.6
Capital Tax	*1.0*	3.6	0.9	1.4	6.0	0.0	6.0
Base Revenue Requirement	*1.0*	**781.8**	**183.2**	**355.1**	**1320.1**	**1.2**	**1321.3**
Less Regulatory Asset Credit	*1.8*	-12.0	-2.8	-5.5	-20.3	0.0	-20.3
Total Revenue Requirement	1.0	**769.8**	**180.4**	**349.7**	**1299.9**	**1.2**	**1301.0**
Less Non-Rate Revenues	*Note 1*	(10.7)	(2.5)	(4.8)	(18.0)	(0.0)	(18.0)
Less Export Revenues	*Note 1*	(12.0)			(12.0)		(12.0)
Plus LVSG Credit	*6.0*			11.2	11.2		11.2
Revenue Requirement by Pool		**747.1**	**177.9**	**356.0**	**1281.1**	**1.2**	**1282.2**
Revenue Requirement for UTR		**747.1**	**177.9**	**356.0**	**1281.1**		**1282.2**
Hydro One Proposed Pool Revenue Requirement	*Note 1*	762.1	180.5	365.6	1308.2	1.2	1309.4

Note 1: See EB-2008-0272 Exhibit G2, Tab 5, Schedule 1, Page 2.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Summary Final Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2010 to December 31, 2010)

	Total MW
Network	242,388
Line Connection	234,657
Transformation Connection	202,860

2010 charge determinants per Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2010

Transmitter	Revenue Requirement ($) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,019,845	$719,086	$1,439,069	$5,178,000
CNPI	$2,690,008	$640,545	$1,281,889	$4,612,443
GLPL	$20,287,097	$4,830,766	$9,667,559	$34,785,422
H1N *(Note 1)*	$747,144,000	$177,910,000	$356,042,000	$1,281,096,000
All Transmitters	$773,140,951	$184,100,396	$368,430,517	$1,325,671,865

Transmitter	Total Annual Charge Determinants (MW) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	44.915	44.915	44.915	
CNPI	583.420	668.600	668.600	
GLPL	4,150.498	2,847.032	2,777.933	
H1N *(Note 2)*	242,387.818	234,657.008	202,860.490	
All Transmitters	247,166.651	238,217.555	206,351.938	

Transmitter	Uniform Rates and Revenue Allocators *(Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.13**	**0.77**	**1.79**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00391**	**0.00391**	**0.00391**	
CNPI Allocation Factor	**0.00348**	**0.00348**	**0.00348**	
GLPL Allocation Factor	**0.02624**	**0.02624**	**0.02624**	
H1N Alocation Factor	**0.96637**	**0.96637**	**0.96637**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2010 Revenue Requirement per Exhibit 2.0

Note 2: Hydro One Networks (H1N) Charge Determinant per Exhibit 3.0

Note 3: Data for Other Transmitters per Exhibit 4.1.

Note 4: Calculated data in shaded cells.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Revenue Requirement and Charge Determinant Assumptions for Other Transmitters

Table 1
Approved Annual Revenue Requirement and Charge Determinants

Transmitter	Annual Revenue Requirement ($)	Annual Charge Determinants (MW)			Approval Reference
		Network	Line Connection	Transformation Connection	
Five Nations Energy (FNEI)	5,178,000	44.915	44.915	44.915	*Note 1*
Canadian Niagara Power (CNPI)	4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power (GLPL)	34,785,422	4,150.498	2,847.032	2,777.933	*Note 3*

Note 1: Board Decision on RP-2001-0036 dated April 24, 2002, pages 23 and 26.

Note 2: Board Decision on RP-2001-0034 dated December 11, 2001, pages 8 and 10.

Note 3:Revenue Requirement per Settlement Agreement on EB-2005-0241, Appendix B, page 5 of 5, approved by the Board September 15, 2005. Charge Determinants per Board Decision on RP-2001-0035 dated December 11, 2001, page 11.

HYDRO ONE NETWORKS INC.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: Date To Come
Ontario Energy Board

APPLICABILITY:

This rate schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

(a) Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual rate of $ 7,000 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

(b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Wholesale Meter Rate Calculations

	Charge Determinant (Avg # of Meter Points)	Revenue Requirement ($ Million)	OEB Approved Rate * ($/Meter Point/Year)	Hydro One Proposed Rate * ($/Meter Point/Year)
	Note 1	*Note 2*		
	(A)	(B)	(B) / (A)	
2010	163	1.2	7,000	7,000

* Rate is rounded down to the nearest $100

Note 1: Per EB-2008-0272, Exhibit H1, Tab 4, Schedule 1, Table 1.
Note 2: Per Exhibit 2.0

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2010

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final LSVG Credit ($M)**
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
202,860	344.8	1.700	2901	19.0%	11.23

Note 1: Per Exhibit 3.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 2.0.

Note 3: Per Exhibit G1, Tab 4, Schedule 1, Table 1

Note 4: See EB-2006-0501 Exhibit G1, Tab 4, Schedule 1, page 2.

The LVSG Credit effective January 1, 2010 is $11.23 million or $935,833 per month.

APPENDIX B

ONTARIO TRANSMISSION RATE SCHEDULES

EB-2008-0272

The rate schedules contained herein shall be effective Date to Come

Issued: Date to Come
Ontario Energy Board

TERMS AND CONDITIONS **(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario. **(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter. **(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV. **(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns, or has fully contributed toward the costs of, all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein. **(F) METERING REQUIREMENTS** In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid. (**G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including

Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets. **(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand[1,2]	**3.13**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.77**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.79**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a “Per Transmission Delivery Point” basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.
2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter
(i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.
3 The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.
4 The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: ETS	EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.00 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Appendix “C” to

ONTARIO UNIFORM RATE ORDER

EB-2008-0272

December 21, 2009

EB-2008-0272
Appendix C

ONTARIO UNIFORM RATE ORDER

REVENUE ALLOCATORS

Effective Date to Come

Transmitter	Network	Line Connection	Transformation Connection
Five Nations Energy Inc.	0.00391	0.00391	0.00391
Canadian Niagara Power Inc.	0.00348	0.00348	0.00348
Great Lakes Power Ltd.	0.02624	0.02624	0.02624
Hydro One Networks Inc.	0.96637	0.96637	0.96637
Total	**1.00000**	**1.00000**	**1.00000**

Ontario Energy Board
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Toronto ON M4P 1E4
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Ontario

BY E-MAIL

December 22, 2009

Ms. Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs
Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto ON M5G 2P5

Dear Ms. Frank:

Re: Draft Uniform Transmission Rates for 2010 Revenue Requirements
Board File Number: EB-2008-0272

Thank you for the draft Revenue Requirements of December 21, 2009, following from the Board's decision in respect of Hydro One's Supplementary Application.

In the Decision with Reasons dated May 28, 2009, the Board determined that a separate cost of capital would be determined for Hydro One Transmission's 2010 revenue requirement and that "September 2009 data should be used to ***update*** the cost of capital parameters" (emphasis added). The Board also stated:

> *The Board will issue a letter to Hydro One setting out Hydro One's 2010 cost of capital parameters in due course. The Board expects that this will be treated as a mechanistic update.*

The Board's letter of November 5, 2009, set out the Board's determination of Hydro One Transmission's return on equity and short-term debt rate for 2010. This approach was confirmed in the Board's Decision of December 16, 2009.

Hydro One has provided a draft Uniform Transmission Rate Order and supporting materials that are based on Cost of Capital parameters which do not apply in this case. The Board expects Hydro One to provide a revised set of draft documents as soon as possible.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Cc All Intervenors in EB-2008-0272

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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

January 5, 2010

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli

EB-2008-0272 – Hydro One Networks' 2009-2010 Electricity Transmission Revenue Requirements – Final Draft Revenue Requirements & Charge Determinants in Accordance with Decision for the 2010 Test Year Incorporating Cost of Capital Parameters per the Board's Letter of November 5, 2009

Per the Board's Letter of December 22, 2009, Hydro One has revised the attached draft exhibits to incorporate the Cost of Capital parameters for return on equity and the cost of short-term debt as provided by the Board in its letter of November 5, 2009.

The attached draft exhibits outline the final revenue requirement as well as the calculation of the 2010 UTR's, charge determinants and revenue shares resulting from the Board's findings in this decision with respect to the approval of Projects D7 and D8.

In summary, Hydro One has:

- Added the capital expenditures in 2009 and 2010 to reflect the Board's approval of Development projects D7 and D8. As these two projects are forecast to come into service in 2010, the 2010 Revenue Requirement has been adjusted upward by $7.1 million.
- Applied the cost of capital parameters based on the Board's letter of November 5, 2009.
- Increased its Low Voltage Switchgear Credit due to the change in the transformation pool revenue requirement for 2010.
- Lowered the 2010 Wholesale Meter Rate to reflect the estimated lower number of meters.

Hydro One has filed the requested attached documents due to the urgency of the timing to ensure new transmission rates can be in place effective January 1, 2010. However, Hydro One is of the belief that the draft rates filed on December 21, 2009 reflecting the mechanistic update of the cost of capital parameters based on the formula applicable for the 2010 test year per the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) released on December 11, 2009 are the appropriate rates to be used for the 2010 test year.

Hydro One will be filing a motion to vary the Board's Decision dated December 16, 2009 in the EB-2008-0272 proceeding respecting the appropriate cost of capital parameters to be used in the determination of the 2010 revenue requirement for Hydro One under separate cover in due course.

Hydro One requests that the 2010 Uniform Transmission Rates be declared interim effective January 1, 2010 until the cost of capital issue is resolved.

If you have any questions regarding this submission please contact Anne-Marie Reilly at 416 345-6482.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors (electronic)

TABLE OF CONTENTS
EB-2008-0272 BOARD DECISION WITH REASONS
FINAL 2010 REVENUE REQUIREMENT AND CHARGE DETERMINANTS

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Revenue Requirement Summary

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
OM&A	Exhibit 1.1	449.7	(23.5)	426.2
Depreciation	Exhibit 1.2	281.5	(0.2)	281.3
Capital Tax	Exhibit 1.5	6.0	(0.0)	6.0
Return on Debt	Exhibit 1.4	269.7	(16.2)	253.5
Return on Equity	Exhibit 1.4	286.1	(29.9)	256.3
Income Tax	Exhibit 1.6	48.0	(13.9)	34.0
Base Revenue Requirement		**1,341.0**	**(83.8)**	**1,257.3**
Deduct: External Revenue	Exhibit 1.7 & Note 1	18.0	-	18.0
Revenue Requirement less external revenues		**1,323.0**	**(83.8)**	**1,239.3**
Deduct: Export Revenue Credit	Note 1	(12.0)	-	(12.0)
Deduct: Other Cost Charges	Exhibit 1.8	(13.0)	(7.3)	(20.3)
Add: Low Voltage Switch Gear		11.5	(0.8)	10.8
Rates Revenue Requirement		**1,309.5**	**(91.8)**	**1,217.7**

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

OM&A Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
OM&A	*See supporting details below*	449.7	(23.5)	426.2

OEB Decision Impact Supporting Details

	Reference		
Sustainment OM&A adjustment	OEB Decision pg. 21		(15.0)
Development OM&A adjustment	OEB Decision pg. 23		(3.2)
Compensation adjustment	OEB Decision pg. 31		(4.0)
Property Tax adjustment	OEB Decision pg. 33		(1.3)
			(23.5)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Rate Base and Depreciation Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
Rate Base	*See supporting details below*	7,650.5	(14.5)	7,636.0
Depreciation	*See supporting details below*	281.5	(0.2)	281.3

OEB Decision Impact Supporting Details	**Reference**	**2010 Detailed Computation**	**2010 Rate Base Impact**	**2010 Depreciation Impact**
Working Capital Adjustment				
Rate Base Details	Pre-filed Evidence Exh			
Utility plant (average)	D1-1-1			
Gross plant at cost		11,780.2		
Less: Accumulated depreciation		(4,179.7)		
Net utility plant		7,600.5		
Working capital				
Cash working capital		11.2		
Materials & supplies inventory		38.7		
Total working capital		50.0		
Total Rate Base		7,650.5		
Working capital as % of OM&A	(a)	11.1%		
OM&A Reduction	Exhibit 1.1 (b)	(23.5)		
Working capital reduction	(c) = (a) x (b)	(2.6)	(2.6)	
Rate Base Adjustment				
Development Capital (removal of projects)				
D9 - 100MVar Shunt Caps at Algoma	Prefiled Evidence	9.7		
D10 - 2 75MVAR Shunt Caps at Mississagi	D1-3-3	10.3		
D28 - Glendale TS - increase capacity		3.2		
D29 - Dunnville TS - increase capacity		0.8		
		24.0		
Associated Depreciation	*Note 1*	0.2		(0.2)
Development Capital Adjustment	*Note 2*	23.8	(11.9)	
Reduction to proposed			(14.5)	(0.2)

Note 1: Assumed 50 year service life and half year depreciation
Note 2: The 2010 net adjustment would be a half year impact on 2010 rate base

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Expenditure Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**Cumulative Updates 2009**	**Cumulative Updates 2010**	**OEB Approved 2009**	**Draft Rate Order 2010**
Capital expenditures	*See supporting details below*	944.0	1,074.1	(7.5)	(16.5)	**936.5**	**1,057.6**

OEB Decision Impact Supporting Details

Development Capital (removal or projects) *Note 1*			
D9 - 100MVar Shunt Caps at Algoma	Pre-filed Evidence	4.6	5.1
D10 - 2 75MVAR Shunt Caps at Mississagi	Exh D1-3-3	2.9	7.4
D28 - Glendale TS - increase capacity	*Note 2*	-	3.2
D29 - Dunnville TS - increase capacity	*Note 2*	-	0.8
		7.5	16.5

Note 1: 4 Development projects were removed from the revenue requirement calculation based on the OEB Decision.
Note 2: Net of capital contributions

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Structure and Return on Capital Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
Return on Rate Base				
Rate Base	Exhibit 1.2	$ 7,650.5	$ (14.5)	$ 7,636.0
Capital Structure:				
Third-Party long-term debt	OEB Decision pg. 54	56.0%	1.4%	57.4%
Deemed long-term debt	OEB Decision pg. 54	0.0%	(1.4%)	-1.4%
Short-term debt		4.0%	0.0%	4.0%
Common equity		40.0%	0.0%	40.0%
Capital Structure:				
Third-Party long-term debt		4,284.0	99.6	4,383.6
Deemed long-term debt		0.3	(107.7)	(107.5)
Short-term debt		306.0	(0.6)	305.4
Common equity		3,060.2	(5.8)	3,054.4
		$ 7,650.5	**$ (14.5)**	**$ 7,636.0**
Allowed Return:				
Third-Party long-term debt	Exhibit 1.4.1	5.80%	(0.05%)	5.76%
Deemed long-term debt	Exhibit 1.4.1	7.29%	(1.53%)	5.76%
Short-term debt	*Note 1*	4.75%	(4.20%)	0.55%
Common equity	*Note 1*	9.35%	(0.96%)	8.39%
Return on Capital:				
Third-Party long-term debt	Prefiled Evidence	248.5	3.8	252.3
Deemed long-term debt	B2-1-1	0.0	(6.2)	(6.2)
Short-term debt		14.5	(12.9)	1.7
AFUDC return on Niagara Reinforcement Project	see below	6.6	(0.9)	5.7
Total return on debt		**$ 269.7**	**$ (16.2)**	**$ 253.5**
Common equity		**$ 286.1**	**$ (29.9)**	**$ 256.3**
AFUDC return on Niagara Reinforcement Project				
CWIP		99.1		99.1
AFUDC Rate	*Note 2*	6.7%		5.76%
		6.6		5.7

Note 1: Used Cost of Capital Letter dated November 5, 2009

Note 2: Used embedded cost of debt return for NRP

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2010) Updated for 2008 Actuals
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/09 ($Millions)	Total Amount Outstanding: at 12/31/10 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-10	278.4	3.6	274.8	98.70	7.34%	278.4	0.0	128.5	9.4	
2	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
5	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
6	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
7	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
8	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
9	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
10	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
11	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
12	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
13	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
14	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
15	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
16	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
17	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
18	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
19	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
20	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.74	4.95%	180.0	180.0	180.0	8.9	
21	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
22	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	0.0	50.8	2.0	
23	15-Mar-09	5.770%	15-Mar-39	337.0	1.7	335.3	99.50	5.81%	337.0	337.0	337.0	19.6	
24	15-Jun-09	5.070%	15-Jun-19	337.0	1.7	335.3	99.50	5.13%	337.0	337.0	337.0	17.3	
25	15-Sep-09	4.380%	15-Sep-14	337.0	1.7	335.3	99.50	4.49%	337.0	337.0	337.0	15.1	
26	15-Mar-10	6.870%	15-Mar-40	170.4	0.9	169.6	99.50	6.91%	0.0	170.4	131.1	9.1	
27	15-Jun-10	6.170%	15-Jun-20	170.4	0.9	169.6	99.50	6.24%	0.0	170.4	91.8	5.7	
28	15-Sep-10	5.480%	15-Sep-15	170.4	0.9	169.6	99.50	5.60%	0.0	170.4	52.4	2.9	
29		**Subtotal**							4267.5	4440.3	4383.6	249.5	
30		Treasury OM&A costs										2.0	
31		Other financing-related fees										0.8	
32		**Total**							4267.5	4440.3	4383.6	252.3	5.7556%

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Tax Summary

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Capital Taxes	*See supporting details below*	6.0	6.0	(0.0)

Capital Tax Supporting Details

($ millions)	**Reference**	
Net Taxable Capital as filed	Pre-filed Evidence Exh C2/T4/S1	7,985.8
Capital Tax rate		0.075%
Capital Tax as filed		6.0
2010 in-service additions	Exhibit 1.2	24.0
Associated depreciation	Exhibit 1.2	(0.2)
Total net taxable capital adjustments		23.8
Revised Taxable Capital		7,962.0
Revised Capital Taxes		6.0

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Income Tax Summary

($ millions)	Supporting Reference	Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Income Taxes	*See supporting details below*	48.0	34.0	(13.9)

Income Tax Supporting Details

			Hydro One Proposed 2010	Cumulative Updates 2010	Draft Rate Order 2010
Rate Base	Exhibit 1.2	a	$ 7,650.5	$ 7,636.0	
Common Equity Capital Structure		b	40.0%	40.0%	
Return on Equity	Exhibit 1.4	c	9.35%	8.39%	
Return on Equity		d = a x b x c	286.1	256.3	
Regulatory Income Tax		e = l	48.0	34.0	
Regulatory Net Income (before tax)		f = d + e	334.1	290.3	(43.8)
Timing Differences *(Note 1)*		g	(182.9)	(182.7)	0.2
Taxable Income		h = f + g	151.2	107.6	(43.6)
Tax Rate	Prefiled Evidence	i	32.0%	32.0%	
Income Tax	C2-6-1	j = h x i	48.4	34.4	
less: Income Tax Credits		k	(0.4)	(0.4)	
Regulatory Income Tax		l = j + k	48.0	34.0	(13.9)

Note 1. Book to Tax Timing Differences are detailed in EB-2008-0272 C2-6-1. The adjustment above to timing differences reflect the change between capital cost allowance and depreciation as a result of the change in rate base as directed in section 6.5 of the OEB decision.

Timing difference adjustments	
less: lower depreciation related to development project adjustment	(0.2)
add: lower CCA claim related to development project adjustment	0.5
Net timing difference adjustment	0.2

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

External Revenue Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Cumulative Updates 2010**	**Draft Rate Order 2010**
External Revenue	Pre-filed Evidence Exh E3/T1/S1 & Note 1	18.0	-	18.0

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Deferral Account Recovery Details

($ millions)	**Supporting Reference**		**Draft Rate Order 2010**
Requested Deferral Account Recovery	*Note 1*		
Tax Changes Account	Pre-filed		(9.3)
OEB Costs Account	Evidence Exh		(2.8)
Pension Account	F1/T1/S1		(0.1)
Total Requested Deferral Account Recovery			**(12.2)**
Add:			
Existing Deferral Account Recovery			
MRP costs	EB-2006-0501		4.1
Export revenue	Board Order		(12.2)
Total Existing Deferral Account Recovery			**(8.1)**
Total Deferral Account Recovery			**(20.3)**

Note 1: 2010 amount is for 12 months

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

2010 Revenue Requirement Continuity Schedule

($ millions)	**Supporting Reference**	**Hydro One Proposed 2010**	**Deferral Account 2010**	**Update LVSG 2010**	**Update OM&A 2010**	**Disallowed Projects 2010**	**Update STD 2010**	**Update LTD 2010**	**Update ROE 2010**	**Draft Rate Order 2010**
OM&A	Exhibit 1.1	449.7	-	-	(23.5)	-	-	-	-	426.2
Depreciation	Exhibit 1.2	281.5	-	-	-	(0.2)	-	-	-	281.3
Capital Tax	Exhibit 1.5	6.0	-	-	-	(0.0)	-	-	-	6.0
Return on Debt	Exhibit 1.4	269.7	-	-	-	(0.6)	(12.8)	(2.8)	-	253.5
Return on Equity	Exhibit 1.4	286.1	-	-	-	(0.5)	-	-	(29.3)	256.3
Income Tax	Exhibit 1.6	48.0	-	-	-	(0.1)			(13.8)	34.0
Base Revenue Requirement		**1,341.0**	**-**	**-**	**(23.5)**	**(1.5)**	**(12.8)**	**(2.8)**	**(43.1)**	**1,257.3**
Deduct: External Revenue	Exhibit 1.7 & Note 1	18.0	-	-	-	-	-	-	-	18.0
Revenue Requirement less external revenues		**1,323.0**	**-**	**-**	**(23.5)**	**(1.5)**	**(12.8)**	**(2.8)**	**(43.1)**	**1,239.3**
Deduct: Export Revenue Credit	Note 1	(12.0)	-	-	-	-	-	-		(12.0)
Deduct: Other Cost Charges	Exhibit 1.8	(13.0)	(7.3)	-	-	-	-	-		(20.3)
Add: Low Voltage Switch Gear		11.5	-	(0.8)	-	-	-	-		10.8
Rates Revenue Requirement		**1,309.5**	**(7.3)**	**(0.8)**	**(23.5)**	**(1.5)**	**(12.8)**	**(2.8)**	**(43.1)**	**1,217.7**

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Final 2010 Revenue Requirement by Rate Pool

	Supporting Exhibit	2010 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.0*	198.6	38.2	113.5	350.3	0.8	351.1
Other Taxes (Grants-in-Lieu)	*1.0*	45.6	11.6	17.9	75.1	0.0	75.1
Depreciation of Fixed Assets	*1.0*	160.3	37.6	76.6	274.5	0.1	274.6
Capitalized Depreciation	*1.0*	(7.8)	(2.0)	(3.2)	(13.0)	(0.0)	(13.0)
Asset Removal Costs	*1.0*	10.8	2.8	4.4	17.9	0.0	17.9
OPEB Amortization	*Note 1*	0.0	0.0	0.0	0.0	0.0	0.0
Other Amortization	*1.0*	1.1	0.3	0.4	1.7	0.0	1.7
Return on Debt	*1.0*	154.0	39.0	60.4	253.4	0.1	253.5
Return on Equity	*1.0*	155.6	39.5	61.0	256.2	0.1	256.3
Income Tax	*1.0*	20.7	5.2	8.1	34.0	0.0	34.0
Capital Tax	*1.0*	3.6	0.9	1.4	6.0	0.0	6.0
Base Revenue Requirement	*1.0*	**742.5**	**173.1**	**340.6**	**1256.1**	**1.2**	**1257.3**
Less Regulatory Asset Credit	*1.8*	-12.0	-2.8	-5.5	-20.3	0.0	-20.3
Total Revenue Requirement	1.0	**730.5**	**170.3**	**335.1**	**1235.9**	**1.1**	**1237.0**
Less Non-Rate Revenues	*Note 1*	(10.6)	(2.5)	(4.9)	(18.0)	(0.0)	(18.0)
Less Export Revenues	*Note 1*	(12.0)			(12.0)		(12.0)
Plus LVSG Credit	*6.0*			10.8	10.8		10.8
Revenue Requirement by Pool		**707.9**	**167.8**	**340.9**	**1216.6**	**1.1**	**1217.7**
Revenue Requirement for UTR		**707.9**	**167.8**	**340.9**	**1216.6**		**1217.7**
Hydro One Proposed Pool Revenue Requirement	*Note 1*	762.1	180.5	365.6	1308.2	1.2	1309.4

Note 1: See EB-2008-0272 Exhibit G2, Tab 5, Schedule 1, Page 2.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Summary Final Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2010 to December 31, 2010)

	Total MW
Network	242,388
Line Connection	234,657
Transformation Connection	202,860

2010 charge determinants per Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2010

Transmitter	Revenue Requirement ($) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,012,819	$714,093	$1,451,088	$5,178,000
CNPI	$2,683,749	$636,098	$1,292,596	$4,612,443
GLPL	$20,239,894	$4,797,224	$9,748,304	$34,785,422
H1N *(Note 1)*	$707,878,000	$167,780,000	$340,941,000	$1,216,599,000
All Transmitters	$733,814,462	$173,927,415	$353,432,988	$1,261,174,865

Transmitter	Total Annual Charge Determinants (MW) *(Note 3, Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	44.915	44.915	44.915	
CNPI	583.420	668.600	668.600	
GLPL	4,150.498	2,847.032	2,777.933	
H1N *(Note 2)*	242,387.818	234,657.008	202,860.490	
All Transmitters	247,166.651	238,217.555	206,351.938	

Transmitter	Uniform Rates and Revenue Allocators *(Note 4)*			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**2.97**	**0.73**	**1.71**	
FNEI Allocation Factor	**0.00411**	**0.00411**	**0.00411**	
CNPI Allocation Factor	**0.00366**	**0.00366**	**0.00366**	
GLPL Allocation Factor	**0.02758**	**0.02758**	**0.02758**	
H1N Alocation Factor	**0.96465**	**0.96465**	**0.96465**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2010 Revenue Requirement per Exhibit 2.0

Note 2: Hydro One Networks (H1N) Charge Determinant per Exhibit 3.0

Note 3: Data for Other Transmitters per Exhibit 4.1.

Note 4: Calculated data in shaded cells.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Revenue Requirement and Charge Determinant Assumptions for Other Transmitters

Table 1
Approved Annual Revenue Requirement and Charge Determinants

Transmitter	Annual Revenue Requirement ($)	Annual Charge Determinants (MW)			Approval Reference
		Network	Line Connection	Transformation Connection	
Five Nations Energy (FNEI)	5,178,000	44.915	44.915	44.915	*Note 1*
Canadian Niagara Power (CNPI)	4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power (GLPL)	34,785,422	4,150.498	2,847.032	2,777.933	*Note 3*

Note 1: Board Decision on RP-2001-0036 dated April 24, 2002, pages 23 and 26.

Note 2: Board Decision on RP-2001-0034 dated December 11, 2001, pages 8 and 10.

Note 3:Revenue Requirement per Settlement Agreement on EB-2005-0241, Appendix B, page 5 of 5, approved by the Board September 15, 2005. Charge Determinants per Board Decision on RP-2001-0035 dated December 11, 2001, page 11.

HYDRO ONE NETWORKS INC.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: Date To Come
Ontario Energy Board

APPLICABILITY:

This rate schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks (“Networks”) and to *metered market participants* that are customers of a Local Distribution Company (“LDC”) that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

(a) Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual rate of $ 6,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

(b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Wholesale Meter Rate Calculations

	Charge Determinant (Avg # of Meter Points)	Revenue Requirement ($ Million)	OEB Approved Rate * ($/Meter Point/Year)	Hydro One Proposed Rate * ($/Meter Point/Year)
	Note 1	*Note 2*		
	(A)	(B)	(B) / (A)	
2010	163	1.1	6,900	6,900

* Rate is rounded down to the nearest $100

Note 1: Per EB-2008-0272, Exhibit H1, Tab 4, Schedule 1, Table 1.
Note 2: Per Exhibit 2.0

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2010

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final LSVG Credit ($M)**
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
202,860	330.2	1.628	2901	19.0%	10.75

Note 1: Per Exhibit 3.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 2.0.

Note 3: Per Exhibit G1, Tab 4, Schedule 1, Table 1

Note 4: See EB-2006-0501 Exhibit G1, Tab 4, Schedule 1, page 2.

The LVSG Credit effective January 1, 2010 is $10.75 million or $895,833 per month.

APPENDIX B

ONTARIO TRANSMISSION RATE SCHEDULES

EB-2008-0272

January 5, 2010

The rate schedules contained herein shall be effective Date to Come

Issued: Date to Come
Ontario Energy Board

TERMS AND CONDITIONS **(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario. **(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter. **(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV. **(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns, or has fully contributed toward the costs of, all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station. **(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein. **(F) METERING REQUIREMENTS** In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid. (**G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including

Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets. **(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand[1,2]	**2.97**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.73**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.71**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.
2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter
(i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.
3 The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.
4 The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: ETS	EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.00 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Appendix C

ONTARIO UNIFORM RATE ORDER

EB-2008-0272

January 5, 2010

EB-2008-0272
Appendix C

ONTARIO UNIFORM RATE ORDER

REVENUE ALLOCATORS

Effective Date to Come

Transmitter	Network	Line Connection	Transformation Connection
Five Nations Energy Inc.	0.00411	0.00411	0.00411
Canadian Niagara Power Inc.	0.00366	0.00366	0.00366
Great Lakes Power Ltd.	0.02758	0.02758	0.02758
Hydro One Networks Inc.	0.96465	0.96465	0.96465
Total	**1.00000**	**1.00000**	**1.00000**